GREEN ENERGY INSTITUTE
Lewis & Clark Law School

Alex Houston, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503) 768-6655
E-Mail: ahouston@lclark.edu

March 4, 2025

VIA ELECTRONIC FILING TO: PUC.FilingCenter@puc.orgeon.gov

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

RE: UG 519: Avista Request for a General Rate Revision, Opening Testimony and Sponsored Exhibits of Intervenors Climate Solutions and the Green Energy Institute at Lewis & Clark Law School

Dear Filing Center:

Attached for filing, please find Intervenors' Opening Testimony and sponsored exhibits for the above-referenced proceeding. The consolidated PDF for filing includes testimony and exhibits of Nora Apter (Exhibit Environmental Intervenors/100–119) and Emily Moore (Exhibit Environmental Intervenors/200–215).

Please feel free to reach out to me directly with any questions about this filing.

Sincerely,

<u>/s/ Alex Houston</u>
OSB No. 214066
Green Energy Institute
at Lewis & Clark Law School
10101 S. Terwilliger Blvd
Portland, OR 97219
(503) 768-6655
ahouston@lclark.edu

GREEN ENERGY INSTITUTE
Lewis & Clark Law School

Alex Houston, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503) 768-6655
E-Mail: ahouston@lclark.edu

CERTIFICATE OF SERVICE
UG 519

I hereby certify that on March 4, 2025, I served CLIMATE SOLUTIONS AND GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL'S OPENING TESTIMONY AND SPONSORED EXHIBITS upon the Commission and each parties representative(s) designated to receive service.

PUC FILING CENTER Filing Center, Public Utilities Commission of Oregon PO Box 1088 Salem, OR 97308-1088 PUC.FilingCenter@state.or.us	**AVISTA** AVISTA CORPORATION 1411 EAST MISSION PO BOX 3727 SPOKANE WA 99220-0500 dockets@avistacorp.com PATRICK EHRBAR **(C)** AVISTA UTILITIES PO BOX 3727 SPOKANE WA 99220-3727 patrick.ehrbar@avistacorp.com DAVID J MEYER **(C)** AVISTA CORPORATION PO BOX 3727 SPOKANE WA 99220-3727 david.meyer@avistacorp.com
AWEC BRADLEY MULLINS **(C)** MW ANALYTICS, ENERGY & UTILITIES LUMMINTIE 13 OULU FI-90460 brmullins@mwanalytics.com CHAD M STOKES **(C)** CABLE HUSTON LLP 1455 SW BROADWAY STE 1500 PORTLAND OR 97201 cstokes@cablehuston.com	**OREGON CITIZENS' UTILITY BOARD** CLAIRE VALENTINE-FOSSUM 610 SW BROADWAY STE 400 PORTLAND OR 97205 claire@oregoncub.org JOHN GARRETT 610 SW BROADWAY STE 400 PORTLAND OR 97205 john@oregoncub.org

Alex Houston, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503) 768-6655
E-Mail: ahouston@lclark.edu

	OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
STAFF STEPHANIE S ANDRUS **(C)** OREGON DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.oregon.gov CURTIS DLOUHY**(C)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308-1088 curtis.dlouhy@puc.oregon.gov	**CLIMATE SOLUTIONS** NORA APTER **(C)** CLIMATE SOLUTIONS 1300 SE STARK ST SUITE 207 PORTLAND OR 97214 nora.apter@climatesolutions.org CLAIRE PRIHODA **(C)** CLIMATE SOLUTIONS 1300 SE STARK ST SUITE 207 PORTLAND OR 97214 claire.prihoda@climatesolutions.org
GREEN ENERGY INSTITUTE CARRA SAHLER LEWIS & CLARK LAW SCHOOL 10101 S TERWILLIGER BLVD PORTLAND OR 97219 sahler@lclark.edu ALEXANDER HOUSTON **(C)** LEWIS & CLARK LAW SCHOOL 10101 S TERWILLIGER BLVD PORTLAND OR 97219 ahouston@lclark.edu	

/s/ Alex Houston
OSB No. 214066
Green Energy Institute
at Lewis & Clark Law School
10101 S. Terwilliger Blvd
Portland, OR 97219
(503) 768-6655
ahouston@lclark.edu

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 519

In the Matter of AVISTA UTILITIES, a division of AVISTA CORPORATION Request for General Rate Revision	CLIMATE SOLUTIONS AND GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL'S OPENING TESTIMONY

OPENING TESTIMONY

OF

CLIMATE SOLUTIONS AND GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL

March 4, 2025

TESTIMONY INDEX

Witness	Content
Nora Apter Climate Solutions	Environmental Intervenors/100: Testimony Environmental Intervenors/101: Qualifications Environmental Intervenors/102: Resume Environmental Intervenors/103–119: Exhibits
Emily Moore Sightline Institute	Environmental Intervenors/200: Testimony Environmental Intervenors/201: Qualifications Environmental Intervenors/202: Resume Environmental Intervenors/203–215: Exhibits

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 519

In the Matter of

AVISTA UTILITIES,
a division of AVISTA CORPORATION

Request for General Rate Revision

OPENING TESTIMONY

OF NORA APTER

ON BEHALF OF CLIMATE SOLUTIONS AND GREEN ENERGY INSTITUTE

(Non-Confidential)

March 4, 2025

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. My name is Nora Apter. My business address is 1300 SE Stark St. Ste 207, Portland, OR 97214.

Q. By whom are you employed and in what capacity?

A. I am employed by Climate Solutions in the role of Oregon Director. Climate Solutions is an independent 501(c)(3) nonprofit organization dedicated to accelerating clean energy solutions to the climate crisis. Climate Solutions works in Oregon to pass and implement policies at the state legislature, county, and city level as well as with utility commissions and regulatory agencies using its experience and expertise in advocacy, research, communications and organizing outreach on the topic of clean energy and decarbonization.

I have worked for Climate Solutions since December 2, 2024. As Climate Solutions' Oregon Director, my responsibilities include directing Climate Solutions on our work in Oregon to pass, implement, and defend cutting-edge policies at the state, local, regulatory, and utility levels, working in partnership with Climate Solutions staff and a broad set of community partners. This includes developing Climate Solutions' short- and long-term state strategy for climate and clean energy policies in Oregon, representing Climate Solutions in multiple policy and coalition efforts and interfacing and mobilizing with business, labor, communities of color, environmental, and other communities. To maximize the organization's impact in statewide policy advocacy and in our programs, I maintain a high level of expertise and credibility in Climate Solutions' areas of focus: clean buildings, energy, and transportation. My work involves developing relationships and collaborating with state legislators, agencies, and other policymakers to support passage, implementation, and defense of equitable climate policies at the state and local levels. I regularly provide public presentations, communicate with media, and testify at hearings.

I also serve as a commissioner and voting member of the Oregon Climate Action Commission. I have served in this role since February 2022, where I help develop recommendations for statutory and administrative changes to be carried out by state and local governments, businesses, and nonprofit organizations to achieve the State's emissions reduction goals.

Q. Please summarize your professional experience.

A. Please see my witness statement and resume attached as Exhibits Environmental Intervenors/101 and Environmental Intervenors/102. I have more than a decade of experience in environmental policy and have advocated for meaningful climate and clean energy across state, federal, and local government. Previously I worked at Oregon Environmental Council (OEC) as the Director of Programs and Climate Program Director. My responsibilities at OEC included policy analysis and development of legislative proposals and administrative rules to advance greenhouse gas (GHG) emissions reductions, affordability, resilience, economic, and public health benefits for Oregon communities, and managing a broad coalition of labor, business, youth, climate, public health, and environmental justice partners with the mission of advancing emissions reductions, economic vitality, and equitable outcomes in Oregon. In these roles, I spearheaded statewide policy advocacy efforts to secure landmark climate policies and solidify Oregon's leadership in climate action. From 2012-2020, I worked in Washington, D.C. defending and expanding federal environmental protections. As Deputy Director of Federal Affairs for NRDC (Natural Resources Defense Council), I guided legislative and administrative strategy across a wide-ranging environmental policy portfolio. I also served as a Legislative Aide to U.S. Senator Ron Wyden of Oregon.

Q. What did you review in preparation for this testimony?

A. I have read Avista's filings pertaining to docket UG 519 and many of the Company's discovery responses.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Climate Solutions and the Green Energy Institute at Lewis & Clark Law School.

Q. Are you sponsoring any exhibits?

A. Yes. In addition to my resume (Environmental Intervenors/101) and witness qualification statement (Environmental Intervenors/102), I am sponsoring exhibits Environmental Intervenors/103 through Environmental Intervenors/119. All sponsored exhibits from my testimony are attached to this document.

Q. Have you previously testified before the Oregon Public Utility Commission?

A. Yes. I served as an expert witness on Oregon and federal climate policy, alternative fuels and the natural gas industry in two of Northwest Natural's previous rate cases, UG 435 and UG 490.

Q. Have you participated in any other proceedings before the Oregon Public Utility Commission?

A. Yes. In my previous role at Oregon Environmental Council, I participated in and provided testimony in several Commission proceedings, including weighing in on the

Commission's proposed plan to implement Executive Order 20-04; "Natural Gas Fact Finding" proceeding (UM 2178); and Community Solar Program (UM 1930). I have also provided testimony in the legislature on several Commission-related laws (both proposed and adopted), including HB 2475, HB 2021 and HB 3141 (in the 2021 legislature) and HB 3152, HB 3409 and HB 3630 (in the 2023 legislature).

Q. To implement the state's climate policies, what rulemakings have you participated in?

A. I have participated in a variety of state rulemaking and other decision-making processes related to climate policy, including Department of Environmental Quality (DEQ) rulemakings to expand the Clean Fuels Program to accelerate transportation electrification and strengthen the program's overall carbon intensity reduction targets, and to cap and reduce pollution from fossil fuel suppliers and large stationary sources in Oregon through the Climate Protection Program (CPP) and the 2023 Climate Rulemaking.

I also served as a member of DEQ's 2024 CPP Rulemaking Advisory Committee (RAC). I have also engaged in Oregon Department of Energy processes including the development of State Energy Strategy, Building Performance Standards, and home energy rebate programs.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

- Section I: Introduction.
- Section II: I summarize my recommendations to the Commission on issues addressed in Section III, IV, V, and VI.

- Section III: Climate Impacts & Natural Gas
- Section IV: Climate Protection Program
- Section V: Return on Equity
- Section VI: Municipal Policy Developments
- Section VII: Membership Dues
- Section VIII: Political Activities
- Section IX: Conclusion

II. Summary of Recommendations:

Q. Please summarize your recommendations

A. In this testimony I make the following recommendations:

- Section III: Climate Impacts & Natural Gas
    - I recommend the Commission require Avista to produce a plan demonstrating how it intends to fully spend funds budgeted annually to its AOLIEE program in Schedule 485.
    - I also recommend that Avista lift the 20% expenditure cap in Schedule 485 for Implementing Organizations' budgetary spending on health, safety, and repair measure funding.
    - I recommend Avista translate materials regarding its low-income program offerings distributed to community action agencies into other languages. Currently the materials are only produced in English and should be translated in Spanish, Russian, Vietnamese, Cambodian and Laotian to reach as many low-income customers as possible.
- Section IV: Climate Protection Program

- I support the recommendations made below in the testimony of Emily Moore:[1]
    - As a condition for capital investment recovery in this and future proceedings, the Commission should require Avista to, moving forward, analyze non-pipeline alternatives (NPAs) for investments in 1) replacing Aldyl-A pipes, 2) replacing pipes at the end of their useful life, and 3) expanding system capacity. Doing so will allow the Company to address safety, reliability, and capacity concerns, while at the same time ensuring prudent investments for ratepayers and reducing the risk of stranded gas assets.
        - As an element of this requirement, the Commission should eliminate the $1 million threshold for triggering NPA analyses as well as expand the scope of what types of projects require an NPA analysis to include investments in pipeline replacement.
        - Additionally, as a condition of recovery on investments in this proceeding and future proceedings, the Commission should order that Avista analyze at least two types of non-pipeline alternatives for all gas system capital investments moving forward.

[1] Environmental Intervenors/200, Moore/Page 5–6.

        - The Commission should require Avista to evaluate targeted electrification and thermal energy networks as two specific NPAs. The Commission should require Avista to propose at least one targeted electrification pilot and one thermal energy network pilot that would allow decommissioning of gas infrastructure and thus reduction in the risk of stranded gas assets. The Commission should require Avista to include its findings and pilot proposals in the Company's 2026 IRP Update.

- Section V: Return on Equity
    - I recommend that the Commission reject Avista's request for an increase to its Return on Equity up to 10.4%.
    - I recommend that the Commission keep Avista's Return on Equity at its current level of 9.5%.
- Section VI: Membership Dues
    - The Commission should disallow recovery of AGA and NWGA industry association dues from ratepayers. Based on the use of association dues funds by AGA and NWGA for political purposes and extensive political advocacy efforts, allowing recovery of these dues would run counter to the Commission's stated policy. In absence of evidence from Avista showing that the funds it pays to AGA and NWGA do not go toward the associations' political activities, the

Commission should disallow cost recovery as contrary to the public interest.

- Section VII: Political Activity
  - The Commission should deny Avista's requests to recover costs incurred challenging Oregon's Climate Protection Program. That is unrecoverable political activity and not in the interest of customers.
  - Commission should deduct $80.456.10 from the Test Year budget for FERC Account No. 923 to deduct costs already billed to ratepayers during the Base Year. Further, the Commission should order that Avista is not allowed to recover costs for its litigation to vacate the CPP, now or in the future, and should further order that any such expenses be billed to FERC Account 426.4.

III. <u>Climate Impacts & Natural Gas</u>

Q. What are the Oregon Climate Assessments?

A. House Bill 3543 (2007) charged the Oregon Climate Change Research Institute with conducting and issuing biennial Oregon Climate Assessments (OCAs) of the state of climate change science, including biological, physical and social science as it relates to Oregon and the likely effects of climate change on the state.[2]

Q. When did OCCRI issue its most recent OCA?

A. The seventh Oregon Climate Assessment was released on January 8, 2025.[3]

[2] Oregon Climate Change Research Institute, *Oregon Climate Assessments* (Jan. 2025) available at: https://blogs.oregonstate.edu/occri/oregon-climate-assessments/.
[3] *Id.*

Q. What does OCCRI's 2025 OCA conclude regarding the impacts of climate change in Oregon?

A. OCCRI's 2025 OCA finds the hazards of climate change are already impacting Oregon and the nation, and that those impacts are accelerating and worsening in scope.[4] According to the OCA, annual temperature is projected to increase by at least 5º Fahrenheit by 2074 and 7.6º F by 2100.[5] This dramatic change in temperature will be accompanied by increasing frequency and severity of a host of climate-related natural disasters including floods, winter storms, and droughts.[6] These changes will have rippling consequences across Oregon, the United States, and the globe, with significant economic, natural systems, and public health impacts.[7]

Q. Why do you think it is so important for Oregon, and Avista as an emitter, to address greenhouse gas pollution?

A. The Commission is well-aware of the impacts of climate change, since erratic weather patterns, flooding, coastal erosion, drought, coral bleaching, wildfires, heatwaves, hurricanes, along with the words "unprecedented," "record-breaking," and "extreme," scream from headlines nearly daily. But it is not just the media. Experts, government officials, and scientists, armed with statistics and scientific evidence, regularly warn that without urgent action across all sectors to immediately reduce the

---

[4] *See generally* Oregon Climate Change Research Institute, *Seventh Oregon Climate Assessment* (Jan. 8, 2025) available at: https://oregonstate.app.box.com/s/ziqc1kisxkup45147phjp526kheugqnb.
[5] Oregon Climate Change Research Institute, *Seventh Oregon Climate Assessment • January 2025 Executive Summary*, 7 (Jan. 8, 2025) available at: https://oregonstate.app.box.com/s/z83552texymv1t0prgsab8tdggk8osxa.
[6] *Id.*
[7] *Id.* at 7–8.

fossil fuel emissions driving climate change, global temperatures would surpass 1.5 degrees Celsius beyond pre-industrial temperatures within the next decade,[8] all but assuring irreversible climate impacts and devastation. Even those forecasts underestimated the extent of the crisis. 2024 was recorded to be the hottest year on record, reflecting average annual global temperatures exceeding the 1.5 degrees Celsius benchmark.[9] According to a recent study by the National Oceanic and Atmospheric Administration, emissions from natural gas' primary pollutant, methane—which results in 86 times the atmospheric warming effects of carbon dioxide over a 20-year period—continued to increase dramatically in 2023.[10]

The climate crisis is no longer imminent; it is here. Urgent action is absolutely necessary to avoid the full scope of societal, economic, and ecological disaster it is bringing with it. Decisive action will be necessary across all facets of society and government to turn the tide, but perhaps most necessary is action by and targeting the polluters whose industry is actively contributing to climate change. Avista, a natural gas utility, is in this group. Oregon has passed numerous policies promoting clean climate futures that will require decarbonization of the energy grid, and ultimately mean electrification will need to replace natural gas sources in buildings. Avista needs to address this reality and this rate case is an opportunity to do so.

---

[8] *See, e.g.* U.S. Global Change Research Program, *Fifth National Climate Assessment* (2023) available at: https://nca2023.globalchange.gov/.

[9] Copernicus Climate Change Service, *Copernicus: 2024 is the first year to exceed 1.5°C above pre-industrial level*, C3S (Jan. 10, 2025) available at: https://climate.copernicus.eu/copernicus-2024-first-year-exceed-15degc-above-pre-industrial-level.

[10] *See* Nat'l Oceanic & Atmos. Admin., *No Sign of Greenhouse Gas Increases Slowing in 2023* (Apr. 5, 2024) available at: https://research.noaa.gov/2024/04/05/no-sign-of-greenhouse-gases-increasesslowing-in-2023/.

Q. What steps has Oregon taken to promote and prioritize electrification as a strategy for decarbonizing its energy system?

A. Oregon has enacted and implemented a host of policies aimed at decarbonizing its energy system, particularly through electrification. For example, in February of 2024, Oregon, joined by eight other states, signed a joint memorandum of understanding to accelerate the transition to pollution-free residential buildings by significantly expanding heat pump sales to meet heating, cooling and water heating demand in the coming years.[11] The Memorandum of Understanding (MOU), led by the Northeast States for Coordinated Air Use Management (NESCAUM), has been signed by directors of environmental agencies from California, Colorado, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon and Rhode Island.[12]

Under the MOU, these states have set a shared goal for heat pumps to meet at least 65% of residential-scale heating, air conditioning and water heating shipments by 2030 and 90% by 2040 across the participating states.[13] States will also collaborate to collect market data, track progress, and develop an action plan within a year to support the widespread electrification of residential buildings.[14] This MOU builds on a September

[11] Allison MacMunn, *Nine States Pledge Joint Action to Accelerate Transition to Clean Buildings,* NSCAUM (2024) available at: https://www.nescaum.org/documents/2.7.24-nescaum-mou-press-release.pdf.
[12] NESCAUM, *Accelerating the Transition to Zero-Emission Residential Buildings: Multistate Memorandum of Understanding* (Feb. 2024) available at: https://www.nescaum.org/documents/Buildings-MOU-Final-with-Signatures---DC.pdf
[13] *Id.* at 2.
[14] *Id.* at 3.

2023 commitment from the U.S. Climate Alliance's twenty-five member states and territories to quadruple heat pump installations by 2030.[15]

Oregon's emphasis on heat pump expansion to decarbonize its grid makes sense, as analysis shows that compared to methane-gas-fueled furnaces and water heaters, heat pumps are two to four times more efficient and lower emissions by 84% over their useful lifetime.[16] Progress in this area is happening quickly; in 2022, U.S. residential heat pump sales exceeded gas furnaces for the first time.[17] This trend has continued each year since, with 3.8 million heat pumps sold nationwide from October 2023 to September 2024, at a rate of 28% higher sales compared to gas furnaces.[18]

Oregon has supported this transition for its residents, recognizing in the State's 2024 Priority Climate Action Plan that "heat pumps are an important home energy efficiency measure to reduce energy usage and greenhouse gas emissions."[19] The Oregon Department of Energy currently operates two heat pump incentive programs – the Oregon Rental Home Heat Pump Program and the Community Heat Pump Deployment Program.[20] These programs were established in 2022 through the adoption of SB 1536,

[15] U.S. Climate Alliance, *U.S. Climate Alliance Announces New Commitments to Decarbonize Buildings Across America, Quadruple Heat Pump Installations by 2030* (Sep. 21, 2023) available at: https://usclimatealliance.org/press-releases/decarbonizing-americas-buildings-sep-2023/.
[16] Environmental Intervenors/103, Apter/Page 1.
[17] Yannick Monschauer, Chiara Delmastro, Rafael Martinez-Gordon, *Global heat pump sales continue double-digit growth*, International Energy Agency (Mar. 31, 2023) available at: https://www.iea.org/commentaries/global-heat-pump-sales-continue-double-digit-growth.
[18] RMI, Tracking the Heat Pump & Water Heater Market in the United States (Dec. 2024) available at: https://rmi.org/insight/tracking-the-heat-pump-water-heater-market-in-the-united-states/.
[19] Office of Greenhouse Gas Programs, *Oregon's Priority Climate Action Plan*, Department of Environmental Quality at 38 (Mar. 2024) available at: https://www.epa.gov/system/files/documents/2024-02/oregon-cprg-pcap.pdf.
[20] *Id.*

which authorized a one-time modest appropriation from the state's general fund.[21] The programs have experienced very high demand for heat pump incentives and have already distributed a majority of program funds.[22]

Q. What programs or offerings does Avista provide to customers for promoting energy efficiency and decarbonizing their energy supply?

A. In addition to contributing to Energy Trust of Oregon-administered energy efficiency programs, the Company also operates the Avista Oregon Low-Income Energy Efficiency Program (AOLIEE).[23] The AOLIEE Program is funded through Avista's tariff Schedule 469, "Public Purpose Funding Surcharge – Oregon", and is implemented under Avista's tariff Schedule 485. The program is designed to allow customers to access and achieve cost-saving improvements for their homes, thereby reducing their monthly energy bill.[24] As of January 1, 2025, Avista's Schedule AOLIEE authorized budget was increased to $2.0 million pursuant to the settlement agreement reached in the Company's previous rate case Docket No. UG 461.[25]

To qualify for AOLIEE, customers must have income levels at or below 200% of the Federal Poverty Level (FPL).[26] Avista offers funding, on an annual basis, to each of the four Agencies within its Oregon service territory and the Agencies, in turn, deliver weatherization services to qualifying customers.[27] Notably, Avista agreed in Section 17.i.

---

[21] *Id.*
[22] *Id.*
[23] Avista/100, Rosentrater/Page 17.
[24] *Id.*
[25] Oregon Public Utility Commission, Docket No. ADV 1656, Advice No. 24-08-G – Avista Utilities Revisions to Schedule 485 at 1 (Oct. 28, 2024) available at: https://edocs.puc.state.or.us/efdocs/UAA/uaa332461025.pdf.
[26] Avista/100, Rosentrater/Page 17.
[27] *Id.*

of the Second Settlement Stipulation 20 (Settlement) of the Company's last general rate case, Docket No. UG 461, Order No. 23- 21 384, to expand the breadth and reach of its AOLIEE Program and has filed revisions to its AOLIEE tariff Schedule 485 to effectuate the Settlement terms.[28]

Q. Is Avista's AOLIEE program adequately spending its funding?

A. No, we are concerned that Avista is underspending its AOLIEE program funds and is denying ratepayers the opportunity to achieve deep cost savings through energy efficiency opportunities. Presently, Avista's tariff Schedule 485 provides that the actual annual spending of AOLIEE funds may be less than the budgeted amount.[29] Because of this allowance, Avista is not obliged to allocate the money it raises for the AOLIEE program under the Public Purpose Charge in the Company's tariff Schedule 469. Avista's 2023 AOLIEE Annual Report revealed the Company only spent $543,358 on the program in 2023, a mere 66% of its budget that year of $821,000.[30] The Company's underspending of AOLIEE funds in 2023 is reflective of a troubling larger pattern, as it spent under its budget every year since at least 2018.[31] Avista's chronic underspending of

[28] *Id.* at 17–18.
[29] AVISTA CORPORATION dba, Avista Utilities, Schedule 485, Fourth Revision Sheet (Jan. 1, 2025) available at: https://www.myavista.com/about-us/our-rates-and-tariffs/oregon-natural-gas.
[30] Oregon Public Utility Commission, Docket No. RG 81, 2023 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report at 2, 7 (Apr. 9, 2024) available at: https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq327782055.pdf.
[31] *See* Oregon Public Utility Commission, Docket No. RG 81, 2022 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report (Mar. 14, 2023) available at: https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq151254.pdf; *see also* Oregon Public Utility Commission, Docket No. RG 81, 2021 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report (Mar. 16, 2022) available at: https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq154053.pdf; *see also* Oregon Public Utility Commission, Docket No. RG 81, 2020 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report (Mar. 18, 2021) available at:

the AOLIEE funds is of particular concern given that the program's budget has more than doubled going into 2025 as a result of the Company's Settlement in UG 461, increasing from $821,000 to $2.0 million.[32] There is now significantly more money in the program to put towards low-income customer energy efficiency and weatherization efforts, which means it is even more critical that the money actually be used to help qualifying program participants in order to help realize the climate, financial, and health benefits from improved energy efficiency and weatherization.

Q. What changes do you propose to Avista's AOLIEE program?

A. We recommend the Commission require Avista to produce a plan demonstrating how it intends to fully spend funds budgeted annually to its AOLIEE program. The plan should reflect consultation with the Energy Trust of Oregon as well as community action agencies in its service territory. As mentioned above, Avista's Schedule 485 currently allows AOLIEE spending to be less than the annually budgeted amount.[33] However, given that AOLIEE funds are generated from charges to ratepayers and for the benefit of ratepayers, Avista should be required to spend either all or a significant portion of its annual AOLIEE budget. Doing so ensures that ratepayers, especially those in the lowest

https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq10559.pdf; *see also* Oregon Public Utility Commission, Docket No. RG 81, 2019 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report (Mar. 2, 2020) available at: https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq145423.pdf; *see also* Oregon Public Utility Commission, Docket No. RG 81, 2018 Avista Oregon Low-Income Energy Efficiency (AOLIEE) Annual Report (Mar. 4, 2019) available at: https://edocs.puc.state.or.us/efdocs/HAQ/rg81haq141654.pdf.

[32] Oregon Public Utility Commission, Docket No. UG 461, Second Settlement Stipulation Resolving All Remaining Issues at 12 (Aug. 17, 2023) available at: https://edocs.puc.state.or.us/efdocs/HAR/ug461har141616.pdf.

[33] AVISTA CORPORATION dba, Avista Utilities, Schedule 485, Fourth Revision Sheet (Jan. 1, 2025) available at: https://www.myavista.com/about-us/our-rates-and-tariffs/oregon-natural-gas.

income brackets, continue to benefit from energy efficiency and weatherization measures, which is especially important to make available to those ratepayers as the Company seeks to raise its rates. Therefore, at minimum, we recommend the Commission require that Avista demonstrate in a plan filed with the Commission how it intends to spend *all* of its existing budget for its AOLIEE program annually. It is unacceptable that low-income ratepayers cannot afford energy bills and get disconnected from service,[34] when Avista has existing money to spend on weatherizing homes. This change is especially important following Avista's increase to the program's the annual budget up to $2.0 million,[35] thereby ensuring the maximum benefit achievable is realized and customers in need are provided the adequate relief from financial pressures likely to increase as a result of Avista's rate increase.

We also recommend that Avista lift the cap on health, safety, and repair measure funding. Schedule 485 currently sets a cap for Implementing Organizations' spending on those measures so as not to exceed 20% of their overall annual budget.[36] Given the amount of deferred maintenance often discovered in homes, the fact that Avista has

[34] Oregon Public Utilities Commission, Docket No. RO 12, Avista Utilities Residential/Small Commercial Service Disconnection Report November 1, 2024-January 31, 2025 at 2–5 (Feb. 20, 2025) available at: https://edocs.puc.state.or.us/efdocs/HAQ/ro12haq335063034.pdf (Avista's disconnection report data shows that from November 1, 2025 through January 31, 2025, the Company conducted 189 residential disconnections. The data shows that of those disconnected customers, 109 were reconnected within 7 days, with a majority reconnected within the first day following disconnection.)
[35] Oregon Public Utility Commission, Docket No. ADV 1656, Advice No. 24-08-G – Avista Utilities Revisions to Schedule 485 at 1 (Oct. 28, 2024) available at: https://edocs.puc.state.or.us/efdocs/UAA/uaa332461025.pdf.
[36] AVISTA CORPORATION dba, Avista Utilities, Schedule 485, Fourth Revision Sheet (Jan. 1, 2025) available at: https://www.myavista.com/about-us/our-rates-and-tariffs/oregon-natural-gas.

repeatedly underspent these funds suggests that opportunities to expand access to funds would be useful to both the utility and the customers it serves.

Q. What other changes do you recommend to Avista's weatherization and low-income customer offerings?

A. I recommend Avista translate its materials regarding the Company's low-income program offerings distributed to agencies. Currently, Avista's materials are only produced in English and should be translated in Spanish, Russian, Vietnamese, Cambodian and Laotian to ensure information is provided to as many eligible customers as possible.[37]

IV. <u>Climate Protection Program</u>

Q. How is this section of your testimony organized?

A. I first discuss the Climate Protection Program (CPP), adopted in 2021, and how it was invalidated. I next describe the 2024 CPP rulemaking process and the similar scope and stringency expected from that process. I then summarize the Commission's response to Avista's 2023 IRP and how that response should impact the Commission's evaluation of Avista's rate case.

Q. What is the Climate Protection Program and how was it initially invalidated?

A. The CPP establishes mandatory requirements for Oregon's gas utilities and other fossil fuel suppliers to reduce regulated GHG emissions 50% below averaged 2017-2019 emissions by 2035, and 90% below averaged 2017-2019 emissions by 2050.[38] The CPP also includes an alternative compliance option for regulated fossil fuel suppliers that will

[37] Environmental Intervenors/104, Apter/Page 1–8.
[38] OAR 340-273-0450(1)–(4)(a)(A); OAR 340-273-9000 Table 2.

generate investments to help reduce emissions from transportation, buildings, and industry, and prioritize funding to support environmental justice communities in the clean energy transition. Through this Community Climate Investment (CCI) program, a regulated entity is allowed to pay the third-party CCI administrator to invest in projects to reduce emissions in Oregon communities–for example, replacing fossil gas appliances with electric heat pumps in an apartment complex–instead of directly reducing some of its own climate pollution.[39] After fossil fuel suppliers, including Avista, challenged the CPP, the Oregon Court of Appeals invalidated the program in December 2023 based on a procedural technicality. Specifically, the Oregon Court of Appeals concluded that DEQ did not fully comply with notice requirements during the initial CPP rulemaking.[40]

Q. What was DEQ's response to the Oregon Court of Appeals' ruling?

A. DEQ quickly initiated a rulemaking to "reestablish a climate mitigation program[.]"[41] On November 21, 2024, Oregon's Environmental Quality Commission (EQC) voted unanimously to reinstate the updated CPP.[42] Just as in the original CPP, the new program sets an enforceable and declining cap on GHG emissions from fossil fuels used in Oregon, including natural gas. It continues to prioritize equity by promoting

[39] OAR §§ 340-273-0810, 0820, 0890, 0910, 0920, 0930.
[40] *NW Nat. Gas Co. v. Env't Quality Comm'n*, 329 Or. App. 648, 664-68 (2023) (EQC rules did not disclose information required by ORS 468A.327(1) with respect to Title V sources).
[41] Or. Dep't of Env't Quality, Climate Protection Program 2024, Proposed Rule Website available at https://www.oregon.gov/deq/rulemaking/Pages/CPP2024.aspx (last visited Feb. 20, 2025).
[42] Environmental Intervenors/105, Apter/Page 1.

benefits for environmental justice communities.[43] The resulting 2024 CPP provides a comparable scope and emissions reduction mandates as the previously adopted CPP.[44]

Q. How has the newly revised CPP changed from the initial version?

A. The overall goals of the CPP have not changed from 2021 to now. It contains the same core aim of achieving a 50% reduction in GHG emissions by 2035, and a 90% reduction by 2050.[45] However, the new rules made certain adjustments in response to feedback from regulated industries, including an exemption for energy intensive trade exposed gas sources from compliance obligations during the first compliance period.[46] The new program also moved to two-year compliance periods compared to the original's three-year compliance windows.[47] DEQ also included additional program evaluation components to address the cost concerns of the natural gas utilities, agreeing to regularly request information from this Commission on changes to natural gas customer rates to determine if these rates have increased significantly due to a utility's cost to comply with CPP 2024 and to consider potential changes to address those impacts.[48]

Other changes to the 2024 CPP include an increased emphasis on Community Climate Investments (CCIs) to better align with program objectives to support

---

[43] OAR 340-273-0900(1)(d).
[44] Department of Environmental Quality, Climate Protection Program 2024 Changes Fact Sheet (2024) available at: https://www.oregon.gov/deq/ghgp/Documents/CPP2024ChangesFactSheet.pdf.
[45] OAR 340-273-0450(1)–(4)(a)(A); OAR 340-273-9000 Table 2.
[46] OAR 340-273-0410(3).
[47] OAR 340-273-0440(1); *see also* Department of Environmental Quality, Climate Protection Program 2024 Changes Fact Sheet (2024) available at: https://www.oregon.gov/deq/ghgp/Documents/CPP2024ChangesFactSheet.pdf.
[48] OAR 340-273-8100(5)–(6); *see also* Department of Environmental Quality, Climate Protection Program 2024 Changes Fact Sheet (2024) available at: https://www.oregon.gov/deq/ghgp/Documents/CPP2024ChangesFactSheet.pdf.

environmental justice communities. Specifically, DEQ included language to further ensure federally recognized Tribes and Tribal communities benefit from CCI funds and the Agency now allows regulated companies to purchase more CCIs than at the start of the program.[49]

Q. How did the CPP impact the Commission's evaluation of Avista's 2023 Integrated Resource Plan?

A. In PUC Docket No. LC 81 the Commission reviewed Avista's long-term plan for a least-cost, least-risk portfolio of resources to serve customer energy needs and satisfy state policy requirements, as well as a corresponding series of implementing actions that Avista intends to take in the next two to four years (the "action plan").[50] Upon review, the Commission acknowledged Avista's plan *in part,* recognizing the Company's revised near-term action plan and declining to acknowledge its long-term plan and preferred resource portfolio.[51]

The Commission recognized that Avista's near-term plan included primarily energy efficiency efforts and noted that in response to the Oregon Court of Appeals' invalidation of DEQ's CPP, the Company had removed numerous action items related to the purchase of CCIs and renewable natural gas that were previously planned for compliance with the CPP.[52] In addition to acknowledging the near-term plan, the

[49] OAR §§ 340-273-0900(3), 0930(4)(D); *see also* Department of Environmental Quality, Climate Protection Program 2024 Changes Fact Sheet (2024) available at: https://www.oregon.gov/deq/ghgp/Documents/CPP2024ChangesFactSheet.pdf.
[50] Oregon Public Utility Commission, Docket No. LC 81, 2023 Integrated Resource Plan Acknowledged in Part, Order No 24-156 at 1 (May 31, 2024) available at: https://apps.puc.state.or.us/orders/2024ords/24-156.pdf.
[51] *Id.*
[52] *Id.*

Commission adopted recommendations from Staff for future planning by the Company including requirements for non-pipes alternatives, resource portfolios and load forecasting.[53]

Conversely, the Commission did not acknowledge Avista's long-term plan and preferred resource portfolio.[54] It explained that the plan had numerous significant deficiencies including the absence of alternative portfolios, errors in climate modeling that impacted the load forecast, and unrealistic assumptions about costs of decarbonized fuels.[55]

Q. Do the revisions to the CPP rules significantly impact how the Commission evaluates IRPs for natural gas companies in the future?

A. Not significantly. As explained above, the CPP remains fundamentally intact in terms of the obligations to reduce emissions including for natural gas utilities. Some incremental changes will occur with respect to the two-year compliance exemption period for gas utilities and certain gas reliant high intensity trade exposed facilities now being independently responsible for compliance. However, the IRP review process will function the same and such utility plans are likely to be evaluated in a similar manner.

Q. Did the Commission modify Avista's IRP schedule following its decision in Docket No. LC 81?

A. Yes. After the Commission partially acknowledged Avista's IRP in Order No. 24-156, Avista returned to the Commission and requested it delay the Company's next IRP filing. Avista's reasoning for the request was:

---

[53] *Id.*
[54] *Id.*
[55] *Id.*

1) With the next IRP process already underway and the timing and contents of CPP rules uncertain, the Company was not able to include CPP compliance obligations in its base case or Preferred Resource Strategy.[56]
2) Staff planned to update IRP guidelines in 2024, which would impact future IRPs, but would not be completed in time for the 2025 IRP.[57]
3) With the schedule of Avista's next two IRPs in Idaho and Washington, extending the Company's next Oregon IRP due date to April 1, 2027, aligned the filing dates in all three states and reduced duplicative and overly burdensome efforts.[58]
4) If the Commission approved of the Company's request to extend the due date, in the interim, Avista would submit an update to its 2023 IRP within 12 months of the Commission's acknowledgement order.[59]

Avista requested that the Commission therefore push its next IRP due date back a year from May 31, 2026 to April 1, 2027, thereby synchronizing it to align with the cadence of the Washington and Idaho IRP schedule the Company was already operating under.[60] Ultimately, the Commission granted Avista's request while also adopting Staff's recommendation that the Company file a second IRP Update on May 31, 2026 in addition to the IRP Update already scheduled for May 31, 2025.[61] Finally, the Commission imposed additional requirements that Avista seek acknowledgement of its action plan in

[56] Oregon Public Utility Commission, Docket No. LC 81, Order No. 24-254, Disposition: Staff's Recommendation Adopted as Modified, Appendix A at 2 (July 29, 2024) available at: https://apps.puc.state.or.us/orders/2024ords/24-254.pdf.
[57] *Id.* at Appendix A at 3.
[58] *Id.*
[59] *Id.*
[60] *Id.*
[61] *Id.* at 1.

the 2025 IRP Update and that the Company respond to the directives of Order No. 24-256 for the 2023 IRP in its 2025 IRP Update filing.[62]

Q. Based on the information you provided above, what are your recommendations for the Commission?

A. I support the recommendations made below in the testimony of Emily Moore[63] including:

- As a condition for capital investment recovery in this and future proceedings, the Commission should require Avista to, moving forward, analyze non-pipeline alternatives (NPAs) for investments in 1) replacing Aldyl-A pipes, 2) replacing pipes at the end of their useful life, and 3) expanding system capacity. Doing so will allow the Company to address safety, reliability, and capacity concerns, while at the same time ensuring prudent investments for ratepayers and reducing the risk of stranded gas assets.
    - As an element of this requirement, the Commission should eliminate the $1 million threshold for triggering NPA analyses as well as expand the scope of what types of projects require an NPA analysis to include investments in pipeline replacement.
    - Additionally, as a condition of recovery on investments in this proceeding and future proceedings, the Commission should order that Avista analyze at least two types of non-pipeline alternatives for all gas system capital investments moving forward.

---

[62] *Id.*
[63] Environmental Intervenors/200, Moore/Page 5–6.

- The Commission should require Avista to evaluate targeted electrification and thermal energy networks as two specific NPAs. The Commission should require Avista to propose at least one targeted electrification pilot and one thermal energy network pilot that would allow decommissioning of gas infrastructure and thus reduction in the risk of stranded gas assets. The Commission should require Avista to include its findings and pilot proposals in the Company's 2026 IRP Update.

V. Return on Equity

Q. What factors does Avista claim justify an increase of its Return on Equity (ROE) from 9.5% to 10.4%?

A. Avista testifies that the "significant new regulatory and governmental mandates" put in place by Oregon and Washington is placing financial strain on the Company.[64] Furthermore, the Company points, in part, to the increased emphasis on "regulatory outcomes" and the level of ROE authorized by the Commission as "one of the primary factors participants in the equity capital markets will review when assessing the adequacy of the outcome of a general rate case for the purpose of making an investment decision.[65] It notes that the regulatory environment facing utilities is a key factor assessed by credit rating agencies when evaluating a company's outlook, as it "sets the pace for cost recovery."[66] It explains that regulatory overreach can make it impossible for even "the

[64] Avista/100, Rosentrater/Page 6.
[65] Avista/200, Christie/Page 4.
[66] Avista/300, Thompson/Page 14 (citing Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014, *see also* S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

best run" utilities to make a reasonable return on their investment necessary to satisfy investors and attract capital.[67] Absent a significant increase to the ROE, Avista alleges it will seriously struggle to attract new investment.[68]

Q. You mentioned that the Company is seeking a higher return on equity due to the regulatory environment and Oregon's decarbonization policies. Given Avista's IRP and the Commission's response, do you believe the Company's request for a higher return on equity is reasonable?

A. No. I do not think it is reasonable for the Commission to increase the Company's return on equity in this rate case as a result of pressure Avista faces surrounding the regulatory requirements to decarbonize its system. While the regulatory environment and the subsequent ROE Avista earns in a rate case may be important to investors, the Company gets the relationship backwards. It is not the regulatory environment that is hampering Avista's growth and economic returns and thus impacting its ability to secure capital; rather, it is the Company's failures to respond in a cost-effective manner to Oregon's regulatory requirements and the expressed preferences and trends amongst customers. The Commission recognized as much when it declined to acknowledge Avista's long-term action plan in its IRP.[69] As the Commission's Order and Staff's analysis identified, Avista's long-term plan lacked "significant" elements necessary for successful long-term utility planning including: 1) a lack of alternative portfolios as required by IRP Guidelines 4h, 4i, and 4j; 2) an error in climate modeling affecting the

[67] *Id.* at 15.
[68] Avista/100, Rosentrater/Page 6–7.
[69] Oregon Public Utility Commission, Docket No. LC 81, 2023 Integrated Resource Plan Acknowledged in Part, Order No 24-156 at 1 (May 31, 2024) available at: https://apps.puc.state.or.us/orders/2024ords/24-156.pdf.

load forecast; and 3) unrealistic assumptions about costly decarbonized fuels.[70] Arguing for greater returns due to factors that the utility fails to incorporate into its required planning documents is unreasonable.

Avista charts a contradictory path in justifying its request for an increased ROE. On the one hand, the Company is acknowledging that the energy transition poses a risk to its business when it is asking customers to pay its shareholders more money to attract capital. Yet on the other hand, Avista is continuing to pursue a business-as-usual long-term plan that does not address the risks and costs of the energy transition nor plan for achieving the state's emissions reduction goals. There may come a time when a gas utility should receive a higher return on equity to attract capital as the Company responds to the energy transition. In fact, as Emily Moore's testimony discusses below, had Avista actually evaluated non-pipeline alternatives in its planning process as substitutes for large-scale capital investment in pipeline replacement and infrastructure it may have found that, electrification, demand response, or other NPAs would save the Company and rate payers money versus the costly pipeline replacement process, reducing the need for a higher ROE. Or it is possible that by studying NPAs, Avista might conclude that the costs of decarbonizing its system were higher than anticipated.[71] There, that scenario might justify a greater ROE to raise capital and invest in technology and infrastructure to accelerate its clean energy transition.[72]

However, Avista did not do such analyses, and stands in neither such position. Simply put, the Company cannot have it both ways: it cannot approach planning as if the

[70] *Id.* at 5–6.
[71] Environmental Intervenors/200, Moore/Page 28–29.
[72] *Id.*

future of gas is business-as usual while also demanding the return on equity of a utility that is adapting to the energy transition. Insofar as an increased return on equity is a financial incentive, the Commission should only use this financial incentive for furthering the public interest. Insofar as an increased return on equity reflects the risk premium utilities must offer investors to attract capital, the Commission should condition this premium on the Company taking steps to mitigate its risk by aligning its business strategy with state policy and market trends. Such alignment will require the Company to incorporate electrification into its decarbonization strategies and aim to avoid expanding its distribution system

Q. What does Avista state is the foundation for its just and reasonable Return on Equity calculations?

A. Avista's testimony relies on two Supreme Court cases, *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923) ("*Bluefield*") and *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*") as the bases for the standard that just and reasonable rates are measured against.[73] According to the Company's testimony, these cases establish that in order for an ROE to be just and reasonable, it must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.[74]

[73] Avista/300, Thompson/Page 8.
[74] *Id.* at 9.

Q. Are there any other Supreme Court-endorsed tests for measuring whether an ROE is just and reasonable?

A. Yes. While I am not a lawyer and do not offer legal opinion,[75] Avista's ROE testimony ignores a key Supreme Court case decided in 1945 the year after *Hope* and clarified under what circumstances an ROE may be reasonable for a utility even where it does not meet the requisite factors found in *Hope.* That case, *Market Street Railway Co. v. Railroad Commission of State of California*, 324 U.S. 548 (1945) ("*Market Street Railway*"), saw the Supreme Court grapple with whether per *Hope*, a regulated company is entitled to earn an ROE "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital and to enable the company to operate successfully, to maintain its financial integrity . . . and to compensate its investors for the risks assumed."[76] In evaluating this question the Supreme Court was explicit that in the case of *Hope*, it dealt with an economically advantaged company, and as such, *Hopes* promises of financial returns "obviously are inapplicable" to a company whose financial integrity is severely undermined.[77] Both *Hope* and *Market Street Railway* are in agreement that "regulation does not assure that the regulated business make a profit."[78] According to the Supreme Court, the Due Process Clause does not require a commission to fix rates based on a product's historical value when it no longer garners that value in the market.[79]

---

[75] Avista's witness, Mr. Thompson, is also not a lawyer, and offers a similar discussion of the legal implications of Supreme Court precedent in the *Hope* and *Bluefield* cases.
[76] *Market St. Ry. Co. v. Railroad Commission of State of Cal.*, 324 U.S. 548, 566 (1945) (internal quotations omitted).
[77] *Id.*
[78] *Id.* (citing *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).
[79] *Id*. at 567.

Q. Why is the *Market Street Railway* test relevant to this rate case proceeding and the future of natural gas utilities?

A. While I am not a lawyer and do not offer a legal opinion, from my position as a Climate Solutions' Oregon Director, it is important to raise the *Market Street Railway* case in response to Mr. Thompson, Avista's financial analyst, whose testimony invokes the *Hope* and *Bluefield* decisions as the basis for justifying the continued increase of the Company's ROE.[80] *Market Street Railway* provides an alternative, Supreme Court endorsed, framework for assessing when ROEs are just and reasonable. It counters the unequivocal declarations in Avista's testimony that ROEs *must* be adequate to attract new capital and protect the company's financial standing.[81] *Market Street Railway* is therefore crucially important to the conclusion that utility regulators are not required to artificially inflate ROEs where they are not warranted in order to "save" a dying company and ensure it can attract capital if economic trends, consumer desires, and capital priorities are all stack against it.

While Avista is not in as extreme of a "hopeless" economic position as the streetcar company in *Market Street Railway* was, the Company's own testimony reveals a declining economic outlook, with its data demonstrating both customer growth and gas usage stagnating.[82] Avista warns that absent an increase in funding, the Company will experience an erosion of earnings below currently authorized levels.[83] Such claims might be more concerning if the Company was projecting accelerating growth or customer

---

[80] Avista/300, Thompson/Page 59.
[81] Avista/300, Thompson/Page 9.
[82] Avista/700, Forsyth/Page 4.
[83] Avista/100, Rosentrater/Page 5.

usage and needed capital in order to improve the system to meet demand; however, the Company's own data shows that is not the case. Avista's testimony includes updated Fall 2024 forecasts that show customer growth in the Oregon service territory from 2023 to 2026 is projected to only increase a modest 1.4%.[84] Of additional concern is the Company's projected use-per-customer (UPC) remaining flat for the entire customer base (residential and commercial customers).[85] The combination of slow customer growth and relatively little UPC growth results in a combined 0.8% increase in customer usage for both these schedules from the twelve-months which ended on December 31, 2023 base year until the twelve-months ending August 31, 2026 test year.[86]

Moreover, Avista's current customer forecast shows "relatively slow" growth in customer numbers in its largest Oregon population centers: Medford, Roseburg, Klamath Falls, and LaGrande over the next five years.[87] Similarly, the usage-per-customer (UPC) forecast for the next five years is flat.[88] The combined influence of the customer and UPC forecasts means that total load growth, compared to pre-pandemic and pandemic load growth, will continue at a slower pace over the next five-years.[89] As Avista experiences economic headwinds and slowing growth, the large credit rating institutions are losing faith in the Company. S&P has placed Avista onto a "negative outlook" status due to its

[84] Avista/700, Forsyth/Page 3.
[85] *Id.*
[86] *Id.*
[87] Avista/700, Forsyth/Page 4.
[88] *Id.*
[89] *Id.*

weaking performance,[90] and are threatening to downgrade the Company's creditworthiness ratings further.[91]

These existing trends are only poised to accelerate as cities in Avista's Oregon service territory continue to enact policies focused on electrification and decarbonizing its energy streams. As discussed below, several of the population centers in Southern Oregon including Ashland and Talent have enacted or in the process of exploring methods for promoting electrification and discouraging new gas investment such as carbon pollution taxes. As more cities join this growing trend demand is slated to slow even further and perhaps start to decline.

Q. Based on the information you provided above, what are your recommendations for the Commission?

A. The Commission should deny Avista's request to increase its ROE. Certainly, given the factors discussed above, increasing the ROE by a near full percentage point as requested by Avista is unwarranted. The Company's allowed ROE was 9.40 percent in 2020, 2021 and 2022, increased to 9.50 percent in 2023, and has remained at that level in 2024.[92] Jumping the ROE to 10.4 percent would financially burden customers currently on the gas system, and given the existing consumer trends and preferences away from gas as well as the regulatory obligations of the CPP and other state policies, increasing an ROE to attract more investment would be imprudent. This is why I am recommending keeping Avista's ROE at the current level of 9.5 percent. The Supreme Court's *Market Street Railway* decision reveals that utilities are *not* entitled to ever increasing ROEs. In

[90] Avista/200, Christie/Page 4.
[91] *Id.* at Page 8.
[92] Avista/300, Thompson/Page 32.

fact, the case stands firmly against the idea of relying too heavily on past performance or market conditions as metrics for fixing future rates.[93] Instead, this Commission should look at Avista's own data and decline to raise rates for a product that is not growing, sending a signal to the Company that it is time to prepare to transition its operations away from gas.

VI. <u>Municipal Policy Developments</u>

Q. Have cities in Avista's Oregon service territory adopted policies targeting the use of natural gas in newly constructed homes?

A. Yes. Just in the past two weeks the City Council of Ashland, Oregon unanimously adopted a first-in-Oregon ordinance that imposes a "carbon pollution impact fee" on the installation of hot water heaters, gas furnaces, kitchen stoves and other gas appliances in new residential construction.[94] The new Ashland law, Ordinance No. 3254,[95] championed by youth climate advocates from the Rogue Climate Action Team[96] will go into effect January 1, 2026, and impose fees—incorporated into the building permits for new residential construction—of $4,118.40 for the installation of gas furnaces, $1,296.60 for the installation of gas hot water heaters, $728 for the installation of gas fireplaces, $374.40 for the installation of gas kitchen ranges, and $145.60 for the installation of gas clothes dryers.[97]

---

[93] *Market Street Railways*, 324 U.S. at 567.
[94] David Runkel, *Ashland, First in Nation with Natural Gas Connection Fee Adoption*, The Ashland Chronical (Feb. 19, 2025) available at: https://theashlandchronicle.com/ashland-first-in-nation-with-gas-connection-fee-adoption/.
[95] Environmental Intervenors/106, Apter/Page 1.
[96] Roman, Battaglia, *Ashland becomes the first city in Oregon to impose a fee on new natural gas hookups,* Oregon Public Broadcasting (Feb. 20, 2025) available at: https://www.opb.org/article/2025/02/20/ashland-fee-natural-gas-hookups/.
[97] Environmental Intervenors/106, Apter/Page 2–4.

The Ashland carbon fee, assessed for each unit in a building and due upon the issuance of the building permit, will be calculated using social cost of greenhouse gases figures, a monetary value assigned to climate change damages resulting from the emission of one metric ton of greenhouse gases.[98] These fees will increase annually, with the charges adjusted by the percentage increase in the Consumer Price Index U.S. city average for the 12 months prior.[99] The fee is estimated to raise over $89,000 in annual revenue,[100] and funds generated from the fees will be put into Ashland's low-income energy assistance program.[101] The ordinance also provides penalties for violation of the law, including the non-payment of the fee or installation of unpermitted gas appliances, with fines allocated to clean energy programs.[102]

Q. Will Ashland's new carbon pollution impact fee affect the demand for natural gas in Avista's service territory?

A. Yes, it is likely Ashland's carbon pollution impact fee will decrease the number of new gas appliance installations in new residential construction in the city, thereby slowing the number of new customers Avista projects and driving down the overall demand for gas. According to its proponents, the fee structure was designed in order to

[98] Gosia Wozniacka, *Ashland approves pollution fee to cut down on new natural gas hookups,* The Oregonian (Feb. 19, 2025) available at: https://www.bendbulletin.com/localstate/ashland-approves-pollution-fee-to-cut-down-on-new-natural-gas-hookups/article_c00c2856-8df1-548f-9e43-99551dd833c0.html.
[99] Environmental Intervenors/106, Apter/Page 2–3.
[100] Lauren Pretto, *Rogue Climate holds rally in support of Carbon Pollution Impact Fee,* NBC 52 (February 18, 2025) available at: https://kobi5.com/news/local-news/rogue-climate-holds-rally-in-support-of-carbon-pollution-impact-fee-266602/.
[101] Roman, Battaglia, *Ashland becomes the first city in Oregon to impose a fee on new natural gas hookups,* Oregon Public Broadcasting (Feb. 20, 2025) available at: https://www.opb.org/article/2025/02/20/ashland-fee-natural-gas-hookups/.
[102] Environmental Intervenors/106, Apter/Page 4.

incentivize developers to build new homes with efficient, electric appliances[103] while disincentivize the installation of gas appliances in new homes, as opposed to outright banning the products.[104] The ordinance itself states its purpose is "promote the health, safety, and general welfare of Ashland residents"[105] by establishing the fee and thereby reducing the prevalence of natural gas systems in new residential homes.

Even prior to Ashland's first-of-its kind policy, Avista's current customer forecast showed "relatively slow" growth in customer numbers in its largest Oregon population centers: Medford, Roseburg, Klamath Falls, and LaGrande over the next five years.[106] This new policy is especially significant for Avista's demand, as Ashland was one of the few population centers in the Company's Oregon service territory not identified in Avista's testimony as showing a slowdown in new customers, but has now introduced a carbon fee policy designed to do exactly that. As Avista's own testimony explains, the adoption of "policies or incentives to restrict the use of natural gas in favor of electricity would adversely impact customer growth [and] usage."[107]

While the ultimate impacts of Ashland's groundbreaking policy will not be realized until after the law takes effect in 2026, the question is not *if* it will reduce the amount of gas infrastructure installed in new homes, but rather *how much* it will decrease demand. Given that under the new ordinance, a home builder seeking to install a gas

[103] Rogue Climate, Press Release: *Ashland Council unanimously votes to pass first reading of youth-led climate policy* (January 22, 2025) available at: https://rogueclimate.org/pollutionfee/.
[104] David Runkel, *Ashland, First in Nation with Natural Gas Connection Fee Adoption*, The Ashland Chronical (Feb. 19, 2025) available at: https://theashlandchronicle.com/ashland-first-in-nation-with-gas-connection-fee-adoption/.
[105] Environmental Intervenors/106, Apter/Page 1–2.
[106] Avista/700, Forsyth/Page 4.
[107] Avista/300, Thompson/Page 24.

furnace, water heater, range, fireplace, and clothes dryer would be required to pay an additional $6,656 in fees,[108] it is likely that many may choose to install the cheaper and more efficient electric alternatives instead.

Q. Did the gas industry, including Avista, oppose the adoption of Ashland's carbon pollution impact fee?

A. Yes, Ashland's proposed ordinance was vigorously opposed by gas industry representatives and organizations. One such organization was the Northwest Coalition for Consumer Energy Choice (NWCEC), a group financially backed by the Northwest Gas Association, a gas industry trade association, of which Avista is a member.

NWCEC financed a disinformation campaign that directly texted, called, and emailed Ashland residents misleading or materially false claims regarding the purpose and impact of the carbon pollution impact fee. These claims include statements that the policy will "cost homeowners thousands"[109] without any discussion of the fact that it only applies to *new* construction so all homes in Ashland constructed prior to 2026 would be unaffected. Nor does it mention that the costs are imposed on the homebuilder directly, and so the price is only passed on to the buyer if the builder chooses to move forward with gas appliances as opposed to cheaper and more efficient electric options. NWCEC claimed that the ordinance will exacerbate the housing shortage and inequality in Oregon,[110] again without any recognition that it is entirely within the builder's discretion to incur the fee or not. In fact, electric appliances are cheaper to buy, install, and operate (especially in Ashland's municipally-owned electric utility territory that receives 95%

---

[108] Environmental Intervenors/106, Apter/Page 2–3.
[109] Environmental Intervenors/110, Apter/Page 1–3.
[110] *Id.*

carbon-free electricity from the Bonneville Power Administration),[111] and therefore, to the extent the policy encourages a shift away from gas and towards electric it is likely to decrease construction costs for the average home in Ashland post-2026. NWCEC urged residents to take action and oppose the policy, and while ultimately unsuccessful, Ashland Councilor Bob Kaplan stated he had received somewhere around 80 emails concerning misinformation and concern surrounding the ordinance in question.[112] He found that when he engaged with each constituent, many became supportive of the policy once they understood the very limited nature of the ordinance. NWCEC's effort in Ashland is representative of a recurring pattern of the gas industry in spreading misinformation in an effort to foment opposition to smart climate policy and decarbonization initiatives that are consistent with city-developed and adopted climate action plans.[113]

Unsurprisingly, Avista—whose Senior Director of Government Relations, K. Collins Sprague, serves as the Secretary of NWCEC,[114] and is a dues paying member of the Northwest Gas Association—opposed the ordinance. Avista Spokesperson Steve Vincent spoke to the Ashland City Council, stating "[he] would encourage you to vote no on the ordinance at this time, and then invite a conversation on how we can look at

[111] *See* City of Ashland, *Electric* (2025) available at: https://ashlandoregon.gov/168/Electric.
[112] Morgan Rothborne, *City Council approves fossil fuel fees on new residential construction,* Ashland.news (Feb. 20, 2025) available at: https://ashland.news/city-council-approves-fossil-fuel-fees-on-new-residential-construction/.
[113] Jennifer Hill-Hart, *NW Natural Spread Misinformation the Oregon Legislature* Oregon Citizens' Utility Board (May 9, 2023) available at: https://oregoncub.org/news/blog/nw-natural-spread-misinformation-in-the-oregon-legislature/2813/ (discussing examples of identical misleading comments organized and submitted from NWCEC on HB 3152, a Utility Consumer Protection Bill addressing gas expansion subsisdies.)
[114] Environmental Intervenors/114, Apter/Page 1.

decarbonization of the community mutually."[115] Following the passage of the ordinance, Avista expressed it was disappointed in the policy's adoption.[116] In fact, Avista spokesperson Jared Webley made a statement repeating many of the same misleading and fear-mongering arguments that NWCEC's materials did, claiming "this new impact fee will worsen housing inequity, increase the overall cost of housing, and add another potential financial barrier for individuals on the cusp of home ownership."[117] Avista, like NWCEC, fails to recognize that the ordinance is quite limited in scope and only imposes increased costs for homes where developers willingly choose to move forward with gas appliances despite the existence of safer, and more efficient alternatives that are actually cheaper for developers to build with. It also attempts to interfere with local government action to improve health and safety outcomes for constituents, while achieving locally-adopted climate goals, by repeating false information about the very narrow impact of the ordinance.

The Environmental Intervenors have submitted discovery requests to Avista inquiring about the relationship between the Company and NWCEC and NWGA with respect to the opposition efforts in Ashland. The Environmental Intervenors seek to ensure that no ratepayer funds are being spent on this anti-climate political activity that is

[115] Roman, Battaglia, *Ashland becomes the first city in Oregon to impose a fee on new natural gas hookups,* Oregon Public Broadcasting (Feb. 20, 2025) available at: https://www.opb.org/article/2025/02/20/ashland-fee-natural-gas-hookups/.
[116] Gosia Wozniacka, *Ashland approves pollution fee to cut down on new natural gas hookups,* Bend Bulletin (Feb. 19, 2025) available at: https://www.bendbulletin.com/localstate/ashland-approves-pollution-fee-to-cut-down-on-new-natural-gas-hookups/article_c00c2856-8df1-548f-9e43-99551dd833c0.html.
[117] *Id.*

distinctly not in the best interest of ratepayers. The Environmental Intervenors anticipate addressing this issue further upon receipt of the discovery request responses.

Q. Are other communities besides Ashland in Avista's Oregon service territory enacting policies to promote electrification?

A. Yes, notably the city of Talent, Oregon in August 2024, unanimously passed Resolution 2024-097-R, which encourages upgrades of homes and nonresidential buildings so they have modern highly efficient appliances.[118] Talent's resolution recognizes the air pollution and climate emissions, and public health risks associated with using gas appliances in the home,[119] and recognizes that the City likely cannot reach its climate goal without transitioning residential and non-residential buildings to low- or zero-emission technologies and away from gas.[120] Talent's resolution contains four substantive terms:

1) The City should encourage transition to low- or zero-emission equipment and appliances in Talent residential and non-residential buildings.[121]
2) The City should investigate possible sources of financial and staffing support for developing measures to mitigate the health impacts of pollution in Talent residential and non-residential buildings, including low- or zero-emission standards for appliances.[122]
3) The City should encourage and provide resources to the Together for Talent Committee, among other entities, to work with community partners in educating

[118] Environmental Intervenors/115, Apter/Page 1.
[119] *Id.*
[120] *Id.*
[121] *Id.*
[122] *Id.*

and engaging the community on the pollution associated with natural gas use in buildings.[123]

4) The City of Talent urges the Oregon Governor, Legislature, state agencies, and Jackson County to accelerate transition to zero-emitting appliances by: promoting decarbonization while protecting low and moderate income rate payers; adopting indoor air quality standards to protect public health; amending building codes to address the adverse health impacts of using natural gas in residential and non-residential buildings; and considering inclusion of the adverse health impacts of natural gas in utility cost-benefit analyses, rate setting, and resource planning.[124]

Installing heat pumps has the potential to significantly reduce Talent's climate forcing GHG emissions from buildings which adds up to 34% of the state's GHG emissions.[125] Furthermore, Talent's passage of the resolution will also help the State of Oregon fulfill its pledge of ensuring that zero-emission electric heat pumps constitute at least 65% of residential-scale heating, air conditioning, and water heating equipment shipments by 2030 and 90% by 2040.[126] Talent's resolution, now followed by Ashland's ordinance, illustrates the growing momentum in the state behind upgrading buildings to clean energy and efficient electric technologies.[127]

---

[123] *Id.*
[124] *Id.*
[125] Oregon Department of Environmental Quality, *Oregon's Priority Climate Action Plan,* at 14 (March 2024) available at: https://www.epa.gov/system/files/documents/2024-02/oregon-cprg-pcap.pdf.
[126] NESCAUM, *Accelerating the Transition to Zero-Emission Residential Buildings: Multistate Memorandum of Understanding* (Feb. 2024) available at: https://www.nescaum.org/documents/Buildings-MOU-Final-with-Signatures---DC.pdf.
[127] Rogue Climate, *Press Release: Talent Passes Resolution to Encourage Upgrades to Clean, Efficient Buildings*, (Aug. 22, 2025) available at: https://rogueclimate.org/talent-passes-clean-air-resolution/.

VII. Membership Dues

Q. What are industry association dues?

A. Industry association dues are charges that companies and organizations pay to be members of an association. These fees or dues are paid on a recurring basis, often annually. The dues paid are then used by the association to cover the expenses of its employees, activity, and overhead for its work.

Q. Does Avista pay industry association dues?

A. Yes, Avista pays several industry association dues, most notably to the American Gas Association (AGA) and the Northwest Gas Association (NWGA).[128]

Q. Could you please provide a brief description of AGA and NWGA?

A. The AGA is a national industry association that represents over 200 gas supply companies.[129] NWGA is a trade organization operating in the Pacific Northwest focused on the natural gas industry.[130]

Q. How much has Avista paid for its industry association dues with AGA and NWGA?

A. Avista paid $269,412.60 in industry association dues to AGA in 2023.[131] Avista paid $101,185 in industry association dues to NWGA in 2023.[132] Of its $269,412.60 in 2023 AGA dues, Avista charged $83,423.61 to its Oregon account.[133] Of its $101,185 in

[128] Environmental Intervenors/107, Apter/Page 1–2.
[129] American Gas Association, *About AGA*, https://www.aga.org/about/ (last visited Feb. 25, 2025).
[130] Northwest Gas Association, *About Us*, https://www.nwga.org/about-us (last visited Feb. 25, 2025).
[131] Environmental Intervenors/107, Apter/Page 1–2.
[132] *Id.*
[133] *Id.*; Environmental Intervenors/116, Apter/Page 2.

2023 NWGA dues, Avista charged $31,331.94 to its Oregon account.[134] This does not include numerous expenses incurred by Avista for registration, lodging, meals, and transportation for its employees to attend conferences hosted by AGA and NWGA.

Q. What expenses related to association fees or dues is Avista seeking to recover from its Oregon ratepayers?

A. Avista is seeking to recover 75% of its industry association dues charged to Oregon.[135] After applying this deduction, the Company is seeking recovery of $63,729 from its AGA dues[136] and $23,499 from its NWGA dues.[137]

Q. How has the Commission typically treated association fees or dues?

A. The Commission does not have set rules for how it analyzes association fees or dues. In prior dockets, the Commission has indicated that it "generally allowed 75 percent of trade association dues to be passed on to ratepayers by Oregon utilities."[138] However, the OPUC Staff has previously noted that industry associations like AGA made "significant expenditures" for nonrecoverable activities, such as promotion and marketing, and the Commission has clarified that it will "disallow a greater portion of trade association dues in the future if an excessive proportion of an association's expenditures are for such activities."[139]

[134] *Id.*
[135] Environmental Intervenors/116 Apter/Page 1–2.
[136] *Id.*
[137] *Id.*
[138] *In the Matter of Revised Tariff Schedules Filed by Northwest Natural Gas Company for a General Rate Increase*, 1989 WL 1793934 at 10 (Or. P.U.C.).
[139] *Id.*

Q. Why should the Commission disallow recovery of trade association dues?

A. The Commission and FERC both prohibit the use of ratepayer funding for political activities. The Commission has stated its policy that it will "not require customers to support causes in which they do not believe," and this proves especially true for utility lobbying, which can actually harm ratepayers.[140] AGA and NWGA's political activities go against many of Avista's ratepayers' beliefs and interests. The associations promote the consumption of gas at the expense of all other forms of energy, and they work to prohibit action at the federal, state, and local levels to address climate change. For this reason, the Commission should find that the industry association dues are not in the best interests of customers and deny Avista's ability to recover the dues.

Q. What type of organization is the AGA, and is it allowed to engage in political activity under IRS rules?

A. AGA is a business league and a registered 501(c)(6) organization.[141] As a business league, it is exempt from paying taxes. According to IRS guidance, business leagues may engage in the following political activities:

- Organizations described in IRC 501(c)(4), (c)(5), and (c)(6) may engage in *an unlimited amount of lobbying*, provided that the lobbying is related to the organization's exempt purpose…

---

[140] *In the Matter of Portland Gen. Elec. Co.*, UE 187, 2009 WL 214804 at 16 (May 19, 2009); 18 CFR § 367.4264.
[141] Environmental Intervenors/109, Apter/Page 2–3.

- IRC 501(c) organizations may generally make expenditures for political campaign activities if such activities (and other activities not furthering its exempt purposes) do not constitute the organization's primary activity.[142]

Q. How much of the AGA's operating expenses come from membership dues?

A. In 2022, AGA earned a total revenue of $36,724,829 from all its revenue sources, with membership dues providing $29,081,971.[143]

Q. Could you please describe AGA's political advocacy?

A. AGA has regularly engaged in lobbying, disclosing well over $1 million in federal lobbying expenditures each year.[144] Beyond lobbying AGA also engages in other forms of controversial political advocacy, including:

- Supporting nationwide construction permits that risk environmental damage;
- Actively participating in litigation seeking to weaken environmental protections;
- Opposing changes to the International Code Council's codes that would have made electric vehicle-ready wiring and accommodations for electric-powered appliances an automatic feature of new buildings;

[142] Internal Revenue Service, Political Campaign and Lobbying Activities of IRC 501(c)(4), (c)(5), a(c)(6) Organizations, at 4-5 (2003) (emphasis added) available at: https://www.irs.gov/pub/irs-tege/eotopicl03.pdf.
[143] Environmental Intervenors/109, Apter/Page 2–3.
[144] Open Secrets, *Client Profile: American Gas Assn*, (last visited Feb. 25, 2025) available at: https://www.opensecrets.org/federal-lobbying/clients/summary?cycle=2024&id=D000000447. (With the exception of 2014 and 2022, AGA has surpassed $1 million in total lobbying expenditures each year of the past decade.)

- Promoting the gas economy and associated infrastructure, despite the critical need to phase out reliance on fossil fuels as we move to a clean energy economy.

In 2020, AGA stated its objective was to "expand efforts at federal, state, and local levels" to block transitions away from fossil fuels.[145] Its "government relations" activity includes active involvement in state-level bills to block climate action and advance pro-gas choice legislation.[146] AGA also engages in regulatory advocacy that benefits the utilities at the expense of ratepayers, including participating in U.S. Department of Energy rulemaking to prevent more stringent appliance efficiency standards.[147]

AGA is also a registered political action committee.[148] AGA's political action committee donated $245,500 to federal candidates in the 2023-2024 election cycle, with 74% of that going to Republican candidates.[149] Of that amount, its largest recipient of expenditure was the National Republican Senatorial Committee.[150]

---

[145] Jeff Brady & Dan Charles, *As Cities Grapple With Climate Change, Gas Utilities Fight To Stay In Business*, NPR (Feb. 22, 2021) available at: https://www.npr.org/2021/02/22/967439914/as-cities-grapple-with-climate-change-gas-utilities-fight-to-stay-in-business.
[146] *Id.*
[147] American Gas Association, et. al., Joint Comments on the Proposed Rulemaking on Energy Conservation Standards for Consumer Furnaces, DOE Docket No. EERE-2014-BT-STD-0031 (Oct. 6, 2022) available at: https://www.regulations.gov/comment/EERE-2014-BT-STD-0031-0391.
[148] American Gas Association, GASPAC, (last visited Feb. 25, 2025) available at: https://www.aga.org/gaspac/.
[149] Open Secrets, *Candidate Recipients: American Gas Assn PAC Contributions to Federal Candidates*, (last visited Feb. 25, 2025) available at: https://www.opensecrets.org/political-action-committees46mericanerican-gas-assn/C00007450/candidate-recipients/2024.
[150] Open Secrets, *Expenditures: American Gas Assn PAC Expenditures*, (last visited Feb. 25, 2025) available at: https://www.opensecrets.org/political-action-committees46mericanerican-gas-assn/C00007450/expenditures/2024.

Q. Does AGA engage in political advocacy in Oregon?

A. Yes. In the past, AGA had expressed its intention to contribute $4 million to anti-electrification campaigns in Eugene.[151] According to IRS filings, AGA has also financially supported other industry associations, like the Edison Electric Institute (EEI), and front groups, such as Partnership for Energy Progress.[152] These associations have aggressively challenged climate policy efforts while promoting and advertising natural gas use to Oregonians.[153]

Q. Could you please describe NWGA's political advocacy?

A. NWGA engages in a variety of political influence activities, including lobbying, as is outlined in NWGA's Strategic Plan:

> In order to accomplish its mission, the NWGA will focus its resources on activities that most effectively support the advocacy message by implementing the following strategies:
>
> 1. Persuasively tell its members' story about the long-term role of gas in meeting society's low carbon policy goals. Win the policy battle.

[151] Anna Phillips, *A Fight Brewing In Oregon Could Decide How We Heat Our Homes and Cook,* Washington Post (Apr. 21, 2023) available at: https://www.washingtonpost.com/climate-environment/2023/04/21/natural-gas-industry-oregon-ban/.
[152] Environmental Intervenors/109, Apter/Page 4–5.
[153] *See* Akielly Hu, *8 states move to ban utilities from using customer money for lobbying*, Grist (Feb. 21, 2024) available at: https://grist.org/politics/8-states-move-to-ban-utilities-from-using-customer-money-for-lobbying/; *see also* Gosia Wozniacka, *NW Natural in existential fight as Oregon eyes electrification*, The Oregonian (Mar. 10, 2023) available at: https://www.oregonlive.com/environment/2023/03/nw-natural-in-existential-fight-as-oregon-eyes-electrification.html.

a. Argue the counter message to the "zero carbon" and "Electrification mandate" movements. Articulate a pathway to Deep Decarbonization that leverages the benefits of natural gas.

b. Raise the awareness and appreciation for the value of low-cost long-term supply availability.

c. Build regional support for a Renewable and Natural Gas partnership as an effective strategy for the PNW region in addressing climate change.

2. Translate this story into specify lobbying forums to influence public policy in practical ways as directed by its membership.

a. Pro-actively introduce legislation as guided by NWGA's members.

b. Represent members' collective position on prospective carbon pricing legislation.

c. Intervene to take advantage of public policy driven funding and subsidies that benefit NWGA's members. [...][154]

In Washington, NWGA openly stated it would fight local and state attempts to address climate change and committed $1 million to those efforts.[155]

Q. Does NWGA engage in political advocacy in Oregon?

A. Yes, NWGA has directly lobbied against critical climate policies in Oregon. In the past, NWGA attempted to influence the outcome of the CPP 2022 Temporary

---

154 UG 461, *Opening Testimony of Greer Ryan*, Environmental Intervenors/300 at Ryan/46–47.

155 Hal Bernton & Daniel Beekman, *Natural gas industry's $1 million PR campaign sets up fight over Northwest's energy future*, The Seattle Times (Dec. 23, 2019) available at: https://www.seattletimes.com/seattle-news/natural-gas-industrys-1-million-pr-campaign-sets-up-fight-over-northwests-energy-future/.

Rulemaking (OAR 340-271-0110).[156] It also engaged by weighing in on bills at the Oregon legislature, including unsuccessfully lobbying against the recently-passed 2023 Climate Resilience package (HB 3409).[157]

NWGA's Executive Director also created the Northwest Coalition for Energy Choice (NWCEC) and is a registered agent for NWCEC in the State of Oregon.[158] NWCEC currently has gas utility executives sitting on its board, including Avista's Senior Director of Government Relations, K. Collins Sprague, who is the acting Secretary.[159] In the past, NWCEC campaigned against HB 3152 ("Utility Customer Protection Bill") with strategies that included spreading misinformation about the bill's impacts. It lobbied against the bill through emails and social media posts, claiming the bill would "limit[] home energy choice."[160]

As previously mentioned in my testimony, NWCEC also recently opposed the "carbon pollution impact fee" ordinance that was unanimously passed by the Ashland City Council using similar tactics.[161] It spread misinformation about the impact of the bill to Ashland residents and organized a last-ditch effort to encourage public testimony in opposition of the ordinance before the City Council. NWGA's Executive Director

---

[156] Dan S. Kirschner to Oregon Department of Environmental Quality (Oct. 31, 2022) available at: https://www.nwga.org/_files/ugd/054dfe_7de9ee2c2d7f4662855a008ef9bb2cdf.pdf.
[157] Dan Kirschner to Senate Committee on Energy and Environment (Mar. 16, 2023) available at: https://olis.oregonlegislature.gov/liz/2023R1/Downloads/PublicTestimonyDocument/65565.
[158] Environmental Intervenors/114, Apter/Page 1.
[159] *Id.*
[160] Docket No. UG 461, Environmental Intervenors/316, Ryan/Page 1.
[161] David Runkel, *Ashland, First in Nation with Natural Gas Connection Fee Adoption*, The Ashland Chronicle (Feb. 19, 2025) available at: https://theashlandchronicle.com/ashland-first-in-nation-with-gas-connection-fee-adoption/.

submitted public testimony directly to oppose the ordinance on behalf of the utilities it represents.[162]

Q. Has Avista provided information that justifies charging ratepayers 75% of the costs associated with its industry association dues?

A. No. Avista has stated in a conclusory fashion that 75% of its association dues can be recovered.[163]

Q. In light of Oregon's strict prohibition against financing political activities using ratepayer funds and the activities of AGA and NWGA in Oregon, how would you recommend the Commission treat AGA and NWGA association dues?

A. The Commission should disallow recovery of AGA and NWGA industry association dues from ratepayers. Based on the use of association dues funds by AGA and NWGA for political purposes and extensive political advocacy efforts, allowing recovery of these dues would run counter to the Commission's stated policy. In absence of evidence from Avista showing that the funds it pays to AGA and NWGA do not go toward the associations' political activities, the Commission should disallow cost recovery as contrary to the public interest.

VIII. <u>Political Spending:</u>

Q. What other costs related to public affairs and political expenses does Avista seek to recover from ratepayers?

[162] Dan Kirschner to Mayor Tonya Graham, *City Council Business Meeting - February 18, 2025*, (Feb. 3, 2025) available at: https://ashlandor.portal.civicclerk.com/event/803/files/attachment/1045.
[163] Environmental Intervenors/116, Apter/Page 2.

A. As previously described, Avista's payment of industry association dues to AGA and NWGA constitute political expenses. Beyond that spending, Avista is passing on the costs of certain expenses to Oregon ratepayers for legal efforts that are contrary to the public interest and threaten Oregon's climate goals.

For this rate case, Avista allocated a total of $140,620 to Oregon for outside services employed during the Base Year.[164] Of that amount, $80,456.10 was included in the Base Year for legal fees incurred for the challenge of the CPP.[165]

Q. When and how did Avista challenge the CPP in litigation?

A. On March 18, 2022, Avista, along with other gas utilities and industry groups, filed a lawsuit against DEQ in the Oregon Court of Appeals asking the court to invalidate and vacate the CPP regulation.[166]

Q. How did Avista previously propose paying for its litigation to overturn the CPP?

A. For its case to invalidate the CPP, Avista sought to recover the cost of its legal fees from ratepayers. In its 2022 rate case, Avista charged ratepayers $51,951 in legal fees for its affirmative lawsuit to overturn the CPP.[167] Through the joint settlement reached in that rate case, Avista agreed not to recover a certain amount of legal fees from its customers.[168]

---

[164] Environmental Intervenors/111, Apter/Page 1.
[165] Environmental Intervenors/112, Apter/Page 1.
[166] Avista, *Avista and partner utilities in Oregon file lawsuit challenging Climate Protection Plan* (Mar. 18, 2022) available at: https://investor.avistacorp.com/news-releases/news-release-details/avista-and-partner-utilities-oregon-file-lawsuit-challenging.
[167] Docket No. UG 461, *Opening Testimony of Greer Ryan*, Environmental Intervenors/300, Ryan/Page 10.
[168] Environmental Intervenors/113, Apter/Page 1.

Q. For its current rate case, has Avista taken the same measures to avoid passing on its legal expenses related to the CPP to Oregon ratepayers?

A. No. Despite the joint settlement agreement reached by the parties in the previous rate case, Avista is now seeking to recover legal fees for its challenge of the CPP. After it failed to recover $51,951 in CPP legal fees in the 2022 rate case, it is now asking the Commission to approve recovery of $80,456.10 for its CPP legal fees.[169] Avista considers these costs to be appropriate to include in customer rates, despite the joint settlement reaching the opposite conclusion in the prior rate case.[170]

Q. Can Avista recover costs for its political activities from ratepayers?

A. In Oregon, the Commission prohibits utilities from recovering the costs of their political activities from ratepayers. The Commission has held that:

> Ratepayers should not be required to contribute to the advancement of political positions in which they may not believe. Exclusion of political expenditures is even more important than exclusion of community affairs expenditures because a utility's lobbying program can actually harm ratepayers. Stockholder interests with respect to issues such as the nature and scope of regulation often conflict with ratepayer interests. A utility's lobbying program can be expected to give preference to stockholder interests when issues such as those arise.[171]

---

[169] *Id.*
[170] *Id.*
[171] *Re Pac. Nw. Bell Tel. Co., Am. Network, Inc., et al.*, UT 43, Order No. 87–406, 82 P.U.R. 4th 293, 320 (Mar. 31, 1987).

FERC regulations also provide that costs related to a utilities' political activities must be billed to shareholders.[172]

Q. Should the Commission allow Avista to recover costs associated with its litigation to vacate the CPP?

A. No. Avista's lawsuit against the CPP is a political activity, and allowing recovery of the legal fees would go against the Commission's position. Requiring ratepayers to fund the costs of its lawsuit would be requiring them to support a litigation position that directly undermines their interests.

Q. What action should the Commission take to deduct these costs?

A. The Commission should deduct $80.456.10 from the Test Year budget for FERC Account No. 923 to deduct costs already billed to ratepayers during the Base Year. Further, the Commission should order that Avista is not allowed to recover costs for its litigation to vacate the CPP, now or in the future, and should further order that any such expenses be billed to FERC Account 426.4.[173]

Q. Are there any other political activities performed by Avista that should be of concern?

A. Yes. As previously mentioned, Avista supports NWGA, and NWGA challenged Ashland's carbon pollution impact fee. Avista was also directly involved in challenging the ordinance. Avista privately submitted a letter to Ashland City Council outside of the public testimony offered by others at the February 18, 2025 City Council Business

[172] 18 CFR § 367.4264.
[173] *Id.* (FERC Account 426.4 is intended for "[e]xpenditures for certain civic, political and related activities.")

Meeting.[174] In this letter, Avista repeated many of the same talking points raised by NWGA and urged the Council to vote "no" on the ordinance.[175] In addition to filing this letter, Avista sent Account Executive Steve Vincent to attend the Business Meeting.[176]

Q. How does the Commission recommend political activity such as this be tracked for a utility rate case?

A. The Commission has recognized the importance of correctly allocating costs for political activity between shareholders and ratepayers.[177] It noted that "indirect" efforts to influence regulatory proceedings may not be recoverable and the burden is on the utility to justify its costs.[178] In order to determine what indirect efforts may be recoverable, the Commission has required a utility to "update its general procedures for its government affairs employees to ensure that future filings for rate recovery capture activities that attempt to influence public officials with regard to regulatory decisions, but that are not directly related to appearances before regulatory or other governing bodies."[179] The Commission explained that only providing data for unrecoverable, "excluded" expenses was insufficient, because it did not ensure that the other costs for which the utility was seeking recovery were in fact recoverable.[180] The Commission stated that, at a minimum,

[174] Environmental Intervenors/117, Apter/Page 1–2.
[175] *Id.*
[176] Roman Battaglia, *Ashland becomes the first city in Oregon to impose a fee on new natural gas hookups*, OPB (Feb. 20, 2025), https://www.opb.org/article/2025/02/20/ashland-fee-natural-gas-hookups/.
[177] UG-490, OPUC Order No. 24-359 (Oct. 25, 2024) at 39.
[178] *Id.* at 39, 42.
[179] *Id.* at 40.
[180] *Id.* at 41.

the utility must track "non-exception time that provides the underlying support for its test year level of expense."[181]

Q. Has Avista provided data sufficient to meet the Commission's recommended approach to political activity?

No. Avista has not provided this level of granularity for its political spending data. For its recent political activity, it has stated that the time spent drafting the letter to Ashland City Council and Steve Vincent's time spent at the February 2025 Business Meeting were "minimal" and "not charged to Oregon customers."[182] As Environmental Intervenors in this rate case, we will continue to work with Avista to validate through additional data that its political activity is correctly being allocated between shareholders and ratepayers under this rate case and that it has a policy and training in place to ensure its employees are accurately tracking exempt and non-exempt time.

IX. Conclusion

Q. Will you please restate your recommendations to the Commission?

A. Yes, I recommend the following:

- Section III: Climate Impacts & Natural Gas
    - I recommend the Commission require Avista to produce a plan demonstrating how it intends to fully spend funds budgeted annually to its AOLIEE program in Schedule 485. I recommend that Avista consult with ETO and community action agencies in producing this

[181] *Id.* at 42.
[182] Environmental Intervenors/118, Apter/Page 1; Environmental Intervenors/119, Apter/Page 1.

plan to ensure it presents solutions that will assist it in spending its budget each year.

  - I also recommend that Avista lift the 20% expenditure cap in Schedule 485 for Implementing Organizations' budgetary spending on health, safety, and repair measure funding.
  - I recommend Avista translate any materials regarding its low-income program offerings distributed to community action agencies into Spanish, Russian, Vietnamese, Cambodian and Laotian. Currently the materials are only produced in English and should be translated to reach as many low-income customers as possible.

- Section IV: Climate Protection Program
  - I support the recommendations made below in the testimony of Emily Moore:[183]
    - As a condition for capital investment recovery in this and future proceedings, the Commission should require Avista to, moving forward, analyze non-pipeline alternatives (NPAs) for investments in 1) replacing Aldyl-A pipes, 2) replacing pipes at the end of their useful life, and 3) expanding system capacity. Doing so will allow the Company to address safety, reliability, and capacity concerns, while at the same time ensuring prudent investments for ratepayers and reducing the risk of stranded gas assets.

[183] Environmental Intervenors/200, Moore/Page 5–6.

        - As an element of this requirement, the Commission should eliminate the $1 million threshold for triggering NPA analyses as well as expand the scope of what types of projects require an NPA analysis to include investments in pipeline replacement.
        - Additionally, as a condition of recovery on investments in this proceeding and future proceedings, the Commission should order that Avista analyze at least two types of non-pipeline alternatives for all gas system capital investments moving forward.
      - The Commission should require Avista to evaluate targeted electrification and thermal energy networks as two specific NPAs. The Commission should require Avista to propose at least one targeted electrification pilot and one thermal energy network pilot that would allow decommissioning of gas infrastructure and thus reduction in the risk of stranded gas assets. The Commission should require Avista to include its findings and pilot proposals in the Company's 2026 IRP Update.
- Section V: Return on Equity
  - I recommend that the Commission reject Avista's request for an increase to its Return on Equity up to 10.4%.

- I recommend that the Commission keep Avista's Return on Equity at its current level of 9.5%.

- Section VI: Membership Dues
  - The Commission should disallow recovery of AGA and NWGA industry association dues from ratepayers. Based on the use of association dues funds by AGA and NWGA for political purposes and extensive political advocacy efforts, allowing recovery of these dues would run counter to the Commission's stated policy. In absence of evidence from Avista showing that the funds it pays to AGA and NWGA do not go to the associations' political activities, the PUC should disallow recovery as contrary to the public interest.
- Section VII: Political Activity
  - The Commission should deny Avista's requests to recover costs incurred challenging Oregon's Climate Protection Program. That is unrecoverable political activity and not in the interest of customers.
  - Commission should deduct $80.456.10 from the Test Year budget for FERC Account No. 923 to deduct costs already billed to ratepayers during the Base Year. Further, the Commission should order that Avista is not allowed to recover costs for its litigation to vacate the CPP, now or in the future, and should further order that any such expenses be billed to FERC Account 426.4.

Q. Does this conclude your testimony.

A. Yes. Thank you.

NORA APTER

Nora.Apter@gmail.com | 971-275-6179

EXPERIENCE

CLIMATE SOLUTIONS—Portland, OR **DEC. 2024 - PRESENT**

Oregon Director

- Develop Climate Solutions' short- and long-term state strategy for strong climate and clean energy policies in Oregon, coordinating Climate Solutions regional resources into these efforts.
- Represent Climate Solutions in multiple policy and coalition efforts and play a leadership role in building and advancing campaigns, interfacing and mobilizing with diverse partners in the business, labor, environmental justice, and other communities.
- Develop relationships and collaborate with state legislators, other policymakers and coalitions of diverse stakeholders to support passage, implementation, and defense of equitable climate policies at the state and local levels.
- Ensure that policies and projects are evaluated for equity implications and advance justice, equity, diversity, and inclusion goals.
- Serve in numerous state and local government advisory positions, including as voting member of the Oregon Climate Action Commission and formal representative on various state agency Rulemaking Advisory Committees.

OREGON ENVIRONMENTAL COUNCIL—Portland, OR **MAR. 2020 - NOV. 2024**

Director of Programs

- Managed program staff, lead strategy and implementation for dynamic multi-issue environmental agenda supporting equitable policy progress on climate protection, clean and just transportation, healthy environments, and clean and plentiful water.
- Cultivated and maintained collaborative, trust-based relationships with Oregon state legislators, the Governor's office, agency leadership, and federal delegation; represented OEC in high-level strategy meetings with decision-makers and stakeholders.
- Served in numerous state and local government advisory positions, including as voting member of the Oregon Climate Action Commission and formal representative on various state agency Rulemaking Advisory Committees.
- Represented OEC in the media, including extensive interviews and regular coverage in *Oregon Public Broadcasting, The Oregonian, Portland Business Journal, Oregon Business Magazine,* and *Oregon Capital Chronicle*.

Senior Program Director, Climate

- Developed and executed an ambitious climate policy agenda; directed and implemented cross-cutting strategy on multiple, simultaneous advocacy campaigns across a multitude of partners, issues areas, and political arenas.
- Communicated policy positions and public engagement opportunities to partners, legislators, the media, and OEC membership, translating complex policy issues into digestible forms appropriate to the target audience.
- Prioritized and integrated equity and environmental justice in policy design, coalition engagement, and advocacy strategy, including by serving as appointed representative on DEQ Equity Advisory Committee.
- Collaborated with development team to identify resource needs, draft grant proposals and reports, and track and manage budgets.

Program Director, Climate

- Directed statewide climate advocacy campaigns to secure historic policy victories to deliver economy-wide greenhouse gas emissions reductions and accelerate an equitable transition to a clean energy future.
- Established and managed statewide coalition of over 50 environmental justice, labor, business, and clean energy organizations; led strategy development and drove engagement on statewide campaigns to advance policy protections.
- Developed strategic communication campaigns, including targeted reporter outreach, polling/message-testing, blogs/op eds, progress reports, organic and promoted social media, and digital ads, to influence public narrative and advance policy outcomes.

NATURAL RESOURCES DEFENSE COUNCIL—Washington, D.C. **DEC. 2015 - MAR. 2020**

Deputy Director of Federal Affairs

- Developed and implemented legislative strategy on a broad portfolio of priority policy issues, including national campaigns to protect public lands, waters and wildlife and defend against environmental rollbacks.
- Effectively pivoted advocacy approach, tools, and tactics to adapt to shifting political landscape and institutional goals.
- Coordinated across the organization's policy, litigation, communications, and membership divisions to ensure the alignment of advocacy work, advance campaign strategy, and drive and deliver rapid response.
- Managed broad coalitions, established lasting strategic partnerships, engaged nontraditional allies, and elevated and centered environmental justice communities in developing and advancing federal environmental advocacy strategy.
- Represented NRDC in high-level meetings and negotiations with leaders in Congress and the administration, major donors, and national coalitions, and in the media, including extensive interviews/coverage in major national news outlets.

Legislative Advocate, Federal Affairs

- Developed proactive and reactive strategies to advance NRDC's legislative agenda and defend against congressional and administrative threats by working directly with policymakers and legislative staff on Capitol Hill.
- Established and maintained collaborative relationships with coalition partners to enhance advocacy before Congress.

UNITED STATES SENATE—Washington, D.C. **SEP. 2012 - NOV. 2015**

Legislative Aide for U.S. Senator Ron Wyden

- Led policy development and strategy, developed talking points and vote recommendations, and represented Senator Wyden in meetings on a broad portfolio of issues including small business, technology, immigration, foreign affairs, and defense.
- Established relationships and maintained constant communication with constituents and stakeholders in Oregon.
- Collaborated with colleagues and stakeholders to create needs-based solutions and introduce effective policy.

Legislative Correspondent for U.S. Senator Ron Wyden

- Tracked and leveraged omnibus legislation (e.g. NDAA, Farm Bill, appropriations, etc.) to advance legislative proposals.
- Gained expertise by meeting with a range of policy experts, constituents, stakeholders, and fellow congressional staffers.

EDUCATION & PROFESSIONAL TRAINING

LEWIS & CLARK COLLEGE—Portland, OR **2012**

Bachelor of Arts - International Affairs Major, Economics Minor

- Delivered qualitative thesis examining clean energy policymaking and the 'greening' of the major political parties in Germany.

EMERGE OREGON — Salem, OR **2022**

Graduate - Signature Political Training Program

- Completed in-depth, eight-month training program for prospective women political candidates the best practices in fundraising, networking, outreach, voter engagement, core campaign communications, political endorsements, and press.

HARVARD BUSINESS SCHOOL — Online **2023**

Certificate - Financial Accounting

- Earned certificate of completion in a seven-part course on the fundamentals of building, interpreting, and analyzing organizational budgets and financial statements.

WITNESS QUALIFICATION STATEMENT

NAME: Nora Apter

EMPLOYER: Climate Solutions

TITLE: Oregon Director

ADDRESS: 1300 SE Stark St. Ste 207, Portland, OR 97214

EDUCATION: Bachelor of Arts, International Affairs

Lewis & Clark College, Portland, OR

EXPERIENCE:

Provided testimony or comments in a variety of PUC dockets from 2020 to 2025, including Executive Order 20-04 implementation related-proceedings, UM 2178, and UM 1930, as well as a number of PUC-related laws, including HB 2475, HB 2021 and HB 3141. Participate(d) in regulatory proceedings and serve(d) as a formal member of various state agency Rulemaking Advisory Committees, including for DEQ's Climate Protection Program (2021, 2023, and 2024) and Clean Fuels Program expansion rulemakings. Served as an expert witness on Oregon and federal climate policy, alternative fuels and the natural gas industry in two of Northwest Natural's previous rate cases, UG 435 and UG 490. Currently serve as a commissioner and voting member on the Oregon Climate Action Commission and inform development of recommendations for statutory and administrative policies to achieve the State's emissions reduction goals. Between 2020 and 2024 served as director of programs and climate program director for Oregon Environmental Council. Between 2012 and 2020, worked for U.S. Senator Ron Wyden and the Natural Resources Defense Council (NRDC) on a variety of public policy and environmental policy issues.

RMI

FACT SHEET

All-Electric Buildings: Key to Achieving Oregon's Climate Goals

To reach Oregon's goal of cutting carbon emissions 80% by 2050, we must stop burning fossil fuels in buildings. Heat pumps are a readily available and effective solution for reducing building emissions today.

Buildings are a major source of carbon emissions

40% of Oregon's energy-related carbon emissions come from buildings.[1] Of this, over one third stems from burning fossil fuels (gas, oil, and propane) for heating, cooking, hot water, and other uses. Despite progress decarbonizing other sectors, these **emissions have not decreased in Oregon since 2016**.[1] The good news is that we have better technology at our fingertips and can convert these fuel-burning appliances to heat pumps and other efficient, electric systems.

"Why are we transitioning off gas?"

Methane gas (a.k.a. natural gas) served as a "bridge fuel" in the transition away from dirtier forms of energy like coal. That need has changed as Oregon has increasingly adopted renewable energy, reducing electric grid emissions by 9% since 2010.[1] It's time to take the next step in the energy transition by harnessing this cleaner grid to power our buildings.

66%

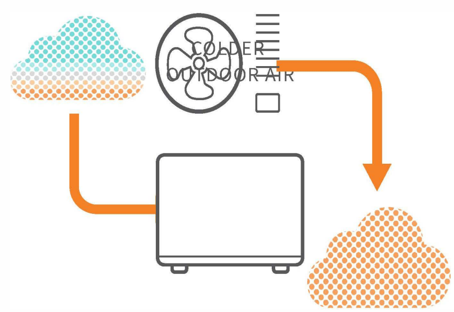
of Oregon homes burn fuels on-site for cooking, heat, or hot water.[2]

68%

of commercial buildings in the Pacific region burn fuels on-site.[3]

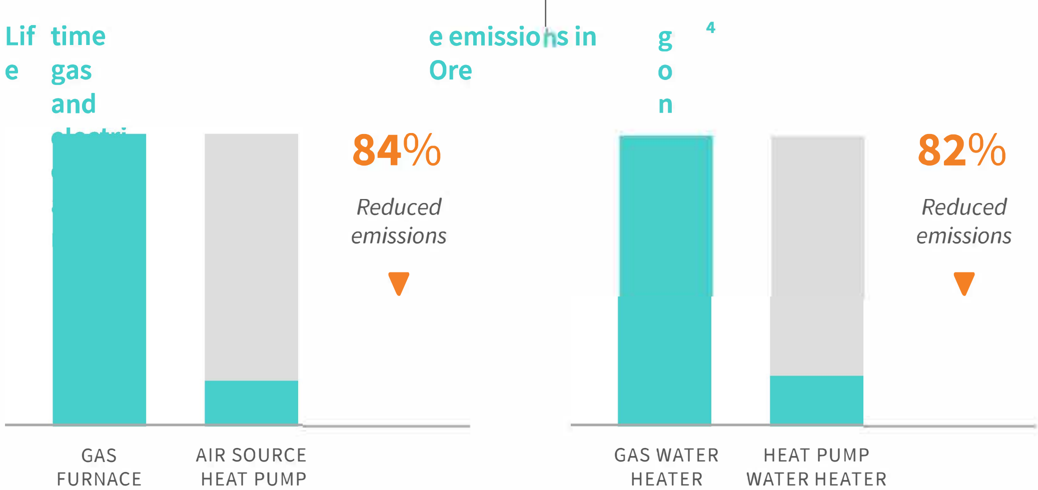
Heat pumps are two efficient appliances in one

Heat pumps are so efficient because **they *move* heat rather than *make* heat**. In winter a heat pump gathers warmth from the air or ground (even in sub-zero temperatures) and moves it indoors. That flow is reversed to cool buildings in summer by moving heat outdoors. Heat pumps can replace both a furnace and an air conditioner. Plus, they can be used in water heaters, clothes dryers, and other appliances.



All-electric buildings reduce carbon emissions

Replacing fossil fuel appliances with electric heat pumps dramatically reduces carbon emissions from buildings in Oregon. This is because **heat pumps are 2 to 4 times more efficient than gas appliances**. The carbon savings are even more significant when replacing oil and propane systems, and will only improve as Oregon's electricity grid continues to get cleaner.



AVISTA

1411 East Mission Avenue
PO Box 3727
Spokane, WA 99220-3727

Account Number: ~~9955810000~~
Notice Date: January 2, 2025
www.myavista.com

Environmental Intervenors/104
Apter/1

Final Notice

Payment was due: **12/13/2024**
Total Amount Due: **$ 257.88**

Charges for Service at:
~~ADAM C STALLSWORTH~~
~~6465 ROGUE RIVER HWY~~
~~GRANTS PASS, OR 97527~~

Your natural gas service is scheduled to be shut off.

To keep your natural gas service connected, your $257.88 past due balance must be paid by 01/14/2025. If payment is not received, your service could be disconnected as early as 01/15/2025.

Please contact us immediately to prevent service disconnection.

To learn about assistance options that may be available to help with your past due balance, visit **www.myavista.com/ORassistance** or give us a call.

- **Immediate hardship grants** may be available through your local community agency.
- **Ongoing bill discounts** through our *My Energy Discount* program are available to income-eligible customers. Enroll through us or your local community agency.
- **Short-term payment plans and longer-term arrangements** can extend due dates and provide more time to catch up. Contact us to see if your account is eligible.
- **Other assistance** for food, transportation, housing, and more may be available through your local community agency.
- **Additional protections** may be available to qualified households (see next page for details).

If you have already sent your payment, please notify us immediately. Payments sent via postal mail or made at pay stations may take several days to post to your account. We accept multiple forms of payment. Find your way to pay at **www.myavista.com/waystopay**.

If your service is disconnected, reconnection requests made Monday through Friday between 7:00 a.m. and 7:00 p.m. will be completed the same day. Requests received outside of these hours will be reconnected on the next business day.

We need to hear from you. Please call us at (800) 227-9187 Monday through Friday from 7:00 a.m. to 7:00 p.m. and Saturday from 9:00 a.m. to 5:00 p.m.

Sincerely,
Avista

TRA1-D-000326/000390 VG4H5W ETM1C00001 6 ACOLL1-10113 9955810000808 (VG4H5W 000326010201O)

Please read other side for important customer information.

Account Number: 9955810000

AVISTA
1411 E MISSION AVE
SPOKANE WA 99252-0001

Due Date: **01/14/2025**
Total Amount Past Due: **$257.88**

Amount Enclosed $

000326 1 AB 0.588 00326/000326/000390 2 2 VG4H5W
~~ADAM C STALLSWORTH~~
~~6465 ROGUE RIVER HWY~~
~~GRANTS PASS OR 97527-4452~~

3429429131
AVISTA
1411 E MISSION AVE
SPOKANE WA 99252-0001

995581000060000025788000000000000000359976

AVISTA www.myavista.com

Important Information

Medical Certificate

If you qualify, you may obtain a medical certificate from a qualified medical professional. The certificate must state that shutting off your natural gas service would significantly endanger your physical health or a member of your household.

The qualified medical professional who gives you the certificate may call us over the phone, but must send a confirmation letter within 30 days. The certificate is valid for the length of the illness or a maximum of six months. You will be required to agree to a time-payment agreement for the overdue balance.

Payment Agreement

You may agree to a payment agreement and choose either a levelized payment plan or an equal-pay arrangement plan to pay the overdue amount.

We are willing to make mutually satisfactory payment arrangements. You may call our toll-free number 1-800-227-9187.

For paystation locations, visit www.myavista.com/paystations

Financial Assistance Contact Information

Several programs provide financial assistance, depending on your circumstances. Call your community action office listed below. They may be able to help you. If they cannot help you, they may be able to find another agency that can.

Oregon Community Action Office

County	Telephone
Douglas	1-855-935-2542
Jackson	1-541-779-9020
Josephine	1-541-956-4050
Klamath	1-866-665-6438
Union	1-541-963-7532

Low Income Protections

If you are a low-income customer, you have access to additional protections. To qualify as an eligible low-income residential customer under Division 21 rules, a customer must either have received energy assistance in the past 12 months, be enrolled in a utility's income-qualified energy assistance program, or self-certify based on income below 60% of Oregon's median income.

Specific protections include:

- No late fees
- No deposits
- One waived reconnection fee (at a minimum) Customers enrolled in My Energy Discount with an income at or below 5% of the state median income will have all reconnection fees waived.

Weather Protections

To ensure your safety, we will not disconnect your service during periods of severe weather. Specifically, disconnections will be suspended when temperatures are forecasted to drop below 32° F or when a winter storm warning is issued, including the 24 hours preceding the forecasted event. Additionally, during local Heat Advisories and extreme events such as wildfires or poor air quality, your service will remain connected. Please stay safe and do not hesitate to contact us if you require assistance.

Complaints and Disputes

If you have a complaint or dispute with Avista, please contact our office at 1-800-227-9187. Any complaint or dispute received by us will be promptly investigated. If we cannot resolve your complaint, you can contact your state public utility commission.

Public Utility Commission of Oregon

Toll-free... 1-800-522-2404

TRA3-D-000326/000391 VG4H5W ETM1C00001 6 ACOLL1-10113 995581000080 8 (VG4H5W 000326020201 0)

Spanish

AVISO IMPORTANTE: Su servicio de gas será suspendido debido a que existe un saldo sin pagar en su cuenta. Ud. debe actuar inmediatamente para evitar la suspensión del servicio. Información importante acerca de cómo puede Ud. evitar la suspension del servicio está impresa en inglés en el aviso adjunto. Si Ud. no entiende inglés, por favor busque a alguien que le traduzca el aviso. Si no dispone de ayuda para la traducción, favor de comunicarse con

1-800-659-7427

quien tratará de ayudarle. Información impresa en este idioma, acerca de los derechos del usuario y las responsabilidades de éste, también se encuentra disponible si llama a este número.

UD. DEBE ACTUAR AHORA MISMO PARA EVITAR LA SUSPENSION DEL SERVICIO

Russian

ВАЖНОЕ УВЕДОМЛЕНИЕ: В Вашем доме будет отключен газ, поскольку Вы не уплатили по предыдущему счету. Для того, чтобы избежать отключения, Вам необходимо немедленно отреагировать. В прилагаемой инструкции, напечатанной на английском языке, содержится важная информация о том, каким образом Вы сможете избежать отключения. Если Вы не читаете по-английски, найдите, пожалуйста, кого-нибудь, кто сможет перевести Вам эту инструкцию. Если никто не сможет Вам в этом помочь, позвоните, пожалуйста, по следующему телефону

1-800-659-7427

Это лицо постарается Вам помочь. По этому же телефону Вы можете заказать Инструкцию о правах и обязанностях потребителя коммунальных услуг, напечатанную на русском языке.

ЧТОБЫ ИЗБЕЖАТЬ ОТКЛЮЧЕНИЯ, РЕАГИРУЙТЕ НЕМЕДЛЕННО

English

IMPORTANT NOTICE: Your gas service will be shut off because of an unpaid balance on your account. You must act immediately to avoid shut-off. Important information about how you can avoid shut-off is printed in English in the enclosed notice. If you cannot understand English, please find someone to translate the notice. If translation assistance is unavailable, please contact

1-800-659-7427

who will try to help you. Information on customer rights and responsibilities printed in this language is also available by calling that number.

YOU MUST ACT NOW TO AVOID SHUT-OFF

Vietnamese

<u>CÁO THỊ QUAN TRỌNG:</u> Hệ thống hơi đốt của bạn sẽ bị cúp bởi vì một ngân khỏan chưa được thanh toán trong trương mục của bạn. Bạn hãy trả ngay tức khắc để tránh tình trạng bị cúp hơi đốt. Những chỉ dẫn quan trọng để tránh việc bị cúp hơi đốt đã được in trong bản tiếng Anh kèm chung với bản cáo thị này. Nếu bạn không hiểu được tiếng Anh, xin hãy nhờ một vị nào đó dịch lại bản cáo thị này cho bạn. Nếu bạn không thể tìm được ai để dịch giúp bạn, xin liên lạc về

1-800-659-7427

Vị này sẽ giúp bạn. Những sự chỉ dẫn về quyền lợi và bổn phận của khách hàng đã được in bằng tiếng Việt; bạn có thể liên lạc về địa chỉ ở trên để được chỉ dẫn.

<u>Bạn phải hành động ngay đ" e tránh tình trạng bị cúp hơi đốt</u>

Cambodian

<u>លិខិតសំខាន់ :</u> ការប្រើប្រាស់ផ្ទែកហ្គាស់អ្នកនឹងត្រូវបិទកាត់ផ្តាច់មកពីមូលហេតុដែលអ្នកមិនបានបង់ប្រាក់តាមបញ្ជីគណនេយ្យ ។ អ្នកត្រូវប្រញាប់ដោះស្រាយកិច្ចនេះជាបន្ទាន់។ ពត៌មានសំខាន់ៗថាតើអ្នកត្រូវធ្វើបែបណាដើម្បីជៀសវាងពីករណីនេះមានសរសេរប្រាប់ជាភាសាអង់គ្លេសភ្ជាប់ជាមួយលិខិតនេះ ។ បើអ្នកមិនយល់ជាភាសាអង់គ្លេសទេ សូមរកមនុស្សដែលគេចេះជួយបកប្រែលិខិតនេះ ។ បើគ្មានជំនួយការបកប្រែទេនោះ សូមទាក់ទង

1-800-659-7427

គេនឹងជួយអ្នកបាន ។ ពត៌មានស្តីពីសិទ្ធិនិងការទទួលខុសត្រូវគ្រប់យ៉ាងសំរាប់អ្នកប្រើប្រាស់មានសរសេរជាភាសានេះ សូមទាក់ទងទូរស័ព្ទទៅលេខដូចបានជំរាប ។

<u>អ្នកត្រូវដោះស្រាយកិច្ចនេះជាបន្ទាន់ដើម្បីជៀសវាងពីការបិទកាត់ផ្តាច់</u>

Laotian

<u>ຄຳຕັກເຕືອນທີ່ສຳຄັນ:</u>

ການບໍລິການແກສຂອງທ່ານຈະຖືກຕັດເພາະທ່ານບໍ່ຈ່າຍເງິນ. ທ່ານຕ້ອງຈ່າຍໃນທັນໃດໂລດເພື່ອເວັ້ນຈາກການຕັດນ້ຳ. ຂໍ້ມູນສຳຄັນກ່ຽວກັບວິທີການທີ່ທ່ານສາມາດເວັ້ນຈາກການຕັດນ້ຳ ແມ່ນພິມເປັນພາສາອັງກິດຢູ່ຄຳເຕືອນທີ່ສົ່ງມາພ້ອມນີ້. ຖ້າທ່ານບໍ່ເຂົ້າໃຈພາສາອັງກິດ, ກະຣຸນາຊອກຫາຜູ້ໃດຜູ້ໜຶ່ງແປຄຳຕັກເຕືອນສະບັບນີ້. ຖ້າຊອກຫາຜູ້ແປພາສາບໍ່ໄດ້, ກະຣຸນາຕິດຕໍ່ກັບ

1-800-659-7427

ຜູ້ຈະພະຍາຍາມຊ່ວຍທ່ານ. ຂໍ້ມູນກ່ຽວກັບສິດ ແລະຄວາມຮັບຜິດຊອບຂອງຜູ້ຮັບການບໍລິການທີ່ພິມເປັນພາສານີ້ກໍມີເໝືອນກັນ ໂດຍໃຫ້ໂທຫານ້ຳເບີນັ້ນ.

<u>ທ່ານຕ້ອງຈ່າຍດຽວນີ້</u>
<u>ເພື່ອເວັ້ນຈາກການຕັດການບໍລິການ</u>

AVISTA

1411 East Mission Avenue
PO Box 3727
Spokane, WA 99220-3727

Account Number: [redacted]
Notice Date: January 2, 2025
www.myavista.com

Environmental Intervenors/104
Apter/5

Past Due Notice

Payment was due:		**12/31/2024**
Total Amount Past Due:	**$**	**306.78**

Charges for Service at:
[redacted]

Our records show your account is past due.

We want to work with you on a plan to manage your balance.

To keep your natural gas service connected, please address your past due balance of $306.78 by 01/29/2025. If this balance is not paid or a payment arrangement is not made, your service may be disconnected as early as 01/30/2025, without further notice.

Find assistance

- **Immediate hardship grants may be available through your local community agency.**
- **Ongoing bill discounts through our My Energy Discount program are available to income-eligible customers. Enroll through us or your local community agency.**
- **Short-term payment plans and longer-term arrangements can extend due dates and provide more time to catch up. Contact us to see if your account is eligible.**
- **Other assistance for food, transportation, housing, and more may be available through your local community agency.**
- **Additional protections may be available to qualified households (see next page for details).**

Payment options
We accept multiple forms of payment. Find your way to pay at www.myavista.com/waystopay. Options include over the phone, on our website, via our mobile app, by text, by postal mail, or at authorized pay stations. If you have already sent your payment, please notify us immediately. Payments sent via postal mail or made at pay stations may take several days to post to your account.

Reconnection
If your service is disconnected, reconnection requests made Monday through Friday between 7:00 a.m. and 7:00 p.m. will be completed the same day. Requests received outside of these hours will be reconnected on the next business day.

Contact us
We want to assist you. Please call us at (800) 227-9187 Monday through Friday from 7:00 a.m. to 7:00 p.m. and Saturday from 9:00 a.m. to 5:00 p.m. Learn more about assistance options at www.myavista.com/ORassistance.

Sincerely,
Avista

TRA1-D-000452/000564 VG4H5W ETM1C00001 6 ACOLL1-10112 7689959493091 (VG4H5W 0004520102010)

Please read other side for important customer information.

Account Number: 7689959493

AVISTA

1411 E MISSION AVE
SPOKANE WA 99252-0001

Due Date: **01/29/2025**
Total Amount Past Due: **$306.78**

Amount Enclosed **$**

000452 1 AB 0.588 00452/000452/000564 2 2 VG4H5W
[redacted]

3429429477
AVISTA
1411 E MISSION AVE
SPOKANE WA 99252-0001

76899594931000001523400000000000000306789

AVISTA www.myavista.com

Important Information

Medical Certificate
If you qualify, you may obtain a medical certificate from a qualified medical professional. The certificate must state that shutting off your natural gas service would significantly endanger your physical health or a member of your household.

The qualified medical professional who gives you the certificate may call us over the phone, but must send a confirmation letter within 30 days. The certificate is valid for the length of the illness or a maximum of six months. You will be required to agree to a time-payment agreement for the overdue balance.

Payment Agreement
You may agree to a payment agreement and choose either a levelized payment plan or an equal-pay arrangement plan to pay the overdue amount.

We are willing to make mutually satisfactory payment arrangements. You may call our toll-free number 1-800-227-9187.

For paystation locations, visit www.myavista.com/paystations

Financial Assistance Contact Information
Several programs provide financial assistance, depending on your circumstances. Call your community action office listed below. They may be able to help you. If they cannot help you, they may be able to find another agency that can.

Oregon Community Action Office

County	Telephone
Douglas	1-855-935-2542
Jackson	1-541-779-9020
Josephine	1-541-956-4050
Klamath	1-866-665-6438
Union	1-541-963-7532

Low Income Protections
If you are a low-income customer, you have access to additional protections. To qualify as an eligible low-income residential customer under Division 21 rules, a customer must either have received energy assistance in the past 12 months, be enrolled in a utility's income-qualified energy assistance program, or self-certify based on income below 60% of Oregon's median income.

Specific protections include:
- No late fees
- No deposits
- One waived reconnection fee (at a minimum) Customers enrolled in My Energy Discount with an income at or below 5% of the state median income will have all reconnection fees waived.

Weather Protections
To ensure your safety, we will not disconnect your service during periods of severe weather. Specifically, disconnections will be suspended when temperatures are forecasted to drop below 32° F or when a winter storm warning is issued, including the 24 hours preceding the forecasted event. Additionally, during local Heat Advisories and extreme events such as wildfires or poor air quality, your service will remain connected. Please stay safe and do not hesitate to contact us if you require assistance.

Complaints and Disputes
If you have a complaint or dispute with Avista, please contact our office at 1-800-227-9187. Any complaint or dispute received by us will be promptly investigated. If we cannot resolve your complaint, you can contact your state public utility commission.

Public Utility Commission of Oregon
Toll-free...1-800-522-2404

Spanish

AVISO IMPORTANTE: Su servicio de gas será suspendido debido a que existe un saldo sin pagar en su cuenta. Ud. debe actuar inmediatamente para evitar la suspensión del servicio. Información importante acerca de cómo puede Ud. evitar la suspension del servicio está impresa en inglés en el aviso adjunto. Si Ud. no entiende inglés, por favor busque a alguien que le traduzca el aviso. Si no dispone de ayuda para la traducción, favor de comunicarse con

1-800-659-7427

quien tratará de ayudarle. Información impresa en este idioma, acerca de los derechos del usuario y las responsabilidades de éste, también se encuentra disponible si llama a este número.

UD. DEBE ACTUAR AHORA MISMO PARA EVITAR LA SUSPENSION DEL SERVICIO

Russian

ВАЖНОЕ УВЕДОМЛЕНИЕ: В Вашем доме будет отключен газ, поскольку Вы не уплатили по предыдущему счету. Для того, чтобы избежать отключения, Вам необходимо немедленно отреагировать. В прилагаемой инструкции, напечатанной на английском языке, содержится важная информация о том, каким образом Вы сможете избежать отключения. Если Вы не читаете по-английски, найдите, пожалуйста, кого-нибудь, кто сможет перевести Вам эту инструкцию. Если никто не сможет Вам в этом помочь, позвоните, пожалуйста, по следующему телефону

1-800-659-7427

Это лицо постарается Вам помочь. По этому же телефону Вы можете заказать Инструкцию о правах и обязанностях потребителя коммунальных услуг, напечатанную на русском языке.

ЧТОБЫ ИЗБЕЖАТЬ ОТКЛЮЧЕНИЯ, РЕАГИРУЙТЕ НЕМЕДЛЕННО

English

IMPORTANT NOTICE: Your gas service will be shut off because of an unpaid balance on your account. You must act immediately to avoid shut-off. Important information about how you can avoid shut-off is printed in English in the enclosed notice. If you cannot understand English, please find someone to translate the notice. If translation assistance is unavailable, please contact

1-800-659-7427

who will try to help you. Information on customer rights and responsibilities printed in this language is also available by calling that number.

YOU MUST ACT NOW TO AVOID SHUT-OFF

TRA3-D-000452/000565 VG4H5W ETM1C00001 6 ACOLL1-10112 7689959493091 (VG4H5W 0004520202010)

Vietnamese

CÁO THỊ QUAN TRỌNG: Hệ thống hơi đốt của bạn sẽ bị cúp bởi vì một ngân khỏan chưa được thanh toán trong trương mục của bạn. Bạn hãy trả ngay tức khắc để tránh tình trạng bị cúp hơi đốt. Những chỉ dẫn quan trọng để tránh việc bị cúp hơi đốt đã được in trong bản tiếng Anh kèm chung với bản cáo thị này. Nếu bạn không hiểu được tiếng Anh, xin hãy nhờ một vị nào đó dịch lại bản cáo thị này cho bạn. Nếu bạn không thể tìm được ai để dịch giúp bạn, xin liên lạc về

1-800-659-7427

Vị này sẽ giúp bạn. Những sự chỉ dẫn về quyền lợi và bổn phận của khách hàng đã được in bằng tiếng Việt; bạn có thể liên lạc về địa chỉ ở trên để được chỉ dẫn.

Bạn phải hành động ngay đ˝e tránh tình trạng bị cúp hơi đốt

Cambodian

លិខិតសំខាន់ : ការប្រើប្រាស់ផ្ទែក ហ្គាស់អ្នកនឹងត្រូវបិទកាត់ផ្តាច់មកពី មូលហេតុដែលអ្នកមិនបានបង់ប្រាក់ តាមបញ្ជីគណនេយ្យ ។ អ្នកត្រូវ ប្រញាប់ដោះស្រាយកិច្ចនេះជាបន្ទាន់។ ពត៌មានសំខាន់ៗថាតើអ្នកត្រូវធ្វើបែប ណាដើម្បីជៀសវាងពីករណីនេះមាន សរសេរប្រាប់ជាភាសាអង់គ្លេសភ្ជាប់ ជាមួយលិខិតនេះ ។ បើអ្នកមិនយល់ជា ភាសាអង់គ្លេសទេ សូមរកមនុស្សដែល គេចេះជួយបកប្រែលិខិតនេះ ។ បើគ្មានជំនួយការបកប្រែទេនោះ សូម ទាក់ទង

1-800-659-7427

គេនិងជួយអ្នកបាន ។ ពត៌មានស្តីពីសិទ្ធិ និងការទទួលខុសត្រូវគ្រប់យ៉ាងសំរាប់ អ្នកប្រើប្រាស់មានសរសេរបោះជា ភាសានេះ សូមទាក់ទងទូរស័ព្ទទៅ លេខដូចបានជំរាប ។

អ្នកត្រូវដោះស្រាយកិច្ចនេះជា បន្ទាន់ដើម្បីជៀសវាងពីការបិទ កាត់ផ្តាច់

Laotian

ຄຳຕັກເຕືອນທີ່ສຳຄັນ: ການບໍລິການແກສຂອງທ່ານຈະຖືກຕັດ ເພາະທ່ານບໍ່ຈ່າຍເງິນ. ທ່ານຕ້ອງຈ່າຍ ໃນທັນໃດໂລດເພື່ອເວັ້ນຈາກການຕັດນ້ຳ. ຂໍ້ມູນສຳຄັນກ່ຽວກັບວິທີການທີ່ທ່ານສາ ມາດເວັ້ນຈາກການຕັດນ້ຳ ແມ່ນພິມເປັນ ພາສາອັງກິດຢູ່ຄຳເຕືອນທີ່ສົ່ງມາພ້ອມນີ້. ຖ້າທ່ານບໍ່ເຂົ້າໃຈພາສາອັງກິດ, ກະລຸນາ ຊອກຫາຜູ້ໃດຜູ້ໜຶ່ງແປຄຳຕັກເຕືອນສະ ບັບນີ້. ຖ້າຊອກຫາຜູ້ແປພາສາບໍ່ໄດ້, ກະລຸນາຕິດຕໍ່ກັບ

1-800-659-7427

ຜູ້ຈະພະຍາຍາມຊ່ວຍທ່ານ. ຂໍ້ມູນກ່ຽວ ກັບສິດ ແລະຄວາມຮັບຜິດຊອບຂອງຜູ້ຮັບ ການບໍລິການທີ່ພິມເປັນພາສານີ້ກໍມີ ເໝືອນກັນ ໂດຍໃຫ້ໂທຫານ້ຳເບີນັ້ນ.

ທ່ານຕ້ອງຈ່າຍດຽວນີ້ ເພື່ອເວັ້ນຈາກການຕັດການບໍລິການ

OFFICE OF THE SECRETARY OF STATE
LAVONNE GRIFFIN-VALADE
SECRETARY OF STATE

CHERYL MYERS
DEPUTY SECRETARY OF STATE
AND TRIBAL LIAISON

ARCHIVES DIVISION
STEPHANIE CLARK
DIRECTOR

800 SUMMER STREET NE
SALEM, OR 97310
503-373-0701

PERMANENT ADMINISTRATIVE ORDER

FILED
11/22/2024 9:09 AM
ARCHIVES DIVISION
SECRETARY OF STATE
& LEGISLATIVE COUNSEL

DEQ 18-2024

CHAPTER 340
DEPARTMENT OF ENVIRONMENTAL QUALITY

FILING CAPTION: Climate Protection Program 2024

EFFECTIVE DATE: 11/22/2024

AGENCY APPROVED DATE: 11/21/2024

CONTACT: Emil Hnidey
503-568-0376
emil.hnidey@deq.oregon.gov

700 NE Multnomah St.
Suite 600
Portland,OR 97232

Filed By:
Emil Hnidey
Rules Coordinator

RULES:
340-012-0054, 340-012-0135, 340-012-0140, 340-215-0040, 340-215-0130, 340-216-8010, 340-253-0600, 340-253-1020, 340-272-0120, 340-273-0010, 340-273-0020, 340-273-0030, 340-273-0090, 340-273-0100, 340-273-0110, 340-273-0120, 340-273-0130, 340-273-0150, 340-273-0400, 340-273-0410, 340-273-0420, 340-273-0430, 340-273-0440, 340-273-0450, 340-273-0490, 340-273-0500, 340-273-0510, 340-273-0590, 340-273-0810, 340-273-0820, 340-273-0830, 340-273-0890, 340-273-0900, 340-273-0910, 340-273-0920, 340-273-0930, 340-273-0950, 340-273-0960, 340-273-0990, 340-273-8100, 340-273-8110, 340-273-8120, 340-273-9000

AMEND: 340-012-0054

RULE TITLE: Air Quality Classification of Violations

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Establishes classifications of violations of division 273 requirements, as part of adopting a schedule of civil penalties.

RULE TEXT:
(1) Class I:
(a) Constructing a new source or modifying an existing source without first obtaining a required New Source Review/Prevention of Significant Deterioration (NSR/PSD) permit;
(b) Constructing a new source, as defined in OAR 340-245-0020, without first obtaining a required Air Contaminant Discharge Permit that includes permit conditions required under OAR 340-245-0005 through 340-245-8050 or without complying with Cleaner Air Oregon rules under OAR 340-245-0005 through 340-245-8050;
(c) Failing to conduct a source risk assessment, as required under OAR 340-245-0050;
(d) Modifying a source in such a way as to require a permit modification under OAR 340-245-0005 through 340-245-8050, that would increase risk above permitted levels under OAR 340-245-0005 through 340-245-8050 without first obtaining such approval from DEQ;
(e) Operating a major source, as defined in OAR 340-200-0020, without first obtaining the required permit;
(f) Operating an existing source, as defined in OAR 340-245-0020, after a submittal deadline under OAR 340-245-0030 without having submitted a complete application for a Toxic Air Contaminant Permit Addendum required under OAR

340-245-0005 through 340-245-8050;

(g) Exceeding a Plant Site Emission Limit (PSEL);

(h) Exceeding a risk limit, including a Source Risk Limit, applicable to a source under OAR 340-245-0100;

(i) Failing to install control equipment or meet emission limits, operating limits, work practice requirements, or performance standards as required by New Source Performance Standards under OAR 340 division 238 or National Emission Standards for Hazardous Air Pollutant Standards under OAR 340 division 244;

(j) Exceeding a hazardous air pollutant emission limitation;

(k) Failing to comply with an Emergency Action Plan;

(l) Exceeding an opacity or emission limit (including a grain loading standard) or violating an operational or process standard, that was established under New Source Review/Prevention of Significant Deterioration (NSR/PSD);

(m) Exceeding an emission limit or violating an operational or process standard that was established to limit emissions to avoid classification as a major source, as defined in OAR 340-200-0020;

(n) Exceeding an emission limit or violating an operational limit, process limit, or work practice requirement that was established to limit risk or emissions to avoid exceeding an applicable Risk Action Level or other requirement under OAR 340-245-0005 through 340-245-8050;

(o) Exceeding an emission limit, including a grain loading standard, by a major source, as defined in OAR 340-200-0020, when the violation was detected during a reference method stack test;

(p) Failing to perform testing or monitoring, required by a permit, permit attachment, rule or order, that results in failure to show compliance with a Plant Site Emission Limit or with an emission limitation or a performance standard established under New Source Review/Prevention of Significant Deterioration, National Emission Standards for Hazardous Air Pollutants, New Source Performance Standards, Reasonably Available Control Technology, Best Available Control Technology, Maximum Achievable Control Technology, Typically Achievable Control Technology, Lowest Achievable Emission Rate, Toxics Best Available Control Technology, Toxics Lowest Achievable Emission Rate, or adopted under section 111(d) of the Federal Clean Air Act;

(q) Causing emissions that are a hazard to public safety;

(r) Violating a work practice requirement for asbestos abatement projects;

(s) Improperly storing or openly accumulating friable asbestos material or asbestos-containing waste material;

(t) Conducting an asbestos abatement project, by a person not licensed as an asbestos abatement contractor;

(u) Violating an OAR 340 division 248 disposal requirement for asbestos-containing waste material;

(v) Failing to hire a licensed contractor to conduct an asbestos abatement project;

(w) Openly burning materials which are prohibited from being open burned anywhere in the state by OAR 340-264-0060(3), or burning materials in a solid fuel burning device, fireplace, trash burner or other device as prohibited by OAR 340-262-0900(1);

(x) Failing to install certified vapor recovery equipment;

(y) Delivering for sale a noncompliant vehicle by a vehicle manufacturer in violation of Oregon Low Emission and Zero Emission Vehicle rules set forth in OAR 340 division 257;

(z) Exceeding an Oregon Low Emission Vehicle average emission limit set forth in OAR 340 division 257;

(aa) Failing to comply with Zero Emission Vehicle (ZEV) sales requirements, or to meet credit retirement and/or deficit requirements, under OAR 340 division 257;

(bb) Failing to obtain a Motor Vehicle Indirect Source Permit as required in OAR 340 division 257;

(cc) Selling, leasing, or renting a noncompliant vehicle by an automobile dealer or rental car agency in violation of Oregon Low Emission Vehicle rules set forth in OAR 340 division 257;

(dd) Violating any of the clean fuel standards set forth in OAR 340-253-0100(6) and in Tables 1 and 2 of OAR 340-253-8010;

(ee) Committing any action related to a credit transfer that is prohibited in OAR 340-253-1005(8);

(ff) Inaccurate reporting that causes illegitimate credits to be generated in the Oregon Clean Fuels Program, OAR chapter 340, division 253, or that understates a registered party’s true compliance obligation in deficits under such program;

(gg) Misstating material information or providing false information when submitting an application for a carbon intensity score under OAR 340-253-0450, OAR 340-253-0460, or OAR 340-253-0470, or when submitting an application for advance credits under OAR 340-253-1100;

(hh) Failing to timely submit a complete and accurate annual compliance report under OAR 340-253-0650;

(ii) Failing to timely submit a complete and accurate emissions data report under OAR 340-215-0044 and OAR 340-215-0046;

(jj) Submitting a verification statement to DEQ prepared by a person not approved by DEQ under OAR 340-272-0220 to perform verification services;

(kk) Failing to timely submit a verification statement that meets the verification requirements under OAR 340-272-0100 and OAR 340-272-0495;

(ll) Failing to submit a revised application or report to DEQ according to OAR 340-272-0435;

(mm) Failing to complete re-verification according to OAR 340-272-0350(2);

(nn) Failing to timely submit a Methane Generation Rate Report or Instantaneous Surface Monitoring Report according to OAR 340-239-0100;

(oo) Failing to timely submit a Design Plan or Amended Design Plan in accordance with OAR 340-239-0110(1);

(pp) Failing to timely install and operate a landfill gas collection and control system according to OAR 340-239-0110(1);

(qq) Failing to operate a landfill gas collection and control system or conduct performance testing of a landfill gas control device according to the requirements in OAR 340-239-0110(2);

(rr) Failing to conduct landfill wellhead sampling under OAR 340-239-0110(3);

(ss) Failing to comply with a landfill compliance standard in OAR 340-239-0200;

(tt) Failing to conduct monitoring or remonitoring in accordance with OAR 340-239-0600 that results in a failure to demonstrate compliance with a landfill compliance standard in OAR 340-239-0200 or the 200 ppmv threshold in OAR 340-239-0100(6)(b) or OAR 340-239-0400(2)(c);

(uu) Failure to take corrective actions in accordance with OAR 340-239-0600(1);

(vv) Failing to comply with a landfill gas collection and control system permanent shutdown and removal requirement in OAR 340-239-0400(1);

(ww) Delivering for sale a new noncompliant on highway heavy duty engine, truck or trailer in violation of rules set forth under OAR 340 division 261;

(xx) Failing to notify DEQ of changes in ownership or operational control or changes to related entities under OAR 340-273-0120;

(yy) Owning or operating a covered entity, identified in OAR 340-273-0110, after a submittal deadline under OAR 340-273-0150(1)(a) or OAR 340-273-0150(2)(a) without having submitted a complete application for a Climate Protection Program permit required under OAR 340-273-0150;

(zz) Failing to comply with a condition in a Climate Protection Program permit, issued according to OAR 340-273-0150;

(aaa) Failing to demonstrate compliance according to OAR 340-273-0450;

(bbb) Failing to comply with the requirements for trading of compliance instruments under OAR 340-273-0500 or 340-273-0510;

(ccc) Submitting false or inaccurate information on any application or submittal required under OAR chapter 340, division 273;

(ddd) Failing to register as a regulated party in the Oregon Clean Fuels Program under OAR 340-253-0100(1) and (4); or

(eee) Failing by a fuel producer to inform DEQ if its operational carbon intensity exceeds its certified carbon intensity as described in OAR 340-253-0450(9)(e)(D) when credits generated from those certified carbon intensity values generated illegitimate credits as described in OAR 340-253-1005(7). .

(2) Class II:

(a) Constructing or operating a source required to have an Air Contaminant Discharge Permit (ACDP), ACDP attachment, or registration without first obtaining such permit or registration, unless otherwise classified;
(b) Violating the terms or conditions of a permit, permit attachment or license, unless otherwise classified;
(c) Modifying a source in such a way as to require a permit or permit attachment modification from DEQ without first obtaining such approval from DEQ, unless otherwise classified;
(d) Exceeding an opacity limit, unless otherwise classified;
(e) Exceeding a Volatile Organic Compound (VOC) emission standard, operational requirement, control requirement or VOC content limitation established by OAR 340 division 232;
(f) Failing to timely submit a complete ACDP annual report or permit attachment annual report;
(g) Failing to timely submit a certification, report, or plan as required by rule, permit or permit attachment, unless otherwise classified;
(h) Failing to timely submit a complete permit application, ACDP attachment application, or permit renewal application;
(i) Failing to submit a timely and complete toxic air contaminant emissions inventory as required under OAR 340-245-0005 through 340-245-8050;
(j) Failing to comply with the open burning requirements for commercial, construction, demolition, or industrial wastes in violation of OAR 340-264-0080 through 0180;
(k) Failing to comply with open burning requirements in violation of any provision of OAR 340 division 264, unless otherwise classified; or burning materials in a solid fuel burning device, fireplace, trash burner or other device as prohibited by OAR 340-262-0900(2).
(l) Failing to replace, repair, or modify any worn or ineffective component or design element to ensure the vapor tight integrity and efficiency of a stage I or stage II vapor collection system;
(m) Failing to provide timely, accurate or complete notification of an asbestos abatement project;
(n) Failing to perform a final air clearance test or submit an asbestos abatement project air clearance report for an asbestos abatement project;
(o) Violating on road motor vehicle refinishing rules contained in OAR 340-242-0620;
(p) Failing to comply with an Oregon Low Emission Vehicle reporting, notification, or warranty requirement set forth in OAR division 257;
(q) Failing to receive Green-e certification for Renewable Energy Certificates used to generate incremental credits when required by OAR 340-253-0470;
(r) Failing to register as an aggregator or submit an aggregator designation form under OAR 340-253-0100(3) and (4)(c);
(s) Failing to keep complete and accurate records under OAR 340-253-0600;
(t) Failing to ensure that a registered party has the exclusive right to the environmental attributes that it has claimed for biomethane, biogas, or renewable electricity either directly as a fuel or indirectly as a feedstock under OAR chapter 340, division 253 by either the registered party, the fuel producer, and/or fuel pathway holder;
(u) Failing to timely submit a complete and accurate quarterly report under OAR 340-253-0630;
(v) Violating any requirement under OAR chapter 340, division 272, unless otherwise classified;
(w) Violating any requirement under OAR chapter 340, division 239, unless otherwise classified;
(x) Failing to comply with the reporting notification or warranty requirements for new engines, trucks, and trailers set forth in OAR chapter 340, division 261;
(y) Violating any requirement under the Climate Protection Program, OAR chapter 340, division 273, unless otherwise classified;
(z) Failing to notify DEQ of a change of ownership or control of a registered party under OAR chapter 340, division 253; or
(3) Class III:
(a) Failing to perform testing or monitoring required by a permit, rule or order where missing data can be reconstructed to show compliance with standards, emission limitations or underlying requirements;

(b) Constructing or operating a source required to have a Basic Air Contaminant Discharge Permit without first obtaining the permit;

(c) Modifying a source in such a way as to require construction approval from DEQ without first obtaining such approval from DEQ, unless otherwise classified;

(d) Failing to revise a notification of an asbestos abatement project, when necessary, unless otherwise classified;

(e) Submitting a late air clearance report that demonstrates compliance with the standards for an asbestos abatement project;

(f) Licensing a noncompliant vehicle by an automobile dealer or rental car agency in violation of Oregon Low Emission Vehicle rules set forth in OAR Chapter 340, division 257;

(g) Making changes to a submitted quarterly or annual report under OAR Chapter 340, division 253 without DEQ approval under OAR 340-253-0650(4); or

(h) Failing to upload transactions to a quarterly report by the 45-day deadline under OAR 340-253-0630.

[Note: Tables and Publications referenced are available from the agency.]

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.045

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025

AMEND: 340-012-0135

RULE TITLE: Selected Magnitude Categories

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Determines the magnitudes of violations of division 273 requirements, as part of adopting a schedule of civil penalties.

RULE TEXT:

(1) Magnitudes for selected Air Quality violations will be determined as follows:

(a) Opacity limit violations:

(A) Major — Opacity measurements or readings of 20 percent opacity or more over the applicable limit, or an opacity violation by a federal major source as defined in OAR 340-200-0020;

(B) Moderate — Opacity measurements or readings greater than 10 percent opacity and less than 20 percent opacity over the applicable limit; or

(C) Minor — Opacity measurements or readings of 10 percent opacity or less over the applicable limit.

(b) Operating a major source, as defined in OAR 340-200-0020, without first obtaining the required permit: Major — if a Lowest Achievable Emission Rate (LAER) or Best Available Control Technology (BACT) analysis shows that additional controls or offsets are or were needed, otherwise apply OAR 340-012-0130.

(c) Exceeding an emission limit established under New Source Review/Prevention of Significant Deterioration (NSR/PSD): Major — if exceeded the emission limit by more than 50 percent of the limit, otherwise apply OAR 340-012-0130.

(d) Exceeding an emission limit established under federal National Emission Standards for Hazardous Air Pollutants (NESHAPs): Major — if exceeded the Maximum Achievable Control Technology (MACT) standard emission limit for a directly-measured hazardous air pollutant (HAP), otherwise apply OAR 340-012-0130.

(e) Exceeding a cancer or noncancer risk limit that is equivalent to a Risk Action Level or a Source Risk Limit if the limit is a Risk Action Level established under OAR 340-245-0005 through 340-245-8050: Major, otherwise apply OAR 340-012-0130.

(f) Air contaminant emission limit violations for selected air pollutants: Magnitude determinations under this subsection will be made based upon significant emission rate (SER) amounts listed in OAR 340-200-0020.

(A) Major:

(i) Exceeding the annual emission limit as established by permit, rule or order by more than the annual SER; or

(ii) Exceeding the short-term (less than one year) emission limit as established by permit, rule or order by more than the applicable short-term SER.

(B) Moderate:

(i) Exceeding the annual emission limit as established by permit, rule or order by an amount from 50 up to and including 100 percent of the annual SER; or

(ii) Exceeding the short-term (less than one-year) emission limit as established by permit, rule or order by an amount from 50 up to and including 100 percent of the applicable short-term SER.

(C) Minor:

(i) Exceeding the annual emission limit as established by permit, rule or order by an amount less than 50 percent of the annual SER; or

(ii) Exceeding the short-term (less than one year) emission limit as established by permit, rule or order by an amount less than 50 percent of the applicable short-term SER.

(g) Violations of Emergency Action Plans: Major — Major magnitude in all cases.

(h) Violations of on road motor vehicle refinishing rules contained in OAR 340-242-0620: Minor — Refinishing 10 or fewer on road motor vehicles per year.

(i) Asbestos violations — These selected magnitudes apply unless the violation does not cause the potential for human exposure to asbestos fibers:

(A) Major — More than 260 linear feet or more than 160 square feet of asbestos-containing material or asbestos-containing waste material;
(B) Moderate — From 40 linear feet up to and including 260 linear feet or from 80 square feet up to and including 160 square feet of asbestos-containing material or asbestos-containing waste material; or
(C) Minor — Less than 40 linear feet or 80 square feet of asbestos-containing material or asbestos-containing waste material.
(D) The magnitude of the asbestos violation may be increased by one level if the material was comprised of more than five percent asbestos.
(j) Open burning violations:
(A) Major — Initiating or allowing the initiation of open burning of 20 or more cubic yards of commercial, construction, demolition and/or industrial waste; or 5 or more cubic yards of prohibited materials (inclusive of tires); or 10 or more tires;
(B) Moderate — Initiating or allowing the initiation of open burning of 10 or more, but less than 20 cubic yards of commercial, construction, demolition and/or industrial waste; or 2 or more, but less than 5 cubic yards of prohibited materials (inclusive of tires); or 3 to 9 tires; or if DEQ lacks sufficient information upon which to make a determination of the type of waste, number of cubic yards or number of tires burned; or
(C) Minor — Initiating or allowing the initiation of open burning of less than 10 cubic yards of commercial, construction, demolition and/or industrial waste; or less than 2 cubic yards of prohibited materials (inclusive of tires); or 2 or less tires.
(D) The selected magnitude may be increased one level if DEQ finds that one or more of the following are true, or decreased one level if DEQ finds that none of the following are true:
(i) The burning took place in an open burning control area;
(ii) The burning took place in an area where open burning is prohibited;
(iii) The burning took place in a non-attainment or maintenance area for PM10 or PM2.5; or
(iv) The burning took place on a day when all open burning was prohibited due to meteorological conditions.
(k) Oregon Low Emission Vehicle Non-Methane Gas (NMOG) or Green House Gas (GHG) fleet average emission limit violations:
(A) Major — Exceeding the limit by more than 10 percent; or
(B) Moderate — Exceeding the limit by 10 percent or less.
(l) Oregon Clean Fuels Program violations:
(A) Violating the clean fuel standards set forth in OAR 340-253-0100(6) and Tables 1 and 2 of OAR 340-253-8010: Major
(B) Failing to register under OAR 340-253-0100(1) and (4): Major;
(C) Failing to timely submit a complete and accurate annual compliance report or quarterly report under OAR chapter 340, division 253: Major;
(D) Generating an illegitimate credit under OAR chapter 340, division 253: Major;
(E) Committing any action related to a credit transfer that is prohibited under OAR 340-253-1005(8): Major.
(m) Failing to timely submit a complete and accurate emissions data report under the Oregon Greenhouse Gas Reporting Program, OAR chapter 340, division 215, where the untimely, incomplete or inaccurate reporting impacts applicability, distribution of compliance instruments, or any compliance obligation under the Climate Protection Program, OAR chapter 340, division 273: Major.
(n) Oregon Climate Protection Program violations:
(A) Failing to demonstrate compliance according to OAR 340-273-0450: Major.
(B) Failing to comply with a condition in a Climate Protection Program permit issued according to OAR 340-273-0150: Major.
(C) Failing to obtain a permit issued under OAR 340-273-0150, for a covered entity, as identified in OAR 340-273-0110: Major.

(2) Magnitudes for selected Water Quality violations will be determined as follows:

(a) Violating wastewater discharge permit effluent limitations:

(A) Major:

(i) The dilution (D) of the spill or technology based effluent limitation exceedance was less than two, when calculated as follows: D = ((QR /4) + QI)/ QI, where QR is the estimated receiving stream flow and QI is the estimated quantity or discharge rate of the incident;

(ii) The receiving stream flow at the time of the water quality based effluent limitation (WQBEL) exceedance was at or below the flow used to calculate the WQBEL; or

(iii) The resulting water quality from the spill or discharge was as follows:

(I) For discharges of toxic pollutants: CS/D was more than CAcute, where CS is the concentration of the discharge, D is the dilution of the discharge as determined under (2)(a)(A)(i), and CAcute is the concentration for acute toxicity (as defined by the applicable water quality standard);

(II) For spills or discharges affecting temperature, when the discharge temperature is at or above 32 degrees centigrade after two seconds from the outfall; or

(III) For BOD5 discharges: (BOD5)/D is more than 10, where BOD5 is the concentration of the five-day Biochemical Oxygen Demand of the discharge and D is the dilution of the discharge as determined under (2)(a)(A)(i).

(B) Moderate:

(i) The dilution (D) of the spill or the technology based effluent limitation exceedance was two or more but less than 10 when calculated as follows: D = ((QR /4)+ QI)/ QI, where QR is the estimated receiving stream flow and QI is the estimated quantity or discharge rate of the discharge; or

(ii) The receiving stream flow at the time of the WQBEL exceedance was greater than, but less than twice, the flow used to calculate the WQBEL.

(C) Minor:

(i) The dilution (D) of the spill or the technology based effluent limitation exceedance was 10 or more when calculated as follows: D = ((QR/4) + QI)/ QI, where QR is the receiving stream flow and QI is the quantity or discharge rate of the incident; or

(ii) The receiving stream flow at the time of the WQBEL exceedance was twice the flow or more of the flow used to calculate the WQBEL.

(b) Violating numeric water quality standards:

(A) Major:

(i) Increased the concentration of any pollutant except for toxics, dissolved oxygen, pH, and turbidity, by 25 percent or more of the standard;

(ii) Decreased the dissolved oxygen concentration by two or more milligrams per liter below the standard;

(iii) Increased the toxic pollutant concentration by any amount over the acute standard or by 100 percent or more of the chronic standard;

(iv) Increased or decreased pH by one or more pH units from the standard; or

(v) Increased turbidity by 50 or more nephelometric turbidity units (NTU) over background.

(B) Moderate:

(i) Increased the concentration of any pollutant except for toxics, pH, and turbidity by more than 10 percent but less than 25 percent of the standard;

(ii) Decreased dissolved oxygen concentration by one or more, but less than two, milligrams per liter below the standard;

(iii) Increased the concentration of toxic pollutants by more than 10 percent but less than 100 percent of the chronic standard;

(iv) Increased or decreased pH by more than 0.5 pH unit but less than 1.0 pH unit from the standard; or

(v) Increased turbidity by more than 20 but less than 50 NTU over background.

(C) Minor:

(i) Increased the concentration of any pollutant, except for toxics, pH, and turbidity, by 10 percent or less of the standard;
(ii) Decreased the dissolved oxygen concentration by less than one milligram per liter below the standard;
(iii) Increased the concentration of toxic pollutants by 10 percent or less of the chronic standard;
(iv) Increased or decreased pH by 0.5 pH unit or less from the standard; or
(v) Increased turbidity by 20 NTU or less over background.
(c) The selected magnitude under (2)(a) or (b) may be increased one or more levels if the violation:
(A) Occurred in a water body that is water quality limited (listed on the most current 303(d) list) and the discharge is the same pollutant for which the water body is listed;
(B) Depressed oxygen levels or increased turbidity and/or sedimentation in a stream in which salmonids may be rearing or spawning as indicated by the beneficial use maps available at OAR 340-041-0101 through 0340;
(C) Violated a bacteria standard either in shellfish growing waters or during the period from June 1 through September 30; or
(D) Resulted in a documented fish or wildlife kill.
(3) Magnitudes for selected Solid Waste violations will be determined as follows:
(a) Operating a solid waste disposal facility without a permit or disposing of solid waste at an unpermitted site:
(A) Major — The volume of material disposed of exceeds 400 cubic yards;
(B) Moderate — The volume of material disposed of is greater than or equal to 40 cubic yards and less than or equal to 400 cubic yards; or
(C) Minor — The volume of materials disposed of is less than 40 cubic yards.
(D) The magnitude of the violation may be raised by one magnitude if the material disposed of was either in the floodplain of waters of the state or within 100 feet of waters of the state.
(b) Failing to accurately report the amount of solid waste disposed:
(A) Major — The amount of solid waste is underreported by 15 percent or more of the amount received;
(B) Moderate — The amount of solid waste is underreported by 5 percent or more, but less than 15 percent, of the amount received; or
(C) Minor — The amount of solid waste is underreported by less than 5 percent of the amount received.
(4) Magnitudes for selected Hazardous Waste violations will be determined as follows:
(a) Failure to make a hazardous waste determination;
(A) Major — Failure to make the determination on five or more waste streams;
(B) Moderate — Failure to make the determination on three or four waste streams; or
(C) Minor — Failure to make the determination on one or two waste streams.
(b) Hazardous Waste treatment, storage and disposal violations of OAR 340-012-0068(1)(b), (c), (h), (k), (l), (m), (p), (q) and (r):
(A) Major:
(i) Treatment, storage, or disposal of more than 55 gallons or 330 pounds of hazardous waste; or
(ii) Treatment, storage, or disposal of at least one quart or 2.2 pounds of acutely hazardous waste.
(B) Moderate:
(i) Treatment, storage, or disposal of 55 gallons or 330 pounds or less of hazardous waste; or
(ii) Treatment, storage, or disposal of less than one quart or 2.2 pounds of acutely hazardous waste.
(c) Hazardous waste management violations classified in OAR 340-012-0068(1)(d), (e) (f), (g), (i), (j), (n), (s) and (2)(a), (b), (d), (e), (h), (i), (k), (m), (n), (o), (p), (r) and (s):
(A) Major:
(i) Hazardous waste management violations involving more than 1,000 gallons or 6,000 pounds of hazardous waste; or
(ii) Hazardous waste management violations involving at least one quart or 2.2 pounds of acutely hazardous waste.
(B) Moderate:
(i) Hazardous waste management violations involving more than 250 gallons or 1,500 pounds, up to and including 1,000

gallons or 6,000 pounds of hazardous waste; or

(ii) Hazardous waste management violations involving less than one quart or 2.2 pounds of acutely hazardous waste.

(C) Minor: Hazardous waste management violations involving 250 gallons or 1,500 pounds or less of hazardous waste and no acutely hazardous waste.

(5) Magnitudes for selected Used Oil violations (OAR 340-012-0072) will be determined as follows:

(a) Used Oil violations set forth in OAR 340-012-0072(1)(f), (h), (i), (j); and (2)(a) through (h):

(A) Major — Used oil management violations involving more than 1,000 gallons or 7,000 pounds of used oil or used oil mixtures;

(B) Moderate — Used oil management violations involving more than 250 gallons or 1,750 pounds, up to and including 1,000 gallons or 7,000 pounds of used oil or used oil mixture; or

(C) Minor — Used oil management violations involving 250 gallons or 1,750 pounds or less of used oil or used oil mixtures.

(b) Used Oil spill or disposal violations set forth in OAR 340-012-0072(1)(a) through (e), (g) and (k).

(A) Major — A spill or disposal involving more than 420 gallons or 2,940 pounds of used oil or used oil mixtures;

(B) Moderate — A spill or disposal involving more than 42 gallons or 294 pounds, up to and including 420 gallons or 2,940 pounds of used oil or used oil mixtures; or

(C) Minor — A spill or disposal of used oil involving 42 gallons or 294 pounds or less of used oil or used oil mixtures.

[NOTE: Tables & Publications referenced are available from the agency.]

STATUTORY/OTHER AUTHORITY: ORS 468.065, 468A.045

STATUTES/OTHER IMPLEMENTED: ORS 468.090 - 468.140, 468A.060

AMEND: 340-012-0140

RULE TITLE: Determination of Base Penalty

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Establishes the base penalty amounts for violations of division 273 requirements, as part of adopting a schedule of civil penalties.

RULE TEXT:

(1) Except for Class III violations and as provided in OAR 340-012-0155, the base penalty (BP) is determined by applying the class and magnitude of the violation to the matrices set forth in this section. For Class III violations, no magnitude determination is required.

(2) $12,000 Penalty Matrix:

(a) The $12,000 penalty matrix applies to the following:

(A) Any violation of an air quality statute, rule, permit or related order committed by a person that has or should have a Title V permit or an Air Contaminant Discharge Permit (ACDP) issued pursuant to New Source Review (NSR) regulations or Prevention of Significant Deterioration (PSD) regulations, or section 112(g) of the federal Clean Air Act, unless otherwise classified.

(B) Open burning violations as follows:

(i) Any violation of OAR 340-264-0060(3) committed by an industrial facility operating under an air quality permit.

(ii) Any violation of OAR 340-264-0060(3) in which 25 or more cubic yards of prohibited materials or more than 15 tires are burned, except when committed by a residential owner-occupant.

(C) Any violation of the Oregon Low Emission and Zero Emission Vehicle rules (OAR 340-257) by a vehicle manufacturer.

(D) Any violation of ORS 468B.025(1)(a) or (1)(b), or of 468B.050(1)(a) by a person without a National Pollutant Discharge Elimination System (NPDES) permit, unless otherwise classified.

(E) Any violation of a water quality statute, rule, permit or related order by:

(i) A person that has an NPDES permit, or that has or should have a Water Pollution Control Facility (WPCF) permit, for a municipal or private utility sewage treatment facility with a permitted flow of five million or more gallons per day.

(ii) A person that has a Tier 1 industrial source NPDES or WPCF permit.

(iii) A person that has a population of 100,000 or more, as determined by the most recent national census, and either has or should have a WPCF Municipal Stormwater Underground Injection Control (UIC) System Permit, or has an NPDES Municipal Separated Storm Sewer Systems (MS4) Stormwater Discharge Permit.

(iv) A person that installs or operates a prohibited Class I, II, III, IV or V UIC system, except for a cesspool.

(v) A person that has or should have applied for coverage under an NPDES Stormwater Discharge 1200-C General Permit for a construction site that disturbs 20 or more acres.

(F) Any violation of the ballast water statute in ORS Chapter 783 or ballast water management rule in OAR 340, division 143.

(G) Any violation of a Clean Water Act Section 401 Water Quality Certification by a 100 megawatt or more hydroelectric facility.

(H) Any violation of a Clean Water Act Section 401 Water Quality Certification for a dredge and fill project except for Tier 1, 2A or 2B projects.

(I) Any violation of an underground storage tanks statute, rule, permit or related order committed by the owner, operator or permittee of 10 or more UST facilities or a person who is licensed or should be licensed by DEQ to perform tank services.

(J) Any violation of a heating oil tank statute, rule, permit, license or related order committed by a person who is licensed or should be licensed by DEQ to perform heating oil tank services.

(K) Any violation of ORS 468B.485, or related rules or orders regarding financial assurance for ships transporting hazardous materials or oil.

(L) Any violation of a used oil statute, rule, permit or related order committed by a person who is a used oil transporter, transfer facility, processor or re-refiner, off-specification used oil burner or used oil marketer.
(M) Any violation of a hazardous waste statute, rule, permit or related order by:
(i) A person that is a large quantity generator or hazardous waste transporter.
(ii) A person that has or should have a treatment, storage or disposal facility permit.
(N) Any violation of an oil and hazardous material spill and release statute, rule, or related order committed by a covered vessel or facility as defined in ORS 468B.300 or by a person who is engaged in the business of manufacturing, storing or transporting oil or hazardous materials.
(O) Any violation of a polychlorinated biphenyls (PCBs) management and disposal statute, rule, permit or related order.
(P) Any violation of ORS Chapter 465, UST or environmental cleanup statute, rule, related order or related agreement.
(Q) Unless specifically listed under another penalty matrix, any violation of ORS Chapter 459 or any violation of a solid waste statute, rule, permit, or related order committed by:
(i) A person that has or should have a solid waste disposal permit.
(ii) A city with a population of 25,000 or more, as determined by the most recent national census.
(R) Any violation of the Oregon Clean Fuels Program under OAR Chapter 340, division 253 by a person registered as an importer of blendstocks,
(S) Any violation classified under OAR 340-012-0054 (1) (dd), (ee), (ff), or (gg).
(T) Any violation of the Oregon Greenhouse Gas Reporting Program under OAR Chapter 340, division 215 by a person with greenhouse gas emissions greater than or equal to 25,000 metric tons per year or by a person that has not reported greenhouse gas emissions to DEQ during the past five years, or by a person for which DEQ has insufficient information to accurately estimate emissions.
(U) Any violation of the Third Party Verification rules under OAR Chapter 340, division 272.
(V) Any violation of the Landfill Gas Emissions rules under OAR chapter 340, division 239 by a person required to comply with OAR 340-239-0110 through OAR 340-239-0800.
(W) Any violation of the rules for Emission Standards for New Heavy-Duty Trucks under OAR chapter 340 division 261 by engine, truck or trailer manufacturers and dealers.
(X) Any violation of the Climate Protection Program rules under OAR chapter 340, division 273.
(Y) Any violation of the Fuel Tank Seismic Stability Program rules under OAR chapter 340, division 300.
(b) The base penalty values for the $12,000 penalty matrix are as follows:
(A) Class I:
(i) Major — $12,000;
(ii) Moderate — $6,000;
(iii) Minor — $3,000.
(B) Class II:
(i) Major — $6,000;
(ii) Moderate — $3,000;
(iii) Minor — $1,500.
(C) Class III: $1,000.
(3) $8,000 Penalty Matrix:
(a) The $8,000 penalty matrix applies to the following:
(A) Any violation of an air quality statute, rule, permit, permit attachment, or related order committed by a person that has or should have an ACDP permit, except for NSR, PSD and Basic ACDP permits, unless listed under another penalty matrix, unless otherwise classified.
(B) Any violation of an asbestos statute, rule, permit or related order except those violations listed in section (5) of this rule.
(C) Any violation of a vehicle inspection program statute, rule, permit or related order committed by an auto repair facility.

(D) Any violation of the Oregon Low Emission Vehicle rules (OAR 340-257) committed by an automobile dealer or an automobile rental agency.
(E) Any violation of a water quality statute, rule, permit or related order committed by:
(i) A person that has an NPDES Permit, or that has or should have a WPCF Permit, for a municipal or private utility sewage treatment facility with a permitted flow of two million or more, but less than five million, gallons per day.
(ii) A person that has a Tier 2 industrial source NPDES or WPCF Permit.
(iii) A person that has or should have applied for coverage under an NPDES or a WPCF General Permit, except an NPDES Stormwater Discharge 1200-C General Permit for a construction site of less than five acres in size or 20 or more acres in size.
(iv) A person that has a population of less than 100,000 but more than 10,000, as determined by the most recent national census, and has or should have a WPCF Municipal Stormwater UIC System Permit or has an NPDES MS4 Stormwater Discharge Permit.
(v) A person that owns, and that has or should have registered, a UIC system that disposes of wastewater other than stormwater or sewage or geothermal fluids.
(F) Any violation of a Clean Water Act Section 401 Water Quality Certification by a less than 100 megawatt hydroelectric facility.
(G) Any violation of a Clean Water Act Section 401 Water Quality Certification for a Tier 2A or Tier 2B dredge and fill project.
(H) Any violation of an UST statute, rule, permit or related order committed by a person who is the owner, operator or permittee of five to nine UST facilities.
(I) Unless specifically listed under another penalty matrix, any violation of ORS Chapter 459 or other solid waste statute, rule, permit, or related order committed by:
(i) A person that has or should have a waste tire permit; or
(ii) A person with a population of more than 5,000 but less than or equal to 25,000, as determined by the most recent national census.
(J) Any violation of a hazardous waste management statute, rule, permit or related order committed by a person that is a small quantity generator.
(K) Any violation of an oil and hazardous material spill and release statute, rule, or related order committed by a person other than a person listed in OAR 340-012-0140(2)(a)(N) occurring during a commercial activity or involving a derelict vessel over 35 feet in length.
(L) Any violation of the Oregon Clean Fuels Program under OAR chapter 340, division 253 unless the violation is otherwise classified in this rule.
(M) Any violation of the Oregon Greenhouse Gas Reporting Program under OAR Chapter 340, division 215 by a person with greenhouse gas emissions less than 25,000 metric tons per year but greater than or equal to 5,000 metric tons per year.
(N) Any violation of the Landfill Gas Emissions rules under OAR chapter 340, division 239 by a person that owns or operates a landfill with over 200,000 tons waste in place and is not required to comply with OAR 340-239-0110 through OAR 340-239-0800.
(O) Any violation of a hazardous waste pharmaceutical statute, rule, permit or related order committed by a person that is a reverse distributor.
(b) The base penalty values for the $8,000 penalty matrix are as follows:
(A) Class I:
(i) Major — $8,000.
(ii) Moderate — $4,000.
(iii) Minor — $2,000.
(B) Class II:
(i) Major — $4,000.

(ii) Moderate — $2,000.

(iii) Minor — $1,000.

(C) Class III: $ 700.

(4) $3,000 Penalty Matrix:

(a) The $3,000 penalty matrix applies to the following:

(A) Any violation of any statute, rule, permit, license, or order committed by a person not listed under another penalty matrix.

(B) Any violation of an air quality statute, rule, permit, permit attachment, or related order committed by a person not listed under another penalty matrix.

(C) Any violation of an air quality statute, rule, permit, permit attachment, or related order committed by a person that has or should have a Basic ACDP or an ACDP or registration only because the person is subject to Area Source NESHAP regulations.

(D) Any violation of OAR 340-264-0060(3) in which 25 or more cubic yards of prohibited materials or more than 15 tires are burned by a residential owner-occupant.

(E) Any violation of a vehicle inspection program statute, rule, permit or related order committed by a natural person, except for those violations listed in section (5) of this rule.

(F) Any violation of a water quality statute, rule, permit, license or related order not listed under another penalty matrix and committed by:

(i) A person that has an NPDES permit, or has or should have a WPCF permit, for a municipal or private utility wastewater treatment facility with a permitted flow of less than two million gallons per day.

(ii) A person that has or should have applied for coverage under an NPDES Stormwater Discharge 1200-C General Permit for a construction site that is more than one, but less than five acres.

(iii) A person that has a population of 10,000 or less, as determined by the most recent national census, and either has an NPDES MS4 Stormwater Discharge Permit or has or should have a WPCF Municipal Stormwater UIC System Permit.

(iv) A person who is licensed to perform onsite sewage disposal services or who has performed sewage disposal services.

(v) A person, except for a residential owner-occupant, that owns and either has or should have registered a UIC system that disposes of stormwater, sewage or geothermal fluids.

(vi) A person that has or should have a WPCF individual stormwater UIC system permit.

(vii) Any violation of a water quality statute, rule, permit or related order committed by a person that has or should have applied for coverage under an NPDES 700-PM General Permit for suction dredges.

(G) Any violation of an onsite sewage disposal statute, rule, permit or related order, except for a violation committed by a residential owner-occupant.

(H) Any violation of a Clean Water Act Section 401 Water Quality Certification for a Tier 1 dredge and fill project.

(I) Any violation of an UST statute, rule, permit or related order if the person is the owner, operator or permittee of two to four UST facilities.

(J) Any violation of a used oil statute, rule, permit or related order, except a violation related to a spill or release, committed by a person that is a used oil generator.

(K) Any violation of a hazardous waste management statute, rule, permit or related order committed by a person that is a very small quantity generator, unless listed under another penalty matrix.

(L) Any violation of ORS Chapter 459 or other solid waste statute, rule, permit, or related order committed by a person with a population less than 5,000, as determined by the most recent national census.

(M) Any violation of the labeling requirements of ORS 459A.675 through 459A.685.

(N) Any violation of rigid pesticide container disposal requirements by a very small quantity generator of hazardous waste.

(O) Any violation of ORS 468B.025(1)(a) or (b) resulting from turbid discharges to waters of the state caused by non-residential uses of property disturbing less than one acre in size.

(P) Any violation of an oil and hazardous material spill and release statute, rule, or related order committed by a person

not listed under another matrix.
(Q) Any violation of the Oregon Greenhouse Gas Reporting Program under OAR Chapter 340, division 215 by a person with greenhouse gas emissions less than 5,000 metric tons per year.
(b) The base penalty values for the $3,000 penalty matrix are as follows:
(A) Class I:
(i) Major — $3,000;
(ii) Moderate — $1,500;
(iii) Minor — $750.
(B) Class II:
(i) Major — $1,500;
(ii) Moderate — $750;
(iii) Minor — $375.
(C) Class III: $250.
(5) $1,000 Penalty Matrix:
(a) The $1,000 penalty matrix applies to the following:
(A) Any violation of an open burning statute, rule, permit or related order committed by a residential owner-occupant at the residence, not listed under another penalty matrix.
(B) Any violation of visible emissions standards by operation of a vehicle.
(C) Any violation of an asbestos statute, rule, permit or related order committed by a residential owner-occupant.
(D) Any violation of an onsite sewage disposal statute, rule, permit or related order of OAR chapter 340, division 44 committed by a residential owner-occupant.
(E) Any violation of an UST statute, rule, permit or related order committed by a person who is the owner, operator or permittee of one UST facility.
(F) Any violation of an HOT statute, rule, permit or related order not listed under another penalty matrix.
(G) Any violation of OAR chapter 340, division 124 or ORS 465.505 by a dry cleaning owner or operator, dry store owner or operator, or supplier of perchloroethylene.
(H) Any violation of ORS Chapter 459 or other solid waste statute, rule or related order committed by a residential owner-occupant.
(I) Any violation of a statute, rule, permit or order relating to rigid plastic containers, except for violation of the labeling requirements under OAR 459A.675 through 459A.685.
(J) Any violation of a statute, rule or order relating to the opportunity to recycle.
(K) Any violation of OAR chapter 340, division 262 or other statute, rule or order relating to solid fuel burning devices, except a violation related to the sale of new or used solid fuel burning devices or the removal and destruction of used solid fuel burning devices.
(L) Any violation of an UIC system statute, rule, permit or related order by a residential owner-occupant, when the UIC disposes of stormwater, sewage or geothermal fluids.
(M) Any Violation of ORS 468B.025(1)(a) or (b) resulting from turbid discharges to waters of the state caused by residential use of property disturbing less than one acre in size.
(b) The base penalty values for the $1,000 penalty matrix are as follows:
(A) Class I:
(i) Major — $1,000;
(ii) Moderate — $500;
(iii) Minor — $250.
(B) Class II:
(i) Major — $500;
(ii) Moderate — $250;
(iii) Minor — $125.

(C) Class III: $100.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468.090 - 468.140, 459A.962

STATUTES/OTHER IMPLEMENTED: ORS 459.995, 459A.655, 459A.660, 459A.860 - 459A.975, 468.035

AMEND: 340-215-0040

RULE TITLE: Greenhouse Gas Registration and Reporting Requirements

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Corrects cross-references to OAR chapter 340, division 273.

RULE TEXT:

(1) Each registration or emissions data report submitted by a regulated entity according to this division must contain certification by a designated representative of the truth, accuracy, and completeness of the submission. This certification and any other certification required under this division must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. The certification must contain the following statement: "Based on information and belief formed after reasonable inquiry, I certify under penalty of perjury that the statements and information submitted are true, accurate and complete."

(2) DEQ may require a regulated entity to submit or make available additional information if the materials submitted with the emissions data report are not sufficient to determine or verify greenhouse gas emissions and related information. Regulated entities must provide within 14 calendar days of notification, unless a different schedule is approved by DEQ, any and all information that DEQ requires for the purposes of assessing applicability, verifying or investigating either or both actual and suspected sources of greenhouse gas emissions, and to ascertain compliance and noncompliance with rules in this division.

(3) Calculating total greenhouse gas emissions. Total carbon dioxide equivalent emissions (CO_2e) must be calculated as the sum of the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and each fluorinated GHG required to be reported in an emissions data report in compliance with this division using equation A-1 in 40 C.F.R. 98.2.

(4) Alternative calculation methods. Regulated entities may petition DEQ to use calculation methods other than those specified in this division. Regulated entities must receive written DEQ approval to use alternative calculation methods prior to reporting.

(5) Third-party verification of emissions data reports. Regulated entities must comply with the requirements of OAR chapter 340, division 272 for third-party verification of emissions data reports, as applicable.

(6) Fuel suppliers and in-state producers must report legal names and addresses of all related entities subject to this division annually by the reporting deadline specified in OAR 340-215-0046(1)(c).

(7) A regulated entity may only use book and claim accounting to report contractual deliveries of biomethane or hydrogen injected into a pipeline when:

(a) The pipeline is part of the natural gas transmission and distribution network connected to Oregon that allows for the transport of biomethane or hydrogen, as applicable; and

(b) No person has used or claimed the environmental attributes of such biomethane or hydrogen in any other program or jurisdiction with the exception of:

(A) The federal Renewable Fuel Standard Program, any reporting required under OAR chapter 340, division 253, or the program under OAR chapter 340, division 273; or

(B) With DEQ written approval, any other program or jurisdiction where DEQ has confirmed that the claim on the environmental attributes can be made for the same use and volume of biomethane or its derivatives as is being claimed under this division.

STATUTORY/OTHER AUTHORITY: ORS 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468, 468A

AMEND: 340-215-0130

RULE TITLE: Separate Violations

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Corrects cross-references and updates for consistency with OAR chapter 340, division 273.

RULE TEXT:

Each metric ton of greenhouse gas emissions not reported according to the requirements of this division by a covered entity, as defined in OAR 340-273-0020, that affects applicability determinations, compliance instrument distribution, or compliance obligations under the Oregon Climate Protection Program, OAR Chapter 340 Division 273, is a separate violation of this division.

STATUTORY/OTHER AUTHORITY: ORS 468A.050, 468A.280

STATUTES/OTHER IMPLEMENTED: ORS 468, 468A

AMEND: 340-216-8010

RULE TITLE: Table 1 — Activities and Sources

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Updates table for consistency with OAR chapter 340, division 273.

RULE TEXT:

[NOTE: This rule is included in the State of Oregon Clean Air Act Implementation Plan that EQC adopted under OAR 340-200-0040.]

[NOTE: For the history of these tables prior to 2014 see the history under OAR 340-216-0020]

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.310

STATUTES/OTHER IMPLEMENTED: ORS 468A

State of Oregon Department of Environmental Quality

OAR 340-216-8010

Table 1 – Activities and Sources

Table 1
Activities and Sources

The following source categories must obtain a permit as required by OAR 340-216-0020 Applicability and Jurisdiction.

Part A: Basic ACDP

1 Autobody repair or painting shops painting more than 25 automobiles in a year and that are located inside the Portland AQMA.

2 Concrete manufacturing including redi-mix and CTB, both stationary and portable, more than 5,000 but less than 25,000 cubic yards per year output.

3 Crematory incinerators with less than 20 tons/year material input.

4 Individual natural gas or propane-fired boilers with heat input rating between 9.9 and 29.9 MMBTU/hour, constructed after June 9, 1989, that do not use more than 9,999 gallons per year of #2 diesel oil as a backup fuel.

5 Prepared feeds for animals and fowl and associated grain elevators more than 1,000 tons/year but less than 10,000 tons per year throughput.

6 Rock, concrete or asphalt crushing, both stationary and portable, more than 5,000 tons/year but less than 25,000 tons/year crushed.

7 Surface coating operations whose actual or expected usage of coating materials is greater than 250 gallons per month but does not exceed 3,500 gallons per year, excluding sources that exclusively use non-VOC and non-HAP containing coatings, e.g., powder coating operations.

8 Sources subject to permitting under Part B of this table, number 85 if all of the following criteria are met:

a. The source is not subject to any category listed on this table other than Part B number 85;

b. The source has requested an enforceable limit on their actual emissions, if the source were to operate uncontrolled, to below Part B number 85 of this table as applicable depending on the source's location through one or both of the following:

i. A limit on hours of operation;
ii. A limit on production;

c. Control devices are not required to be used or otherwise accounted for to maintain emissions levels compliant with 8.b above;
d. The source is not subject to and does not have any affected emissions units subject to a 40 C.F.R. part 60, part 61, or part 63 standard (NSPS or NESHAP);
e. The source is not subject to any specific industry or operation standard in OAR chapter 340, divisions 232, 234, or 236.
f. DEQ has determined that the source is not required to conduct source testing and source testing for emission factor verification will not be required.

9

Part B: General, Simple or Standard ACDP

1 Aerospace or aerospace parts manufacturing subject to RACT under OAR chapter 340, division 232.

2 Aluminum, copper, and other nonferrous foundries subject to an area source NESHAP under OAR chapter 340, division 244.

3 Aluminum production – primary.

4 Ammonia manufacturing.

5 Animal rendering and animal reduction facilities.

6 Asphalt blowing plants.

7 Asphalt felts or coating manufacturing.

8 Asphaltic concrete paving plants, both stationary and portable.

9 Bakeries, commercial over 10 tons of VOC emissions per year.

10 Battery separator manufacturing.

11 Lead-acid battery manufacturing and re-manufacturing.

12 Beet sugar manufacturing.

13 Oil-fired boilers and other fuel burning equipment whose total heat input rating at the source is over 10 MMBTU/hour; or individual natural gas, propane, or butane-fired boilers and other fuel burning equipment 30 MMBTU/hour or greater heat input rating.

14 Building paper and building board mills.

15 Calcium carbide manufacturing.

16 Can or drum coating subject to RACT under OAR chapter 340, division 232.[2]

17 Cement manufacturing.

18 Cereal preparations and associated grain elevators 10,000 or more tons/year throughput.[1]

19 Charcoal manufacturing.

20 Chlorine and alkali manufacturing.

21 Chrome plating and anodizing subject to a NESHAP under OAR chapter 340, division 244.

22 Clay ceramics manufacturing subject to an area source NESHAP under OAR chapter 340, division 244.

23 Coffee roasting, roasting 30 or more green tons per year.

24 Concrete manufacturing including redi-mix and CTB, both stationary and portable, 25,000 or more cubic yards per year output.

25 Crematory incinerators 20 or more tons/year material input.

26 Degreasing operations, halogenated solvent cleanings subject to a NESHAP under OAR chapter 340, division 244.

27 Electrical power generation from combustion, excluding units used exclusively as emergency generators and units less than 500 kW.

28 Commercial ethylene oxide sterilization, excluding facilities using less than 1 ton of ethylene oxide within all consecutive 12-month periods after December 6, 1996.

29 Ferroalloy production facilities subject to an area source NESHAP under OAR chapter 340, division 244.

30 Flatwood coating subject to RACT under OAR chapter 340, division 232.[2]

31 Flexographic or rotogravure printing subject to RACT under OAR chapter 340, division 232.[2]

32 Flour, blended and/or prepared and associated grain elevators 10,000 or more tons/year throughput.[1]

33 Galvanizing and pipe coating, except galvanizing operations that use less than 100 tons of zinc/year.

34 Bulk gasoline plants, bulk gasoline terminals, and pipeline facilities.

35 Gasoline dispensing facilities, excluding gasoline dispensing facilities with monthly throughput of less than 10,000 gallons of gasoline per month[3].

36 Glass and glass container manufacturing subject to a NSPS under OAR chapter 340, division 238 or a NESHAP under OAR chapter 340, division 244.

37 Grain elevators used for intermediate storage 10,000 or more tons/year throughput.[1]

38 Reserved.

39 Gray iron and steel foundries, malleable iron foundries, steel investment foundries, steel foundries 100 or more tons/year metal charged, not elsewhere identified.

40 Gypsum products manufacturing.

41 Hardboard manufacturing, including fiberboard.

42 Hospital sterilization operations subject to an area source NESHAP under OAR chapter 340, division 244.

43 Incinerators with two or more tons per day capacity.

44 Lime manufacturing.

45 Liquid storage tanks subject to RACT under OAR chapter 340, division 232.[2]

46 Magnetic tape manufacturing.

47 Manufactured home, mobile home and recreational vehicle manufacturing.

48 Marine vessel petroleum loading and unloading subject to RACT under OAR chapter 340, division 232.

49 Metal fabrication and finishing operations subject to an area source NESHAP under OAR chapter 340, division 244, excluding facilities that meet all the following:

a. Do not perform any of the operations listed in OAR 340-216-0060(3)(b)(V)(i) through (iii);

b. Do not perform shielded metal arc welding (SMAW) using metal fabrication and finishing hazardous air pollutant (MFHAP) containing wire or rod; and

c. Use less than 100 pounds of MFHAP containing welding wire and rod per year.

50 Millwork manufacturing, including kitchen cabinets and structural wood members, 25,000 or more board feet/maximum 8 hour input.

51 Molded plastic container manufacturing, using extrusion, molding, lamination, and foam processing and molded fiberglass container manufacturing, excluding injection molding.

52 Motor coach, travel trailer, and camper manufacturing.

53 Motor vehicle and mobile equipment surface coating operations subject to an area source NESHAP under OAR chapter 340, division 244, excluding motor vehicle surface coating operations painting less than 10 vehicles per year or using less than 20 gallons of coating and 20 gallons of methylene chloride containing paint stripper per year, mobile equipment surface coating operations using less than 20 gallons of coating and 20 gallons of methylene chloride containing paint stripper per year, and motor vehicle surface coating operations registered pursuant to OAR 340-210-0100(2).

54 Natural gas and oil production and processing and associated fuel burning equipment.

55 Nitric acid manufacturing.

56 Nonferrous metal foundries 100 or more tons/year of metal charged.

57 Organic or inorganic chemical manufacturing and distribution with ½ or more tons per year emissions of any one criteria pollutant, sources in this category with less than ½ ton/year of each criteria pollutant are not required to have an ACDP.

58 Paint and allied products manufacturing subject to an area source NESHAP under OAR chapter 340, division 244.

59 Paint stripping and miscellaneous surface coating operations subject to an area source NESHAP under OAR chapter 340, division 244, excluding paint stripping and miscellaneous surface coating operations using less than 20 gallons of coating and also using less than 20 gallons of methylene chloride containing paint stripper per year.

60 Paper or other substrate coating subject to RACT under OAR chapter 340, division 232.[2]

61 Particleboard manufacturing, including strandboard, flakeboard, and waferboard.

62 Perchloroethylene dry cleaning operations subject to an area source NESHAP under OAR chapter 340, division 244, excluding perchloroethylene dry cleaning operations registered pursuant to OAR 340-210-0100(2).

63 Pesticide manufacturing 5,000 or more tons/year annual production.

64 Petroleum refining and re-refining of lubricating oils and greases including asphalt production by distillation and the reprocessing of oils and/or solvents for fuels.

65 Plating and polishing operations subject to an area source NESHAP under OAR chapter 340, division 244.

66 Plywood manufacturing and/or veneer drying.

67 Prepared feeds manufacturing for animals and fowl and associated grain elevators 10,000 or more tons per year throughput.

68 Primary smelting and/or refining of ferrous and non-ferrous metals.

69 Pulp, paper and paperboard mills.

70 Rock, concrete or asphalt crushing, both stationary and portable, 25,000 or more tons/year crushed.

71 Sawmills and/or planing mills 25,000 or more board feet/maximum 8 hour finished product.

72 Secondary nonferrous metals processing subject to an Area Source NESHAP

under OAR chapter 340, division 244.

73 Secondary smelting and/or refining of ferrous and nonferrous metals.

74 Seed cleaning and associated grain elevators 5,000 or more tons/year throughput.[1]

75 Sewage treatment facilities employing internal combustion engines for digester gasses.

76 Soil remediation facilities, both stationary and portable.

77 Steel works, rolling and finishing mills.

78 Surface coating in manufacturing subject to RACT under OAR chapter 340, division 232.[2]

79 Surface coating operations with actual emissions of VOCs, if the source were to operate uncontrolled, of 10 or more tons/year.

80 Synthetic resin manufacturing.

81 Tire manufacturing.

82 Wood furniture and fixtures 25,000 or more board feet/maximum 8 hour input.

83 Wood preserving (excluding waterborne).

84 All other sources, both stationary and portable, not listed herein that DEQ determines an air quality concern exists or one which would emit significant malodorous emissions.

85 All other sources, both stationary and portable, not listed herein which would have the capacity of 5 or more tons per year of direct PM2.5 or PM10 if located in a PM2.5 or PM10 nonattainment or maintenance area, or 10 or more tons per year of any single criteria pollutant .[4]

86 Chemical manufacturing facilities subject to 40 C.F.R. part 63 subpart VVVVVV.

87 Stationary internal combustion engines if:

a. For emergency generators and firewater pumps, the aggregate engine horsepower rating is greater than 30,000 horsepower; or

b. For any individual non-emergency or non-fire pump engine, the engine is subject to 40 CFR part 63, subpart ZZZZ and is rated at 500 horsepower or more, excluding two stroke lean burn engines, engines burning exclusively landfill or digester gas, and four stroke engines located in remote areas; or

c. For any individual non-emergency engine, the engine is subject to 40 CFR part 60, subpart IIII and:

A. The engine has a displacement of 30 liters or more per cylinder; or

B. The engine has a displacement of less than 30 liters per cylinder and is rated at 500 horsepower or more and the engine and control device are either not certified by the manufacturer to meet the NSPS or not operated and maintained according to the manufacturer's emission-related instructions; or

d. For any individual non-emergency engine, the engine is subject to 40 CFR part 60, subpart JJJJ and is rated at 500 horsepower or more and the engine and control device are either not certified by the manufacturer to meet the NSPS or not operated and maintained according to the manufacturer's emission-related instructions.

88 All sources subject to RACT under OAR chapter 340, division 232, BACT or LAER under OAR chapter 340, division 224, a NESHAP under OAR chapter 340, division 244, a NSPS under OAR chapter 340, division 238, or State MACT under OAR 340-244-0200(2), except sources:

a. Exempted in any of the categories above;

b. For which a Basic ACDP is available; or

c. Registered pursuant to OAR 340-210-0100(2).

89 Pathological waste incinerators.

90 Landfills with more than 200,000 tons of waste in place and calculated methane generation rate is less than 664 metric tons per year which are subject to the requirements in OAR 340 division 239.

---

[1] Applies only to Special Control Areas

[2] Portland AQMA, Medford-Ashland AQMA or Salem-Keizer in the SKATS only

[3] "monthly throughput" means the total volume of gasoline that is loaded into, or dispensed from, all gasoline storage tanks at the gasoline dispensing facility during a month. Monthly throughput is calculated by summing the volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at the gasoline dispensing facility during the month, plus the total volume of gasoline loaded into, or dispensed from, all gasoline storage tanks at the gasoline dispensing facility during the previous 11 months, and then dividing that sum by 12

[4] A source subject to permitting from this category may be able to obtain a Basic ACDP under Part A number 8 of this table. For sources that meet the criteria of Part A number 8 of this table, the enforceable production or hours limitation in an issued ACDP may be used to demonstrate a permit is not required by Part B number 85 of this table irrespective of the term 'uncontrolled'.

Part C: Standard ACDP

1 Incinerators for PCBs, other hazardous wastes, or both.

2 All sources that DEQ determines have emissions that constitute a nuisance.

3 All sources electing to maintain the source's netting basis.

4 All sources that request a PSEL equal to or greater than the SER for a regulated pollutant.

5 All sources having the potential to emit 100 tons or more of any regulated pollutant, except GHG, in a year.

6 All sources having the potential to emit 10 tons or more of a single hazardous air pollutant in a year.

7 All sources having the potential to emit 25 tons or more of all hazardous air pollutants combined in a year.

8 Landfills with more than 200,000 tons of waste in place and calculated methane generation rate is greater than or equal to 664 metric tons per year which are subject to the requirements in OAR 340 division 239.

NOTE: For the history of these tables prior to 2014 see the history under OAR 340-216-0020. This history is also shown below:

DEQ 9-2013(Temp), f. & cert. ef. 10-24-13 thru 4-22-14
DEQ 4-2013, f. & cert. ef. 3-27-13
DEQ 14-2011, f, & cert. ef. 7-21-11
DEQ 13-2011, f. & cert. ef. 7-21-11
DEQ 11-2011, f. & cert. ef. 7-21-11
DEQ 5-2011, f. 4-29-11, cert. ef. 5-1-11
DEQ 1-2011, f. & cert. ef. 2-24-11
DEQ 12-2010, f. & cert. ef. 10-27-10
DEQ 10-2010(Temp), f. 8-31-10, cert. ef. 9-1-10 thru 2-28-11
DEQ 9-2009(Temp), f. 12-24-09, cert. ef. 1-1-10 thru 6-30-10
DEQ 8-2009, f. & cert. ef. 12-16-09
DEQ 15-2008, f. & cert. ef 12-31-08
DEQ 8-2007, f. & cert. ef. 11-8-07
DEQ 7-2007, f. & cert. ef. 10-18-07
DEQ 4-2002, f. & cert. ef. 3-14-02
DEQ 6-2001, f. 6-18-01, cert. ef. 7-1-01
DEQ 14-1999, f. & cert. ef. 10-14-99, Renumbered from 340-028-1720
DEQ 22-1996, f. & cert. ef. 10-22-96
DEQ 19-1996, f. & cert. ef. 9-24-96
DEQ 22-1995, f. & cert. ef. 10-6-95
DEQ 22-1994, f. & cert. ef. 10-4-94
DEQ 19-1993, f. & cert. ef. 11-4-93
DEQ 12-1993, f. & cert. ef. 9-24-93, Renumbered from 340-020-0155
DEQ 4-1993, f. & cert. ef. 3-10-93

DEQ 27-1991, f. & cert. ef. 11-29-91
DEQ 12-1987, f. & cert. ef. 6-15-87
DEQ 3-1986, f. & cert. ef. 2-12-86
DEQ 11-1983, f. & cert. ef. 5-31-83
DEQ 23-1980, f. & cert. ef. 9-26-80
DEQ 20-1979, f. & cert. ef. 6-29-79
DEQ 125, f. & cert. ef. 12-16-76
DEQ 107, f. & cert. ef. 1-6-76, Renumbered from 340-020-0033
DEQ 63, f. 12-20-73, cert. ef. 1-11-74
DEQ 47, f. 8-31-72, cert. ef. 9-15-72

AMEND: 340-253-0600

RULE TITLE: Records

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Corrects cross-references to OAR chapter 340, division 273.

RULE TEXT:

(1) Records Retention. Registered parties must retain the following records for at least seven years:

(a) Product transfer documents as described in section (2);

(b) Records related to obtaining a carbon intensity or other value described in OAR 340-253-0450, OAR 340-253-0460, and OAR 340-253-0470;

(c) Copies of all data and reports submitted to DEQ;

(d) Records related to each fuel transaction;

(e) Records used for compliance or credit calculations;

(f) Records used to establish that feedstocks are specified source feedstocks; and

(g) Records related to third-party verification, if required under OAR 340-253-0700.

(2) Documenting Fuel Transactions.

(a) Except as provided in subsection (b), fuel transactions must be documented through a product transfer document and include the information specified below:

(A) Transferor company name, address, and contact information;

(B) Recipient company name, address, and contact information;

(C) Transaction date;

(D) Fuel pathway code;

(E) Carbon intensity;

(F) Volume/amount;

(G) A statement identifying whether the transferor or the recipient has the compliance obligation;

(H) The EPA fuel production company identification number and facility identification number as registered with the RFS program; and

(I) The state where the fuel will be delivered, if known at the time of sale. If unknown, then the PTD must state the destination as unknown.

(b) For transactions of clear and blended gasoline and diesel below the rack where the fuel is not destined for export, only the records described in paragraphs (2)(a)(A), (B), (C), (F), and (G) are required to be retained.

(3) Documenting Credit Transactions. Registered parties must retain the following records related to all credit transactions for at least seven years:

(a) The contract under which the credits were transferred;

(b) Documentation on any other commodity trades or contracts between the two parties conducting the transfer that are related to the credit transfer in any way; and

(c) Any other records relating to the credit transaction, including the records of all related financial transactions.

(4) Review by DEQ. All data, records, and calculations used by a registered party, a fuel producer, or fuel pathway holder registered under OAR 340-253-0500(2) to comply with OAR chapter 340, division 253 are subject to inspection and verification by DEQ. Registered parties, fuel producers, and fuel pathway holders must provide records retained under this rule within 30 calendar days after the date DEQ requests a review of the records, unless DEQ specifies otherwise.

(5) Information exempt from disclosure. Pursuant to the provisions of the Oregon public records law, ORS 192.410 to 192.505, all information submitted to DEQ is subject to inspection upon request by any person unless such information is determined to be exempt from disclosure under the Oregon public records law or other applicable Oregon law.

(6) Attestations regarding environmental attributes used for book and claim for renewable electricity, biomethane, or biogas.

(a) A registered party reporting any fuel claimed in the CFP using a book and claim accounting method must retire RTCs

or RECs that embody the full environmental attributes of that fuel in an electronic tracking system approved by DEQ. The quantity of energy covered by the RTC or the REC must match or exceed the volume of fuel claimed in the CFP. The environmental attributes embodied by that RTC or REC must not have been used or claimed in any other program or jurisdiction with the exception of the federal RFS, any reporting required under OAR chapter 340, division 215, and the program under OAR chapter 340, division 273. To be validly used in compliance with this division, any such claims under the federal RFS or OAR chapter 340, divisions 215 and 273, must be made for the same use and volume of biomethane or its derivatives as it is being claimed for in the CFP.
(b) A fuel pathway holder using directly delivered renewable electricity, biogas or biomethane as a process energy or feedstock must obtain and keep attestations from each upstream party collectively demonstrating that such holder has exclusive right to use those environmental attributes. The attestation must include documentation that shows:
(A) The entity claiming the environmental attributes for renewable electricity, biogas or biomethane in the CFP must have the exclusive right to claim the environmental attributes associated with the use of that fuel; and
(B) The environmental attributes have not been used or claimed in any other program or jurisdictions with the exception of the federal RFS and any reporting required under OAR chapter 340, divisions 215 and 273. To be validly used in compliance with this division, any such claims under the federal RFS or OAR chapter 340, divisions 215 and 273 must be made for the same use and volume of biomethane or its derivatives as it is being claimed for in the CFP.
(c) Any attestation or retirement records for biogas, biomethane, and renewable electricity must be provided to DEQ within seven calendar days of receiving a request for such attestation by DEQ. Failure to provide such attestations is grounds for credit invalidation under OAR 340-253-0670.
(9) Monitoring plan for registered parties who are required to obtain third-party verification services under OAR 340-253-0700. Each registered party responsible for obtaining third-party verification of their data under OAR chapter 340, division 272 must complete and retain a written monitoring plan for review by a verifier or DEQ. If a fuel production facility is required to complete and maintain a monitoring plan by the California LCFS, the same monitoring plan may be used to meet the requirements of this rule unless there are substantive differences between the two programs' treatment of the fuel production process. A monitoring plan must include the following, as applicable:
(a) All of the following general items are required for all monitoring plans:
(A) Information to allow DEQ and the verification team to develop a general understanding of boundaries and operations relevant to the entity, facility, or project, including participation in other markets and other third-party audit programs;
(B) Reference to management policies or practices applicable to reporting pursuant to this division, including recordkeeping;
(C) Explanation of the processes and methods used to collect necessary data for reporting pursuant to this division, including identification of changes made after January 1, 2020;
(D) Explanations and queries of source data to compile summary reports of intermediate and final data necessary for reporting pursuant to this division;
(E) Reference to one or more simplified block diagrams that provide a clear visual representation of the relative locations and positions of measurement devices and sampling locations, as applicable, required for calculating reported data (e.g., temperature, total pressure, LHV or HHV, fuel consumption); the diagram(s) must include storage tanks for raw material, intermediate products, and finished products, fuel sources, combustion units, and production processes, as applicable;
(F) Clear identification of all measurement devices supplying data necessary for reporting pursuant to this division, including identification of low flow cutoffs as applicable, with descriptions of how data from measurement devices are incorporated into the submitted report;
(G) Descriptions of measurement devices used to report CFP data and how acceptable accuracy is demonstrated, e.g., installation, maintenance, and calibration method and frequency for internal meters and financial transaction meters; this provision does not apply to data reported in the Oregon Fuels Reporting System for generating credits for EV charging;

(H) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for CFP reports;
(I) Original equipment manufacturer (OEM) documentation or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used to collect necessary data for reporting pursuant to this division;
(J) The dates of measurement device calibration or inspection, and the dates of the next required calibration or inspection;
(K) Requests for postponement of calibrations or inspections of internal meters and subsequent approvals by DEQ. The entity must demonstrate that the accuracy of the measured data will be maintained pursuant to the measurement accuracy requirements of OAR 340-253-0450(12);
(L) A listing of the equation(s) used to calculate flows in mass, volume, or energy units of measurement, and equations from which any non-measured parameters are obtained, including meter software, and a description of the calculation of weighted average transport distance;
(M) Identification of job titles and training practices for key personnel involved in CFP data acquisition, monitoring, reporting, and report attestation, including reference to documented training procedures and training materials;
(N) Records of corrective and subsequent preventative actions taken to address verifier and DEQ findings of past nonconformance and material misstatements;
(O) Log of modifications to a fuel pathway report conducted after attestation in response to review by third-party verifier or DEQ staff;
(P) Written description of an internal audit program that includes data report review and documents ongoing efforts to improve the entity's CFP reporting practices and procedures, if such an internal audit program exists; and
(Q) Methodology used to allocate the produced fuel quantity to each fuel pathway code;
(b) Any monitoring plan related to a fuel pathway carbon intensity or reporting quantities of fuels must also include the following elements specific to fuel pathway carbon intensity calculations and produced quantities of fuels per fuel pathway code:
(A) Explanation of the processes and methods used to collect necessary data for fuel pathway application and annual fuel pathway reports and all site-specific OR-GREET 3.0 inputs, as well as references to source data;
(B) Description of steps taken, and calculations made to aggregate data into reporting categories, for example aggregation of quarterly fuel transactions per fuel pathway code;
(C) Methodology for assigning fuel volumes by fuel pathway code, if not using a method prescribed by DEQ. If using a DEQ prescribed methodology, the methodology should be referenced;
(D) Methodologies for testing conformance to specifications for feedstocks and produced fuels, particularly describing physical testing standards and processes;
(E) Description of procedure taken to ensure measurement devices are performing in accordance with the measurement accuracy requirements of OAR 340-253-0450(12);
(F) Methodology for monitoring and calculating weighted average feedstock transport distance and modes, including the specific documentation records that will be collected and retained on an ongoing basis;
(G) Methodology for monitoring and calculating fuel transport distance and modes, including the specific documentation records that will be collected and retained on an ongoing basis;
(H) References to contracts and accounting records that confirm fuel quantities were delivered into Oregon for use in carbon intensity determination, and confirm feedstock and finished fuel transportation distance; and
(I) All documentation required pursuant to OAR 340-253-0600(10) for specified source feedstocks, defined in OAR 340-253-0400(6); and
(c) The monitoring plan must also include documentation that can be used to justify transaction types reported for fuel in the Oregon Fuels Reporting System, including the production amount, sale/purchase agreements and final fuel dispensing records. Such documentation must be specific to quarterly fuel transactions reports for importers of blendstocks, importers of finished fuels, Oregon producers, credit generators, aggregators, and out-of-state producers.

(10) Feedstock Transfer Documents. A feedstock transfer document for specified source feedstocks must prominently state the following information:

(a) Transferor company name, address and contact information;

(b) Recipient company name, address and contact information;

(c) Type and amount of feedstock, including units; and

(d) Transaction date.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.266, 468A.268, 468A.277

STATUTES/OTHER IMPLEMENTED: ORS 468.020, ORS 468A.265 through 468A.277

AMEND: 340-253-1020

RULE TITLE: Calculating Credits and Deficits

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Corrects cross-references to OAR chapter 340, division 273.

RULE TEXT:

(1) Except as provided in sections (2) and (3), credit and deficit generation must be calculated for all fuels included in OAR 340-253-1010:

(a) Using credit and deficit basics as directed in OAR 340-253-1000;

(b) Calculating energy in megajoules by multiplying the amount of fuel by the energy density of the fuel in Table 6 under OAR 340-253-8010;

(c) Calculating the adjusted energy in megajoules by multiplying the energy in megajoules from section (2) by the energy economy ratio of the fuel listed in Table 7 under OAR 340-253-8010 or as approved by DEQ under OAR 340-253-0460, as applicable;

(d) Calculating the carbon intensity difference by subtracting the fuel's carbon intensity as approved under OAR 340-253-0400 through -0470, adjusted for the fuel application's energy economy ratio as listed in Table 7 under OAR 340-253-8010 or as approved under OAR 340-253-0460 as applicable, from the clean fuel standard for gasoline or gasoline substitutes listed in Table 1 under OAR 340-253-8010 or diesel fuel and diesel substitutes listed in Table 2 under OAR 340-253-8010, or alternative jet fuel listed in table 3 under OAR 340-253-8010, as applicable;

(e) Calculating the grams of carbon dioxide equivalent by multiplying the adjusted energy in megajoules in section (3) by the carbon intensity difference in section (4);

(f) Calculating the metric tons of carbon dioxide equivalent by dividing the grams of carbon dioxide equivalent calculated in section (5) by 1,000,000; and

(g) Determining under OAR 340-253-1000(5) whether credits or deficits are generated.

(2) Calculating credits for electricity used to power fixed guideway vehicles on track placed in service prior to 2012 and forklifts from model year 2015 and earlier. Credit generation must be calculated by:

(a) Using credit and deficit basics as directed in OAR 340-253-1000;

(b) Calculating energy in megajoules by multiplying the amount of fuel by the energy density of the fuel in Table 6 under OAR 340-253-8010;

(c) Calculating the carbon intensity difference by subtracting the fuel's carbon intensity as approved under OAR 340-253-0400 through -0470, adjusted for the fuel application's energy economy ratio listed in Table 7 under OAR 340-253-8010 as applicable, from the clean fuel standard for gasoline or gasoline substitutes listed in Table 1 under OAR 340-253-8010 or diesel fuel and diesel substitutes listed in Table 2 under OAR 340-253-8010, as applicable;

(d) Calculating the grams of carbon dioxide equivalent by multiplying the adjusted energy in megajoules in section (3) by the carbon intensity difference in section (4);

(e) Calculating the metric tons of carbon dioxide equivalent by dividing the grams of carbon dioxide equivalent calculated in section (5) by 1,000,000; and

(f) Determining under OAR 340-253-1000(5) whether credits or deficits are generated.

(3) Calculating credits for electricity used in residential charging of electric vehicles. credit calculations must be based on the total electricity dispensed (in kilowatt hours) to vehicles, measured by:

(a) The use of direct metering (either sub-metering or separate metering) to measure the electricity directly dispensed to all vehicles at each residence; or

(b) For residences where direct metering has not been installed, DEQ will calculate the total electricity dispensed as a transportation fuel based on analysis of the total number of BEVs and PHEVs in a utility's service territory based on Oregon Department of Motor Vehicles records. DEQ will perform this analysis at least twice a year and issue credits based on it. DEQ will select one of the following methods for estimating the amount of electricity charged based on its analysis of which is more accurate and feasible at the time it is performing the analysis:

(A) An average amount of electricity consumed by BEVs and PHEVs at residential chargers, based on regional or national data; or
(B) An analysis of the average electric vehicles miles traveled by vehicle type or make and model, which compares the total amount of estimated charging for those electric vehicle miles travelled with the total reported charging in those territories in order to determine the amount of unreported charging that can be attributed to residential charging. The analysis may be done on a utility territory specific or statewide basis.
(c) If DEQ determines after the issuance of residential electric vehicle credits that the estimate under (b) contained a significant error that led to one or more credits being incorrectly generated, the error will be corrected by withholding an equal number of credits to the erroneous amount from the next generation of residential electric vehicle credits.
(d) A credit generator or aggregator may propose an alternative method, subject to the approval of DEQ upon its determination that the alternative method is more accurate than either of the methods described in subsection (b).
(e) Credits generated under this subsection will be calculated by DEQ under section 1 of this rule using the estimated amount of electricity under subsection (3)(b) and issued at least twice per year into the OFRS account of the utility or the backstop aggregator within three months of the close of that year.
(4) Calculating Incremental Credits. In calculating incremental credits for actions that lower the carbon intensity of electricity, the credit calculations must be performed based on section (1) of this rule, except that the carbon intensity difference is calculated based on the carbon intensity of the renewable power and the carbon intensity used to calculate the base credits for that electric vehicle or charging equipment, and consistent with following requirements, as applicable:
(a) Incremental credits for non-residential charging are generated upon the retirement of RECs that qualify under OAR 340-253-0470(5) by the credit generator, its aggregator, or the incremental aggregator, or by another entity on their behalf. For credit generators and their aggregators, RECs must be retired prior to or at the same time as the submittal as the quarterly report where the charging is being reported and REC retirement records must be submitted with the quarterly report as supplemental documentation. RECs may be retired by another entity on behalf of the credit generator or aggregator for their electric vehicle charging so long as it is clearly documented, and that documentation is submitted with the quarterly report.
(b) For incremental credits generated using a Utility Renewable Electricity Product or Power Purchase Agreement, evidence that the chargers were covered by such a product must be submitted at least annually along with a quarterly report. Upon request by DEQ, any entity using a Power Purchase Agreement or a Utility Renewable Electricity Product must produce evidence that the charging equipment was covered by that agreement or product for all time periods when the entity was claiming incremental credits.
(c) For the incremental aggregator, incremental credits are generated when it retires RECs on behalf of non-residential electric vehicle charging.
(d) Incremental credits for residential charging are generated by a utility or its aggregator when RECs are retired on behalf of that charging, or when a utility demonstrates to DEQ that EVs are being charged by customers enrolled in its Utility Renewable Electricity Products.
(5) Additional credits.
(a) Except as provided in subsection (b), starting in 2023, fuel pathway holders that are registered parties may request additional credits from the prior year if their fuel facility has:
(A) Completed verification under OAR 340-253-0700 and OAR chapter 340, division 272; and
(B) The verified operational carbon intensity value for a given fuel pathway is more than 1gCO2e/MJ lower than the certified carbon intensity value for that year.
(b) Subsection (a) does not apply to lookup table, temporary, or provisional carbon intensities.
(c) DEQ will determine the number of additional credits to award in response to a request under subsection (a) by:
(A) Calculating the difference between the certified and verified operational carbon intensities;
(B) Multiplying the difference calculated under paragraph (A) by the total obligated volume for the year; and
(C) DEQ may adjust the obligated volume for a given year for this calculation if it is aware that a volume of the fuel

under a given fuel pathway code was imported or produced in the fourth quarter of a year and exported or otherwise removed from the obligated fuel pool in the first quarter of the following year.

(d) DEQ will deposit the additional credits determined under subsection (c) into the fuel pathway holder's account.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.266, 468A.268, 468A.277

STATUTES/OTHER IMPLEMENTED: ORS 468.020, ORS 468A.265 through 468A.277

AMEND: 340-272-0120

RULE TITLE: Requirements for Verification of GHG Reporting Program Emissions Data Reports Submitted under OAR Chapter 340, Division 215

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Corrects a cross-reference to OAR chapter 340, division 273.

RULE TEXT:

(1) Annual verification of GHG Reporting Program emissions data reports.
(a) Applicability. The following persons must meet the requirements of this division and engage the services of a verification body for the purposes of annual verification of the entire emissions data report, including required site visit(s), for each separate emissions data report submitted under OAR chapter 340, division 215, except as otherwise provided under subsection (b):
(A) A regulated entity that submits an emissions data report as described under OAR 340-215-0044(1) that indicates emissions equaled or exceeded 25,000 metric tons of CO2e, excluding CO2 from biomass-derived fuels;
(B) A third party that is not the Bonneville Power Administration (BPA) that registers and submits an emissions data report on behalf of a consumer-owned utility for emissions, data, and information submitted for each individual utility with emissions that equaled or exceeded 25,000 metric tons of CO2e, excluding CO2 from biomass-derived fuels and excluding emissions associated with preference power purchased from BPA;
(C) A regulated entity that submitted an emissions data report that indicated emissions exceeded the threshold in paragraph (A) in the previous year, but that submits an emissions data report that indicates emissions are reduced below that applicability threshold in the current reporting year;
(D) All regulated entities subject to the Climate Protection Program requirements described under OAR chapter 340, division 273, regardless of emissions reported; and
(E) All regulated entities that are electric companies and electricity service suppliers as defined in ORS 757.600, regardless of emissions reported.
(b) Exemptions. The following are not subject to the requirements of this division:
(A) A regulated entity that is not an electric company and not subject to requirements under OAR chapter 340, division 215 and that submits an emissions data report as described under OAR 340-215-0044(1) that indicates emissions were less than 25,000 metric tons of CO2e, excluding CO2 from biomass-derived fuels. For the purposes of this rule, any GHG emissions in emissions data reports as described under OAR 340-215-0044(1)(c) submitted by fuel suppliers or in-state producers that are related entities or share full or partial common ownership or operational control must be aggregated together to determine whether or not the exemption applies;
(B) An emissions data report as described under OAR 340-215-0044(1)(a) that includes emissions data and information described in 40 C.F.R. part 98 subpart HH – Municipal Solid Waste Landfills;
(C) An emissions data report as described under OAR 340-215-0044(1)(d) submitted by a natural gas supplier that is an interstate pipeline; and
(D) Any emissions data report as described under OAR 340-215-0044(1)(e) submitted by Bonneville Power Administration (BPA) acting as a third-party reporter on behalf of any consumer-owned utility, as allowable under OAR 340-215-0120(4).
(c) Verification schedule. Responsible entities that are subject to the subsection (a) requirement to engage the services of a verification body to perform verification of emissions data reports must ensure a verification statement for each emissions data report is submitted to DEQ according to OAR 340-272-0100.
(A) These requirements are in addition to the requirements in 40 C.F.R. 98.3(f).
(B) An asset-controlling supplier that submitted an emissions data report to DEQ as described under OAR 340-215-0044(1)(f) that includes the same data and information reported to and verified under California ARB's Mandatory Reporting of Greenhouse Gas Emissions program may submit the same verification statement to DEQ. If an adverse verification statement is received, a current issues log must also be submitted to DEQ.

(2) Cessation of verification requirement.

(a) Responsible entities must have an emissions data report verified for the first year that the report indicates emissions are reduced below the applicability threshold defined in paragraph (1)

(a)(A). An emissions data report is not subject to verification in any following year thereafter where emissions remain below the threshold.

(b) A responsible entity that meets the verification cessation requirements for two consecutive years must notify DEQ in writing in the second year that it is ceasing the verification requirement according to this paragraph and provide the reason(s) for cessation of verification. The notification must be submitted no later than the applicable reporting deadline under OAR chapter 340, division 215 for that year.

(c) If in any subsequent year after meeting verification cessation requirements an emissions data report meets the applicability requirements of subsection (1)(a), the responsible entity must have the emissions data report verified according to the requirements of this division, and verification must continue until the cessation requirement is met again.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.050, 468A.280

STATUTES/OTHER IMPLEMENTED: ORS 468A.010, 468A.015, 468A.050, 468A.280

ADOPT: 340-273-0010

RULE TITLE: Purpose and Scope

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the purposes of the Climate Protection Program, including to reduce greenhouse gas emissions that cause climate change from sources in Oregon, achieve co-benefits from reduced emissions of other air contaminants, support a strong economy, and enhance public welfare for Oregon communities, particularly environmental justice communities.

RULE TEXT:

(1) This division establishes rules and requirements for the Climate Protection Program for certain air contamination sources that emit greenhouse gases or that cause greenhouse gases to be emitted.

(2) 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.

(a) Fuel combustion and industrial processes result in emissions of greenhouse gases, which are air contaminants that cause climate change;

(b) Reducing greenhouse gas emissions may also reduce emissions of other air contaminants, which may improve air quality for Oregon communities; and

(c) Environmental justice communities in Oregon are disproportionately burdened by air contamination, including through disproportionate risk of the impacts of climate change.

(3) The purposes of the Climate Protection Program are to reduce greenhouse gas emissions from sources in Oregon, achieve co-benefits from reduced emissions of other air contaminants, support a strong statewide economy, and enhance public welfare for Oregon communities, particularly environmental justice communities disproportionately burdened by the effects of climate change and air contamination. To support these purposes, this division:

(a) Requires that covered entities reduce greenhouse gas emissions;

(b) Supports reduction of emissions of other air contaminants that are not greenhouse gases;

(c) Prioritizes reduction of greenhouse gases and other air contaminants in environmental justice communities;

(d) Provides covered entities with compliance options to minimize disproportionate business and consumer economic impacts associated with meeting the Climate Protection Program requirements;

(e) Incentivizes the reduction of greenhouse gas emissions from industries in Oregon, while allowing trade exposed industries to remain competitive; and

(f) Allows covered entities to comply with the Climate Protection Program requirements in part through contributing community climate investment funds to support projects that reduce greenhouse gas emissions and prioritize benefits for environmental justice communities in Oregon.

(4) DEQ administers this division in all areas of the State of Oregon.

(5) (a) Whenever the DEQ Director has good cause to believe that any person is engaged or is about to engage in any acts or practices that constitute a violation of this division, the Director may authorize DEQ to institute actions or proceedings for legal or equitable remedies to enforce compliance thereto or to restrain further violations.

(b) The proceedings authorized by subsection (a) may be instituted without the necessity of prior DEQ notice, hearing and order.

(c) The provisions of this section are in addition to and not in substitution of any other civil or criminal enforcement provisions available to DEQ. This includes, without limitation, the authority to impose civil penalties and issue orders according to ORS Chapter 468.090 to 468.140 and OAR chapter 340, divisions 11 and 12.

(6) If any dates under this division occur on a Saturday, Sunday, or a state holiday, the deadline is extended to the following business day.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050, 468A.135

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468A.135, 468.035, 468.010, 468A.015, 468A.045, 468A.295

ADOPT: 340-273-0020

RULE TITLE: Definitions

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Defines terms relating to this division of rules, including key definitions of "covered entity," which establishes who is regulated by these rules.

RULE TEXT:

The definitions in OAR 340-200-0020, OAR 340-215-0020, and this rule apply to this division. If the same term is defined in this rule and either or both OAR 340-200-0020 and OAR 340-215-0020, the definition in this rule applies to this division. If the same term is defined in OAR 340-200-0020 and OAR 340-215-0020, but not in this rule, then the definition in OAR 340-215-0020 applies to this division.

(1) "Air contamination source" has the meaning given the term in ORS 468A.005. Air contamination sources include, without limitation, stationary sources, fuel suppliers, in- state fuel producers, and local distribution companies.

(2) "Biomass-derived fuels" has the meaning given the term in OAR 340-215-0020. Biomass-derived fuels include, without limitation, biomethane, biodiesel, renewable diesel, renewable propane, woody biomass, and ethanol.

(3) "Cap" means the total number of compliance instruments generated by DEQ for each calendar year.

(4) "Climate Protection Program permit" or "CPP permit" means a permit issued to a covered entity according to this division.

(5) "Community climate investment credit" or "CCI credit" or "credit" means an instrument issued by DEQ to track a covered entity's payment of community climate investment funds, and which may be used in lieu of a compliance instrument, as further provided and limited in this division.

(6) "Community climate investments," "community climate investment funds" or "CCI funds" means money paid by a covered entity to a community climate investment entity to support implementation of community climate investment projects and any interest that accrues on the money while it is held by a CCI entity or subcontractor.

(7) "Community climate investment entity" or "CCI entity" means a nonprofit organization that has been approved by DEQ as a CCI entity and that has entered into a written agreement with DEQ consistent with OAR 340-273-0920 to implement projects supported by community climate investment funds.

(8) "Compliance instrument" means an instrument issued by DEQ that authorizes the emission of one MT CO_2e of greenhouse gases.

(9) "Compliance obligation" means the total quantity of covered emissions from a covered fuel supplier rounded down to the nearest metric ton of CO_2e.

(10) "Compliance period" means a period of multiple consecutive calendar years, as described in OAR 340-273-0440.

(11) "Covered direct natural gas source" or "Covered DNG source" means an air contamination source as described in OAR 340-273-0110(6).

(12) "Covered EITE source" means an air contamination source as described in OAR 340-273-0110(5).

(13) "Covered emissions" means the greenhouse gas emissions described in any of subsections OAR 340-273-0110(3)(b), (4)(b), (5)(b), and 6(b) for which covered entities may be subject to the requirements of this division.

(14) "Covered entity" means an air contamination source subject to the requirements of this division. A covered entity may be one or more of a covered fuel supplier, a covered EITE source, or a covered DNG source.

(15) "Covered fuel supplier" means an air contamination source that is one or more of the following:

(a) A fuel supplier or in-state producer as described in OAR 340-273-0110(3); or

(b) A local distribution company as described in OAR 340-273-0110(4).

(16) "Designated representative" means the person responsible for certifying, signing, and submitting any registration, report, or form required to be submitted according to this division, on behalf of a covered entity. For the owner or operator of a covered entity with an Oregon Title V Operating Permit, the designated representative is the responsible official and certification must be consistent with OAR 340-218-0040(5).

(17) "Direct natural gas source" or "DNG source" means a stationary source that uses natural gas distributed to the

source by an entity other than a local distribution company.

(18) “Emissions-intensive and trade-exposed source” or “EITE source” means a stationary source engaged in a sector described in OAR 340-273-9000 Table 7.

(19) “Eligible projects” means projects undertaken by a CCI entity that reduce anthropogenic greenhouse gas emissions as described in OAR 340-273-0900(2)(a).

(20) “Environmental justice communities” means communities of color, communities experiencing lower incomes, communities experiencing health inequities, tribal communities, rural communities, remote communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth and persons with disabilities.

(21) “Nominal electric generating capacity” has the meaning given in ORS 469.300.

(22) “Shut down” means that all operations of a covered entity are permanently shut down, including but not limited to decommissioning and cancelling air permits. Permanent shutdown may include continued operations of space heaters and water heaters as necessary to support decommissioning activities.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0030

RULE TITLE: Acronyms

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Defines acronyms relating to this division of rules.

RULE TEXT:

(1) “CCI” means community climate investment.

(2) “CFR” means Code of Federal Regulations.

(3) “CPI-U West” means the US Bureau of Labor and Statistics West Region Consumer Price Index for All Urban Consumers for all Items.

(4) “CPP” means Oregon Climate Protection Program established in this division.

(5) “DEQ” means Oregon Department of Environmental Quality.

(6) “EITE” means emissions-intensive and trade-exposed.

(7) “EQC” means Environmental Quality Commission.

(8) “EPA” means US Environmental Protection Agency.

(9) “IRS” means US Internal Revenue Service.

(10) “Metric tons of CO2e” or “MT CO2e” means metric tons of carbon dioxide equivalent.

(11) “NAICS” means North American Industry Classification System.

(12) “US” means United States.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0090

RULE TITLE: Overview of Program Provisions for Covered Entities and CCI Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Provides an outline of the program-related rules of this division.

RULE TEXT:

(1) OAR 340-273-0100 describes general requirements for covered entities.

(2) OAR 340-273-0110 describes which air contamination sources are covered entities subject to the requirements of the CPP.

(3) OAR 340-273-0120, OAR 340-273-0130, and 340-273-0150 describe covered entity requirements including notifying DEQ of changes in ownership, operational control, and related entities; cessation of applicability; and requirements to obtain CPP permits, respectively.

(4) OAR 340-273-400 describes the generation of compliance instruments under the cap.

(5) OAR 340-273-0410 through OAR 340-273-0890 describe
the provisions that apply to covered entities.

(6) OAR 340-273-0900 through OAR 340-273-0990 describe the provisions for how DEQ will approve CCI entities and how CCI entities will implement eligible projects supported by CCI funds.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.065, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0100

RULE TITLE: Oregon Climate Protection Program Requirements

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes general requirements for covered entities.

RULE TEXT:

(1) A person who owns or operates a covered entity must comply with the rules in this division, including all provisions of this division that create any type of obligation of, or requirement that applies to, the covered entity that such person owns or operates. Compliance with this division does not relieve a person who owns or operates a covered entity of the obligation to comply with any other provisions of OAR chapter 340, as applicable.

(2) A person who owns or operates a covered entity identified in OAR 340-273-0110 must apply for and hold a CPP permit according to OAR 340-273-0150 that authorizes the person's covered emissions and subjects the person to the requirements of this division.

(3) A person who owns or operates a covered entity must submit reports and attestations required in this division, as applicable.

(4) A person who owns or operates a covered entity must develop and retain all records required in this division, as applicable.

(5) A person who owns or operates a covered entity must use forms and reporting tools approved and issued by DEQ for all certifications, attestations and submissions. All submissions must be made electronically unless otherwise requested or approved by DEQ.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.065, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0110

RULE TITLE: Covered Entity and Covered Emissions Applicability

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the covered DNG sources, covered EITE sources, and covered fuel suppliers to which this division of rules apply and the emissions from those sources that are regulated by these rules.

RULE TEXT:

(1) Calculations of covered emissions, compliance obligations, and distribution of compliance instruments will be based on emissions data and information submitted in accordance with this rule and in emissions data reports submitted by a person described in this rule and required according to OAR chapter 340, division 215, which may be subject to verification according to OAR chapter 340, division 272. For any person that does not submit sufficient information in compliance with OAR chapter 340, divisions 215 and 272, calculations will be informed by additional best data available to DEQ. For any person that has not registered and reported according to division 215, such calculations will be based on the best data available to DEQ, following all reporting requirements and assumptions that would be applicable had the person reported according to that division.

(2) A covered entity is subject to the requirements of this division for its covered emissions described in this rule. A person remains a covered entity until cessation is met according to OAR 340-273-0130.

(3) Applicability for fuel suppliers and in-state fuel producers. A person is a covered fuel supplier if the person is described in subsection (a) and has annual covered emissions described in subsection (b) in any applicability determination calendar year that equal or exceed the threshold for applicability listed in Table 1 in OAR 340-273-9000. All persons that are related entities must aggregate their emissions together to determine applicability and each becomes a covered fuel supplier if applicability is met. When applicability is met, each person is a covered fuel supplier beginning with the calendar year a person becomes a covered fuel supplier, as provided in Table 1 in OAR 340-273-9000. Once a person is a covered fuel supplier, the person remains a covered fuel supplier until the person has met the cessation requirements according to OAR 340- 273-0130.

(a) The person is a fuel supplier or in-state producer that imports, sells, or distributes fuel for use in Oregon, and is one or more of the following:

(A) A dealer, as that term is defined in ORS 319.010 that is subject to the Oregon Motor Vehicle and Aircraft Fuel Dealer License Tax in OAR chapter 735, division 170;

(B) A seller, as that term is defined in ORS 319.520, that is subject to the Oregon Use Fuel Tax in OAR chapter 735, division 176;

(C) A person that produces, imports, sells, or distributes gasoline or distillate fuel oil for use in Oregon and that is not subject to the Oregon Motor Vehicle and Aircraft Fuel Dealer License Tax or the Oregon Use Fuel Tax in OAR chapter 735, divisions 170 and 176; or

(D) A person that either produces propane in Oregon or imports propane for use in the state.

(b) Except as provided in paragraph (B), covered emissions include emissions described in paragraph (A).

(A) Covered emissions include emissions of anthropogenic greenhouse gases in metric tons of CO_2e that would result from the complete combustion or oxidation of the annual quantity of propane and liquid fuels (including, for example and without limitation, gasoline and petroleum products) imported, sold, or distributed for use in this state.

(B) Covered emissions do not include:

(i) Emissions that are from the combustion of biomass-derived fuels;

(ii) Emissions that are from the combustion of fuels used for aviation including, for example and without limitation, aviation gasoline, kerosene-type jet fuel, and alternative jet fuel;

(iii) Emissions described in 40 CFR part 98 subpart W – Petroleum and Natural Gas Systems; and

(iv) Emissions from fuels that have been used in a manner other than combustion or oxidization, and that does not result in material emissions of CO_2e, if documented in information provided to DEQ.

(4) Applicability for local distribution companies. A person is a covered fuel supplier if the person is described in

subsection (a) and has annual covered emissions described in subsection (b) in 2020 or any subsequent calendar year, unless the person has met the cessation requirements according to OAR 340-273-0130.
(a) The person is a local distribution company that either produces natural gas, compressed natural gas, or liquefied natural gas in Oregon, or that imports, sells, or distributes natural gas, compressed natural gas, or liquefied natural gas to end users in the state.
(b) Except as provided in paragraph (B), covered emissions include emissions described in paragraph (A).
(A) Covered emissions include emissions of anthropogenic greenhouse gases in metric tons of CO2e that would result from the complete combustion or oxidation of the annual quantity of natural gas imported, sold, or distributed for use in this state.
(B) Covered emissions do not include:
(i) Emissions that are from the combustion of biomass-derived fuels;
(ii) Emissions described in 40 CFR part 98 subpart W – Petroleum and Natural Gas Systems;
(iii) Emissions avoided where the use of natural gas results in greenhouse gas emissions captured and stored, if documented by information provided to DEQ under approved protocols;
(iv) Emissions from natural gas delivered to an air contamination source that is an electric power generating plant with a total nominal electric generating capacity greater than or equal to 25 megawatts; and
(v) Emissions from the combustion or oxidation of natural gas at a covered EITE source as described in section (5).
(5) Applicability for EITE sources. A person is a covered EITE source if the person is described in subsection (a) and has annual covered emissions described in subsection (b) in 2020 or any subsequent calendar year that equal or exceed 15,000 MT CO2e.
(a) The person owns or operates a source engaged in a sector described in OAR 340-273-9000 Table 7.
(b) Except as provided in paragraph (B), covered emissions include emissions described in paragraph (A).
(A) Covered emissions include all emissions of anthropogenic greenhouse gases in metric tons of CO2e, including without limitation, emissions from all uses of natural gas and solid fuels, from energy production, from industrial processes, and from any other processes.
(B) Covered emissions do not include:
(i) Emissions from the use of biomass-derived fuels;
(ii) Emissions from the use of liquid fuels or propane;
(iii) Emissions from an air contamination source that is owned or operated by an interstate natural gas pipeline and that is operating under authority of a certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission;
(iv) Emissions from an air contamination source that is an electric power generating plant with a total nominal electric generating capacity greater than or equal to 25 megawatts.
(v) Emissions described in 40 CFR part 98 subpart HH – Municipal Solid Waste Landfills;
(vi) Emissions described in 40 CFR part 98 subpart TT – Industrial Waste Landfills; and
(vii) Emissions avoided where greenhouse gas emissions are captured and stored, if documented by information provided to DEQ under approved protocols;
(6) Applicability for direct natural gas sources. A person is a covered DNG source if the person is described in subsection (a) and has annual covered emissions described in subsection (b) in 2020 or any subsequent calendar year that equal or exceed 15,000 MT CO2e.
(a) The person owns or operates a stationary source that:
(A) Is not in a source classification described in OAR 340-273-9000 Table 7; and
(B) Uses natural gas distributed to the source by an entity other than a local distribution company.
(b) Except as provided in paragraph (B), covered emissions include emissions described in paragraph (A).
(A) Covered emissions include all emissions of anthropogenic greenhouse gases in metric tons of CO2e, including without limitation, emissions from all uses of natural gas and solid fuels, from energy production, from industrial processes, and from any other processes.

(B) Covered emissions do not include:

(i) Emissions from the use of biomass-derived fuels;

(ii) Emissions from the use of liquid fuels or propane;

(iii) Emissions from an air contamination source that is owned or operated by an interstate natural gas pipeline and that is operating under authority of a certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission;

(iv) Emissions from an air contamination source that is an electric power generating plant with a total nominal electric generating capacity greater than or equal to 25 megawatts;

(v) Emissions described in 40 CFR part 98 subpart HH – Municipal Solid Waste Landfills;

(vi) Emissions described in 40 CFR part 98 subpart TT – Industrial Waste Landfills;

(vii) Emissions avoided where greenhouse gas emissions are captured and stored, if documented by information provided to DEQ under approved protocols; and

(viii) Emissions from natural gas, compressed natural gas, or liquefied natural gas used on site that was delivered by a local distribution company.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468A.010, 468A.015, 468A.045, 468.035

ADOPT: 340-273-0120

RULE TITLE: Changes in Covered Entity Ownership and Changes to Related Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes covered entity requirements for reporting to DEQ on changes in ownership and changes to related entities.

RULE TEXT:

(1) Changes in ownership or operational control.

(a) If a covered entity undergoes a change in ownership or operational control, the new person that owns or operates the covered entity must notify DEQ in writing within 30 days of the ownership or operational control change. The person must submit a complete and accurate notification, including providing the following information:

(A) The name of the previous owner or operator;

(B) The name of the new owner or operator;

(C) The date of ownership or operator change;

(D) Name of the designated representative;

(E) If the covered entity is a covered fuel supplier that is not a local distribution company information about each person that was a related entity prior to the change in ownership or operational control and that was required to report emissions according to OAR chapter 340, division 215, including legal name, full mailing address, and whether each is a covered fuel supplier and holds a CPP permit; and

(F) If the covered entity is a covered fuel supplier that is not a local distribution company, information about each person that is a related entity after the change in ownership or operational control and that is required to report emissions according to OAR chapter 340, division 215, including legal name, full mailing address, and whether each is a covered fuel supplier and holds a CPP permit.

(b) The covered entity continues to be a covered entity following a change in ownership or operational control, until it meets the cessation requirements in OAR 340-273-0130. Any other covered entity that was a related entity also continues to be a covered entity following the change in ownership or operational control, until it meets the cessation according to OAR 340-273-0130.

(c) Following a change in ownership or operational control, a covered fuel supplier that holds a compliance instrument or CCI credit according to OAR 340-273-0430 or OAR 340-273-0830 continues to hold the compliance instrument or CCI credit according to each rule, as applicable.

(2) Changes to related entities of covered fuel suppliers.

(a) If a person subject to any regulations in OAR chapter 340, division 215, becomes a new related entity to a covered fuel supplier that is not a local distribution company due to a change in ownership or operational control, the designated representative of the covered fuel supplier must notify DEQ in writing, on a form approved by DEQ, within 30 days of the ownership or operational control change. The designated representative must submit a complete and accurate notification, including providing the following information:

(A) Information about the new related entity, including legal name, full mailing address, and whether the person is a covered fuel supplier and holds a CPP permit;

(B) The name of the previous owner or operator of the new related entity;

(C) The name of the new owner or operator of the new related entity;

(D) The date of ownership or operator change for the new related entity; and

(E) Information about all other related entities subject to any regulations in OAR chapter 340, including legal names, full mailing addresses, and whether each is a covered fuel supplier and holds a CPP permit.

(b) If the person that is the new related entity to a covered fuel supplier identified in paragraph (a)(A) is not already a covered fuel supplier, the person:

(A) Becomes a covered fuel supplier beginning with the date of ownership or operator change;

(B) Must apply to DEQ for a CPP permit according to OAR 340-273-0150(1)(a)(B); and

(C) If the person is a covered fuel supplier, the person will have compliance obligations beginning with covered emissions from the calendar year in which the ownership or operator change occurred.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.065, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0130

RULE TITLE: Cessation of Covered Entity Applicability

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the conditions under which a person ceases to be a covered entity.

RULE TEXT:

(1) Cessation for covered fuel suppliers.

(a) A person that is a covered fuel supplier as described in OAR 340-273-0110 remains a covered fuel supplier until the person receives written notification from DEQ after either or both:

(A) The person's annual covered emissions are 0 (zero) MT CO2e for six consecutive calendar years. If the person is not a local distribution company, the covered emissions of the person's related entities must also be 0 (zero) MT CO2e for the same six consecutive calendar years; or

(B) The person was designated a covered fuel supplier in OAR 340-273-0110(3), the sum of its annual covered emissions and the annual covered emissions of its related entities are less than 25,000 MT CO2e for six consecutive calendar years and the person applies to DEQ according to subsection (c).

(b) After a covered fuel supplier identified according to paragraph (a)(A) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(A), DEQ will notify the designated representative of the covered fuel supplier in writing that cessation is met.

(c) In order for cessation according to paragraph (a)(B) to take effect, a covered fuel supplier must apply to cease being a covered fuel supplier by submitting the following information to DEQ on a form approved by DEQ:

(A) Information about the covered fuel supplier, including:

(i) Name and full mailing address, and website; and

(ii) Designated representative's contact information including name, title or position, phone number, and email address;

(B) If the person is not a local distribution company information about each related entity required to report emissions according to OAR chapter 340, division 215, for each of the six consecutive calendar years, including legal name, full mailing address, and whether each is a covered fuel supplier and holds a CPP permit;

(C) Information about remaining requirements that must be met according to this division at the time the application is submitted to DEQ; and

(D) The following attestation, signed by the designated representative of the covered fuel supplier:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. [Covered fuel supplier] meets the eligibility for cessation as a covered fuel supplier according to Oregon Administrative Rules chapter 340, division 273. I understand that ceasing to be a covered fuel supplier means that [covered fuel supplier] will also cease to hold any compliance instruments and CCI credits.

(d) After the covered fuel supplier applying for cessation according to paragraph (a)(B) and subsection (c) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(B), DEQ will notify the designated representative of the covered fuel supplier in writing that the application for cessation is approved and that cessation is met.

(e) A person that ceases to be a covered fuel supplier according to this section must comply with all remaining applicable recordkeeping requirements of this division from the last date on which the person was a covered fuel supplier.

(f) When a person ceases to be a covered fuel supplier:

(A) The cessation does not change the compliance obligation for any year for which the person has already demonstrated compliance;

(B) Any remaining compliance instruments held by the person will be retired, held in reserve, or distributed by DEQ according to OAR 340-273-0430(3); and

(C) Any remaining community climate investment credits held by the person will be canceled according to OAR 340-273-0830(1)(c).
(2) Cessation for covered EITE sources.
(a) A person that is a covered EITE source as described in OAR 340-273-0110(5) remains a covered EITE source until the person receives written notification from DEQ after either or both:
(A) The person's annual covered emissions are 0 (zero) MT CO2e for six consecutive calendar years.; or
(B) The person's annual covered emissions are less than 15,000 MT CO2e for six consecutive calendar years and the person applies to DEQ according to subsection (c).
(b) After a covered EITE source identified according to paragraph (2)(a)(A) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(A), DEQ will notify the designated representative of the covered EITE source in writing that cessation is met.
(c) In order for cessation according to paragraph (2)(a)(B) to take effect, a covered EITE source must apply to cease being a covered EITE source by submitting the following information to DEQ on a form approved by DEQ:
(A) Information about the covered EITE source, including:
(i) Name and full mailing address; and
(ii) Designated representative's contact information including name, title or position, phone number, and email address;
(B) Information about remaining requirements that must be met according to this division at the time the application is submitted to DEQ; and
(C) The following attestation, signed by the designated representative of the covered EITE source:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. [EITE source name] meets the eligibility for cessation as a covered EITE source according to Oregon Administrative Rules chapter 340, division 273. I understand that ceasing to be a covered EITE source means that [EITE source name] will also cease to hold any compliance instruments and CCI credits.

(d) After the covered EITE source applying for cessation according to paragraph (a)(B) and subsection (c) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(B), DEQ will notify the designated representative of the covered EITE source in writing that the application for cessation is approved and that cessation is met.
(e) A person that ceases to be a covered EITE source according to this section must comply with all remaining applicable recordkeeping requirements of this division from the last date on which the person was a covered EITE source.
(f) When a person ceases to be a covered EITE source:
(A) The cessation does not change the compliance obligation for any year for which the person has already demonstrated compliance;
(B) Any remaining compliance instruments held by the person will be retired, held in reserve, or distributed by DEQ according to OAR 340-273-0430(3); and
(C) Any remaining community climate investment credits held by the person will be canceled according to OAR 340-273-0830(1)(c).
(3) Cessation for covered DNG sources.
(a) A person that is a covered DNG source as described in OAR 340-273-0110(6) remains a covered DNG source until the person receives written notification from DEQ after either or both:
(A) The person's annual covered emissions are 0 (zero) MT CO2e for six consecutive calendar years.; or
(B) The person's annual covered emissions are less than 15,000 MT CO2e for six consecutive calendar years and the person applies to DEQ according to subsection (c).
(b) After a covered DNG source identified according to paragraph (3)(a)(A) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(A), DEQ will notify the designated

representative of the covered DNG source in writing that cessation is met.
(c) In order for cessation according to paragraph (3)(a)(B) to take effect, a covered DNG source must apply to cease being a covered DNG source by submitting the following information to DEQ on a form approved by DEQ:
(A) Information about the covered DNG source, including:
(i) Name and full mailing address; and
(ii) Designated representative's contact information including name, title or position, phone number, and email address.
(B) Information about remaining requirements that must be met according to this division at the time the application is submitted to DEQ; and
(C) The following attestation, signed by the designated representative of the covered DNG source:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. [DNG source name] meets the eligibility for cessation as a covered DNG source according to Oregon Administrative Rules chapter 340, division 273. I understand that ceasing to be a covered DNG source means that [DNG source name] will also cease to hold any compliance instruments and CCI credits.

(d) After the covered DNG source applying for cessation according to paragraph (a)(B) and subsection (c) demonstrates compliance with compliance obligations for the years up to and including the years described in paragraph (a)(B), DEQ will notify the designated representative of the covered DNG source in writing that the application for cessation is approved and that cessation is met.
(e) A person that ceases to be a covered DNG source according to this section must comply with all remaining applicable recordkeeping requirements of this division from the last date on which the person was a covered DNG source.
(f) When a person ceases to be a covered DNG source:
(A) The cessation does not change the compliance obligation for any year for which the person has already demonstrated compliance;
(B) Any remaining compliance instruments held by the person will be retired, held in reserve, or distributed by DEQ according to OAR 340-273-0430(3); and
(C) Any remaining community climate investment credits held by the person will be canceled according to OAR 340-273-0830(1)(c).

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0150

RULE TITLE: Covered Entity Permit Requirements

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes covered entity requirements for obtaining a CPP permit.

RULE TEXT:

(1) A person described in either or both OAR 340-273-0110(3) or (4) must apply for a CPP permit as provided in this section.

(a) The person must apply for a CPP permit according to subsections (b) and (c) by the following deadlines:

(A) If DEQ notifies the person in writing that the person is a covered fuel supplier, then the person must apply to DEQ for a CPP permit within 30 days of the notification or by another date DEQ specifies in the notification that is at least 30 days after the date of the notification;

(B) If DEQ does not provide a notification according to paragraph (A), then the person must apply to DEQ for a CPP permit by April 15 of the year after the calendar year that the person becomes a covered fuel supplier; or

(C) If there was a change in ownership or operational control according to OAR 340- 273-0120(2), then the person must apply to DEQ for a CPP permit within 45 days of the change in ownership or operational control.

(b) A person that submits a CPP permit application to DEQ must submit a complete and accurate application. The application for a CPP permit must be submitted to DEQ using a form approved by DEQ and include:

(A) Identifying information about the covered fuel supplier including name, full mailing address, and website, and designated representative's contact information including name, title or position, phone number, and email address;

(B) If the person is a covered fuel supplier that is not a local distribution company, information about each related entity required to report emissions according to OAR chapter 340, division 215, including legal name, full mailing address, and whether each is a covered fuel supplier and holds a CPP permit; and

(C) The following attestation, signed by the designated representative of the person considered a covered fuel supplier;

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. [Covered entity] meets the Climate Protection Program applicability requirements described in OAR 340-273-0110 and requests a permit with the understanding that [covered entity] must comply with such permit as provided in Oregon Administrative Rules chapter 340, division 273.

(c) DEQ may issue a CPP permit to a covered fuel supplier that submits a complete and accurate application. The permit may contain all applicable provisions of this division and such other conditions as DEQ determines are necessary to implement, monitor and ensure compliance with this division.

(2) A person described in either OAR 340-273-0110(5) or (6) must apply for a CPP permit as provided in this section.

(a) The CPP permit application deadlines are:

(A) If DEQ notifies the owner or operator in writing that they are a covered entity, then the owner or operator must apply to DEQ for a CPP permit within 60 days of the notification or by another date DEQ specifies in the notification that is at least 60 days after the date of the notification; or

(B) If DEQ does not provide a notification according to paragraph (A), then the owner or operator must apply to DEQ for a CPP permit by April 15 of the year after the calendar year that the EITE source or DNG source becomes a covered entity.

(b) A covered EITE source or DNG source that submits a CPP permit application to DEQ must submit a complete and accurate application. The application for a CPP permit must be submitted to DEQ using a form approved by DEQ and include:

(A) Identifying information about the covered entity, including name and the name of the person that owns or operates the covered entity, full mailing address, the physical address of the covered entity, and a description of the nature of business being operated, the name, phone number and email address of the designated representative who is responsible for compliance with the permit, the permit number for a source that has already been issued an air quality permit, and the primary and any secondary NAICS code(s) of the covered entity;

(B) A process flow diagram showing the complete production or operational process at the covered entity including all emission units;

(C) For each process or product produced by the covered entity:

(i) The type of process or product and a proposed metric of emissions intensity;

(ii) The level of process or quantity of product produced in each of the 5 previous calendar years, or all years of operation if the facility has not been in operation for 5 years; and

(iii) A calculation of all greenhouse gas emissions in MT CO2e resulting from the process or production of the product in each of the same five previous calendar years used in subparagraph (ii). If multiple processes or products are produced at the covered entity, provide a methodology for allocating emissions to each product; and

(D) Any other information requested by DEQ.

(c) DEQ may issue a CPP permit to a covered EITE source or covered DNG source that submits a complete and accurate application. The permit may contain all applicable provisions of this division and such other conditions as DEQ determines are necessary to implement, monitor and ensure compliance with this division.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.135

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.135, 468.065, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0400

RULE TITLE: Generation of Compliance Instruments

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how DEQ generates compliance instruments, each of which authorizes a covered entity to emit one metric ton of carbon dioxide equivalent (MT CO2e) of greenhouse gas emissions. The total amount of compliance instruments DEQ will generate is equal to annual emissions caps in Table 2. with the exception of additional compliance instruments for 2025.

RULE TEXT:

(1) Each year, DEQ will generate the number of compliance instruments equal to the cap for the calendar year identified in Table 2 in OAR 340-273-9000.

(2) Additional 2025 compliance instruments. DEQ will add together the 2022, 2023, and 2024 emissions that would have been considered covered emissions as described in OAR 340-273-0110(3)(B) for all fuel suppliers that individually, or as a group of related entities, had covered emissions greater than or equal to 200,000 MT CO2e from any calendar year between 2018 and 2022, and DEQ will compare these total emissions to a benchmark of 81,003,850 MT CO2e. If the total emissions from those fuel suppliers are at least 10,000 MT CO2e below the benchmark, DEQ will generate additional compliance instruments equal to the difference between those total emissions and 81,003,850 and will distribute those additional compliance instruments in 2025 as described in OAR 340-273-0420(5).

(3) A compliance instrument is a regulatory instrument and does not constitute personal property, a security or any other form of property.

(4) Compliance instruments may not be divided into fractions.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0410

RULE TITLE: Distribution of Compliance Instruments to Covered Emissions-Intensive and Trade-Exposed Sources and Covered Direct Natural Gas Sources

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how DEQ will distribute compliance instruments to covered EITE and DNG sources and that these sources are not distributed compliance instruments for the first compliance period.

RULE TEXT:

(1) DEQ will distribute compliance instruments annually to covered EITE sources and covered DNG sources according to this rule. DEQ will distribute compliance instruments from a cap no later than June 30 of each calendar year.

(2) In order to be eligible for an annual distribution of compliance instruments, a covered EITE source or covered DNG source must:

(a) Provide DEQ with timely and accurate reports as required under OAR Chapter 340, Division 215; and

(b) Hold a CPP permit as required by OAR 340-273-0150(4).

(3) Covered EITE sources and covered DNG sources are exempt from compliance obligations for the first compliance period.

(a) Covered EITE sources and covered DNG sources do not have compliance obligations for covered emissions for 2025, 2026, and 2027.

(b) Covered EITE sources and covered DNG sources will not receive a distribution of compliance instruments in 2025, 2026, or 2027.

(4) The EQC recognizes that EITE sources may face competition from sources operating outside of Oregon and not subject to these rules. Avoiding leakage of emissions and economic activity to other jurisdictions as a result of the cost of compliance with this division of rules is a critical objective of this division of rules. To achieve this objective while hastening investments to decarbonize manufacturing in Oregon, DEQ staff will work to develop a proposed baseline emissions intensity value for each covered EITE source and covered DNG source for the second and subsequent compliance periods from data provided by each covered entity. DEQ staff anticipates that the proposed baseline emissions intensity value would calculate the number of metric tons of CO2e emitted per unit of applicable product or operational process for each covered entity, and then DEQ staff would propose to establish an annual decline from the proposed baseline emissions intensity value for all such covered entities. Each calendar year DEQ could propose to distribute to each covered EITE source and covered DNG source compliance instruments from the annual cap equivalent to the applicable emission intensity target times the number of applicable units using emissions and production data from the previous calendar year. DEQ staff will develop this proposal for potential adoption by the EQC.

(5) For the second and subsequent compliance periods, DEQ will distribute compliance instruments to each covered EITE source and covered DNG source equal to the covered entity's average covered emissions for 2022 through 2023 multiplied by the emission reduction target in OAR 340-273-9000 Table 8 for each year of the compliance period. If DEQ does not have emissions data for a covered EITE source or covered DNG source for either or both 2022 and 2023, DEQ will replace the missing year(s) with the most recent calendar year(s) of emissions data that is available from calendar years 2017 through 2024. If DEQ only has one year of emissions data for a covered EITE source or covered DNG source between 2017 and 2024, DEQ will distribute the number of compliance instruments equal to the covered entity's covered emissions for that one year. If DEQ does not have any emissions data for a covered entity from 2017 through 2024, DEQ will distribute compliance instruments equal to the covered entity's 2024 covered emissions.

(6) A covered EITE source or covered DNG source that begins operations in 2025 or any subsequent year will not incur a compliance obligation for covered emissions occurring until the first year of the next compliance period after they become a covered entity.

(a) For any covered EITE source or covered DNG source that begins operations in 2025 or any subsequent year, DEQ will use the most recent year(s) of available data to calculate a covered emissions baseline, up to two years.

(b) A covered EITE source or covered DNG source that begins operations in 2025 or any subsequent year will not receive a distribution of compliance instruments until the first year of the next compliance period after becoming a covered entity.

(c) Beginning in the first year of the next compliance period after becoming a covered EITE source, the EITE source will receive a distribution of compliance instruments equal to the covered EITE source's emissions baseline, as described in subsection (a), multiplied by an emission reduction target of 1. The emissions reduction target will decrease by 0.03 per year until this target reaches an equivalent emissions reduction to the emissions reduction target for that calendar year outlined in Table 8.

(d) Beginning in the first year of the next compliance period after becoming a covered DNG source, the DNG source will receive a distribution of compliance instruments equal to the covered DNG source's emissions baseline, as described in subsection (a), multiplied by an emission reduction target of 1. The emissions reduction target will decrease by 0.05 per year until this target reaches an equivalent emissions reduction to the emissions reduction target for that calendar year outlined in Table 8.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0420

RULE TITLE: Distribution of Compliance Instruments to Covered Fuel Suppliers

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how DEQ will distribute compliance instruments to covered fuel suppliers.

RULE TEXT:

(1) DEQ will distribute compliance instruments to covered fuel suppliers according to this rule. DEQ will distribute compliance instruments from a cap according to sections (2), (3), (4), (5), (6), and (7) no later than June 30 of the calendar year of that cap.

(2) Annual distribution of compliance instruments to covered fuel suppliers that are local distribution companies. DEQ will annually distribute to each local distribution company, or to its successor(s) due to a change in ownership or operation, the percentage of compliance instruments from the calendar year's cap stated in Table 4 in OAR 340-273-9000. This percentage shall be derived from the remaining compliance instruments under the cap after the number of compliance instruments distributed to covered EITE sources and covered DNG sources according to OAR 340-273-0410 are subtracted from the cap.

(3) DEQ will establish a compliance instrument reserve for covered fuel suppliers that are new to the program and are not local distribution companies. DEQ will hold, according to subsection (4)(a), a subset of compliance instruments in the reserve from the caps identified in Table 2 in OAR 340-273-9000. Once a compliance instrument is held in the reserve, it remains in the reserve until DEQ determines, at its discretion, to undertake one of the following actions:

(a) DEQ distributes the compliance instrument according to section (6) to a new covered fuel supplier that is not a local distribution company;

(b) DEQ retires the compliance instrument because the compliance instrument reserve exceeds the size described in Table 3 OAR 340-273-9000, provided that after such retirement the size of the compliance instrument reserve will equal or exceed the reserve size described in Table 3; or

(c) DEQ distributes the compliance instrument to a covered fuel supplier that is not a local distribution company because the size of the compliance instrument reserve exceeds the reserve size described in Table 3 in OAR 340-273-9000. DEQ will only distribute compliance instruments from the reserve according to this subsection if there are at least 10,000 compliance instruments to distribute and if the remaining size of the reserve after this distribution will equal or exceed the reserve size described in Table 3 in OAR 340-273-9000. DEQ will calculate the number of compliance instruments to distribute to each covered fuel supplier that is not a local distribution company according to subsection (4)(b), except "total compliance instruments to distribute" means the total number of compliance instruments DEQ is distributing from the reserve according to this subsection.

(4) Annual distribution of compliance instruments to covered fuel suppliers that are not local distribution companies. DEQ will annually distribute compliance instruments from the applicable calendar year's cap to covered fuel suppliers that are not local distribution companies as follows:

(a) If the size of the compliance instrument reserve is less than the reserve size described in Table 3 in OAR 340-273-9000 for the calendar year, then DEQ will calculate the difference and hold in the compliance instrument reserve that quantity of compliance instruments. Otherwise, the number of compliance instruments in the reserve will not be changed.

(b) Except for compliance instruments identified in Table 4 in OAR 340-273-9000 for distribution according to section (2) and the compliance instruments held in the reserve according to section (3) and subsection (4)(a), DEQ will calculate the number of compliance instruments to distribute to each covered fuel supplier that is not a local distribution company as described in this subsection, including paragraphs (A) through (E), based on emissions data from the prior calendar year as reported by each covered fuel supplier as required by OAR chapter 340, division 215, and subject to DEQ's initial review for errors, but prior to completion of third-party verification as required by OAR chapter 340, division 272. A person that becomes a covered fuel supplier after DEQ has distributed the compliance instruments for that year will not receive a distribution under this subsection.

(A) Beginning with the 2026 annual distribution of compliance instruments, prior to each calculation of compliance instrument distribution described in paragraph (B), DEQ will apply a "Verified emissions data correction factor" to the annual compliance instrument distribution of each covered fuel supplier. DEQ will recalculate the compliance instrument distribution from the previous year using third-party verified emissions data. If DEQ determines that the reported emission data used for the previous year's compliance instrument distribution resulted in a lesser or greater number of compliance instruments being distributed to a covered fuel supplier, when compared to the recalculation using the third-party verified data, DEQ will increase or reduce, respectively, the number of compliance instruments distributed to the covered fuel supplier by an equal amount in the current compliance instrument distribution.
(B) DEQ will use the following formula to calculate the number of compliance instruments to distribute to each covered fuel supplier:

Number of Compliance Instruments = (Total compliance instruments to distribute * ([Covered fuel supplier covered emissions + covered fuel supplier biofuel emissions] / Total emissions)) ± Verified emissions data correction factor – Compliance instrument holding limit reduction

(C) As used in the formula in paragraph (B):
(i) "Total compliance instruments to distribute" means the cap for the calendar year, according to Table 2 in OAR 340-273-9000, minus the number of compliance instruments identified in Table 4 in OAR 340-273-9000; and minus the number of compliance instruments held in the compliance instrument reserve;
(ii)(I) For the 2026 and all subsequent annual distributions, "covered fuel supplier covered emissions" means the sum of a covered fuel supplier's covered emissions for the prior calendar year;
(II) For the 2025 annual distribution of compliance instruments, each covered fuel supplier's "covered fuel supplier covered emissions" will be either the sum of the covered fuel supplier's verified covered emissions for the 2023 calendar year or the sum of the covered fuel supplier's unverified covered emissions for the 2024 calendar year. The verified 2023 data will be used if the sum of a covered fuel supplier's verified 2023 covered emissions plus the verified emissions described in OAR 340-271- 0110(3)(b)(B)(i) that result from the complete combustion or oxidation of all biomass- derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state in 2023 is greater than the sum of a covered fuel supplier's unverified 2024 covered emissions plus the unverified emissions described in OAR 340-271-0110(3)(b)(B)(i) that result from the complete combustion or oxidation of all biomass- derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state in 2024. The unverified 2024 data will be used if the sum of a covered fuel supplier's unverified 2024 covered emissions plus the unverified emissions described in OAR 340-271-0110(3)(b)(B)(i) that result from the complete combustion or oxidation of all biomass-derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state in 2024 is greater than the sum of a covered fuel supplier's verified 2023 covered emissions plus the verified emissions described in OAR 340-271-0110(3)(b)(B)(i) that result from the complete combustion or oxidation of all biomass- derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state in2023;
(iii)(I) For the 2026 and all subsequent annual distributions, "covered fuel supplier biofuel emissions" means emissions described in OAR 340-273-0110(3)(b)(B)(i) that result from the complete combustion or oxidation of the annual quantity of biomass- derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state for the prior calendar year;
(II) For the 2025 annual distribution of compliance instruments, if a covered fuel supplier's covered fuel supplier covered emissions, as determined under sub- subparagraph (ii)(II), are its verified 2023 calendar year emissions, then its "covered fuel supplier biofuel emissions" will be based on verified 2023 calendar year emissions data, but if a covered fuel supplier's covered fuel supplier covered emissions, as determined under sub-subparagraph (ii)(II), are its unverified 2024 calendar year emissions, then its "covered fuel supplier biofuel emissions" will be based on unverified 2024 calendar year emissions data;
(iv) "Total emissions" means the sum of "covered fuel supplier covered emissions" and "covered fuel supplier biofuel

emissions" for the prior calendar year for all covered fuel suppliers whose compliance instrument distribution is calculated according to this section. For the 2025 annual distribution of compliance instruments, "Total emissions" means the sum of "covered fuel supplier covered emissions" and "covered fuel supplier biofuel emissions" used for that year's calculation, as described in subparagraphs (ii) and (iii); and
(v) "Verified emissions data correction factor" means a correction applied as a result of changes to reported data since the previous distribution of compliance instruments, as described in paragraph (A); and
(vi) "Compliance instrument holding limit reduction" means the number of compliance instruments described in OAR 340-273-0430(2). If the compliance instrument holding limit reduction exceeds the number of compliance instruments that a covered fuel supplier would have received in the distribution before subtracting the compliance instrument holding limit reduction, then the covered fuel supplier will not receive any compliance instruments in the distribution, and a compliance instrument holding limit reduction equal to the amount by which it exceeded the number of compliance instruments that a covered fuel supplier would have received in the distribution before subtracting the compliance instrument holding limit will be applied in the following year.
(D) DEQ will distribute a number of compliance instruments to each covered fuel supplier using the formula in paragraph (B) and rounded down to the nearest whole number.
(E) Any remaining compliance instruments not distributed due to rounding as described in paragraph (D) will be held in the compliance instrument reserve.
(5) DEQ will distribute any additional 2025 compliance instruments generated as described in OAR 340-273-0400 no later than June 30, 2025 as follows:
(a) DEQ will use the following formula to calculate the number of additional 2025 compliance instruments to distribute to each covered fuel supplier:

Number of Additional Compliance Instruments = Total additional compliance instruments to distribute * (Sum of covered fuel supplier biofuel emissions / Total biofuel emissions)

(b) As used in subsection (5)(a):
(A) "Total additional compliance instruments to distribute" means the number of additional compliance instruments generated as described in OAR 340-273-0400, if any;
(B) "Sum of covered fuel supplier biofuel emissions" means the sum of a covered fuel supplier's emissions described in OAR 340-273-0110(3)(b)(B)(i) that result from the complete use of the quantity of biomass-derived fuels that the covered fuel supplier imported, sold, or distributed for use in the state in 2022, 2023, and 2024; and
(C) "Total biofuel emissions" means the sum of emissions described in OAR 340-273- 0110(3)(b)(B)(i) that result from the complete use of the quantity of biomass-derived fuels that all covered fuel suppliers whose compliance instrument distribution is calculated according to this section imported, sold, or distributed for use in the state in 2022, 2023, and 2024.
(6) Distribution from compliance instrument reserve for new covered fuel suppliers that are not local distribution companies.
(a) A covered fuel supplier is eligible for a distribution from the compliance instrument reserve if it is not a local distribution company and if the person was not included in the distribution of compliance instruments for that year according to section (4).
(b) A covered fuel supplier meeting the requirements of subsection (a) is not eligible for a distribution of compliance instruments from the reserve if the person is a related entity to a covered fuel supplier that received a distribution of compliance instruments under section (4).
(c) A covered fuel supplier identified according to subsection (a) and not ineligible under subsection (b) may request a distribution of compliance instruments from the reserve by submitting an application to DEQ, on a form approved by DEQ, that includes the information described in paragraphs (A) through (D), no later than June 1 of the year after the calendar year of the annual distribution of compliance instruments from which the covered fuel supplier was not

included. The covered fuel supplier must submit a separate application for each year for which it is seeking distribution of compliance instruments from the reserve.
(A) Information about the covered fuel supplier, including:
(i) Name and full mailing address; and
(ii) Designated representative's contact information including name, title or position, phone number, and email address;
(B) The calendar year of covered emissions for which compliance instruments are requested;
(C) The reason for the request, including description of eligibility according to subsection (a); and
(D) The following attestation, signed by the designated representative of the covered fuel supplier:

I certify under penalty of perjury under the laws of the State of Oregon that I am a representative of [covered fuel supplier], am authorized to submit this application on its behalf, and that, to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. [Covered fuel supplier] is a covered fuel supplier in the year indicated in this application and requests compliance instruments from the reserve according to the information included in this application.

(d) DEQ will review an application submitted according to subsection (b) to ensure that it meets the requirements of this section. DEQ will inform the applicant either that the submitted application is complete or that additional specific information is required to make the application complete. If the application is incomplete, DEQ will not consider the application further until the applicant provides the additional information requested by DEQ.
(e) If DEQ approves an application, DEQ will distribute one or more compliance instruments to the covered fuel supplier from the reserve no later than June 15 of the year after the calendar year of the annual distribution of compliance instruments from which the covered fuel supplier was not included. DEQ will distribute compliance instruments from the reserve to the covered fuel supplier, as follows:
(A) A maximum distribution amount that will not exceed the covered fuel supplier's covered emissions in that calendar year using emissions data from the prior calendar year as reported by each covered fuel supplier as required by OAR 340, division 215, and subject to DEQ's initial review for errors, but prior to completion of third-party verification as required by OAR 340, division 272; and
(B) If there are fewer compliance instruments in the reserve at the time of distribution than have been requested by all covered fuel suppliers who are approved for a reserve distribution for a calendar year, DEQ shall allocate compliance instruments in the reserve according to the ratio of each covered fuel supplier's covered emissions in that calendar year to the total covered emissions from all covered fuel suppliers in that calendar year.
(7) Each year, the sum of all compliance instruments that are not distributed to fuel suppliers in the distribution under section (4) as a result of compliance instrument holding limit reductions will be distributed to all covered fuel suppliers that did not have any compliance instrument holding limit reduction using the formula described in paragraph OAR 340-273-0420(4)(b)(B), except that, for purposes of such redistribution, "total compliance instruments to distribute" means the total number of compliance instruments that DEQ did not distribute to fuel suppliers in the general distribution under section (4) as a result of compliance instrument holding limit reductions. Such additional distribution of compliance instruments shall be made at the same time as the distribution described in section (4). Any remaining compliance instruments not distributed due to rounding will be held in the compliance instrument reserve.
(8) Upon distribution of compliance instruments according to sections (2), (4), (5), (6), and (7), DEQ will notify the designated representative of each covered fuel supplier in writing of the availability of compliance instruments.
(9) DEQ will track distributed compliance instruments.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0430

RULE TITLE: Holding Compliance Instruments

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how a covered entity that is issued or acquires compliance instruments can bank compliance instruments that have not yet been used to demonstrate compliance. Describes how a compliance instrument holding limit reduction is assessed for covered fuels suppliers that are not local distribution companies.

RULE TEXT:

(1) A covered entity that is issued or acquires a compliance instrument under this division may continue to hold the compliance instrument until any of the following apply:

(a) The covered entity uses the compliance instrument toward its demonstration of compliance with a compliance obligation according to OAR 340-273-0450;

(b) The covered entity transfers the compliance instrument to another covered entity according to OAR 340-273-0500; or

(c) The covered entity has ceased being a covered entity according to OAR 340-273- 0130. When this occurs, DEQ may, at its discretion:

(A) Retire the compliance instrument;

(B) Hold the compliance instrument in the compliance instrument reserve described in OAR 340-273-0420(3); or

(C) Distribute the compliance instrument to covered fuel suppliers according to OAR 340-273-0420, by adding the compliance instrument to the total compliance instruments to be distributed to covered fuel suppliers during the next annual distribution of compliance instruments. DEQ will only distribute the compliance instrument if there are at least 10,000 compliance instruments to distribute.

(2) For each covered fuel supplier that is not a local distribution company, a compliance instrument holding limit reduction will be calculated on November 22 of the year following the end of each compliance period, or 25 days after DEQ's notification in OAR 340-273-0450(1), whichever is later. A covered fuel supplier's compliance instrument holding limit reduction is the number of compliance instruments from any prior year held by the covered fuel supplier on that date that exceeds one and a half times the sum of the covered fuel supplier's annual compliance obligation(s) and biofuel emissions for each year of the prior compliance period. In the year subsequent to the year after the end of a compliance period, if a fuel supplier did not receive any compliance instruments in the distribution under section OAR 340-273-0420(4) in the prior year because its compliance instrument holding limit reduction exceeded the number of compliance instruments that it otherwise would have been distributed, then the fuel supplier's compliance instrument holding limit reduction will be reduced as provided in subparagraph OAR 340-273-0420(4)(b)(B)(vi), and such reduced compliance instrument holding limit reduction will be used in the subsequent year's compliance instrument distribution calculation under section OAR 340-273-0420(4).

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0440

RULE TITLE: Compliance Periods

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes a three-year compliance period for the first compliance period followed by two- year compliance periods. The first compliance period includes calendar years 2025,2026 and 2027.

RULE TEXT:

(1) The first compliance period is three consecutive calendar years. Each subsequent compliance period is two consecutive calendar years.

(2) The first compliance period begins with calendar year 2025 and includes calendar years 2026 and 2027.

(3) A new compliance period begins with the calendar year following the last calendar year of the preceding compliance period.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0450

RULE TITLE: Demonstration of Compliance

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how covered entities demonstrate compliance. Covered entities demonstrate compliance once for each compliance period for their total compliance obligations. Covered entities may use compliance instruments or CCI credits, but there is a limit to the percent of its total compliance obligations that can be achieved with CCI credits for each compliance period. DNG and EITE sources do not have any compliance obligations for the first compliance period.

RULE TEXT:

(1) DEQ will determine the total compliance obligation for a compliance period for each covered fuel supplier, each covered EITE source, and each covered DNG source as the sum of the covered entity's annual compliance obligation(s) for each year of the compliance period. DEQ will base its determinations on emissions calculated according to OAR 340-273-0110(1). DEQ will notify each covered entity of DEQ's determination.

(2) A covered fuel supplier must demonstrate compliance according to this rule by December 9 of the year following the end of each compliance period, or 40 days after DEQ's notification described in section (1), whichever is later.

(3) A covered EITE source or covered DNG source must demonstrate compliance according to this rule by December 9 of the year following the end of the first compliance period in which they have a compliance obligation according to OAR 340-273-0410, or 40 days after DEQ's notification described in section (1), whichever is later.

(4) To demonstrate compliance for a compliance period, each covered entity required to demonstrate compliance must submit the following to DEQ:

(a) For each metric ton of CO_2e of the total compliance obligation, either a compliance instrument or a CCI credit, subject to the following limitations:

(A) A covered entity may only submit compliance instruments that DEQ distributed from the caps for the calendar years of the applicable compliance period or from caps for earlier compliance periods; and

(B) The quantity of CCI credits used to demonstrate compliance as a percentage of the total compliance obligation for the applicable compliance period may not exceed the allowable percentage specified in Table 5 in OAR 340-273-9000; and

(b) A demonstration of compliance form, approved by DEQ that includes:

(A) Name and full mailing address of the covered entity;

(B) Designated representative's contact information including name, title or position, phone number, and email address;

(C) Identification of the compliance period and calendar year(s) for which the covered entity is demonstrating compliance;

(D) The total compliance obligations in metric tons of CO_2e for the compliance period and listed separately for each calendar year in the compliance period;

(E) The total number of compliance instruments the covered entity is submitting to DEQ to demonstrate compliance, and separately the total number submitted from each calendar year's cap;

(F) The total number of CCI credits the covered entity is submitting to DEQ to demonstrate compliance; and

(G) The following attestation, signed by the designated representative of the covered entity:

I certify under penalty of perjury under the laws of the State of Oregon that I am a representative of [covered entity name], am authorized to submit this report on its behalf, and that, to the best of my knowledge and belief, the information provided in this form is true, accurate, and complete. It is the intent of [covered entity] to use the quantity of compliance instruments and credits listed on this form and submitted to DEQ for the demonstration of compliance. I certify that [covered entity] has not exceeded the allowable use of CCI credits. If any portion of these compliance obligations remain unmet after this submission, I understand that [covered entity] must still demonstrate compliance with the remaining portion and may be subject to enforcement action.

(5) Each metric ton of CO_2e of a compliance obligation for which a covered entity does not demonstrate compliance according to this rule is a separate violation of this division.
(6) If a change in ownership of a covered entity occurs, the person that owns or operates the covered entity as of December 31 in the final year of a compliance period is responsible for demonstration of compliance according to this rule for each annual compliance obligation during the compliance period. Compliance obligations may not be split or subdivided based on ownership changes during the compliance period or during any year within the compliance period.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0490

RULE TITLE: Recordkeeping Requirements Related to Demonstration of Compliance

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the recordkeeping requirements for covered entities related to demonstrating compliance.

RULE TEXT:

(1) A covered entity must retain the following records necessary for determining compliance obligations, in paper or electronic format, for a period of at least seven years beginning September 30 of the year following a year in which covered emissions occurred:

(a) Records according to the recordkeeping requirements of OAR chapter 340, divisions 215 and 272, as applicable;

(b) Copies of reports and forms submitted to DEQ related to determination of compliance obligations according this division and OAR chapter 340, divisions 215 and 272, including but not limited to:

(A) Applicable emissions data reports submitted according to OAR chapter 340, division 215; and

(B) Applicable verification statements submitted according to OAR chapter 340, division 272; and

(c) All other information and documentation used to calculate and report emissions and used to determine emissions and compliance obligations according to this division.

(2) A covered entity must retain the following records necessary for supporting demonstration of compliance, according to OAR 340-273-0450, in paper or electronic format for a period of at least seven years following the deadline for demonstration of compliance in OAR 340-273-0450:

(a) Copies of reports and forms submitted to DEQ related to demonstration of compliance, including but not limited to demonstration of compliance forms; and

(b) All other information and documentation used to support demonstration of compliance.

(3) A covered entity must make available to DEQ upon request all of the records it is required to retain according to this rule. DEQ will specify the date by which the covered entity must fulfill a records request from DEQ.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0500

RULE TITLE: Trading of Compliance Instruments

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes requirements for covered entities to be able to trade compliance instruments.

RULE TEXT:

(1) Covered entities may trade one or more compliance instruments only according to this rule. A covered entity may transfer one or more compliance instruments to another covered entity up to the amount that it has available and has not used to demonstrate compliance. A covered entity may acquire one or more compliance instruments from another covered entity.

(2) Covered entities may not trade fractions of a compliance instrument. All compliance instrument trades must be of whole compliance instruments.

(3) Covered entities may not engage in a trade of a compliance instrument involving, related to, in service of, or associated with any of the following:

(a) Fraud, or an attempt to defraud or deceive using any device, scheme or artifice;

(b) Use of any unconscionable tactic in connection with the transfer, by any person;

(c) Any false report, record, or untrue statement of material fact or omission of a material fact related to the transfer or conditions that would relate to the value of the compliance instrument being traded. A fact is material if it is reasonably likely to influence a decision by another person or by DEQ;

(d) Any activity intended to lessen competition or tend to create a monopoly, or to injure, destroy or prevent competition in the market for compliance instruments;

(e) A conspiracy in restraint of trade or commerce; or

(f) An attempt to monopolize holding of compliance instruments, or to combine, collude, or conspire with any other person or persons to monopolize.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0510

RULE TITLE: Compliance Instrument Trade Notifications and Process

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes requirements for covered entities to notify DEQ of trades of compliance instruments.

RULE TEXT:

(1) Covered entities that trade one or more compliance instruments as authorized by OAR 340-273-0500 must notify DEQ of the trade. The designated representatives of both the covered entity transferring the compliance instrument and the covered entity acquiring the compliance instrument must sign and submit a compliance instrument trade form that meets the requirements of this section, using a form approved by DEQ.

(a) The covered entity transferring one or more compliance instruments must sign first; and

(b) The covered entity acquiring the compliance instrument(s) must sign the same form and submit it to DEQ no later than one week after the transferring covered entity signs the form.

(c) All of the following must be included on a compliance instrument trade form:

(A) The agreed upon date of the trade.

(B) The total number of compliance instruments traded, and separately the total number traded from each calendar year's cap.

(C) The total value per compliance instrument (in US dollars), excluding any fees. If a specific dollar value is not paid for the compliance instrument, an estimate must be provided.

(D) As applicable, other information about the trade that DEQ determines is necessary to support DEQ's monitoring of trades and that DEQ includes on the form;

(E) The following information about the covered entity transferring the compliance instrument(s):

(i) Name and full mailing address of the covered entity.

(ii) Designated representative's contact information including name, title or position, phone number, and email address.

(iii) The following attestation, signed by the designated representative:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief the information in this form is true, accurate, and complete. [Covered entity] is transferring these compliance instruments to [covered entity that is acquiring] for the price described in this form.

(F) The following information about the covered entity acquiring the compliance instrument(s):

(i) Name and full mailing address of the covered entity.

(i) Designated representative's contact information including name, title or position, phone number, and email address.

(iii) The following attestation, signed by the designated representative:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief the information in this form is true, accurate, and complete. [Covered entity] is acquiring compliance instruments from [covered entity that is transferring] for the price described in this form.

(2) After DEQ receives a compliance instrument trade form for one or more compliance instruments as described in section (1), DEQ will inform the applicant either that the submitted form is complete or that additional specific information is required to make the form complete. Upon receipt of a complete form signed by both parties involved in a trade, DEQ will track traded compliance instruments. DEQ will notify the designated representative of the covered entity acquiring compliance instrument(s) in writing of availability of these compliance instruments. DEQ will notify the designated representative of the covered entity transferring compliance instrument(s) in writing that the covered entity no longer holds the compliance instruments. If DEQ determines that the form is incomplete, DEQ will not track the requested trade unless and until the applicant provides the additional information requested by DEQ to make the form

complete, and such instruments will not be available to the covered fuel supplier acquiring the instruments.
(3) A covered entity acquiring one or more compliance instrument(s) in a trade may not use the compliance instrument(s) in other trades or toward demonstration of compliance with any compliance obligation until the trade has been reported to DEQ and DEQ has tracked the traded compliance instrument(s).

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0590

RULE TITLE: Recordkeeping Requirements Related to Trading

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the recordkeeping requirements for covered entities related to trades.

RULE TEXT:

(1) A covered entity that transfers one or more compliance instruments in a trade according to OAR 340-273-0510 must retain the following records related to each trade, in paper or electronic format for a period of at least seven years following the submission date of a complete compliance instrument trade form:

(a) A copy of each compliance instrument trade form submitted to DEQ;

(b) A copy of any invoice or documentation of monetary payment received related to the trade;

(c) A statement from a financial institution showing receipt of any payment for the compliance instrument;

(d) Documentation of any service or other qualitative compensation received related to the trade; and

(e) A copy of all other data, reports, or other information related to the trade.

(2) A covered entity that acquires one or more compliance instruments in a trade according to OAR 340-273-0510 must retain the following records related to each trade, in paper or electronic format for a period of at least seven years following the submission date of a complete compliance instrument trade form:

(a) A copy of each compliance instrument trade form submitted to DEQ;

(b) A copy of any invoice or documentation of monetary payment related to the trade;

(c) A statement from a financial institution showing any payment for the compliance instrument;

(d) Documentation of any service or other qualitative compensation provided related to the trade; and

(e) A copy of all other data, reports, or other information related to the trade.

(3) Covered entities must make the records retained according to this rule available to DEQ upon request. DEQ will specify the date by which the covered entity must fulfill a records request from DEQ.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0810

RULE TITLE: Application for Community Climate Investment Credits

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how covered entities may receive CCI credits from DEQ after contributing funds to one or more CCI entity(ies).

RULE TEXT:

(1) Covered entities are eligible to receive one or more CCI credits if they contribute CCI funds according to this rule. Covered EITE sources and covered DNG sources are ineligible to receive CCI credits for contributions made to a CCI entity prior to January 1, 2028.

(a) The covered entity may receive CCI credits only for contributions to a CCI entity that has been approved by DEQ according to OAR 340-273-0920(1) and that has entered into a written agreement with DEQ to accept and administer CCI funds according to OAR 340-273-0920(2).

(b) If more than one CCI entity is approved to accept funds according to subsection (a) the covered entity must contribute an equal amount of CCI funds to each CCI entity that may receive funds consistent with its agreement with DEQ according to OAR 340-273- 0920(2). The contribution amount to each CCI entity may vary by up to one US dollar.

(2) A covered entity must apply to receive CCI credits by submitting an application to DEQ, on a form approved by DEQ that includes the information described in section (3). A covered entity may not submit an application to request CCI credits on behalf of another person.

(3) A covered entity that submits an application to DEQ to request CCI credits must submit a complete and accurate application. The application must include:

(a) Information about the covered entity, including:

(A) Name and full mailing address; and

(B) Designated representative's contact information including name, title or position, phone number, and email address;

(b) The name of each CCI entity that received CCI funds from the covered entity;

(c) A copy of the receipt(s) described in OAR 340-273-0930(1)(a) received from each CCI entity;

(d) The total CCI funds (in US dollars) contributed to each CCI entity, excluding any fees; and

(e) The following attestation, signed by the designated representative of the covered fuel supplier:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief the information in this application is true, accurate, and complete. [Covered entity] contributed the community climate investment funds noted in this application to each community climate investment entity listed for the purposes of supporting eligible projects as described in OAR 340-273-0900.

(4)(a) A covered entity seeking to receive CCI credits in order to use them to demonstrate compliance for a particular compliance period must submit its application to DEQ no later than November 14 of the year it will demonstrate compliance according to OAR 340-273-0450, or 11 days after DEQ's notice described in OAR 340-273-0450(1), whichever is later.

(b) DEQ's determination of the quantity of CCI credits to generate and distribute is based on the amount of the covered entity's contribution to CCI entities, as documented in its application and the CCI credit contribution amount described in Table 6 in OAR 340-273-9000 that was in effect on the date the contribution was made, adjusted for inflation according to OAR 340-273-0820(3).

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0820

RULE TITLE: Generation and Distribution of Community Climate Investment Credits

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how DEQ will generate and distribute CCI credits to covered entities, including the contribution amount required to earn a CCI credit.

RULE TEXT:

(1) DEQ will review an application submitted according to OAR 340-273-0810 to ensure that it meets the requirements of that rule. DEQ will inform the applicant either that the submitted application is complete or that additional specific information is required to make the application complete. If DEQ determines that the application is incomplete or does not meet the requirements of OAR 340-273-0810, DEQ will not consider the application further until the applicant provides the additional information requested by DEQ.

(2) DEQ will approve an application for CCI credits submitted by a covered entity if DEQ determines that the application is accurate and complete according to the requirements of OAR 340-273-0810, and DEQ determines that the CCI funds have been provided to an approved CCI entity that is in good standing according to OAR 340-273-0910 through OAR 340-273-0990.

(3) Approval of an application for CCI credits.

(a) Upon approval of an application for CCI credits, DEQ will notify the applicant in writing that DEQ has approved the application and will generate and distribute to the covered entity the quantity of CCI credits approved according to subsection (b).

(b) The amount of CCI credits that DEQ will generate and distribute to the covered entity is one CCI credit for every verified contribution of the CCI credit contribution amount that a covered entity provides to a CCI entity, rounded down to the nearest whole number. The CCI credit contribution amount is the applicable amount in Table 6 in OAR 340-273-9000 for the date the contribution was made, with the CCI credit contribution amount adjusted for inflation and rounded to the nearest dollar using the inflation rate since January 2024, as provided by the United States Bureau of Labor and Statistics West Region Consumer Price Index for All Urban Consumers for all Items. DEQ will post the current, inflation adjusted CCI credit contribution amount on its website effective March 1 of each year. The formula for the adjustment is as follows:

CCI Credit Contribution Amount = CCI Credit Contribution Amount in Table 6 in
OAR 340-273-9000 * (CPI-U West for January of the calendar year for the price in Table 6 in OAR 340-273-9000 that is currently in effect / CPI-U West for January 2024)

(4) A CCI credit is a regulatory instrument and does not constitute personal property, a security or any other form of property.

(5) DEQ will track distributed CCI credits.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0830

RULE TITLE: Holding Community Climate Investment Credits

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes when DEQ would cancel CCI credits distributed to a covered entity and that CCI credits cannot be traded.

RULE TEXT:

(1) After DEQ distributes a CCI credit to a covered entity according to OAR 340-273- 0820, the covered entity may continue to hold the CCI credit until any of the following apply:

(a) The covered entity uses the CCI credit toward its demonstration of compliance according to OAR 340-273-0450;

(b) Two demonstration of compliance deadlines described in OAR 340-273-0450(2) have passed since the date DEQ provided written notice of its approval of the CCI credit to the covered entity according to OAR 340-273-0820 and the covered entity has not used the CCI credit in its demonstration(s) of compliance. In such a case, DEQ will cancel the CCI credit. A cancelled CCI credit may not be used toward demonstration of compliance; or

(c) The covered entity has ceased being a covered entity according to OAR 340-273-0130. When a covered entity ceases to be a covered entity, DEQ will cancel the CCI credit at the time of such cessation. A cancelled CCI credit may not be used toward any demonstration of compliance.

(2) Only the covered entity that receives a CCI credit from DEQ may hold the CCI credit. CCI credits may not be traded.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0890

RULE TITLE: Recordkeeping Requirements Related to Community Climate Investment Funds

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the recordkeeping requirements for covered entities related to CCIs.

RULE TEXT:

(1) A covered entity that provides CCI funds to a CCI entity must retain the following records, in paper or electronic format, for a period of time that begins with the date it provides the CCI funds and lasts seven years after all resulting CCI credits are submitted to demonstrate compliance or are cancelled:

(a) A copy of any invoice or documentation of monetary payment related to CCI funds;

(b) A statement from a financial institution showing any payments related to CCI funds;

(c) A copy of any receipt received from a CCI entity; and

(d) All other information and documentation related to the CCI funds provided to a CCI entity.

(2) A covered entity must retain the following records, in paper or electronic format, for a period that begins the date it applies for a CCI credit and lasts seven years after the CCI credit is used to demonstrate compliance or is cancelled:

(a) A copy of each application submitted to DEQ to request CCI credits; and

(b) All other information and documentation related to CCI credit(s) received from DEQ.

(3) A covered entity must make available to DEQ upon request all of the records it is required to retain according to this rule. DEQ will specify the date by which the covered entity must fulfill a records request from DEQ.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040, 468A.050

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468A.050, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0900

RULE TITLE: Purposes of Community Climate Investments and Eligible Uses of CCI Funds

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the purposes of CCIs, including to achieve reductions of at least one MT CO2e of greenhouse gas emissions per CCI credit distributed by DEQ on average as well as other purposes. CCI funds may only be spent on projects that reduce anthropogenic greenhouse gas emissions in Oregon and for related costs, such as for reporting, oversight, and capacity building.

RULE TEXT:

(1) The purposes of community climate investments are to:

(a) Provide covered entities with an optional means of meeting part of their compliance obligation for one or more compliance periods;

(b) Reduce anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT CO2e per CCI credit distributed by DEQ;

(c) Reduce emissions of other air contaminants that are not greenhouse gases, particularly in or near environmental justice communities in Oregon;

(d) Promote public health, environmental, and economic benefits for environmental justice communities throughout Oregon to mitigate impacts from climate change, air contamination, energy costs, or any combination of these; and

(e) Accelerate the transition of residential, commercial, industrial and transportation- related uses of fossil fuels in or near environmental justice communities in Oregon to zero or to other lower greenhouse gas emissions sources of energy in order to protect people, communities and businesses from increases in the prices of fossil fuels.

(2) A CCI entity may use CCI funds only for:

(a) Implementing eligible projects in Oregon, which are actions that reduce anthropogenic greenhouse gas emissions that would otherwise occur in Oregon in the transportation, residential, industrial and commercial sectors. Eligible projects include, without limitation, actions that reduce emissions in Oregon resulting from:

(A) Transportation of people, freight, or both;

(B) An existing or new residential use or structure;

(C) An existing or new industrial process or structure; and

(D) An existing or new commercial use or structure.

(b) The costs of administering CCI funds and eligible projects, including costs of reporting and other requirements included in OAR 340-273-0930 and costs of capacity- building for implementation of eligible projects.

(3) A CCI entity must use a minimum of 15% of CCI funds that are used for implementing eligible projects for projects that benefit federally recognized tribes and tribal communities in Oregon.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0910

RULE TITLE: Application to DEQ for Approval as a Community Climate Investment Entity

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the criteria and application requirements for organizations that apply to be CCI entities approved by DEQ.

RULE TEXT:

(1) To be eligible for DEQ approval as a community climate investment entity, an entity must demonstrate that it:

(a) Is authorized to do business in Oregon, and that it is exempt from federal taxation according to Section 501(c)(3) of the U.S. Internal Revenue Code, 26 U.S.C. § 501(c)(3);

(b) Has the capacity to administer and spend CCI funds to carry out eligible projects as specified in OAR 340-273-0900(2);

(c) Has or will have staff capable of conducting work associated with being a CCI entity according to this division;

(d) Has or will have staff or subcontractors capable of implementing eligible projects throughout Oregon; and

(e) Is not a covered entity or a related entity of a covered entity.

(2) An eligible entity described in section (1) may apply to be approved as a CCI entity to implement eligible projects directly or by agreement with one or more subcontractors, or both. Subcontractors are not CCI entities, and do not need to meet the eligibility requirements of section (1). However, a CCI entity may not use CCI funds to pay a subcontractor that is a covered entity or a related entity of a covered entity.

(3) An entity that seeks approval as a CCI entity must submit an application to DEQ, in a format approved by DEQ that includes the following:

(a) Information about the entity, including:

(A) Name, full mailing address, and website address;

(B) Contact person's information including name, title or position, phone number, and email address;

(C) Information to describe how the entity meets the eligibility criteria in section (1);

(D) A copy of the entity's current articles of incorporation and bylaws, and a description of the mission of the entity and how being a CCI entity supports the mission;

(E) A description of the experience and expertise of key individuals, who would be working to implement eligible projects with CCI funds or assigned work associated with the requirements of a CCI entity described in OAR 340-273-0930;

(F) A description of experience implementing or supporting implementation of eligible projects or project types, including projects or project types that reduce anthropogenic greenhouse gas emissions in the transportation, residential, industrial and commercial sectors particularly in environmental justice communities in Oregon. This may include the experience of the key individuals described in paragraph (E) whether or not that prior experience occurred while working with the entity;

(G) Information regarding any violation by the entity related to federal or state laws, including labor laws, within the preceding five years;

(H) The entity's IRS Form 990 for each of the three most recent years, if available; and

(I) Proof that the IRS has certified the entity as qualifying as an exempt organization according to Section 501(c)(3) of the U.S. Internal Revenue Code, 26 U.S.C. § 501(c)(3);

(b) Information about each known or planned subcontractors, as available, including:

(A) Name, full mailing address, and website address;

(B) Contact person's contact information including name, title or position, phone number, and email address;

(C) Confirmation that the subcontractor is not a covered entity or any of its related entities;

(D) If applicable, a description of the mission of the subcontractor and how being a subcontractor of a CCI entity supports the mission;

(E) A description of the experience and expertise of key individuals who would be working to implement eligible projects with CCI funds;

(F) A description of the subcontractor's prior experience implementing or supporting implementation of eligible projects, including projects or project types that reduce anthropogenic greenhouse gas emissions in the transportation, residential, industrial, and commercial sectors, and a description of prior experience serving communities in Oregon. This may include the experience of the key individuals described in paragraph (E), whether or not that prior experience occurred while working with the subcontractor; and

(G) Information regarding any violation by the proposed subcontractor related to federal or state laws, including labor laws, within the preceding five years;

(c) Information about how any subcontractor(s) may be selected during project implementation if there are none listed in the application or if the entity expects to select one or more additional subcontractors during project implementation;

(d) If known, a general description of either or both of the following:

(A) Anticipated eligible project(s) or project type(s) that support the purposes of CCIs described in OAR 340-273-0900(1) and that are eligible projects as defined in OAR 340-273-0900(2) that the entity plans to implement if approved as a CCI entity; and

(B) The communities in Oregon that are anticipated to benefit if the entity is approved as a CCI entity;

(e) Description of the administrative processes and financial controls the entity will use to ensure all CCI funds are held separately from the entity's other funds. This must detail how the entity will manage and invest funds in a manner consistent with ORS 128.318(2), (3), and (5)(a) through (f); and

(f) The following attestation, signed by the entity's contact person:

I certify under penalty of perjury under the laws of the State of Oregon that to the best of my knowledge and belief the information in this application is true, accurate, and complete. [Entity] seeks to become a community climate investment entity and, if approved, will comply with the applicable requirements in Oregon Administrative Rules chapter 340, division 273.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0920

RULE TITLE: DEQ Review and Approval of Community Climate Investment Entities and Agreements for Approved CCI Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the DEQ process for making CCI entity-related approvals and written agreements, including consultation with the equity advisory committee. The written agreement must be approved before an entity receives final approval as a CCI entity and is authorized to receive CCI funds.

RULE TEXT:

(1) DEQ will review and may approve applications from entities proposing to be approved as CCI entities according to subsections (a) through (d).

(a) DEQ will review an application submitted according to OAR 340-273-0910 to ensure that it meets the requirements of that rule. DEQ will inform the entity either that the submitted application is complete or that additional specific information is required to make the application complete. If the application is incomplete, DEQ will not consider the application further until the entity provides the additional information requested by DEQ.

(b) When evaluating complete applications submitted according to OAR 340-273-0910, DEQ will consult with the equity advisory committee described in OAR 340-273-0950 and may consult with any other relevant experts selected by DEQ.

(c) DEQ will consider the following when evaluating a complete application:

(A) The content of the application;

(B) Whether the entity meets the eligibility criteria in OAR 340-273-0910(1);

(C) Whether each proposed subcontractor, if applicable, complies with the eligibility criteria in OAR 340-273-0910(1)(e);

(D) The overall ability of the entity and, if applicable, its subcontractor(s) to use CCI funds to complete eligible projects, including projects or project types that reduce anthropogenic greenhouse gas emissions in the transportation, residential, industrial, and commercial sectors, that advance the purposes set forth in OAR 340-273- 0900(1) and that collectively reduce anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT CO_2e per CCI credit distributed by DEQ based on CCI contributions to the entity;

(E) The overall ability of the entity and/or its subcontractor(s) to use CCI funds as described in paragraph (D) relative to the overall ability of other applicants and approved CCI entities; and

(F) Whether the applicant or any proposed subcontractors have violated any federal or state laws, including labor laws, in the preceding five years.

(d) DEQ will notify the applicant in writing whether provisional approval as a CCI entity is granted or denied.

(2) If provisional approval as a CCI entity is granted, DEQ will then work with the CCI entity to complete a written agreement. The written agreement must be approved before an entity receives final approval as a CCI entity and is authorized to receive CCI funds. The written agreement will include, but is not limited to:

(a) Agreement to use CCI funds only for the uses specified in OAR 340-273-0900(2);

(b) The initial term of the agreement and approval, which may not exceed ten years;

(c) Requirements for monitoring and reporting of project outcomes sufficient to document emissions reductions;

(d) Provisions for, and limitations on, the payment of administrative expenses;

(e) Provisions for extensions, amendments, or renewal of the agreement;

(f) Other conditions that DEQ determines are necessary to include in the agreement in order to meet the requirements of this division, such as a limit on the amount of CCI funds that a CCI entity may accept.

(3) If DEQ finds that any of the events in subsections (a) through (c) occur, DEQ may suspend or revoke approval of a CCI entity completely or in part.

(a) The CCI entity fraudulently obtained DEQ approval;

(b) The CCI entity is in violation of any applicable provisions of this division or any written agreement between the CCI entity and DEQ; or

(c) DEQ determines that the CCI entity is not in compliance with one or more of the eligibility criteria for approval in OAR 340-273-0910(1).

(4) DEQ will maintain a current list of approved CCI entities on DEQ's website.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0930

RULE TITLE: Requirements for Community Climate Investment Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the requirements for CCI entities, including financial controls, work plans to propose eligible projects and calculation methodologies that will be used to estimate emission reductions. Work plans must be approved by DEQ prior to a CCI entity beginning work.

RULE TEXT:

(1) Acceptance of CCI funds.

(a) Once approved by DEQ, unless otherwise specified in the agreement between a CCI entity and DEQ, a CCI entity must accept CCI funds from any covered entity that seeks to contribute CCI funds, except that a CCI entity may not accept funds from any covered EITE source or covered DNG source during calendar years 2025, 2026 and 2027.

(b) The CCI entity must provide a receipt to the covered fuel supplier upon receipt of CCI funds from the covered fuel supplier. The receipt must include:

(A) The name of the covered fuel supplier;

(B) The name of the CCI entity;

(C) The US dollar amount of the CCI funds accepted;

(D) The date the CCI entity accepted the CCI funds; and

(E) The following attestation:

I verify that [CCI Entity] received the contribution from [Covered entity] as described on this receipt and I affirm that I am a representative of [CCI entity] authorized to sign this receipt.

(c) Unless otherwise specified in the agreement between the CCI entity and DEQ, a CCI entity must accept CCI funds transferred to it from another CCI entity according to section (8).

(2) Holding CCI funds.

(a) A CCI entity must hold all CCI funds in one or more accounts separate from any other funds. Additionally, prior to being spent in compliance with the provisions of this division and its agreement with DEQ, funds must be managed and invested in a manner consistent with ORS 128.318(2), (3), and (5)(a) through (f). A CCI entity may not encumber CCI funds or pledge CCI funds as a security for other purposes than completing one or more projects under a DEQ-approved work plan.

(b) A CCI entity must complete an independent financial audit of CCI funds for each year in which it holds CCI funds and review the auditor relationship every five years.

(3) Use of CCI funds. A CCI entity may only spend CCI funds for the uses specified in OAR 340-273-0900(2). The expenditures of CCI funds must conform to the CCI's work plan approved by DEQ under section (4) of this rule.

(4) Work Plan.

(a) A CCI entity must submit a proposed work plan to DEQ for review and approval. The period of the work plan will normally be a calendar year, unless otherwise specified in the agreement between DEQ and the CCI entity. A CCI entity must obtain DEQ approval of a work plan prior to committing or expending CCI funds for the period of the work plan. The first proposed work plan must be submitted within 90 days of the date on which the CCI entity has received at least $5 million in CCI funds from covered entities. Each subsequent work plan must be submitted no later than 60 days prior to the end of the current work plan period.

(b) The work plan must include:

(A) A description of the project(s) or project type(s) the CCI entity expects to support with CCI funds during the period of the work plan, and how the project(s) or project type(s) support each of the purposes of CCIs described in OAR 340-273-0900(1)(b) through (e);

(B) A description of how the project(s) or project type(s) will benefit communities in Oregon, including description of the potential locations of communities or regions of Oregon in which projects may be implemented or a description of how locations may be selected;

(C) A description of how each project or project type would benefit environmental justice communities in Oregon;

(D) A description of the how project or project type would benefit federally recognized tribes and tribal communities, a description of how the CCI entity has engaged with federally recognized tribes and tribal communities on the work plan, or a description for how the CCI entity intends to engage with federally recognized tribes and tribal communities in the future, as investments benefitting federally recognized tribes and tribal communities is a priority.

(E) A description of the methodology that the CCI entity is using to estimate the reductions in anthropogenic greenhouse gas emissions that will result from the project(s) or project type(s) in the work plan, along with an estimate of the anticipated reductions during the period of the work plan. The methodology must be sufficient to allow DEQ to perform the necessary calculations in a program review according to OAR 340-273-8100(1)(a);

(F) A description of the methodology that the CCI entity is using to estimate the reductions in other air contaminant emissions that will result from the project(s) or project type(s) in the work plan, along with an estimate of the anticipated reductions during the period of the work plan;

(G) The name and contact person's contact information of subcontractors that will be involved in any project activities during the period of the work plan; and

(H) The estimated total budget for the period of the work plan. CCI funds must be listed separately from any other funds, as applicable. This must separately include the following:

(i) All costs related to project implementation, listed separately for groups of project(s) or project type(s), including but not limited to personnel costs and materials costs; and

(ii) Administrative costs related to the project implementation and meeting the requirements of this rule.

(c) A CCI entity may request DEQ approval of modifications to a DEQ-approved work plan by submitting modifications to the information described in subsection (b). The CCI entity must obtain DEQ approval of any modification to a work plan prior to beginning work according to a modified work plan.

(d) Prior to approving a work plan, DEQ will solicit input from the equity advisory committee and any other relevant experts selected by DEQ. DEQ will review each proposed work plan to ensure that it meets the requirements of this section. DEQ will inform the CCI entity if the proposed work plan is incomplete and the additional specific information required to make the work plan complete. If the work plan is incomplete, DEQ will not consider the work plan further until the CCI entity provides the additional information requested by DEQ. DEQ will consider the following in its review and approval of a workplan:

(A) The overall ability of the CCI entity to conduct work according to the work plan;

(B) Whether following the work plan is reasonably likely to reduce anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT CO2e per CCI credit distributed by DEQ based on CCI fund contributions to the CCI entity;

(C) Whether the work plan is consistent with the purposes of CCIs described in OAR 340-273-0900; and

(D) Input from the equity advisory committee described in OAR 340-273-0950 and from any other relevant experts selected by DEQ.

(5) Annual report. Date of submission of annual report to be determined in written agreement as described in OAR 340-273-0920 (2). A CCI entity must submit to DEQ an annual report each year that describes its CCI-related activities and finances for the preceding year. The information provided must be sufficient to allow DEQ to perform the necessary calculations in a program review according to OAR 340-273-8100(1)(a), and must include:

(a) The following information related to CCI funds received, held, or spent during the year:

(A) Each financial statement for the account(s) where CCI funds were held and the results of the CCI entity's most recent independent financial audit;

(B) The date, amount of CCI funds accepted, and as applicable, the name of the covered fuel supplier for each separate contribution received;

(C) Total CCI fund interest accrual;

(D) Total CCI funds spent, including separate totals of:

(i) CCI funds spent on each project, including but not limited to personnel costs and materials costs; and

(ii) Administrative costs related to the project, including project development, and implementation and meeting the requirements of this rule;

(E) Total CCI funds the CCI entity holds that remain unspent as of the end of the year; and

(F) Total non-CCI funds spent on implementation of each project or project type, as applicable;

(b) The following information related to implementation progress of project(s) or project type(s) during the year:

(A) Documentation of work completed or progress made on each project or project type, including the number of projects completed of each project type, as applicable;

(B) A summary of project outcomes. This must include estimated annual greenhouse gas emissions reductions in metric tons of CO2e and non-greenhouse gas air contaminant emissions reductions in metric tons of the applicable air contaminant that are anticipated to be achieved from any project(s) completed during the year. Emissions reductions must be estimated using the methodology included in the applicable work plan. Emissions reductions may be reported by individual project or may be grouped by project type, if the CCI entity can provide sufficient information to demonstrate that the emissions reductions of multiple projects of the same type are comparable; and

(C) A description of work that occurred compared to the most recently approved work plan or modified work plan. If projects were not implemented as planned, the CCI entity must describe the reason for delay and must describe any steps that may be taken to work to remedy the delay or prevent similar delays in subsequent years; and

(c) A copy of the CCI entity's most recent IRS form 990.

(6) Establishing and maintaining efforts to engage and involve environmental justice communities in the design, administration, and implementation of the funds.

(7) Maintaining CCI entity eligibility.

(a) A CCI entity must notify DEQ in writing as soon as possible, and not later than 15 days after it no longer meets any of the eligibility criteria for approval in OAR 340-273- 0910(1), or if it is in violation of any of the requirements of this rule.

(b) A CCI entity must notify DEQ in writing as soon as possible and not later than 15 days after any changes are made to the administrative processes or financial controls that keep CCI funds separate from other funds;

(c) A CCI entity must notify DEQ in writing as soon as possible and not later than 15 days after any changes related to key individuals or their assigned work associated with being a CCI entity.

(d) A CCI entity must notify DEQ in writing as soon as possible and not later than 15 days after any finding of a violation related to federal or state labor laws by the CCI entity or by an approved subcontractor;

(e) Upon written request by DEQ, a CCI entity must provide to DEQ in a reasonably timely manner any and all information that DEQ reasonably requires for evaluating the CCI entity's continued compliance with the requirements of this division, including the criteria for approval as a CCI entity and eligible projects.

(8) Voluntary withdrawal from DEQ approval. An approved CCI entity may request to withdraw voluntarily its approval by providing a written notice to DEQ requesting such withdrawal.

(9) Rollover of CCI funds. If DEQ approval is suspended, revoked, or voluntarily withdrawn, DEQ may require the entity to transfer any uncommitted CCI funds to another CCI entity and provide proof to DEQ that the transfer has been made. If a transfer of funds is required, DEQ will determine allowable expenses for the transition of projects and the remaining funds.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0950

RULE TITLE: Fee for Community Climate Investment Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Each Community Climate Investment Entity must pay a fee to DEQ equal to 4.5% of all CCI contributions that the entity receives from covered fuel suppliers to support DEQ's oversight and administration of the CCI program.

RULE TEXT:

(1) Each approved Community Climate Investment Entity must pay a fee to DEQ equal to 4.5% of all CCI contributions that the entity receives from covered fuel suppliers and:

(a) The fee is due biannually. No later than February 1 of each year, DEQ will send a fee invoice to each Climate Community Investment Entity. Each CCI Entity must pay a fee of 4.5% for all CCI contributions that the entity received from covered fuel suppliers between July 1 and December 31 of the previous calendar year. No later than August 1 of each year each DEQ will send a fee invoice to each Community Climate Investment Entity. Each CCI Entity must pay a fee of 4.5% for all CCI contributions that the entity received from covered fuel suppliers from January 1 through June 30 of that calendar year. Each CCI Entity must pay the fee within 30 calendar days of DEQ sending the fee invoice.

(b) DEQ may reduce the fee for any given fee period if a lesser amount is adequate to cover the costs of administering and overseeing the CCI program. The fee percentage for the fee period will be included in the fee invoice to each CCI entity.

(c) A report of all CCI contributions and date of contributions made during the previous fee period must accompany the fee payment.

(d) If no CCI contributions were received during the previous fee period, the CCI Entity must provide notification to DEQ that no contributions were received, and no fee to be paid.

(e) If a CCI Entity has not paid the CCI fee within the 30 calendar days of DEQ sending the fee invoice, a late fee will be assessed. The late fee may not be paid for using CCI funds. CCI Entity will be subject to late fees as follows:

(A) One hundred dollars per day for payments received between one and seven days late;

(B) Two hundred dollars per day for payments received between eight and thirty days late; and

(C) Five hundred dollars per day for payments received on or after thirty days late.

(2) Reporting. Each fiscal year DEQ will report, post online, and present to the equity advisory committee its program expenditures and revenue related to the CCI fee.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.295

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.295

ADOPT: 340-273-0960

RULE TITLE: Equity Advisory Committee and Environmental Justice Community Engagement

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the DEQ-appointed equity advisory committee and DEQ's commitment to engage with environmental justice communities on CCI-related topics.

RULE TEXT:

(1) DEQ will appoint and convene an equity advisory committee to assist DEQ with:

(a) Review of:

(A) Applications to become a CCI entity;

(B) Requests for DEQ approval of work plans; and

(C) Other submittals by CCI entities that require DEQ review; and

(b) Outreach to environmental justice communities.

(2) Advisory committee member selection.

(a) DEQ may solicit applications from residents of the state of Oregon to be appointed to serve as members of the equity advisory committee and may select the committee from those applications.

(b) DEQ will prioritize convening an advisory committee that represents multiple areas of expertise, interest, or lived experience in the following areas:

(A) Environmental justice;

(B) Impacts of climate change on communities in Oregon;

(C) Impacts of air contamination on communities in Oregon; and

(D) Greenhouse gas emissions reductions, including in the transportation, residential, industrial and commercial sectors, and climate change.

(c) DEQ will prioritize convening an advisory committee that represents multiple regions across Oregon.

(d) DEQ may appoint each committee member to a term of up to three years.

(e) DEQ will appoint at least one committee member that represents a federally recognized tribe or tribal interests.

(3) In addition to outreach conducted by CCI third party entities to environmental justice communities throughout Oregon, DEQ will conduct outreach to these communities to seek input on projects that may be of interest to those communities. The equity advisory committee will consider this input when assisting DEQ as described in section (1). DEQ will consider this input when making approval decisions regarding CCI entities, projects and project types, and work plans.

(4) DEQ will offer guidance and conduct outreach to support the equity advisory committee and environmental justice communities in Oregon in understanding the provisions related to CCIs.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-0990

RULE TITLE: Recordkeeping Requirements for Community Climate Investment Entities

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes the recordkeeping requirements for CCI entities.

RULE TEXT:

(1) A CCI entity must retain the following records, in paper or electronic format, for a period of at least seven years following the date of transaction or submission to DEQ:

(a) A copy of each application submitted to DEQ for approval as a CCI entity;

(b) A copy of any invoice or documentation of monetary payment related to CCI funds;

(c) A statement from a financial institution showing any payments related to CCI funds;

(d) A copy of any receipt provided to a covered entity that makes a CCI payment to the CCI entity;

(e) A copy of any work plan submitted to DEQ by the CCI entity;

(f) A copy of any report or written request for approval submitted to DEQ by the CCI entity;

(g) All other information and documentation related to CCI funds;

(h) All records related to any implemented projects; and

(i) All records and information supporting estimates of greenhouse gas emissions reductions and other air contaminant emissions reductions achieved from implemented projects or project types.

(2) CCI entities must make records required to be retained in this rule available to DEQ upon request. DEQ will specify the date by which the CCI entity must fulfill a records request from DEQ.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-8100

RULE TITLE: Program Review

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes DEQ's program review and reporting to the EQC.

RULE TEXT:

(1) DEQ will report to the EQC on community climate investments and request that the EQC provide input on community climate investment implementation and future improvements. DEQ will submit the first report to the EQC by August 30, 2027 and every two years thereafter. DEQ will share each report with current members of the equity advisory committee after submission to the EQC. Each community climate investment report will include:

(a) A review of community climate investments, including:

(A) CCI credits distributed to covered entities;

(B) CCI credits used by covered entities to demonstrate compliance;

(C) Estimates of greenhouse gas emissions reductions that are anticipated to be achieved by completed projects that CCI entities have reported to DEQ by March 31 of the year DEQ is reporting to the EQC;

(D) Estimates of non-greenhouse gas air contaminant emissions reductions that are anticipated to be achieved by completed projects that CCI entities have reported to DEQ by March 31 of the year DEQ is reporting to the EQC;

(E) Calculation of the average anthropogenic greenhouse gas emissions reductions achieved per CCI credit distributed based on (A) and (C) and whether reductions of approximately one MT CO2e or more of anthropogenic greenhouse gas emissions for the average CCI credit distributed by DEQ was achieved; and

(F) Description of community benefits achieved; and

(b) DEQ's recommendations regarding any necessary or desirable changes to the CPP provisions relating to CCIs, including, without limitation, recommendations on changes to the CCI credit contribution amounts described in Table 6 in OAR 340-273-9000 necessary to assure that the use of CCI funds is reducing anthropogenic greenhouse gas emissions in Oregon by an average of at least one MT CO2e per CCI credit distributed by DEQ, as well as recommendations on how to best achieve the purposes of CCIs described in OAR 340-273-0900, if applicable.

(2) DEQ will engage internal and external auditors as necessary to conduct independent audits of CCI contributions and greenhouse gas emission reductions of completed projects.

(3) DEQ will report to the EQC on implementation of the Climate Protection Program. DEQ will submit the first report to the EQC five years after the date of adoption of this division and at least once every five years thereafter. Each program review report will include:

(a) A review of the Climate Protection Program, including:

(A) Summary of covered fuel suppliers', covered EITE sources', and covered DNG sources' demonstrations of compliance for compliance periods that have occurred since program start, including:

(i) Caps for each year and compliance period;

(ii) Compliance obligations for each year and compliance period;

(iii) Compliance instruments submitted for each compliance period; and

(iv) CCI credits submitted for each compliance period;

(B) Summary of the distribution of compliance instruments, including the size of the compliance instrument reserve at the start and end of each program year that has occurred and compared to Table 3 in OAR 340-273-9000;

(C) Summary of activity relating to trading of compliance instruments for each program year that has occurred;

(D) A current list of covered entities by name and whether each is a covered fuel supplier, covered EITE source, or covered DNG source; and

(E) Description of any enforcement actions taken that involved civil penalties, if applicable; and

(b) DEQ's recommendations regarding any potential changes to the CPP including, for example and without limitation, recommendations regarding potential changes to best achieve the goals described in OAR 340-273-0010(3).

(4) In addition to making the written reports required under sections (1) and (3) DEQ will report to the EQC on the

ongoing implementation of the Climate Protection Program, so the EQC can better evaluate progress on achieving program goals as described in OAR 340-273-0010 and assess whether any changes to the program rules or program implementation are warranted. DEQ will provide the first update to the EQC no later than by December 1, 2026, and will report no less frequently than annually thereafter.
(5) If the average annual statewide retail cost of gasoline, diesel, or propane in Oregon increases year-over-year by an amount that is more than 20 percent higher than the average change in cost for the same fuel over the same period in Washington, Idaho, and Nevada, DEQ will investigate the cause(s) of the increase and report to the EQC regarding whether changes to the rules in this division should be made that would ameliorate a relative increase in costs in Oregon. If necessary, in addition to deferrals, DEQ will consider recommending rule changes, such as changes to caps and distribution of additional compliance instruments, changes to the compliance instrument reserve, or changes to the allowable usage of CCI credits.
(6) DEQ will regularly, and at a minimum at least once per compliance period, request information from the Oregon Public Utility Commission to determine what changes in each local distribution company's proposed or current rates for different customer classes may be attributable to a local distribution company's projected or actual costs of compliance with this division of rules. If DEQ determines that the rates will significantly increase, when compared over a similar timeframe to neighboring states with enforceable and declining limits on greenhouse gas emissions from natural gas, due to local distribution companies' actual costs to comply with this rule, in addition to compliance deadline extensions specified in OAR 340-273-8110, DEQ will recommend to the EQC changes to this division of rules intended to moderate impacts to the affordability of local distribution company rates. These changes could include, but are not limited to, adjustment to future years' caps, changes to the CCI amount, or changes to the allowable usage of CCI credits.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-8110

RULE TITLE: Deferrals

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how DEQ may extend reporting or demonstration of compliance deadlines as DEQ deems necessary or appropriate.

RULE TEXT:

DEQ may extend reporting or demonstration of compliance deadlines as DEQ deems necessary or appropriate and will issue written notice of any extensions.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-8120

RULE TITLE: Severability

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes how each provision of this division is severable and that any remaining provisions will continue in full force and effect.

RULE TEXT:
Each requirement of this division is severable, and if any requirement of this division is held invalid, the remainder of the requirements of this division will continue in full force and effect.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

ADOPT: 340-273-9000

RULE TITLE: Tables

NOTICE FILED DATE: 07/29/2024

RULE SUMMARY: Describes tables referenced in this division of rules.

RULE TEXT:

(1) Table 1. Thresholds for applicability described in OAR 340-273-0110(3).

(2) Table 2. Oregon Climate Protection Program caps.

(3) Table 3. Compliance instrument reserve size.

(4) Table 4. Compliance instrument percentage distribution to covered fuel suppliers that are local distribution companies.

(5) Table 5. Covered entity allowable usage of community climate investment credits to demonstrate compliance as described in OAR 340-273-0450(3).

(6) Table 6. CCI credit contribution amount.

(7) Table 7. EITE source classifications.

(8) Table 8. Emission reduction targets for second and subsequent periods for covered EITE and covered DNG sources.

STATUTORY/OTHER AUTHORITY: ORS 468.020, 468A.025, 468A.040

STATUTES/OTHER IMPLEMENTED: ORS 468.020, 468A.025, 468A.040, 468.035, 468A.010, 468A.015, 468A.045

Oregon Department of Environmental Quality

OAR 340-273-9000

Tables

Table 1 Thresholds for applicability described in OAR 340-273-0110(3)		
Applicability determination calendar year(s)	**Threshold for applicability to compare to annual covered emissions**	**Calendar year a person becomes a covered fuel supplier**
Any year from 2020 through 2025	100,000 MT CO2e	2025
2026	100,000 MT CO2e	2026
2027	100,000 MT CO2e	2027
Any year from 2025 through 2028	50,000 MT CO2e	2028
2029	50,000 MT CO2e	2029
Any year from 2028 through 2030	25,000 MT CO2e	2030
2031	25,000 MT CO2e	2031
Each subsequent year	25,000 MT CO2e	Each subsequent year

Table 2 Oregon Climate Protection Program caps	
Calendar year	**Cap**
2025	24,157,161
2026	23,280,253
2027	22,403,346
2028	25,533,741
2029	24,129,251
2030	23,135,118
2031	21,689,592
2032	20,244,066
2033	18,798,540
2034	17,353,013
2035	15,907,487
2036	15,059,088
2037	14,210,689
2038	13,362,289
2039	12,513,890
2040	11,665,491
2041	10,817,091
2042	9,968,692
2043	9,120,293
2044	8,271,893
2045	7,423,494
2046	6,575,095
2047	5,726,695
2048	4,878,296
2049	4,029,897
2050 and each calendar year thereafter	3,181,497

Table 3 Compliance instrument reserve size	
Calendar year(s) of the cap	**Reserve size**
2025 through 2028	800,000 compliance instruments
2029 through 2034	500,000 compliance instruments
2035 and each calendar year thereafter	250,000 compliance instruments

Table 4 Compliance instrument distribution percentages to covered fuel suppliers that are local distribution companies			
	Compliance instruments to distribute to Avista Utilities	Compliance instruments to distribute to Cascade Natural Gas Corporation	Compliance instruments to distribute to Northwest Natural Gas Company
2025	2.76%	2.25%	19.74%
2026	2.76%	2.25%	19.74%
2027	2.76%	2.25%	19.74%
2028	2.69%	2.20%	19.25%
2029	2.69%	2.20%	19.25%
2030 and each calendar year thereafter	2.68%	2.18%	19.13%

Table 5 Covered entity allowable usage of community climate investment credits to demonstrate compliance as described in OAR 340-273-0450(3)	
Compliance period	**Allowable percentage of total compliance obligation(s) for which compliance may be demonstrated with CCI credits**
Compliance period 1 (2025 through 2027)	15%
Compliance period 2 (2028 through 2029), and for each compliance period thereafter	20%

Table 6 CCI credit contribution amount	
Effective date	**CCI credit contribution amount in 2024 dollars, to be adjusted according to OAR 340-273-0820(3)**
March 1, 2025	$129
March 1, 2026	$129
March 1, 2027	$130
March 1, 2028	$131
March 1, 2029	$132
March 1, 2030	$133
March 1, 2031	$134
March 1, 2032	$135
March 1, 2033	$136
March 1, 2034	$137
March 1, 2035	$138
March 1, 2036	$139
March 1, 2037	$140
March 1, 2038	$141
March 1, 2039	$142
March 1, 2040	$143
March 1, 2041	$144
March 1, 2042	$145
March 1, 2043	$146
March 1, 2044	$147
March 1, 2045	$148
March 1, 2046	$149
March 1, 2047	$150
March 1, 2048	$151
March 1, 2049	$152
March 1, 2050	$153

Table 7
EITE source classifications

NAICS Code	Sector Definition
3364	Aerospace Product and Parts Manufacturing
3251	Basic Chemical Manufacturing
3273	Cement and Concrete Product Manufacturing
3315	Foundries
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing
3272	Glass and Glass Product Manufacturing
3311	Iron and Steel Mills and Ferroalloy Manufacturing
3274	Lime and Gypsum Product Manufacturing
3314	Nonferrous Metal (except Aluminum) Production and Processing
2123	Nonmetallic Mineral Mining and Quarrying
3329	Other Fabricated Metal Product Manufacturing
3279	Other Nonmetallic Mineral Product Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing
3261	Plastics Product Manufacturing
3221	Pulp, Paper, and Paperboard Mills
3211	Sawmills and Wood Preservation
3344	Semiconductor and Other Electronic Component Manufacturing
3212	Veneer, Plywood, and Engineered Wood Product Manufacturing

Table 8 Emissions reduction targets for covered EITE sources and covered DNG sources for compliance period 2 and subsequent periods	
Compliance period	**Emissions reduction target**
Compliance period 2 (2028 through 2029)	1
Compliance period 3 (2030 through 2031)	0.95
Compliance period 4 (2032 through 2033)	0.90
Compliance period 5 (2034 through 2035)	0.85
Compliance period 6 (2036 through 2037)	0.80
Compliance period 7 (2038 through 2039)	0.75
Compliance period 8 (2040 through 2041)	0.70
Compliance period 9 (2042 through 2043)	0.65
Compliance Period 10 (2044 through 2045)	0.60
Compliance Period 11 (2046 through 2047)	0.55
Compliance Period 12 (2048 through 2049)	0.50
Compliance Period 13 (2049 through 2051) and thereafter	0.45

Translation or other formats

Español | 한국어 | 繁體中文 | Русский | Tiếng Việt | العربية
800-452-4011 | TTY: 711 | deqinfo@deq.oregon.gov

Non-discrimination statement

DEQ does not discriminate on the basis of race, color, national origin, disability, age or sex in administration of its programs or activities. Visit DEQ's Civil Rights and Environmental Justice page.

ORDINANCE NO. 3254

AN ORDINANCE AMENDING AMC TITLE 9 HEALTH AND SANITATION CREATING CHAPTER 9.45 CARBON POLLUTION IMPACT FEE AND ESTABLISHING STANDARDS FOR A CARBON POLLUTION IMPACT FEE FOR NEW RESIDENTIAL STRUCTURES IN THE CITY OF ASHLAND

Annotated to show deletions and additions to the Ashland Municipal Code sections being modified. Deletions are **~~bold lined through~~**, and additions are **bold underlined.**

Powers of the City. The City shall have all powers which the constitutions, statutes, and common law of the United States and of this State expressly or impliedly grant or allow municipalities, as fully as though this Charter specifically enumerated each of those powers, as well as all powers not inconsistent with the foregoing; and, in addition thereto, shall possess all powers hereinafter specifically granted. All the authority thereof shall have perpetual succession.

WHEREAS, the City of Ashland has declared a commitment to climate recovery goals in Title 9 of the Municipal Code as detailed in the Climate and Energy Action Plan (CEAP); and

WHEREAS, emissions from buildings represent one of the largest sources of greenhouse gas emissions in Ashland; and

WHEREAS, reducing fossil fuel consumption is essential to meeting the City's CEAP goals; and

WHEREAS, transitioning to low-carbon electric homes is most feasible in new construction; and

WHEREAS, adding new residential structures reliant on fossil fuels increases the City's carbon footprint and requires additional mitigation efforts; and

WHEREAS, an upfront carbon pollution impact fee provides a mechanism to account for and offset the environmental, health, and societal costs associated with fossil fuel-based systems; and

WHEREAS, revenue generated from this fee could support programs promoting clean technology installations, including support for low-income households, furthering the City's decarbonization goals.

THE PEOPLE OF THE CITY OF ASHLAND DO ORDAIN AS FOLLOWS:

SECTION 1. Chapter 9.45 Carbon Pollution Impact Fee is hereby created to read as follows:

<u>9.45.010 Purpose</u>
<u>The purpose of this chapter is to promote the health, safety, and general welfare of Ashland residents by establishing a Carbon Pollution Impact Fee for new residential development</u>

utilizing fossil fuel-powered thermal energy systems. This ordinance aligns with the goals set forth in Chapter 9.40 (Climate Recovery) and implements the Climate and Energy Action Plan (CEAP) to the full extent of the City's authority under applicable federal, state, and local laws.

9.45.020 Definitions. For purposes of this chapter, the following definitions apply:
A. Thermal Energy System: Any system for space conditioning, water heating, cooking, process heat, or other building energy use that relies on fossil fuel combustion, excluding outdoor grills, heaters, or other systems designed for exclusive use outside of enclosed residential structures.

B. Fossil Fuel: Fuels derived from hydrocarbons, including but not limited to natural gas, coal, oil, propane, and kerosene.

~~C. New Residential Building: The new construction of any residential building, excluding additions, alterations, renovations, or repairs to existing buildings, and complete demolition and rebuilds, and any accessory dwelling unit.~~

C. New Residential Building: New construction of any residential building, including complete demolition and rebuilds, and any accessory dwelling units. This definition does not include additions, alterations, renovations, or repairs to existing buildings.

D. Social Cost of Greenhouse Gases (SCGHG): The monetary value assigned to climate change damages resulting from the emission of one metric ton (MT) of greenhouse gases. The SCGHG shall be determined as follows:

1. The base value shall be set at the November 2023 determination published by the United States Environmental Protection Agency (EPA).

2. On January 1 of each subsequent year, the SCGHG shall be adjusted by the percentage increase in the Consumer Price Index (CPI-U, U.S. city average, not seasonally adjusted) for the 12 months preceding the previous September 1.

3. Should the EPA release updated SCGHG values in line with leading scientific standards, the City Council may review and adopt such values by ordinance.

E. CO2e: Carbon dioxide equivalent, a standardized measure for comparing the impact of different greenhouse gases.

9.45.030 Carbon Pollution Impact Fee
A. Fee Assessment:
Applicants utilizing a fossil fuel thermal energy system in a new residential building shall be assessed a Carbon Pollution Impact Fee for each dwelling unit therein. This fee shall be due upon the issuance of building permits.

1. Exceptions: No fee shall be assessed for the following:

i. Outdoor thermal energy systems, including but not limited to propane grills, patio heaters, and other systems designed for exclusive use outside of enclosed residential structures.
ii. Thermal energy systems not explicitly listed in Section 9.45.030 B (Fee Calculation)

B. Calculation of Fee:
The Carbon Pollution Impact Fee is calculated as follows:

Fee=(SCGHG)×(MTCO2e)×(Service Life)

Where:

- SCGHG is \$208 per metric ton (adjusted annually).
- MTCo2e is 2.49 metric tons for an average residential natural gas home in Ashland, adjusted for specific appliance usage.
- Service Life is the expected operational lifespan of the appliance, as detailed below:

Appliance	CO2e (MT/year)	Service Life (Years)	Fee Example
Furnace	1.32	15	\$208 × 1.32 × 15 =\$4118.40
Water Heater	0.62	10	\$208 × 0.62 × 10 = \$1289.60
Range	0.12	10	\$208 × 0.12 × 15 = \$374.40
Gas Fireplace	0.35	10	\$208 × 0.35 × 10 = \$728.00
Clothes Dryer	0.07	10	\$208 x 0.07 x 10 = \$145.60

If fossil fuel piping is present for an appliance but no appliance is installed, the absent appliance will be assumed to use fossil fuels, and the fee will be calculated accordingly. However, if a new electric appliance is installed, even with existing fossil fuel piping, no fee will be applied.

C. Annual Adjustment:
On January 1 of each year, the SCGHG shall be adjusted in proportion to the Consumer Price Index (CPI-U, U.S. city average, not seasonally adjusted) for the 12 months preceding the previous September 1.

9.45.040 Reporting requirement.
A. Record Maintenance:
The City shall maintain records of all fees collected and report annually on the revenue generated and its allocation.

B. Annual Reporting Requirements for Fossil Fuel Utilities Operating in the City's Right of Way:
Any utility providing fossil fuels and operating within the City's Right of Way must submit an annual report detailing total residential and commercial fossil fuel consumption. For metered fossil fuel services, the report must include the total number of operational meters, separated into residential and commercial accounts. This data shall be provided on the same schedule as payments to the City for Right of Way use.

<u>9.45.050 Penalties</u>
<u>A. Violators of this chapter, including non-payment of the fee or installation of unpermitted fossil fuel systems, are subject to the general penalty provisions in chapter 1.08. A separate violation occurs each day the violation continues. Revenues collected from penalties may be allocated to clean energy programs.</u>

<u>SECTION 2. Effective Date</u>. The provisions of this chapter shall take effect on January 1, 2026.

<u>SECTION 3. Severability.</u> Each section of this ordinance, and any part thereof, is severable, and if any part of this ordinance is held invalid by a court of competent jurisdiction, the remainder of this ordinance shall remain in full force and effect.

<u>SECTION 4. Codification</u>. Provisions of this Ordinance shall be incorporated in the City Code and the word "ordinance" may be changed to "code", "article", "section", "chapter" or another word, and the sections of this Ordinance may be renumbered, or re-lettered, provided however that any Whereas clauses and boilerplate provisions (i.e. Sections 3-5) need not be codified and the City Recorder is authorized to correct any cross-references and any typographical errors.

The foregoing ordinance was first read by title only in accordance with Article X, Section 2(C) of the City Charter on the 21st day of January, 2025, and duly PASSED and ADOPTED this 18 day of February, 2025.

PASSED by the City Council this 18 day of February, 2025.

ATTEST:

Alissa Kolodzinski, City Recorder

SIGNED and APPROVED this 18 day of February, 2025.

Tonya Graham, Mayor

Reviewed as to form:

Douglas M. McGeary, Acting City Attorney

Industry Association Dues for AGA and NWGA

Notes on exhibit:

- Native Excel Spreadsheet: UG 519_NONC_AVAtoOPUC_DR57R_Attach1_10302024.xlsx
- Tab: Download
- Data filters:
  - FERC Account = 93020
  - Vendor Name = NORTHWEST GAS ASSOCIATION, AMERICAN GAS ASSOCIATION
- Columns from the original workbook were hidden to improve the readability of the exhibit.

lts of O	FERC Account	FERC Account Description	Accounting Year	Vendor Number	Vendor Name	Ser.Jur	Labor/Non-Labor Flag For DR 057	Transaction Description	Transaction Amount	Gas North Amount	Gas South Amount
Yes	930200	MISC GENERAL EXPENSE	2023	27208	NORTHWEST GAS ASSOCIATI(	GD.AA	Non-Labor	2023 Annual Membership dues	101,185	69,853.06	31,331.94
Yes	930200	MISC GENERAL EXPENSE	2023	5025	AMERICAN GAS ASSOCIATION	GD.AA	Non-Labor	AGA 2023 membership dues	269,412.6	185,988.99	83,423.61

Chambers of Commerce Membership Dues

Notes on exhibit:

- Native Excel Spreadsheet: UG 519_NONC_AVAtoOPUC_DR57R_Attach1_10302024.xlsx
- Tab: Download
- Data filters:
  - FERC Account = 93020
  - Vendor Name = ASHLAND CHAMBER OF COMMERCE, BOARDMAN CHAMBER OF COMMERCE, CENTRAL POINT CHAMBER OF COMMERCE, GRANTS PASS & JOSEPHINE COUNTY, ROSEBURG AREA CHAMBER OF COMMERCE, THE CHAMBER OF MEDFORD / JACKSON COUNTY
- Columns from the original workbook were hidden to improve the readability of the exhibit.

lts of Or	FERC Account	FERC Account Description	Accounting Year	Vendor Number	Vendor Name	Ser.Jur	Labor/Non-Labor Flag For DR 057	Transaction Description	Transaction Amount	Gas North Amount	Gas South Amount
Yes	930200	MISC GENERAL EXPENSE	2023	59760	GRANTS PASS & JOSEPHINE C	GD.OR	Non-Labor	Chamber of Commerce Membership Dues	145		145
Yes	930200	MISC GENERAL EXPENSE	2023	5173	THE CHAMBER OF MEDFORD /	GD.OR	Non-Labor	Chamber of Medford/Jackson County Memb	613		613
Yes	930200	MISC GENERAL EXPENSE	2023	14564	CENTRAL POINT CHAMBER OF	GD.OR	Non-Labor	Central Point Chamber Membership Dues	125		125
Yes	930200	MISC GENERAL EXPENSE	2023	93399	BOARDMAN CHAMBER OF COM	GD.OR	Non-Labor	Boardman Chamber of Commerce Dues	82.5		82.5
Yes	930200	MISC GENERAL EXPENSE	2023	5173	THE CHAMBER OF MEDFORD /	GD.OR	Non-Labor	Medford Chamber of Commerce Forum for E	4,000		4,000
Yes	930200	MISC GENERAL EXPENSE	2023	23497	ASHLAND CHAMBER OF COMM	GD.OR	Non-Labor	Ashland Chamber Membership Dues	212.5		212.5
Yes	930200	MISC GENERAL EXPENSE	2023	6281	ROSEBURG AREA CHAMBER C	GD.OR	Non-Labor	membership	227.5		227.5

Recovery of Industry Association Dues

Notes on exhibit:

- Native Excel Spreadsheet:
- Tab:
- Data filters:
    -
    -
- Columns from the original workbook were hidden to improve the readability of the exhibit.

efile GRAPHIC print - DO NOT PROCESS | As Filed Data - | DLN: 93493318188733

Form **990**

Return of Organization Exempt From Income Tax

Under section 501(c), 527, or 4947(a)(1) of the Internal Revenue Code (except private foundations)

▶ Do not enter social security numbers on this form as it may be made public.

▶ Go to *www.irs.gov/Form990* for instructions and the latest information.

Department of the Treasury
Internal Revenue Service

OMB No. 1545-0047

2022

Open to Public Inspection

A For the 2022 calendar year, or tax year beginning 01-01-2022 , and ending 12-31-2022

B Check if applicable:
☐ Address change
☐ Name change
☐ Initial return
☐ Final return/terminated
☐ Amended return
☐ Application pending

C Name of organization
AMERICAN GAS ASSOCIATION

Doing business as

Number and street (or P.O. box if mail is not delivered to street address) 400 N CAPITOL ST NW 450 | Room/suite

City or town, state or province, country, and ZIP or foreign postal code
WASHINGTON, DC 200011503

D Employer identification number
13-0431590

E Telephone number
(202) 824-7000

G Gross receipts $ 54,336,823

F Name and address of principal officer:
KAREN HARBERT
400 N CAPITOL ST NW 450
WASHINGTON, DC 200011503

H(a) Is this a group return for subordinates? ☐Yes ☑No
H(b) Are all subordinates included? ☐Yes ☐No
If "No," attach a list. See instructions.
H(c) Group exemption number ▶

I Tax-exempt status: ☐ 501(c)(3) ☑ 501(c) (6) ◀ (insert no.) ☐ 4947(a)(1) or ☐ 527

J **Website:** ▶ WWW.AGA.ORG

K Form of organization: ☑ Corporation ☐ Trust ☐ Association ☐ Other ▶

L Year of formation: 1971

M State of legal domicile: DE

Part I Summary

Activities & Governance

1 Briefly describe the organization's mission or most significant activities:
AGA IS AN ADVOCATE FOR NATURAL GAS UTILITY COMPANIES AND THEIR CUSTOMERS. AGA HELPS NATURAL GAS UTILITIES ACHIEVE OPERATIONAL EXCELLENCE IN THE SAFE, RELIABLE AND EFFICIENT DELIVERY OF NATURAL GAS.

2 Check this box ▶ ☐ if the organization discontinued its operations or disposed of more than 25% of its net assets.

3	Number of voting members of the governing body (Part VI, line 1a)	3	51
4	Number of independent voting members of the governing body (Part VI, line 1b)	4	50
5	Total number of individuals employed in calendar year 2022 (Part V, line 2a)	5	104
6	Total number of volunteers (estimate if necessary)	6	5,318
7a	Total unrelated business revenue from Part VIII, column (C), line 12	7a	455,486
b	Net unrelated business taxable income from Form 990-T, Part I, line 11	7b	106,436

			Prior Year	Current Year
Revenue	8	Contributions and grants (Part VIII, line 1h)	0	0
	9	Program service revenue (Part VIII, line 2g)	33,283,034	34,691,909
	10	Investment income (Part VIII, column (A), lines 3, 4, and 7d)	1,171,991	657,361
	11	Other revenue (Part VIII, column (A), lines 5, 6d, 8c, 9c, 10c, and 11e)	1,239,001	1,375,559
	12	Total revenue—add lines 8 through 11 (must equal Part VIII, column (A), line 12)	35,694,026	36,724,829
Expenses	13	Grants and similar amounts paid (Part IX, column (A), lines 1–3)	654,065	555,935
	14	Benefits paid to or for members (Part IX, column (A), line 4)	0	0
	15	Salaries, other compensation, employee benefits (Part IX, column (A), lines 5–10)	20,802,070	20,592,124
	16a	Professional fundraising fees (Part IX, column (A), line 11e)	0	0
	b	Total fundraising expenses (Part IX, column (D), line 25) ▶0		
	17	Other expenses (Part IX, column (A), lines 11a–11d, 11f–24e)	13,539,335	15,823,452
	18	Total expenses. Add lines 13–17 (must equal Part IX, column (A), line 25)	34,995,470	36,971,511
	19	Revenue less expenses. Subtract line 18 from line 12	698,556	-246,682
			Beginning of Current Year	**End of Year**
Net Assets or Fund Balances	20	Total assets (Part X, line 16)	54,599,533	59,928,098
	21	Total liabilities (Part X, line 26)	23,303,115	33,087,779
	22	Net assets or fund balances. Subtract line 21 from line 20	31,296,418	26,840,319

Part II Signature Block

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than officer) is based on all information of which preparer has any knowledge.

Sign Here

****** | 2023-11-14
Signature of officer | Date

TERRI OLIVA CHIEF FINANCIAL OFFICER
Type or print name and title

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
		2023-11-14		P00397829

Firm's name ▶ RSM US LLP | Firm's EIN ▶ 42-0714325

Firm's address ▶ 1250 H STREET SUITE 700
WASHINGTON, DC 20005 | Phone no. (202) 293-2200

May the IRS discuss this return with the preparer shown above? (see instructions) ☑ Yes ☐ No

Part VIII Statement of Revenue

Check if Schedule O contains a response or note to any line in this Part VIII . . . . ☐

			(A) Total revenue	(B) Related or exempt function revenue	(C) Unrelated business revenue	(D) Revenue excluded from tax under sections 512 - 514
Contributions, Gifts, Grants and Other Similar Amounts						
1a Federated campaigns	1a					
b Membership dues	1b					
c Fundraising events	1c					
d Related organizations	1d					
e Government grants (contributions)	1e					
f All other contributions, gifts, grants, and similar amounts not included above	1f					
g Noncash contributions included in lines 1a - 1f:$	1g					
h **Total.** Add lines 1a-1f ▶						
Program Service Revenue		Business Code				
2a MEMBERSHIP DUES		900099	29,081,971	29,081,971		
b MEETINGS/EXHIBIT		900099	3,763,702	3,763,702		
c SPONSORSHIPS		900099	1,114,250	1,114,250		
d SERVICE INCOME		900004	228,930		228,930	
e PUBLICATIONS		541800	226,556		226,556	
f All other program service revenue.			276,500	276,500		
g **Total.** Add lines 2a–2f. ▶		34,691,909				

Other Revenue			(A)	(B)	(C)	(D)
3 Investment income (including dividends, interest, and other similar amounts) ▶			527,407			527,407
4 Income from investment of tax-exempt bond proceeds ▶						
5 Royalties ▶			1,375,559			1,375,559
	(i) Real	(ii) Personal				
6a Gross rents (6a)						
b Less: rental expenses (6b)						
c Rental income or (loss) (6c)						
d Net rental income or (loss) ▶						
	(i) Securities	(ii) Other				
7a Gross amount from sales of assets other than inventory (7a)	17,736,524	5,424				
b Less: cost or other basis and sales expenses (7b)	17,577,232	34,762				
c Gain or (loss) (7c)	159,292	-29,338				
d Net gain or (loss) ▶			129,954			129,954
8a Gross income from fundraising events (not including $ ______ of contributions reported on line 1c). See Part IV, line 18	8a					
b Less: direct expenses	8b					
c Net income or (loss) from fundraising events ▶						
9a Gross income from gaming activities. See Part IV, line 19	9a					
b Less: direct expenses	9b					
c Net income or (loss) from gaming activities ▶						
10a Gross sales of inventory, less returns and allowances	10a					
b Less: cost of goods sold	10b					
c Net income or (loss) from sales of inventory ▶						
Miscellaneous Revenue		Business Code				
11a						
b						
c						
d All other revenue						
e **Total.** Add lines 11a–11d ▶						
12 **Total revenue.** See instructions ▶			36,724,829	34,236,423	455,486	2,032,920

Additional Data

Software ID:
Software Version:
EIN: 13-0431590
Name: AMERICAN GAS ASSOCIATION

Form 990,Schedule I, Part II, Grants and Other Assistance to Domestic Organizations and Domestic Governments.

(a) Name and address of organization or government	**(b)** EIN	**(c)** IRC section if applicable	**(d)** Amount of cash grant	**(e)** Amount of non-cash assistance	**(f)** Method of valuation (book, FMV, appraisal, other)	**(g)** Description of non-cash assistance	**(h)** Purpose of grant or assistance
PARTNERS FOR ENERGY PROGRESS 1414 CHERRY STREET SE OLYMPIA, WA 98501	84-3818906	501C4	75,000	0			SUPPORT
COLORADANS FOR ENERGY ACCESS 1315 S CLAYTON SUITE 300 DENVER, CO 80210	86-1971581	501C4	50,000	0			SUPPORT

Form 990,Schedule I, Part II, Grants and Other Assistance to Domestic Organizations and Domestic Governments.

(a) Name and address of organization or government	(b) EIN	(c) IRC section if applicable	(d) Amount of cash grant	(e) Amount of non-cash assistance	(f) Method of valuation (book, FMV, appraisal, other)	(g) Description of non-cash assistance	(h) Purpose of grant or assistance
EDISON ELECTRIC INSTITUTE 701 PENNSYLVANIA AVE NW WASHINGTON, DC 20004	13-0659550	501C6	25,000	0			SUPPORT
NATIONAL ASSOCIATION OF COUNTIES PO BOX 38059 BETHESDA, MD 212978057	53-0190321	501C4	25,000	0			SPONSORSHIP

------- Forwarded Message -------
From: Kurt Swanson <info@nwenergychoice.org>
Date: On Friday, March 10th, 2023 at 4:00 PM
Subject: Oregon Introduces Legislation that Threatens Energy Choice

NW Coalition for Energy Choice

Oregon House Climate, Energy & Environment Committee Taking Up Legislation Limiting Home Energy Choice

On Monday, March 13th at 3pm, the Oregon legislature will be hearing a bill that will harm our most vulnerable residents. HB 3152 will restrict incentives or subsidies for Oregon residents to purchase gas appliances. It will also end the funds being used for gas lines in residential buildings to support the flow of natural gas.

Low-income residents depend on these funds in order to heat their homes in the winter and HB 3152 will make it impossible for natural gas to remain affordable and dependable for many Oregonians - especially our most vulnerable populations.

Please send a pre-written message to the Oregon House Committee on House Committee On Climate, Energy, and Environment, urging them to OPPOSE this harmful legislation.

TAKE ACTION

5:26

+1 (458) 206-[redacted]

Hi [redacted] this is Ann with Luce Research. Ashland City Council is about to approve a 100% tax increase on natural gas appliances for new home construction. This tax on affordable, efficient natural gas appliances will cost homeowners thousands. For example, a natural gas furnace will cost homebuilders over $4,000 in new taxes!

Take action today, and send a quick message to the City Council, urging them to oppose this massive tax increase on new homebuyers!

https://www.votervoice.net/NWCEC/campaigns/120542/respond?TrackingID=MMS1

Text STOP to end messages

The sender is not in your contact list.

Report Junk

Text Message • SMS

5:26

+1 (458) 206[redacted]

Hi [redacted] this is Ann with Luce Research. Ashland City Council is about to approve a 100% tax increase on natural gas appliances for new home construction. This tax on affordable, efficient natural gas appliances will cost homeowners thousands. For example, a natural gas furnace will cost homebuilders over $4,000 in new taxes!

Take action today, and send a quick message to the City Council, urging them to oppose this massive tax increase on new homebuyers!

Text Message • SMS

PAID ADVERTISEMENT

AN OPEN LETTER TO THE ASHLAND COMMUNITY

Tell your Councilmember in Ashland to Oppose Ordinance No. 3254

A NEW TAX ON APPLIANCES IS BAD POLICY FOR ASHLAND. TOO MUCH AT STAKE. TOO MANY UNINTENDED CONSEQUENCES.

As members of this community from all walks of life, who together, specialize in providing homes with safe and reliable energy, we are writing with concerns about Ordinance 3254 – an approximate 100% tax on appliances that will impact new home construction. There is too much at stake and there are too many unintended consequences resulting from this ordinance.

This proposed ordinance represents a 100% tax on new appliances, without the vote of Ashland residents. Lower income Ashland residents and families looking to buy their first new home will have to pay even more for housing, creating inequities in our community and exacerbating the affordability problem in Oregon. For example, a new home with a natural gas furnace, will have an added $4,118 in costs to Ashland homebuyers. According to a 2024 Priced Out report by the National Association of Home Builders, for every $1,000 increase in the cost of building a home, 812 Oregon households are priced out from the housing market.

Ordinance 3254 will make the equity divide even worse in Oregon. According to a 2024 State of the State's Housing report from Oregon Housing and Community Services, there is a 15.3% gap in homeownership by race and ethnicity, with exclusionary policies, wealth gaps, and institutional barriers that prevent BIPOC communities from buying homes cited as primary drivers. Imposing more taxes on new home construction are an example of these exclusionary policies.

According to the same report, Oregon has the highest number of families with kids experiencing homelessness in the country. With housing costs so high, many parents have to choose between keeping a roof over their heads or putting food on the table – when they should have both. Even those who have housing are struggling to keep up, as prices keep rising faster than wages.

Here are some other astonishing facts from the report that have a direct correlation to the disproportionate impact the ordinance will have on housing affordability:

- While higher-income groups and individuals are increasingly experiencing cost burdening, this has long been a reality for BIPOC communities and low-income households. Over the past two decades, these disparities have worsened, disproportionately impacting Oregon's most vulnerable populations.
- Both renters and homeowners spend more than 30% of their income on housing.
- Oregon ranks 3rd in the nation for people experiencing homelessness.

Ordinance 3254 is not going to help us solve the problem of housing affordability in Ashland, in fact the new tax will make it worse. Oregonians need real solutions that don't involve imposing additional affordability barriers on anyone, especially those who are least likely to afford them.

Brad Hicks
Interim Executive Director, Builders Association of Southern Oregon

Zachary Lindahl
Government Affairs Director, Multifamily NW

Drew Johnson
Government Affairs Committee Chair, Oregon REALTORS®

Paul Elder
Business Manager, UA Local 290

Harvey Gail
Executive Director, Oregon Hearth Patio Barbecue Association

Scan the QR code to tell Ashland City Council to OPPOSE this new tax!

PAID FOR BY NW COALITION FOR ENERGY CHOICE

FERC Account No. 923 Outside Services Employed

Notes on exhibit:

- Native Excel Spreadsheet: UG 519_NONC_AVAtoOPUC_DR57R_Attach1_10302024.xlsx
- Tab: Download
- Data filters:
  - FERC Account = 92300
  - Ser.Jur = GD.OR
- Columns from the original workbook were hidden to improve the readability of the exhibit.

lts of O	FERC Account	FERC Account Description	Accounting Year	Vendor Number	Vendor Name	Ser.Jur	Labor/Non-Labor Flag For DR 057	Transaction Description	Transaction Amount	Gas North Amount	Gas South Amount
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V AVISTA ET AL	700.03		700.03
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	2021000055	3,081		3,081
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	440.38		440.38
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	7137	DAVIS WRIGHT TREMAINE LLP	GD.OR	Non-Labor	202300049	574.5		574.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	IDAHO POWER V. AVISTA ET AL	663.5		663.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CCP/DEQ	1,438.43		1,438.43
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	994.95		994.95
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	1,205.93		1,205.93
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	Apx Accrual 202310	4,355.66		4,355.66
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V. AVISTA ET AL	5,995.55		5,995.55
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	3,796.13		3,796.13
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	108.68		108.68
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	89.55		89.55
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	Apx Accrual 202212	-13.17		-13.17
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	718.35		718.35
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V. AVISTA ET AL	1,825.5		1,825.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	1,484.85		1,484.85
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V AVISTA ET AL	1,585.76		1,585.76
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	251.18		251.18
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	167.33		167.33
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	IDAHO POWER V AVISTA ET AL	517.5		517.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	150.45		150.45
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN	1,343		1,343
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	8,847.15		8,847.15
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN (CPP)	1,027		1,027
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	12,406.58		12,406.58
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	1,528.05		1,528.05
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	7137	DAVIS WRIGHT TREMAINE LLP	GD.OR	Non-Labor	TYREE BOLI COMPLAINT	26,731.5		26,731.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN (CPP)	237		237
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN (CPP)	5,135		5,135
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V AVISTA ET AL	7,216		7,216
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	Apx Accrual 202310	-4,355.66		-4,355.66
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	1,280.72		1,280.72
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	Apx Accrual 202307	-5,750		-5,750
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	LEGALS COST REIMBURSEMENT	-500		-500
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V AVISTA ET AL	11,238.67		11,238.67
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	202200006	17,659.62		17,659.62
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	12,396.19		12,396.19
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	112064	SNELL & WILMER LLP	GD.OR	Non-Labor	OREGON CPP/DEQ	31.43		31.43
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	VIN MCHTAI INVOICE COLLECTION	500		500
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	DEQ LITIGATION GROUP	213.15		213.15
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V AVISTA ET AL	225		225
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	111053	SMITH & MALEK PLLC	GD.OR	Non-Labor	BOTANICAL RESEARCH	2,746.5		2,746.5
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN (CPP)	1,501		1,501
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023			GD.OR	Non-Labor	Apx Accrual 202307	5,750		5,750
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	101877	BAKER BOTTS LLP	GD.OR	Non-Labor	CLIMATE PROTECTION PLAN (CPP)	2,923		2,923
Yes	923000	OUTSIDE SERVICES EMPLOYED	2023	43039	RANDALL DANSKIN ATTORNEY	GD.OR	Non-Labor	ALF FAMILY TRUST V. AVISTA ET AL	157.5		157.5

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/17/2025
CASE NO:	UG 519	WITNESS:	Kevin Christie
REQUESTER:	Coalition	RESPONDER:	Shawn Bonfield
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CS & GEI – 016	TELEPHONE:	(509) 495-2782
		EMAIL:	shawn.bonfield@avistacorp.com

REQUEST:

For any legal fees incurred from the matters listed in Coalition Data Request No. 15 to Avista, what was charged to Oregon ratepayers and what is Avista's justification for charging those expenses to Oregon ratepayers.

RESPONSE:

$80,456.10 is included in the Base Year of this case for legal fees incurred for the challenge to the first iteration of the Climate Protection Program (CPP). As noted in the Company's response to CS & GEI Data Request No. 15, the prior rate case settlement was not a precedent for future rate cases. As such, these costs are appropriate to include in customer rates. In the normal course of business, the Company becomes involved in various claims, controversies, disputes and other contingent matters. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, as appropriate, the Company will vigorously protect and defend its interests and pursue its rights, all of which benefits customers. Of course, no assurance can be given as to the ultimate outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Utilities' operations, it is appropriate for the Company to recover the costs incurred to protect the utility and its customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/17/2025
CASE NO:	UG 519	WITNESS:	Kevin Christie
REQUESTER:	Coalition	RESPONDER:	Shawn Bonfield
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CS & GEI – 015	TELEPHONE:	(509) 495-2782
		EMAIL:	shawn.bonfield@avistacorp.com

REQUEST:

Please state how Avista is paying for legal fees for its participation in any of the following matters:

a. Lawsuits challenging the Climate Protection Program.
b. Lawsuits challenging the Washington State Building Code Council's amendments to the state building codes.
c. Rulemaking related to the Washington State Building Code Council's amendments to the building codes.
d. Comments on the Climate Commitment Act.
e. Advocacy related to Governor Brown's Executive Order 20-04.

RESPONSE:

a. There are no current lawsuits challenging the Climate Protection Program (CPP). Regarding the prior lawsuit against the first iteration of the CPP, Avista agreed to not recover from customers a certain amount of legal fees as part of the settlement of its 2022 general rate case, which was not a precedent for future rate cases. In this case, the Company is seeking to recover legal fees associated with challenging the CPP that were incurred in the Base Year.

b. Any such costs are not applicable to Oregon as they were directly assigned to the Company's Washington jurisdiction.

c. Any such costs are not applicable to Oregon as they were directly assigned to the Company's Washington jurisdiction.

d. Any such costs are not applicable to Oregon as they were directly assigned to the Company's Washington jurisdiction.

e. Beyond the CPP discussed in part a. above, the Company has not incurred any legal fees for advocacy related to Governor Brown's Executive Order 20-04.

egov.sos.state.or.us/br/pkg_web_name_srch_inq.show_detl?p_be_rsn=2297729&p_srce=BR_INQ&p_print=FALSE

OREGON SECRETARY OF STATE
Corporation Division
HOME
Business Xpress | business name search | oregon businessguide
license directory | business registry/renewal | forms/fees | notary public
uniform commercial code | uniform commercial code search | documents & data services

Business Name Search

New Search | Printer Friendly

Business Entity Data

03-03-2025 02:54

Registry Nbr	Entity Type	Entity Status	Jurisdiction	Registry Date	Next Renewal Date	Renewal Due?
194526498	DNP	ACT	OREGON	03-18-2022	03-18-2026	

Entity Name	NW COALITION FOR ENERGY CHOICE
Foreign Name	
Non Profit Type	MUTUAL BENEFIT

New Search | Printer Friendly

Associated Names

Type	PPB	PRINCIPAL PLACE OF BUSINESS				
Addr 1	1914 WILLAMETTE FALLS DR #260					
Addr 2						
CSZ	WEST LINN	OR	97068		Country	UNITED STATES OF AMERICA

Please click here for general information about registered agents and service of process.

Type	AGT	REGISTERED AGENT		Start Date	03-18-2022	Resign Date
Name	DAN		KIRSCHNER			
Addr 1	1914 WILLAMETTE FALLS DRIVE #260					
Addr 2						
CSZ	WEST LINN	OR	97068		Country	UNITED STATES OF AMERICA

Type	MAL	MAILING ADDRESS				
Addr 1	1914 WILLAMETTE FALLS DRIVE #260					
Addr 2						
CSZ	WEST LINN	OR	97068		Country	UNITED STATES OF AMERICA

Type	PRE	PRESIDENT				Resign Date
Name	BRAD		ARCHULETA			
Addr 1	UA LOCAL 290					
Addr 2	20210 SW TETON AVE					
CSZ	TUALATIN	OR	97062		Country	UNITED STATES OF AMERICA

Type	SEC	SECRETARY				Resign Date
Name	COLLINS		SPRAGUE			
Addr 1	1411 E MISSION AVE					
Addr 2						
CSZ	SPOKANE	WA	99202		Country	UNITED STATES OF AMERICA

New Search | Printer Friendly

Name History

Business Entity Name	Name Type	Name Status	Start Date	End Date
NW COALITION FOR ENERGY CHOICE	EN	CUR	03-18-2022	

Please read before ordering Copies.

New Search | Printer Friendly

Summary History

Image Available	Action	Transaction Date	Effective Date	Status	Name/Agent Change	Dissolved By
	AMENDED ANNUAL REPORT	02-06-2025		FI		
	AMENDED ANNUAL REPORT	03-08-2024		FI		
	AMENDED ANNUAL REPORT	03-17-2023		FI		
	ARTICLES OF INCORPORATION	03-18-2022		FI	Agent	

RESOLUTION NO. 2024-097-R

A RESOLUTION OF THE CITY COUNCIL OF TALENT, OREGON TO ADVANCE THE PUBLIC HEALTH BENEFITS OF TRANSITION TO CLEAN AIR AND CLEAN ENERGY EQUIPMENT AND APPLIANCES

WHEREAS, the City of Talent recognizes the air pollution and climate emissions public health risks associated with using natural gas for heating, cooling, and cooking; [i] [ii]

WHEREAS, the State of Oregon joined eight other states pledging that zero - emission electric heat pumps will constitute at least 65% of residential-scale heating, air conditioning, and water heating equipment shipments by 2030 and 90% by 2040[iii]; and

WHEREAS, the City of Talent's climate goals as stated in the City's Comprehensive Plan, Clean Energy Element, likely cannot be met without transition to low- or zero-emission technologies in residential and non-residential buildings.

NOW, THEREFORE, BE IT RESOLVED by the Talent City Council, as follows:

1. The City should encourage transition to low- or zero-emission equipment and appliances in Talent residential and non-residential buildings.
2. The City should investigate possible sources of financial and staffing support for developing measures to mitigate the health impacts of pollution in Talent residential and non-residential buildings, including low- or zero-emission standards for appliances.
3. The City should encourage and provide resources to the Together for Talent Committee, among other entities, to work with community partners in educating and engaging the community on the pollution associated with natural gas use in buildings.
4. The City of Talent urges the Oregon Governor, Legislature, state agencies, and Jackson County to accelerate transition to zero-emitting appliances by: promoting decarbonization while protecting low and moderate income rate payers; adopting indoor air quality standards to protect public health; amending building codes to address the adverse health impacts of using natural gas in residential and non-residential buildings; and considering inclusion of the adverse health impacts of natural gas in utility cost-benefit analyses, rate setting, and resource planning.

Duly enacted by the City Council in open session on August 21st, 2024, by the following vote:

AYES: **NAYS:** **ABSTAIN:** **ABSENT:**

____

Hector Flores, City Recorder and Custodian of City Records

[i] American Lung Association, "Literature Review of Health impacts of Residential Combustion in Homes", July 2022; https://www.lung.org/policy-advocacy/healthy-air-campaign/healthy-efficient-homes/residential-combustion

[ii] "Gas and Propane Combustion from Stoves Emits Benzine and Increases Indoor Air Pollution"; Environmental Science & Technology, June 15, 2023; https://doi.org/10.1021/acs.est.2c09289 .

[iii] "Nine States Pledge Joint Action to Accelerate Transition to Clean Buildings"; Northeast States for Coordinated Air Use Management, February 2024; https://www.nescaum.org/documents/2.7.24-nescaum-mou-press-release.pdf

Recovery of Industry Association Dues

Notes on exhibit:

- Native Excel Spreadsheet: 3.01 OR Membership and Dues UG-519
- Tab: M&D-1

AVISTA UTILITIES
Oregon Jurisdiction
Twelve Month Base Year Ending December 31, 2023
Memberships & Dues Summary

Purpose: this adjustment classifies membership and dues expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is similar to that which was recommended to the Company during Staff review of the December 31, 1994 Earnings Report, however the company has applied updated allocation factors to the historic test period.

Dues/Memberships Allocated and Direct Charges to:

Expenditure Type 830 Dues M&D-2 $155,964

Adjust Memberships & Dues by:	Type	Jur / Ser	Charged to Oregon	% Allowed	Allowed	
American Gas Association	2	CDAA/GDAA	84,972	75%	63,729	
Western Energy Institute	2	CDAA	3,674	75%	2,756	
Northwest Gas Association	2	CDAA	31,332	75%	23,499	
Washington Roundtable	3	CDAA	0	0%	0	
Corporate Executive Board	1	CDAA	0	100%	0	
WA Technology Center	3	CDAA	0	0%	0	
Chamber of Commerce	3	GDOR	2,168	0%	0	
Other- Oregon Allocated, Utility Code 7 and 8	3*	CDAA/GDAA/GDOR	33,818	20%	6,764	
Total			155,964		96,748	
			a		*b*	
					Remove	**($59,216)**
					c	*c=b-a*

Type definitions:
1 Industry research organizations: 100 % allowed
2 National and regional trade organization: 75% allowed
3 Other memberships and dues: Disallowed, unless utility shows just & reasonable for ratemaking
* Estimated 20 % of these expenditures related to individual memberships in professional organizations directly related to their duties, and remaining expenditures are for memberships in commercial and trade-type organizations

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/27/2025
CASE NO:	UG 519	WITNESS:	Marcus Garbarino
REQUESTER:	Coalition	RESPONDER:	Joel Anderson
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CS & GEI – 30	TELEPHONE:	(509) 495-2811
		EMAIL:	joel.anderson@avistacorp.com

REQUEST:

Please provide a copy of the letter Avista sent to Ashland City Council or staff related to Ashland Ord. No. 2354.

RESPONSE:

Provided below is the text of the written submittal provided to the Ashland City Council via an online form:

> Avista Utilities encourages Ashland City Council members to consider the consequences of the proposed ordinance, vote no on this second reading, and explore opportunities to work together with the many stakeholders who've expressed concerns about the proposed ordinance with the aim of finding constructive ways to reduce overall community carbon emissions and while considering implications on the City's electric utility operations and on local energy system reliability.
>
> We believe preserving energy choices for our customers is important and that natural gas plays an important role in reliability, resilience, and energy affordability for the region. We also believe that natural gas plays an important role in reducing carbon emissions, particularly when used directly by customers in their homes rather than used to generate electricity to meet the same needs.
> While we recognize the good intentions of the City of Ashland, one element of this impact fee that has largely been overlooked is the financial inequity this ordinance poses. This fee will add another potential financial barrier for some individuals on the cusp of home ownership.
>
> For decades, we have worked with our customers to use natural gas efficiently, saving them money. We have funded programs to improve the energy efficiency of homes and to replace dirtier heating fuels, such as wood, pellets, heating oil, and kerosene with natural gas.
>
> We remain committed and continue to work towards, a cleaner energy future. However, the imposition of an impact fee designed to preclude customers from choosing natural gas in their homes is not, in our view, a constructive solution. Not only does it unfairly limit energy choice, it may also impact reliability, resilience, and affordability over the long term.
>
> Avista Utilities encourages council members to consider the consequences of the ordinance, vote no on this second reading, and explore opportunities to work together with

stakeholders who've expressed concerns with the aim of finding constructive ways to reduce overall community carbon emissions and while considering implications on the City's electric utility operations and on local energy system reliability.
While we recognize the good intentions, one element of this impact fee that has largely been overlooked is the financial inequity this ordinance poses. This fee will add another potential financial barrier for some individuals on the cusp of home ownership.

We remain committed and continue to work towards, a cleaner energy future. However, the imposition of an impact fee designed to preclude customers from choosing natural gas in their homes is not, in our view, a constructive solution. Not only does it unfairly limit energy choice, it may also impact reliability, resilience, and affordability over the long term.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/27/2025
CASE NO:	UG 519	WITNESS:	Marcus Garbarino
REQUESTER:	Coalition	RESPONDER:	Joel Anderson
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CS & GEI – 31	TELEPHONE:	(509) 495-2811
		EMAIL:	joel.anderson@avistacorp.com

REQUEST:

For any expenses incurred in the drafting of the letter referenced in Coalition Data Request No. 30, what was charged to Oregon ratepayers and what is Avista’s justification for charging those expenses to Oregon ratepayers?

RESPONSE:

Expenses incurred in the drafting of the letter referenced in Coalition Data Request No. 30 have been minimal and recorded as a non-utility expense and not charged to Oregon customers.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/27/2025
CASE NO:	UG 519	WITNESS:	Marcus Garbarino
REQUESTER:	Coalition	RESPONDER:	Joel Anderson
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CS & GEI – 29	TELEPHONE:	(509) 495-2811
		EMAIL:	joel.anderson@avistacorp.com

REQUEST:

If Avista is charging ratepayers for any of Steve Vincent's expenses related to Ashland Ord. No. 2354, please provide all documents, including correspondence, from Steve Vincent in his capacity as an Account Executive or Oregon Regional Business Manager for Avista related to the Ashland Ord. No. 2354.

RESPONSE:

Steve Vincent was not involved with Ashland's Ordinance No. 2354 during the Base Year of 2023. Any expenses incurred for his involvement in 2024 and 2025 have been minimal and recorded as a non-utility expense and not charged to Oregon customers.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 519

In the Matter of

AVISTA UTILITIES,
a division of AVISTA CORPORATION

Request for General Rate Revision

OPENING TESTIMONY

OF EMILY MOORE

ON BEHALF OF CLIMATE SOLUTIONS AND GREEN ENERGY INSTITUTE

(Non-Confidential)

March 4, 2025

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. My name is Emily Moore. My business address is 92 Lenora St. #189 Seattle, WA 98121.

Q. By whom are you employed and in what capacity?

A. I am employed by Sightline Institute, an independent, nonpartisan think tank conducting research and policy analysis in Oregon, Washington, and the broader Pacific Northwest. Sightline has researched, written, and published findings about energy, climate policy, and environmental sustainability in the Pacific Northwest for more than 30 years. I have worked at Sightline since January 2022 and am the Director of the Climate and Energy program. In that role, I lead Sightline's research, writing, and policy analysis on decarbonization and the clean energy transition in the Northwest, including in the gas and electric utility sector.

Q. What did you review in preparation for this testimony?

A. I have read Avista's filings pertaining to docket UG 519 and many of the Company's discovery responses.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Climate Solutions and the Green Energy Institute at Lewis & Clark Law School.

Q. Are you sponsoring any exhibits?

A. Yes. In addition to my resume (Environmental Intervenors/201) and witness qualification statement (Environmental Intervenors/202), I am sponsoring exhibits

Environmental Intervenors/203 through Environmental Intervenors/215. All sponsored exhibits from my testimony are attached to this document.

Q. Please summarize your professional experience.

A. Please see my witness statement and resume attached as Exhibits Environmental Intervenors/201 and Environmental Intervenors/202. I joined Sightline in January of 2022. As Sightline's Director of Climate and Energy, I lead the organization's research on decarbonization and the clean energy transition. One of the major bodies of my work at Sightline has been about gas utilities decarbonization, a topic which I have researched and written about extensively.[1]

I also advise legislators in Oregon and Washington on climate policies and provide input and comments on regulatory proceedings. Previously I worked at Dalberg Advisors, a leading global consulting firm. In that role, I provided strategic guidance to large social sector clients including the MacArthur Foundation, the UN Population Fund, and the Bill and Melinda Gates Foundation. Prior to that I worked on strategy and operations at Global Health Corps, a global health nonprofit. I earned a Masters in Public Policy from the Harvard Kennedy School and a BA from Brown University.

Q. Have you testified before the Oregon Public Utility Commission previously?

A. No.

[1] The scope and breadth of my research and publications is available for review at: Sightline Institute, Emily Moore-Latest Articles, available at: https://www.sightline.org/profile/emily-moore/?query-fdde42e3-page=2.

Q. Have you testified in regulatory proceedings in other states?

A. No, but I have provided comments on regulatory proceedings in Washington state on behalf of Sightline Institute.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

- Section I: Introduction.
- Section II: I summarize my recommendations to the Commission on issues addressed in Section III.
- Section III: Non-Pipeline Alternatives.

II. <u>Summary of Recommendations:</u>

Q. Please summarize your recommendations

A. In this testimony I make the following recommendations:

- Section III: Non-Pipeline Alternatives:
  - As a condition for capital investment recovery in this and future proceedings, the Commission should require Avista to, moving forward, analyze non-pipeline alternatives (NPAs) for investments in 1) replacing Aldyl-A pipes, 2) replacing pipes at the end of their useful life, and 3) expanding system capacity. Doing so will allow the Company to address safety, reliability, and capacity concerns, while at the same time ensuring prudent investments for ratepayers and reducing the risk of stranded gas assets.
    - As an element of this requirement, the Commission should eliminate the $1 million threshold for triggering NPA analyses as

well as expand the scope of what types of projects require an NPA analysis to include investments in pipeline replacement.

- Additionally, as a condition of recovery on investments in this proceeding and future proceedings, the Commission should order that Avista analyze at least two types of non-pipeline alternatives for all gas system capital investments moving forward.

- The Commission should require Avista to evaluate targeted electrification and thermal energy networks as two specific NPAs. The Commission should require Avista to propose at least one targeted electrification pilot and one thermal energy network pilot that would allow decommissioning of gas infrastructure and thus reduction in the risk of stranded gas assets. The Commission should require Avista to include its findings and pilot proposals in the Company's 2026 IRP Update.

III. <u>Non-Pipeline Alternatives</u>

A. *Overview of Non-Pipeline Alternatives*

Q. What are non-pipeline alternatives?

A. Non-pipeline alternatives (NPAs) are solutions that natural gas utilities deploy to meet energy demands and enhance system reliability without constructing or expanding gas pipeline infrastructure. Similar to "non-wires alternatives" in the electric utility industry, non-pipeline alternatives refer to the concept that there are investments utilities can—and often should—make in lieu of building or replacing traditional infrastructure.

NPAs often involve a portfolio of diverse resources including demand response, energy efficiency, electrification of space and water heating, and behavioral programs. NPAs aim to mitigate challenges associated with expanding or replacing gas infrastructure such as increased customer costs, increased or continued greenhouse gas emissions, and other environmental concerns. By leveraging alternatives, utilities can often meet energy demand in a more cost-effective, flexible, and environmentally sustainable way than by replacing existing pipes or expanding gas infrastructure. Because pipeline investments are capital intensive and ultimately at the expense of ratepayers, NPAs serve as a tool to evaluate whether such investments are in the best interest of customers.

Q. What are the financial benefits of non-pipeline alternatives?

A. Expanding, replacing, and maintaining gas pipeline infrastructure requires significant capital investments that are ultimately borne by ratepayers, with costs continuing to spiral upwards each year.[2] NPA analysis allows the utility to identify whether there are less expensive alternatives to pipeline investments that can meet energy demand. As gas utilities face rising prices, evolving climate regulation, and weakening customer demand, the need to make prudent capital investments is more important than ever. NPAs provide a way to cost-effectively respond to this changing context.

Q. Do non-pipeline alternatives help avoid the risk of stranding utility assets?

A. Yes. A "stranded asset" refers to infrastructure, in this case, a natural gas pipeline or other piece of utility infrastructure, "that no longer serves a useful purpose but has not yet exceeded its book life originally projected by the utility and approved by the regulator."[3]

---

[2] Magdalen Sullivan & Erin Murphy, Non-Pipeline Alternatives: Meeting Energy Demand Responsibly, Environmental Defense Fund at 8 (Feb. 2024) available at: https://www.edf.org/sites/default/files/2024-02/Non-Pipeline-Alternatives-Report_EDF_Feb2024.pdf; *see also* Avista/602, Benjamin/Page 157; Avista Utilities, *Natural Gas Safety Project Plan – Oregon* at 26 (Sep. 24, 2024) available at: https://edocs.puc.state.or.us/efdocs/HAQ/um1898haq331590025.pdf.

[3] *Id.* at 10.

Typically, utilities project how long an asset will be useful to customers, with that projected timeline serving as the period over which the utility will recover its costs and garner its return on the investment through monthly customer bills.[4] If an asset is within its book life, the utility still recovers its capital costs through depreciation and a return on the original cost of the asset through customer rates.[5] In Avista's case, new pipes installed to replace Aldyl-A distribution mains have a book life of 50.25–51.55 years.[6]

This traditional approach to asset depreciation and cost recovery relies on the assumption that the gas system will operate in perpetuity, and that costs can be distributed over a large customer base over decades. But, in Oregon, the newly readopted Climate Protection Program sets declining and enforceable caps on greenhouse gas emitters—including natural gas utilities—to reduce fossil fuel pollution by 90% by 2050.[7] This policy, coupled with incentives for building electrification, is expected to result in declining natural gas demand and consumption, shortening the useful life—but not the book life—of pipeline assets.

As Oregon and the cities within it pursue building electrification to meet climate goals, absent policy and regulatory changes, the ratepayers remaining on the gas system will be burdened with an ever-mounting share of costs to pay for gas assets that provide diminishing benefits, i.e., stranded assets. This so-called "utility death spiral," functions as a negative feedback loop. As more customers leave the gas system, gas rates rise to cover the

---

[4] *Id.*
[5] Andy Bilich et al., Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California, ENV'T DEF. FUND at 15–16 (2019) available at: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.
[6] Environmental Intervenors/204, Moore/Page 1.
[7] OAR 340-273-0450(1)–(4)(a)(A); OAR 340-273-9000 Table 2.

utility's fixed costs and previous investments, further incentivizing the remaining customers to leave. The customers most likely to remain on the gas system and shoulder the burden of stranded gas assets are renters or those without the financial means to electrify.

Non-pipeline alternatives reduce the risk of stranded gas assets by avoiding the investment and construction of large and expensive gas infrastructure projects that gas ratepayers will likely have to pay for decades past when they will be useful. By meeting the demand for energy through methods such as electrification or demand response, utilities can save customers money, reduce stranded asset risk from overbuilding, and provide critical greenhouse gas emissions reductions.

Q. Do non-pipeline alternatives reduce greenhouse gas emissions?

A. Yes. Natural gas is primarily comprised of methane, a potent greenhouse gas.[8] Natural gas combustion also releases nitrogen oxides (NOx), carbon monoxide (CO), carbon dioxide (CO_2) and particulate matter (PM2.5), pollutants that endanger public health and welfare.[9] Where NPAs reduce gas use, they also reduce pollution and emissions.

---

[8] *See generally* Ramón A. Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, 361 SCIENCE 186 (2018), https://www.science.org/doi/10.1126/science.aar7204; *see also* Zachary D. Weller et al., A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems, 54 ENV'T SCI. TECH. 8958, (2020), https://pubs.acs.org/ doi/10.1021/acs.est.0c00437?ref=pdf; U.S. EIA, Carbon Dioxide Emissions Coefficients (last released Sept. 7, 2023), https://www.eia.gov/environment/emissions/ co2_vol_mass.php.

[9] *See* U.S. EPA, 2020 National Emissions Inventory (NEI) Data, https://www.epa.gov/air-emissionsinventories/2020-national-emissions-inventory-nei-data (last updated Aug. 14, 2023); Amneh Minkara et al., National Building Pollution Report, WE ACT (Oct. 2023), https://www.weact.org/wp-content/uploads/2023/10/ AppliancePollution_Report_FINAL.pdf; *see also* Center for Climate and Energy Solutions, *Natural Gas At-a-glance* (2025) available at: https://www.c2es.org/content/naturalgas/#:~:text=At%2Da%2Dglance,per%20unit%20of%20energy%20delivered.

Multiple states, including Oregon, have adopted climate targets requiring reductions in greenhouse gas emissions. For example, Oregon's Climate Protection Program requires a 90% reduction in emissions from fossil fuel usage by 2050, including by Avista and other gas utilities.[10] Progress towards this goal can be significantly advanced through gas utilities' adoption of non-pipeline alternatives. To this end, Oregon Public Utility Commission Staff recently noted that, "Staff is supportive of doing everything possible to eliminate unnecessary investments in the gas distribution system,"[11] and recommended that, "[f]uture distribution system planning should include a cost benefit analysis for non-pipe alternatives."[12]

Beyond the primary benefits of emissions reductions and ratepayer cost savings, NPAs provide many additional community co-benefits. For example, implementing NPAs can improve air quality, especially in densely populated areas, due to reduced gas usage.[13] Additionally, NPAs help to reduce the environmental impact of natural gas infrastructure projects, such as habitat disruption from pipeline construction.

Q. How does targeted electrification serve as a non-pipeline alternative to natural gas pipeline replacement and expansion?

A. Targeted electrification involves strategically converting certain areas of the gas distribution system from natural gas use to electricity.[14] It allows gas utilities to either

[10] OAR 340-273-0450(1)–(4)(a)(A); OAR 340-273-9000 Table 2.
[11] Docket LC 79, Final Staff Comments, at 15. Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc79hac142022.pdf.
[12] *Id.* at 15.
[13] Magdalen Sullivan & Erin Murphy, Non-Pipeline Alternatives: Meeting Energy Demand Responsibly, Environmental Defense Fund at 12 (Feb. 2024) available at: https://www.edf.org/sites/default/files/2024-02/Non-Pipeline-Alternatives-Report_EDF_Feb2024.pdf.
[14] Kiki Velez, CA: *$20B Potential Savings from Targeted Electrification*, NRDC (June 19, 2024) available at: https://www.nrdc.org/bio/kiki-velez/ca-20b-potential-savings-targeted-

decommission the gas infrastructure that is no longer being used, saving ratepayers money, or avoid those costs altogether. The goal of targeted electrification is to meet the energy needs of a community while reducing carbon emissions and the risk of stranded gas assets. Practically, targeted electrification programs involve converting key energy uses such as space heating, water heating and cooking from gas to electric alternatives.

A recent study[15] in California found that targeted electrification was cheaper than gas pipeline replacement from a "total cost" perspective for all 11 San Francisco Bay Area gas pipeline replacement projects examined.[16] The study found the net benefits of targeted electrification and gas decommissioning "far exceed the costs."[17] Both electric and gas ratepayers saw benefits that far outweighed the respective costs incurred,[18] with electric ratepayers benefitting from the increase in electric loads driving down costs[19] and gas ratepayers benefitting from the avoided gas pipeline replacement costs.[20]

The study also found that targeted electrification was most cost-effective in less dense communities because the amount of dollars invested per mile of pipeline per customer (and thus the avoided pipeline replacement cost) is higher when there are fewer users in a

---

electrification#:~:text=The%20No%2DRegrets%20Option%3A%20Targeted,effective%20than%20replacing%20the%20pipeline.

[15] Aryeh Gold-Parker, et. al., *Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California*, Energy and Environmental Economics, Inc., Ava Community Energy, Gridworks Organization at 57 (December 2023) https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf.

[16] *Id.* at 26 (explaining that 'Total Cost Perspective' is assessed using the Total Resource Cost test which measures all benefits and costs to utility ratepayers, including participant and nonparticipant benefits and costs).

[17] *Id.* at 11.

[18] *Id.*

[19] *Id.*

[20] *Id.*

given area.[21] Given that Avista's Oregon service territory is considerably less densely populated—in terms of customers per mile—than the study area in the San Francisco Bay Area, targeted electrification as an NPA could be even more cost-effective for Avista.

Q. Are there examples of other utilities analyzing or implementing NPAs?

A. Yes, there are several examples from across the United States of utilities analyzing and implementing NPAs. For example, in 2023, the Public Service Company of Colorado (PSCo[22]) proposed to NPAs to capacity expansion for the Pearl Street Mall in downtown Boulder, Colorado. This proposal came as part of PSCo's 'Initial 2023-2028 Gas Infrastructure Plan.'[23] The Company analyzed targeted electrification of the mall as an NPA to replacing segments of pipe facing capacity constraints.[24] The Company estimated it would cost $6.7 million to meet increased demand with pipeline investments.[25] PSCo evaluated the NPA costs, emissions reductions, electric system impacts, and other factors in a benefit-cost analysis. The Company determined the NPA program cost to be $3.2 million, $3.5 million less than the cost of replacing the gas pipeline.[26] The NPA project also resulted in greater net benefits than the traditional infrastructure solution, according to the Company's benefit-cost analysis, and thus PSCo proposed to implement the project.[27]

Additionally, New York State Electric & Gas (NYSEG) previously faced reliability concerns in its service territory in and around Lansing, NY during the coldest days of the year. These reliability challenges led to the utility issuing a moratorium on new or expanded

[21] *Id.* at 57.
[22] PSCo is now known as Xcel Energy.
[23] Environmental Intervenors/205, Moore/Page 60, 76
[24] *Id.* at Moore/Page 57–63.
[25] *Id.* at Moore/Page 45, 76.
[26] *Id.* at Moore/Page 76.
[27] *Id.*

gas service in the area beginning in 2015.[28] Following this moratorium on expanding gas infrastructure, the New York Public Service Commission directed NYSEG to pursue non-pipeline alternative resources and approved an NPA portfolio in 2021 that contained a diverse set of resources including heat pumps, energy efficiency, heat recovery, demand response, electrification, and customer education and outreach.[29] Meanwhile, gas utility National Grid issued a RFP in 2021 for demand-side NPAs, such as energy efficiency, weatherization, and electrification, to help address winter capacity constraints.[30]

Q. Are there examples of other utilities pursuing targeted electrification and/or gas decommissioning as an NPA?

A. Yes, in New York, Central Hudson Gas & Electric Corporation, beginning in 2019, issued an RFP for NPAs to avoid the costly replacement of leak-prone pipes and instead enable pipeline retirements.[31] The Company has identified more than 60 project locations where it would be "potentially feasible and cost-effective to permanently retire or avoid sections of gas pipeline" through electrification of its customers' heating and appliances.[32]

---

[28] Environmental Intervenors/206, Moore/Page 7–9.
[29] *Id.* at Moore/Page 1–6.
[30] National Grid, *Request for Proposal Demand-Side Non-Pipeline Alternatives (NPA) for North Queens Gas System Capacity Constraints* (Dec. 13, 2021) at 4, 8, available at: https://www.nationalgridus.com/media/pdfs/bus-partners/non-pipeline-alternatives/dny-rfp-sow-north-queens.pdf.
[31] Environmental Intervenors/207, Moore/Page 4–6
[32] *Id.* at Moore/Page 5 (The first three cases were submitted in 2019 Implementation Plan. In 2020, the Company broadened its scope for potential projects and identified 37 additional cases as potential TMA candidates. Five of these new cases were identified as "high priority" and included in Central Hudson's "2020 Implementation Plan," filed in June 2020. On September 15, 2021, the Company filed its "2021 Implementation Plan Update." Thirteen additional NPA project opportunities were included in this update; seven cases from 2020 which did not proceed with NPA conversions at that time, and six new cases being initially pursued in 2021. On October 24th, 2022, the Company filed its "2022 Implementation Plan Update." Six additional NPA project opportunities were included in the update; five cases from the 37 potential projects identified in 2020, and one new case identified in 2022. On November 1st, 2023 the Company

Additionally, in January 2025, the Colorado PUC ordered gas utility, Black Hills Energy (Black Hills), to offer electrification rebates to gas customers as a way to comply with the State's Clean Heat law in Decision No. C25-0091, Proceeding No. 23A-0633G.[33] Enacted in 2021, Colorado's Clean Heat law requires gas utilities to submit plans that reduce emissions to specific levels.[34] At issue in the recent proceeding was Black Hills Energy's Clean Heat Plan Settlement Agreement and the adequacy of its proposals and budget surrounding targeted electrification—called 'beneficial electrification' under Colorado's statute.[35] Under the proposed agreement Black Hills agreed to allocate $100,000 to an electrification pilot in Rocky Ford, Colorado,[36] but strongly opposed the inclusion of any beneficial electrification in its Clean Heat Plan, arguing that requiring gas-only utilities to support electrification amounted to a violation of the takings clause and results in unjust cross-subsidization.[37]

The Colorado Commission rejected Black Hills' stance, finding that the Clean Heat Statute made no distinction between gas-only and dual-fuel utilities as to which resource are

filed its "2023 Implementation Plan Update."9 Four additional NPA project opportunities were included in the update, all being new cases identified in 2023. On September 13, 2024 the Company filed its "2024 Implementation Plan Update."10 Five additional LPP NPA project opportunities were included in the update, two being new cases identified in 2024. Five TSR NPA opportunities we included in the update, all cases identified from the Transmission Service Relocation Program).

[33] Environmental Intervenors/208, Moore/Page 24

[34] *Id.* at Moore/Page 2.

[35] CRS § 40-1-102(1.2)(a) ("Beneficial electrification" means converting the energy source of a customer's end use from a nonelectric fuel source to a high-efficiency electric source, or avoiding the use of nonelectric fuel sources in new construction or industrial applications, if the result of the conversion or avoidance is to: (I) Reduce net greenhouse gas emissions over the lifetime of the conversion or avoidance; and (II) Reduce societal costs or provide for more efficient utilization of grid resources").

[36] Environmental Intervenors/208, Moore/Page 8.

[37] *Id.* at Moore/Page 18.

available.[38] The Commission explained that requiring the utility to offer rebates for electrification was *not* the same as forcing the Company electrify its customers.[39] The Commission approved a Settlement Agreement budget of $18.37 million for 2025 through 2027, with the vast majority of funds dedicated to building electrification and energy efficiency.[40] This is one of the first instances in the nation where a gas-only utility will be required to support electrification of its customers, such as replacing gas furnaces and water heaters with efficient electric heat pumps.[41]

Finally, in Washington State as a result of settlement in GRC UE 220066, Puget Sound Electric (PSE), Washington's largest investor-owned utility, agreed to update its targeted electrification study, develop a targeted electrification pilot that deployed heat pumps, and incorporate a targeted electrification strategy based on the study and pilot findings into its next gas IRP and Biennial Conservation Plan.[42] The parties' rate case Settlement, approved by the Washington Utilities and Transportation Commission in Final Order No. 24/10, committed PSE to up to $15 million in company funds for targeted electrification activities.[43]

PSE's Targeted Electrification Pilot, launched in June 2023 was designed to support and increase residential electrification by installing heat pumps in low-income customers homes, providing home electrification assessments, offering fuel-switching heat pump

---

[38] *Id.* at Moore/Page 19.
[39] *Id.*
[40] *Id.* at Moore/ Page 4, 21
[41] SWEEP, *Colorado PUC approves Black Hills Clean Heat Plan, mandates statewide beneficial electrification* (Jan. 22, 2025) available at: https://www.swenergy.org/colorado-puc-approves-black-hills-clean-heat-plan/.
[42] Environmental Intervenors/209, Moore/Page 18–19.
[43] Environmental Intervenors/210, Moore/Page 37.

rebates, pursuing multi-family residential building electrification projects, and installing heat pumps in small businesses, among other efforts.[44] PSE planned for a Phase 2 of the Targeted Electrification Pilot to that would include expanded heat pump incentives, low-income and equity-based pilot programs for underserved communities, and pilot programs converting current natural gas customers to all-electric energy sources.[45]

The results from PSE's Target Electrification Pilot demonstrate strong customer interest in shifting away from gas and toward electrification, with over 1,700 residential ratepayers opting to replace their gas furnaces with electric heat pumps.[46] Additionally, replacing gas furnaces with electric heat pumps reduced customers' overall energy use and saved customers $75 per year on average in utility bills.[47] The pilot program reduced natural gas by 64% among the customers involved in the program and reduced overall energy consumption by 30% on average.[48] Customers that replaced their furnaces with heat pumps on average saw a 3% decrease in their annual cost for home energy.[49]

Furthermore, PSE found that by electrifying home heating it was able to reduce greenhouse gas emissions. The Company's results revealed that program participants reduced their carbon dioxide emissions by 19.7% simply by switching their home heating away from gas to electric heat pumps.[50] Heat pumps can reach 300% to 400% efficiency or higher, meaning they're putting out three to four times as much energy in the form of heat as they're

[44] Environmental Intervenors/211, Moore/Page 8.
[45] *Id.* at Moore/Page 19
[46] Puget Sound Energy, *Targeted Electrification Pilot Final Presentation* (Dec. 4, 2024) available at: https://www.youtube.com/watch?v=i7xW9GxVMf8.
[47] *Id.*
[48] *Id.*
[49] *Id.*
[50] *Id.*

using in electricity.[51] They are far more efficient than gas furnaces and, given Washington's commitment to relying on 100% carbon free electricity by 2045, will eventually become a zero-carbon emission technology.[52]

Q. What are thermal energy networks?

A. A thermal energy network (TEN), is a connected system of pipes linking multiple buildings to a shared common thermal energy source such as geothermal heat, surface water, and waste heat.[53] The system of water-filled pipes sharing thermal energy connects to ground-source electric heat pumps in each building to provide space heating, cooling, and hot water to the connected buildings.[54] TENs produce no direct carbon emissions.[55] TENs have been implemented successfully on college campuses and housing developments across the country.[56] Privately owned and operated thermal energy network technology has been in use for years and has seen successful implementation on campuses like Colorado Mesa University, which has a networked geothermal system that operates at a rate three times more efficient than conventional heating.[57] Similarly, housing developments with TENs, like

---

[51] *Id.*
[52] *Id.*
[53] NYSERDA, *Thermal Energy Networks* New York State (last visited: Feb. 28, 2025) available at: https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Communities/High-Impact-Actions/Toolkits/Thermal-Energy-Networks.
[54] *Id.*
[55] Elisa Wood, *After We Ditch the Gas Pipes, What Then?* Energy Changemakers (Jan. 8, 2024) available at: https://energychangemakers.com/non-pipeline-alternatives-ders/#:~:text=A%20range%20of%20clean%20energy,pursue%20a%20mix%20of%20solutions.
[56] Kristin George Bagdanov, Amy Rider, Claire Halbrook, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition & Gridworks at 13 (Nov. 2023), https:// buildingdecarb.org/wp-content/uploads/BDC_ Neighborhood-Scale-Report.pdf.
[57] Xcel Energy, *Evaluating a Community Ground Source Heat Pump System at Colorado Mesa University*, Case study (2022).

Whisper Valley in Austin, Texas, have garnered significant national attention and praise and are spreading throughout the country.[58]

When owned by a utility, thermal energy networks allow the utility to retain customers on its system and meet their heating needs with thermal energy instead of gas. Utility-owned thermal energy networks also allow utilities to leverage their existing financing, customers, workforce, and rights-of-way.[59] TENs therefore, may serve as an important avenue for gas utilities to continue providing space and water heating services to existing customers with carbon-free sources, a pathway that will be key to explore for utilities seeking to maintain a healthy business in response to Oregon's climate laws.

Q. How do thermal energy networks serve as a non-pipeline alternative to natural gas pipeline replacement and expansion?

A. Thermal energy networks can serve as NPAs to gas infrastructure replacement or expansion because, once a collection of buildings is connected to the shared thermal system, they no longer need gas delivery.[60] As a result, those previously connected buildings can be pruned from the system.

---

[58] Saul Elebin, *A clean-energy Texas suburb goes national*, The Hill (Mar. 6, 2023) available at: https://thehill.com/policy/equilibrium-sustainability/3883082-a-clean-energy-texas-suburb-goes-national/.
[59] Kristin George Bagdanov, Amy Rider, Claire Halbrook, *Neighborhood Scale: The Future of Building Decarbonization*, Building Decarbonization Coalition & Gridworks at 13–14 (Nov. 2023), https:// buildingdecarb.org/wp-content/uploads/BDC_ Neighborhood-Scale-Report.pdf.
[60] Magdalen Sullivan & Erin Murphy, *Non-Pipeline Alternatives: Meeting Energy Demand Responsibly*, Environmental Defense Fund at 87 (Feb. 2024) available at: https://www.edf.org/sites/default/files/2024-02/Non-Pipeline-Alternatives-Report_EDF_Feb2024.pdf.

Q. Are thermal energy networks being successfully piloted by utilities around the country?

A. Yes. Regulators and gas utilities have begun to explore the utility-owned TEN model in hopes of realizing the advantages discussed above. Eight states have passed legislation supporting utility construction of thermal energy networks,[61] with more presently considering similar policies. Utilities have proposed at least 27 TENs pilot projects nationwide.[62]

Massachusetts has led the charge on this front, with state regulators at the Department of Public Utilities issuing December 2023 Regulatory Framework Order DPU 20-80-B, that identified networked geothermal (i.e., thermal energy networks) as the highest priority non-pipeline alternative for slowing the expansion of utility gas infrastructure.[63] Framingham, Massachusetts is home to the country's first utility-scale thermal energy network which went online in June 2024 and has expanded service to 135 residential and commercial customers.[64]The utility, Eversource Energy, estimates pilot customers' winter heating bills will be reduced by as much as 75%.[65]

[61] Sarah Shemkus, *Connecticut considers incentives to spur networked geothermal projects*, Canary Media (Feb. 20, 2025) available at: https://www.canarymedia.com/articles/policy-regulation/connecticut-considers-incentives-to-spur-networked-geothermal-projects.
[62] *Id.*
[63] Environmental Intervenors/212, Moore/Page 5 (Notably, the Order also identified "geographically targeted electrification" as the second highest priority NPA to gas expansion.)
[64] Sarah Shemkus, *Connecticut considers incentives to spur networked geothermal projects*, Canary Media (Feb. 20, 2025) available at: https://www.canarymedia.com/articles/policy-regulation/connecticut-considers-incentives-to-spur-networked-geothermal-projects.
[65] *Id*.

Q. Is the Oregon legislature exploring thermal energy networks for natural gas utilities?

A. Yes. On February 27, 2024, Oregon legislators introduced SB 1143, a bill titled "Relating to thermal energy networks; prescribing an effective date."[66] The proposed bill would "direct the Public Utility Commission to establish a pilot program that allows each natural gas company to develop a utility-scale thermal energy network pilot project to provide heating and cooling services to customers."[67] The purpose of the bill and the pilot programs established as a result, is to "[d]emonstrate the use and effectiveness of thermal energy networks to provide heating and cooling services while reducing or eliminating greenhouse gas emissions or improving energy efficiency."[68] If enacted, the law would allow the natural gas utilities to gain experience with the planning and implementation of TENs, as well as the PUC experience on how to integrate the networks into their regulatory processes.[69]

If enacted, the Commission would direct the gas utilities to file, within 24 months, a proposal for a TEN pilot and a plan for measuring the effectiveness of the pilot using specific metrics.[70] The bill includes a provision allowing the gas companies to recover costs from ratepayers for prudent expenses incurred related to the development and operation of a thermal energy pilot project under the law.[71]

---

[66] Environmental Intervenors/213, Moore/Page 1.
[67] *Id.* at Moore/Page 1, Section 1(2).
[68] *Id.* at Moore/Page 1, Section 1(2)(a).
[69] *Id.* at Moore/Page 1, Section 1(2)(b), (c).
[70] *Id.* at Moore/ Page 1–2, Section 1(3).
[71] *Id.* at Moore/Page 2, Section 1(5).

Q. What actions do you recommend Avista take with respect to thermal energy networks?

A. Whether or not lawmakers enact SB 1143, Avista should propose a thermal energy network pilot project. Given the decarbonization requirements Avista faces under Oregon's Climate Protection Program, the Company needs to plan and explore a way to meet customer demand for heating that does not rely on natural gas. TENs are one such option.

Therefore, consistent with the requirements of SB 1143, the Commission should require Avista to file within 24 months a proposal for its TEN pilot and a plan for measuring the effectiveness of that pilot.

Q. Are other state utility commissions addressing the use of NPAs to replace traditional gas infrastructure capital investments?

A. Yes. For example, the Massachusetts Department of Public Utilities conducted a Future of Gas investigation and identified NPA analysis as a requirement for all capital investments in its distribution system going forward. The Department of Public Utilities found that "going forward, [utilities] will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains."[72] Specifically, the Department found that NPAs should be examined as a method for replacing sub-optimal pipes, encouraging NPAs as alternatives to replacing aged pipes and/or installing new mains.[73]

Several other states have required NPA analysis for certain capital projects. In Colorado, gas utilities are required to conduct NPA analysis for all capacity expansion and

---

[72] Environmental Intervenors/212, Moore/Page 18.
[73] *Id.* at Moore/Page 100.

new business projects over $3 million.[74] Rhode Island has set a similar NPA cost threshold at $500,000.[75] Meanwhile, New York does not rely on a specific cost threshold and rather created a separate small and large project threshold for each gas distribution company.[76]

In 2022, the California Public Utilities Commission (CPUC) adopted a framework to comprehensively review utility natural gas infrastructure investments in order to help the state transition away from natural gas-fueled technologies and avoid stranded assets in the gas system. The decision targets large-scale natural gas project investments requiring utilities to seek CPUC approval of natural gas infrastructure projects of $75 million or more or those with significant air quality impacts.[77] Among other things, utility applications must demonstrate the need for the project and provide information on projected financial impacts on customers and a summary of engagement with local communities likely to be impacted.[78]

To advance transparency in long-term gas system planning, the CPUC decision directs utilities to file annual reports detailing planned long-term infrastructure projects exceeding $50 million over the next 10 years.[79] The reports must include a detailed description of the project, projected capital expenditures, cost drivers, and environmental implications.[80] For projects planned to start within five years, utilities must provide

[74] Sarah Steinberg, *What Colorado's First-Ever Gas Infrastructure Plan Teaches Us About Gas Planning*, Advanced Energy United (Mar. 25, 2024) available at: https://blog.advancedenergyunited.org/what-colorados-first-ever-gas-infrastructure-plan-teaches-us-about-gas-planning.
[75] Ron Nelson, et. al., *Part 1 | Non-Pipeline Alternatives to Natural Gas Utility Infrastructure, An Examination of Existing Regulatory Approache*s, A Strategen & Lawrence Berkeley National Laboratory at 10 (Nov. 2023) available at: https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_1_final.pdf.
[76] *Id.*
[77] Environmental Intervenors/214, Moore/Page 24.
[78] *Id.* at Moore/Page 75.
[79] *Id.* at Moore/Page 97.
[80] *Id.* at Moore/Page 82.

information on non-pipeline alternatives, projected operational costs, and reliability benefits from the project.[81] This will facilitate close CPUC review of such projects, and improves transparency in utility gas system planning.[82]

Q. Are other state utility commissions addressing the pace and scope of gas utility pipeline replacement efforts?

A. Yes. There are examples from at least Illinois, California, and Washington D.C. of utility commissions addressing gas utilities' plans to replace pipelines. In November 2023, the Illinois Commerce Commission (ICC) disallowed $265 million for the 2024 gas pipeline replacement program—otherwise known as the Safety Modernization Program (SMP)—for Peoples Gas Light and Coke Company and North Shore Gas Company (PGL).[83] The ICC's order required PGL to pause implementation of the program, opened a new investigation into the program's effectiveness, and initiated a statewide Future of Gas proceeding.[84] In its discussion on why the ICC found that the PGL provided inadequate record justification for its proposed spending level, the ICC noted several times that the Company did not examine alternatives to the gas utility's current SMP approach.[85] The ICC recently issued an order disbanding PGL's chronically over-budget Safety Modernization Program.[86] The ICC set out

[81] *Id.* at Moore/Page 83.
[82] *Id.* at Moore/Page 80, 85–86.
[83] Illinois Commerce Commission, Dockets No. 23-0068, 23-0069, North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed general increase in rates and revision to service classifications, riders, and terms and conditions of service at 29 (tariff filed January 6, 2023). Order, November 16, 2023 available at: https://www.icc.illinois.gov/docket/P2023-0068/documents/344306/files/601245.pdf
[84] *Id.* at 25–26.
[85] *Id.* at 25–30.
[86] Illinois Commerce Commission, *ICC replaces controversial Peoples Gas System Modernization Program with new directive to retire high-risk, leak-prone pipes,* (Feb. 20, 2025) available at: https://ltgov.illinois.gov/news/press-release.30954.html.

guidelines for PGL to establish a new program that eliminated unreasonable and unjustifiable costs to customers from unnecessary pipe replacement, and instead, focuses on identifying and retiring or replacing the highest risk-prone pipes.[87]

In June 2024, the District of Columbia Public Service Commission rejected Washington Gas Light Company's $672 million 'ProjectPipes3 Program' investments and ordered the Company to file a new plan.[88] The Commission found that the Company's pipeline replacement program needed to be revised to better align with federal and District climate initiatives and "balance the need to replace leak-prone, highest-risk pipe segments… while minimizing the stranded assets as the District continues to undergo the energy transition."[89]

In California, the CPUC issued a decision in December 2023 adopting review criteria for repair or replacement of gas transmission pipeline infrastructure.[90] The decision also included criteria to determine when declining demand can enable transmission pipelines

---

[87] *Id.*
[88] DC Public Service Commission Says No to $672 Million Gas Pipe Replacement Program, Sierra Club Press Release, June 13, 2024. https://www.sierraclub.org/dc/blog/2024/06/dc-public-service-commission-says-no-672-million-gas-pipe-replacement-program.
[89] Public Service Commission of the District of Columbia, Formal Case No. 1154, In the Matter of Washington Gas Light Company's Application for Approval of ProjectPipes2 Plan, and Formal Case No. 1175, In the Matter of Washington Gas Light Company's Application for Approval of ProjectPipes3 Plan, and Foma Case No. 1179, In the Matter of the Investigation into Washington Gas Light Company's Strategically Targeted Pipe Replacement Plan. Order No. 22003, page 17 (June 12, 2024) available at https://edocket.dcpsc.org/apis/api/Filing/download?attachId=206883&guidFileName=8abcb06b-def7-4421-b43b-39393ead96d7.pdf,
[90] California Public Utilities Commission, Rulemaking 20-01-007, 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. Decision No. 23-12-003, Decision on Phase 2 Issues Regarding Transmission Pipelines and Storage, at 2 (Dec. 12, 2023) available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K892/521892086.PDF

to be derated or decommissioned without negatively affecting reliability.[91] Additionally, Commission Staff have issued a "Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals" as part of the CPUC's Long-Term Gas Planning Rulemaking.[92] Under this framework, CPUC Staff recommended that utilities prioritize distribution pipelines for decommissioning by focusing on areas with the highest expected long-term benefits first.[93] According to Staff, the following criteria are associated with higher expected benefits from decommissioning and should be prioritized: 1) higher pipeline risk; 2) higher existing environmental health burden, including as reflected in the CalEnviroScreen scores, which underlie Disadvantaged Community designation; 3) higher gas infrastructure cost savings; 4) lower energy and community affordability, as reflected in measures like rent burden; and 5) higher gas demand.[94]

CPUC Staff recommended that these criteria be used to classify all census tracts with distribution infrastructure into five tranches, ranging from those to be decommissioned early to hard-to-electrify areas, using the approach detailed in this proposal.[95] CPUC Staff recommended that non-emergency repair or replacement of distribution infrastructure be minimized.[96] To implement these priorities, this proposal also suggests that utility non-emergency proposals to repair or replace gas infrastructure include cost estimates, timelines,

---

[91] *Id.* at 10–14.
[92] California Public Utilities Commission, Rulemaking 20-01-007, 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, Staff Proposal on Gas Distribution Infrastructure Decommission Framework in Support of Climate Goals (Dec. 21, 2022) available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/framework-staff-proposal.pdf
[93] *Id*. at 3
[94] *Id.*
[95] *Id* at 3–4.
[96] *Id.* at 4.

impact on estimated risk, the location of the proposed work (which enables identification of the tranche in which it is located), and comparison with non-pipeline alternatives.[97]

CPUC Staff's framework recognizes that despite the State's overall climate goals and movement towards shrinking the gas industry, there are legitimate safety and reliability reasons why gas distribution pipes will need to be replaced. The framework ensures that the pipes being replaced are those that are highest-risk and in areas where continued gas service may be necessary and useful in the future.

Oregon's PUC would be wise to adopt a similar framework governing the pipe replacement program of Avista and other gas utilities to protect ratepayers from rising costs and ensure that the utility is only replacing the highest priority pipe segments and is adequately evaluating NPAs. Currently that information is left entirely in the hands of the utilities and there is little way for the public to ensure that such investments are made with these concerns in mind until after the money is already spent and the utility is seeking recovery from the Commission.

B. *Non-Pipeline Alternatives in Oregon*

Q. What Oregon Administrative Rules address non-pipeline alternatives for gas utilities?

A. Under Oregon Administrative Rules (OAR) 860-024-0400, Oregon utilities are required to file an Integrated Resource Plan (IRP) every two years. The IRP process involves evaluating alternative methods to meet future energy demands. [98] This process must include the evaluation of a variety of supply- and demand-side options, including non-pipeline

[97] *Id.*
[98] OAR 860-024-0400(2).

alternatives such as energy efficiency measures, renewable energy, and distributed energy resources. Additionally, utilities are encouraged to consider NPAs to help ensure resource adequacy while reducing costs and potential environmental impacts. This might involve solutions like renewable energy or demand response programs that substitute the need for gas infrastructure investments.

Q. What requirements does the Oregon Public Utility Commission impose on utilities regarding non-pipeline alternatives?

A. In 2021, the PUC directed its Staff to conduct a fact-finding proceeding to lay a foundation for understanding the implications, especially for ratepayers, of decarbonization policy in the natural gas sector.[99] Staff's Report laid the groundwork for the Commission's consideration and implementation of non-pipeline alternatives requirements, suggesting that the gas utilities incorporate demand side solutions and NPAs as elements of their IRPs.[100]

The PUC adopted many of Staff's suggestions in the Avista 2023 General Rate Case Settlement. As a condition of the parties' settlement agreement in Avista's previous rate case, UG 461, the Company agreed to implement an NPA framework in Oregon.[101] The agreed upon settlement framework includes requirements that Avista will perform NPA analyses for supply-side resources and distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects.[102] Avista agreed that if an NPA is not selected for projects that meet this criteria, the

---

[99] Oregon Public Utility Commission, Docket No. UM 2178, Natural Gas Fact Finding Per EO 20-04 PUC Year One Work Plan, (June 8, 2021) Available at: https://edocs.puc.state.or.us/efdocs/HAA/um2178haa11959.pdf
[100] *Id.* at 30.
[101] Oregon Public Utility Commission Docket No. UG 461, Order No. 23-384 at 11 (Oct. 26, 2023) available at: https://apps.puc.state.or.us/orders/2023ords/23-384.pdf.
[102] *Id.*

Company will include the NPA analysis as part of the justification when it seeks recovery of the resource addition or distribution system reinforcement or expansion in a rate case.[103] Furthermore, Avista agreed that for resources or projects that meet the above criteria, the Company will include electrification as an NPA, and that non-energy impacts will be included as part of the NPA evaluation.[104]

The Commission revisited the Settlement requirements shortly thereafter in its 2023 Avista IRP decision in Docket No. LC 81, Order. No. 24-156, where, the PUC adopted requirements for Avista's consideration of NPA analyses in future IRPs.[105] The Commission's Order explains that by requiring Avista to consider NPAs in the planning process it hopes to avoid the need to resort to costly capital upgrades to a system where it is avoidable, thereby saving such unnecessary costs from falling on the backs of ratepayers.[106] In its Order, the Commission adopted Staff's framework for addressing Avista's "DSP practices and IRP processes," which includes the need to consider NPAs during the planning stage.[107]

C. *Applicability of Non-Pipeline Alternatives in this Rate Case*

Q. Has Avista performed non-pipeline alternatives analyses in response to the Commission's regulatory directives?

A. Up to now, Avista has performed very few NPA analyses. Despite the agreements in UG 461's settlement, the Company has not included projects that meet the NPA criteria, namely the cost threshold, into its planning documents. Avista's 2023 IRP for example, did

[103] *Id.*
[104] *Id.*
[105] Oregon Public Utility Commission Docket No. LC 81, Order No. 24-156 at 11–12 (May, 31, 2024) available at: https://apps.puc.state.or.us/orders/2024ords/24-156.pdf.
[106] *Id.* at 12.
[107] *Id.* at 11, Attachment C.

not provide sufficient analysis of least-cost, least-risk compliance pathways to satisfy Oregon's Climate Protection Program's emissions mandates.[108]

Avista's reluctance to analyze NPAs in its planning process stands in contrast to utilities elsewhere in the country who have engaged more robustly with alternatives upon request from their commissions. PSCo in Colorado for example, in May 2023 submitted its initial NPA process and project evaluations to Colorado Public Utilities Commission as part of its required gas plan filing. In its first filing PSCo evaluated five different eligible capital projects for NPAs, concluding that two of the five were eligible for implementation.[109] PSCo's more robust NPA analyses is the direct result of Colorado's regulatory requirement that all utilities with more than 500,000 customers in the state must analyze *at least* five NPAs using at least one "clean heat resource."[110]

Q. What rate base additions does Avista propose and how are they categorized?

A. In this rate case, Avista proposes $59.8 million in additions to its rate base,[111] with $46.4 million in natural gas distribution expenditures.[112] The Company divides capital investments into six categories:

1) **Customer Requested:** Includes new service connections, line extensions, and other investments associated with customer growth.[113] For January 1, 2024

[108] Oregon Public Utility Commission, Docket No. LC 81, Avista's 2023 Integrated Resource Plan, Order No. 24-156 at 4 (May, 31, 2024) available at: https://apps.puc.state.or.us/orders/2024ords/24-156.pdf.
[109] Ron Nelson, et. al., *Non-Pipeline Alternatives: A Regulatory Framework and Case Study of Colorado,* Strategen & Lawrence Berkeley National Laboratory at 5, (October 2023) available at: https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_2_final.pdf
[110] 4 CCR § 723-4-4553.
[111] Avista/600, Benjamin/Page 7–8.
[112] *Id.* at 8.
[113] Avista/200, Christie/Page 16.

through August 31, 2025, Avista seeks recovery for $10 million in Customer Requested expenditures.[114]

2) **Mandatory and Compliance:** Includes costs related to compliance with local, state and federal regulations.[115] For January 1, 2024 through August 31, 2025, Avista seeks recovery for $25.2 million in Mandatory and Compliance investments.[116] This includes the $14.2 million allocated for Aldyl-A Pipeline Replacement.[117]

3) **Failed Plant and Operations:** Includes unplanned work associated with asset replacements and repairs related to shallow pipes, customer requests, and leaks, among other work.[118] For January 1, 2024 through August 31, 2025, Avista seeks recovery for $6.1 million in Failed Plant and Operations spending.[119]

4) **Asset Condition:** Includes the replacement of assets at the end of their useful lives, such as pipelines, general plant investments, and enterprise technology.[120] Avista classifies some capacity upgrade and expansion costs in this category.[121] For January 1, 2024 through August 31, 2025, Avista seeks recovery for $5.4 million in Asset Condition expenditures.[122]

5) **Customer Service Quality and Reliability:** Includes those investments required to maintain or improve the quality of services provided to customers, to

---

[114] Avista/600, Benjamin/Page 7–8.
[115] *Id.* at 16–17.
[116] *Id.* at 7–8.
[117] *Id.* at 18.
[118] *Id.* at 17.
[119] *Id.* at 7–8.
[120] *Id.* at 17.
[121] *Id.*
[122] *Id.* at 7–8.

introduce new types of services and options based on an analysis of customer needs and expectations, to ensure customer service quality requirements are achieved, and to meet electric system reliability objectives.[123] For January 1, 2024 through August 31, 2025, Avista seeks recovery for $2.6 million in Customer Service Quality and Reliability costs.[124]

6) **Performance and Capacity:** Includes asset performance improvements and capacity expansion to meet winter peak load needs.[125] For January 1, 2024 through August 31, 2025, Avista seeks recovery for $10.6 million in Performance and Capacity spending.[126]

Q. Which of Avista's above rate base capital investment categories should be subject to NPA requirements?

A. As a condition of recovery of portions of expenses in the ""Customer Requested," "Mandatory Compliance," "Asset Condition," and "Performance and Capacity" rate base addition categories the Commission should require Avista to conduct NPA analyses moving forward for 1) projects in the Aldyl-A pipeline replacement program 2) projects to replace pipes at the end of their useful life 3) capacity expansion projects.

As mentioned above, Avista seeks recovery for $10 million in Customer Requested expenditures.[127] Avista's investments associated with customer growth should be targets of future NPA analysis, because s such expenditures and upgrades to Avista's system run the risk of becoming stranded assets. Avista's testimony reveals that of the $10,009,537 spent in

[123] *Id.*
[124] *Id.*
[125] *Id.* at 16–17.
[126] *Id.* at 7–8.
[127] Avista/600, Benjamin/Page 7–8.

this category, at least $2,872,109[128] is attributable to investments associated with customer growth, such as the cost of new gas regulators and the cost of gas meters and metering equipment to serve load.[129] While Avista may have an obligation to serve new customers who request service, the Commission should take steps to ensure that the Company is not spending excessively on investments that run the risk of becoming stranded assets. Requiring NPA analysis by the Company prior to such investments moving forward helps safeguard the prudency of expanding the system given the regulatory landscape of the CPP and projected future declining demand.

Similarly, recovery of Avista's expenditures in Mandatory and Compliance investments should be subject to requirements of NPA analysis moving forward. This is Avista's largest spending category. The Company seeks recovery for $25.2 million in investment,[130] of which $14.2 million is for Aldyl-A Pipeline Replacement.[131] Discussed in more detail below, given the slowing demand for gas and the substantial and increasing costs of the Aldyl-A Pipeline Replacement program,[132] it is imperative that the Company adequately assess these investments via NPAs prior to further spending.

The need for NPA analysis prior to investing in new pipes extends beyond the Aldyl-A Pipeline Replacement Program. Under the Asset Condition category, Avista seeks recovery for $5.4 million in Asset Condition expenditures,[133] which includes not only the replacement of pipelines at the end of their useful lives but also capacity upgrades and expansions.[134] As

[128] Avista/601, Benjamin/Page 3
[129] *Id.*
[130] Avista/600, Benjamin/Page 7–8.
[131] *Id.* at 18.
[132] Avista/700, Forsyth/Page 2–4.
[133] Avista/600, Benjamin/Page 7–8.
[134] *Id.* at 17.

noted above, replacing pipelines and expanding system capacity creates a substantial stranded asset risk, given the more than 50yeare book-life of gas pipelines [135] The Commission should therefore require Avista analyze NPAs to all proposed investments in new or replacement distribution pipes and expanded capacity.

Finally, the Commission should condition approval of the $10.6 million in Performance and Capacity spending Avista seeks to recover on future analysis of NPAs to upgrades to its system.[136] Instead of spending millions on capacity expansion to meet winter peak load needs,[137] Avista should evaluate the potential for NPAs to reduce winter peak load needs.

Q. You identify the need for Avista to conduct analysis that looks at NPAs in lieu of its current Aldyl-A pipeline replacement program; can you describe the current pipeline replacement and repair plans?

A. Yes. Beginning in 2012 Avista established its Aldyl-A Pipe Replacement Program.[138] Originally designed to last 20 years, the project intends to replace select portions of DuPont Aldyl-A pipe found in the Company's natural gas distribution system in Oregon.[139] Recently, Avista has extended the duration of the Aldyl-A pipe replacement in Oregon from 20 to 25 years, with the project not slated to conclude until at least 2037.[140] In doing so, the Company concluded there was no appreciable increase to the risk of pipe failure from the extension.[141] The replacement effort focuses on reducing natural gas system risk, on a prioritized basis, by

[135] Environmental Intervenors/204, Moore/Page 1.
[136] Avista/600, Benjamin/Page 7–8; *see also* Avista/601, Benjamin/Page7–8.
[137] Avista/600, Benjamin/Page 16–17.
[138] *Id.* at 19.
[139] *Id.*
[140] *Id.*
[141] *Id.* at 20.

replacing priority Aldyl-A pipe throughout Avista's system.[142] As such, the continuation of the Aldyl-A Pipeline Replacement Program remains a substantial capital cost for which the company seeks recovery in this rate case.

Q. How much does Avista seek to recover for pipeline replacement in this proceeding?

A. Avista identifies $14.2 million in expenditures related to replacing Aldyl-A pipe from January 1, 2024 to August 31, 2025 for which it seeks recovery.[143] This amounts to 30.6% of the total $46.4 million natural gas distribution investment the Company is making during this period.[144] Further, the total amount customers will be required to pay back is considerably higher than $14.2 million. Over the book life of the investment, which can extend beyond fifty years,[145] Avista will recover not only the initial $14.2 million investment, but also a guaranteed rate of return on that investment, as well as taxes, interest, and other expenses. That means the final figure that customers are responsible for and pay via their monthly rates will be much higher than the already substantial up-front pipeline replacement cost.

Q. Are the Aldyl-A Pipeline Replacement Program's costs increasing?

A. Yes, Avista recognizes the program is already expensive, with costs continuing to rise year after year.[146] As Avista's testimony reveals, replacing these pipelines is costly and logistically challenging as the new pipe must be installed in fully developed and occupied areas that consist of numerous below ground facilities, paved streets, sidewalks, arterials,

---

[142] Avista/601, Benjamin/Page 6.
[143] *Id.*
[144] Avista/601, Benjamin/Page 1
[145] Environmental Intervenors/204, Moore/Page 1.
[146] Avista/602, Benjamin/Page157

landscaped residential neighborhoods, and hard-surfaced commercial developments.[147] Avista reported its experience with replacement construction costs rising in particular.[148]

As a result, the average per foot replacement costs for pipeline has as much as doubled in price between the first years of the program and today. Avista includes in its testimony figures from the Company's 'Study of Aldyl-A Pipe Leaks 2022 Update' which identifies that in 2021 the cost of main pipe replacement was as much as $155 per linear foot, whereas in 2012 the average costs ranged from $69 to $83 per foot.[149] However, Avista's testimony neglects to include the most updated figures from the Company's '2024 Natural Gas Safety Project Plan,' which found that by 2023 the price per foot had ballooned to as much as $265 per linear foot,[150] with even the average price of $188 per linear foot exceeding the max 2021 price Avista references in its testimony in this proceeding.[151]

While the Company spends considerable time and effort in its testimony analyzing the risks associated with delaying pipe replacement until 2037 in order to offset the rising costs over time, it does not address whether such rising prices and lowered demand warrant not replacing the pipes at all and instead, exploring non-pipeline alternatives such as targeted electrification. This points towards the necessity of requiring utilities to demonstrate NPA analysis as a prerequisite to cost recovery, since, absent such considerations, the utilities remain incentivized to invest in and replace infrastructure even if costly and not warranted by demand.

---

[147] *Id.*
[148] *Id.*
[149] *Id.*
[150] Avista Utilities, *Natural Gas Safety Project Plan – Oregon* at 26 (Sep. 24, 2024) available at: https://edocs.puc.state.or.us/efdocs/HAQ/um1898haq331590025.pdf.
[151] Avista/602, Benjamin/Page 157.

Q. Does Avista anticipate growth in customers or demand necessitating large scale investments in pipe replacements?

A. No, Avista's data reflects slowing customer growth, stagnating usage per customer, and only a limited increase in usage per customer, all of which are indicative of the slowing demand and declining customer interest for natural gas. These trends mean large scale investments in pipeline replacement and additional capacity and distribution expansion are not in the best interest of the customers. The slowdown of customer growth and demand in Avista's business is especially stark when compared to just two years ago when the Company filed its previous rate case in UG 461. As explained below, the drop-off in customer growth, use-per-customer, and overall customer usage underscore the reasons large-scale investment in pipe replacement and extension of the life of Avista's distribution system by decades may be imprudent.

Specifically, Avista's testimony includes updated Fall 2024 forecasts that show the number of new customers in the Oregon service territory from 2023–2026 is projected to increase 1.4%,[152] down from the 2.0% customer growth rate projected in Avista's previous rate case.[153] Additionally, the Company's projected use-per-customer (UPC) remains flat for the entire customer base (residential and commercial customers).[154] By contrast, in 2023, Avista projected increases in UPC for the Company's residential and commercial customers.[155]

[152] Avista/700, Forsyth/Page 3.
[153] Docket No. UG 461, Avista/800, Forsyth/Page 2.
[154] Avista/700, Forsyth/Page 3.
[155] Docket No. UG 461, Avista/800, Forsyth/Page 3.

In this proceeding, the combination of slow customer growth and flattening UPC growth results in a combined "customer usage" increase of 0.8% for both these schedules from the twelve-months which ended on December 31, 2023 base year until the twelve-months ended August 31, 2026 test year.[156] Only two years ago in UG 461, Avista projected a combined usage across both the Company's rate schedules of 4.8%.[157] This 4 percentage point decrease in customer usage is indicative of the larger challenges and trends facing the gas industry as customers demand for the product is waning and state climate policy further decreases the room for gas in Oregon's energy mix. The trends are further reflected in the Company's current customer forecasts which show "relatively slow" growth in customer numbers in its largest Oregon population centers: Medford, Roseburg, Klamath Falls, and LaGrande over the next five years.[158] Given that Avista's Oregon service territory is predominately rural, a decline in customers in Southern Oregon's cities and towns will make for a significant challenge to the Company's growth and financial standing in the coming years.

These updated projections add color to Avista's 2023 IRP findings which found that "the demand for natural gas decreases across all studied scenarios in this IRP" with the overall gas "demand projected decrease across these fourteen scenarios an average of 31% by 2045 as compared to 2025."[159] The 2023 IRP also shows the expected customer counts are lower than in the last 2021 IRP.[160] Moreover, Avista's previous IRP projected Oregon

[156] Avista/700, Forsyth/Page 3.
[157] Docket No. UG 461, Avista/800, Forsyth/Page 3.
[158] Avista/700, Forsyth/Page 4.
[159] Avista/401, Holland/Page 171.
[160] *Id.* at 29.

customer growth rates for 2021 and 2022 that were higher than those actually realized.[161] Therefore, the Company may be overestimating its already lower-than-average customer growth projects.

Q. What do you recommend to the Commission in order to support greater NPA efforts by Avista?

A. I recommend that the Commission adopt a requirement in this proceeding that, moving forward, Avista demonstrate that it has considered non-pipeline alternatives as a condition of recovering future investment in the Company's capacity and distribution systems. This includes future investments made under the Aldyl-A Replacement Program as well as investments in replacing pipes at the end of their useful life. The Commission should also remove the minimum investment threshold of $1 million for NPA analysis.

Additionally, the Commission should follow the example of the Washington Utilities and Transportation Commission (WUTC) and require a minimum number of NPA analyses. The WUTC required Avista to analyze at least two distinct NPAs, for distribution and capacity projects relating to customer growth over $500,000, in Avista's 2023 Washington consolidated rate case—UE-240006/UG-240007.[162] Requiring Avista to conduct a certain minimum number of NPA analyses in Oregon—even where projects fall below a cost threshold—will be valuable in spurring utility efforts in this area

Requiring a utility to demonstrate that it conducted an alternatives analysis fits neatly into the traditional planning process and it would not require alternatives to be selected or implemented in all scenarios. Not all areas needing pipe replacement will have a

[161] *Id.* at 56.
[162] Environmental Intervenors/215, Moore/Page 80, 225.

commercially feasible NPA available and pipeline replacement would therefore be appropriate.

Avista has resisted this approach, explaining in a Discovery Request response to CUB that it was not bound to consider NPAs for the Aldyl-A Pipe Replacement program under the Commission's Settlement Order No. 23-384 from the previous rate case UG 461, because its terms only apply to "supply-side resources and for distribution system reinforcements and expansion projects."[163] The Pipeline Replacement Program, Avista contends, is "first and foremost" a safety related program[164] and therefore no NPA is required under the Settlement. Avista's response misses the mark on multiple levels. First, "distribution system reinforcements"[165] as identified Order. No. 23-384 is broad enough to cover the replacement of Aldyl-A pipe replacement, because the Company is reinforcing the safety and reliability of the pipes in its distribution system. More important however, is that even if Avista is not obligated to consider NPAs under the previous settlement for the pipeline replacement program, it may still choose to do so and as explained above, considering the declining demand and regulatory emissions requirements facing the Company, it should be evaluating alternatives to pipe replacement where feasible.

The Commission and Avista must begin to shift how they think about investments in the gas system given the projected economic and consumer trends and Oregon's climate obligations. We can no longer continue with business as usual for pipeline expansion and replacement. The bare minimum utilities should be doing during planning and

[163] Environmental Intervenors/203, Moore/Page 1
[164] *Id.*
[165] Oregon Public Utility Commission, Docket No. UG 461 Order No. 23-384, Appendix B at 15 (Oct. 26, 2023) available at: https://apps.puc.state.or.us/orders/2023ords/23-384.pdf

implementation processes is assessing whether NPAs exist and are commercially viable. Thus, the Commission should condition, as an element of demonstrating an investments prudency necessary for cost recovery, that NPAs were fully examined by the utility prior to any expenditure on new pipes.

Q. Why is now the time for the Commission to require, and Avista to incorporate, an alternatives analysis framework for evaluating opportunities to implement NPAs?

A. Oregon is at the forefront of a global energy transition. The state has passed nationally leading climate policies including Oregon House Bill 2021 (HB 2021), requiring 100% clean energy from the electric utility sector, as well as implemented the Climate Protection Program (CPP) through the Department of Environmental Quality (DEQ), requiring a 90% reduction in emissions from fossil fuel usage by 2050, including those from Avista and other gas utilities. These actions, among many others demonstrate the explicit steps the State is taking to reshape energy market and reduce greenhouse gas emissions across the energy sector.

DEQ's CPP lays out a regulatory framework that reduces GHG emissions associated with natural gas by the three gas utilities. Emissions must decline by 50 percent between 2022 and 2035, and by 90 percent by 2050.[166] While the program includes some flexibilities such as Community Climate Investments, these rules represent a significant, rapid, and mandatory requirement in the reduction of the utilities' natural gas related emissions.

In the current energy environment where natural gas companies are subject to state and local climate policies and scrutiny from regulators and advocacy groups it is disappointing to see the lack of innovation in Avista's long-term vision. There is no

[166] OAR 340-273-0450(1)–(4)(a)(A); OAR 340-273-9000 Table 2.

discussion of any non-pipe alternatives as options for avoiding investments in Aldyl-A pipeline replacement that the Company should or could have evaluated for these significant expenditures. Given that Avista has extended the deadlines for completing the pipeline replacements to 2037 and notes the ever-increasing costs associated with such replacements it is important that the Company take steps to evaluate whether NPAs exist that could alleviate some of the needs to replace aging pipe, especially if Avista continues to seek recovery from ratepayers for such capital expenditures.

IV. Conclusion

Q. Will you please restate your recommendations to the Commission?

A. Yes, I recommend the following:

- Section III: Non-Pipeline Alternatives:
    - As a condition for capital investment recovery in this and future proceedings, the Commission should require Avista to, moving forward, analyze non-pipeline alternatives (NPAs) for investments in 1) replacing Aldyl-A pipes, 2) replacing pipes at the end of their useful life, and 3) expanding system capacity. Doing so will allow the Company to address safety, reliability, and capacity concerns, while at the same time ensuring prudent investments for ratepayers and reducing the risk of stranded gas assets.
        - As an element of this requirement, the Commission should eliminate the $1 million threshold for triggering NPA analyses as well as expand the scope of what types of projects require an NPA analysis to include investments in pipeline replacement.

        - Additionally, as a condition of recovery on investments in this proceeding and future proceedings, the Commission should order that Avista analyze at least two types of non-pipeline alternatives for all gas system capital investments moving forward.
    - The Commission should require Avista to evaluate targeted electrification and thermal energy networks as two specific NPAs. The Commission should require Avista to propose at least one targeted electrification pilot and one thermal energy network pilot that would allow decommissioning of gas infrastructure and thus reduction in the risk of stranded gas assets. The Commission should require Avista to include its findings and pilot proposals in the Company's 2026 IRP Update.

Q. Does this conclude your testimony?

A. Yes. Thank you

EMILY N. MOORE
92 Lenora St, #189, Seattle, WA 98121 • emily@sightline.org

PROFESSIONAL EXPERIENCE

SIGHTLINE INSTITUTE | Seattle, WA **Jan. 2022-present**
Director, Climate & Energy
Promoted to Director after one year.

- Lead Sightline's research on energy regulation and policy in Oregon, Washington, Montana, Idaho, and British Columbia.
- Publish original analysis, including on natural gas decarbonization, thermal energy networks, targeted electrification, non-pipeline alternatives, and line extension allowances.
- Advise policymakers on legislation, including bills to advance thermal energy networks and electric transmission development in Oregon and Washington.
- Act as expert source to media outlets. Have been quoted in *The Seattle Times*, *Oregon Public Broadcasting*, *Heatmap News*, *Grist*, *The New Republic, KNKX*, and more.

DALBERG ADVISORS | Seattle, WA and New York, NY **Sept. 2017-Jan. 2022**
Senior Project Manager
Promoted twice within four years.

- Advised senior leadership of government agencies, non-profits, and foundations on $1M-$200M+ strategies.
- Oversaw all team research and analysis; synthesize data to inform recommendations.
- Managed teams of 5+, providing regular professional development feedback and coaching.
- Led all client relationship management and oral and written communication; facilitated workshops, led presentations, and conducted interviews with diverse partners.
- Shaped strategic direction and expansion of firm's racial equity work and served on DEI taskforce.
- Clients included: the Bill T. and Catherine D. MacArthur Foundation, Blue Meridian Group, First Lady Michelle Obama's Reach Higher Initiative, the UN Population Fund, and others.

M.A. EXECUTIVE OFFICE OF LABOR & WORKFORCE DEVELOPMENT | Boston, MA **2017**
Graduate Student Researcher

- Developed policy recommendations to improve racial justice impact of pay equity legislation.

GLOBAL HEALTH CORPS | New York, NY **June 2012-May 2015**
Promoted after two years.

Strategic Partnership Manager

- Reported to CEO, led first ever strategic planning process.
- Secured $1.2M in organizational funding through successful proposal writing.
- Developed inaugural operating systems and internal processes, including financial management systems in Excel and QuickBooks, CRM system, and monitoring and evaluation tools.
- Managed and streamlined fellowship selection process with 4,000 applicants.

EDUCATION

HARVARD UNIVERSITY, John F. Kennedy School of Government **2017**

- Master's in Public Policy; courses in economics, statistics, and policy analysis.
- Dean's Fellowship: Full-tuition merit scholarship and stipend

BROWN UNIVERSITY **2012**

- Bachelor of Arts in International Relations, 3.9 GPA
- Senior Prize for Academic Excellence

ADDITIONAL INFORMATION

Languages: Advanced French
Technical Skills: Advanced Microsoft PowerPoint, Excel, Word; Experience in Salesforce, WordPress, Adobe Suite, QuickBooks, STATA

WITNESS QUALIFICATION STATEMENT

NAME: Emily Moore

EMPLOYER: Sightline Institute

TITLE: Director, Climate & Energy

ADDRESS: 92 Lenora St # 189, Seattle, WA 98121

EDUCATION: Master's in Public Policy, Harvard University

Bachelor of Arts, International Relations, Brown University

EXPERIENCE:

Expert in energy policy in Oregon, Washington, and the broader Pacific Northwest. Research and publish original analysis on gas utility decarbonization, the electric transmission grid, building electrification, and other climate and energy topics. Select relevant research includes:

- Analysis of targeted electrification as a non-pipeline alternative, including review of cases around the United States.
- Analysis of thermal energy networks as a non-pipeline alternative.
- Analysis of potential climate-friendly gas utility business models.
- Analysis of gas utility line extension allowances (published by my colleague, Sightline Fellow, Laura Feinstein, with my guidance).
- Analysis of the potential for electric heat pumps in the Northwest.

Provide policy guidance to legislators on gas utility decarbonization. Advised Washington state policymakers on the Northwest's first thermal energy network law, Washington state House Bill 2131, and Puget Sound Energy's decarbonization planning bill, House Bill 1589 in 2024.

Provide recommendations to regulators on utility decarbonization, including comments on rulemaking in ESHB 1589 in Washington state and the Future of Gas docket at the Washington Utilities and Transportation Commission.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	02/14/2025
CASE NO:	UG 519	WITNESS:	Tia Benjamin
REQUESTER:	CUB	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CUB – 105	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

REQUEST:

Has Avista conducted non-pipe alternatives (NPA) analysis, as discussed in Oregon PUC Order NO. 23-384, Appendix B Page 15 of 27 (https://apps.puc.state.or.us/orders/2023ords/23-384.pdf), for its Aldyl-A Pipe Replacement Program?

RESPONSE:

The referenced citation is as follows:

> **Non-Pipe Alternatives (NPA):** Avista agrees to implement a NPA framework in Oregon, including the following elements.
>
> i. Upon rate-effective date, NPA analysis will be performed for supply-side resources and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects. If a NPA is not selected for projects that meet this criteria, Avista will include the NPA analysis as part of the justification when it seeks recovery of the resource addition or distribution system reinforcement or expansion in a rate case.
>   1. "Supply-side resources" includes but is not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts.
>   2. "Geographically-related projects" means a group of projects that are interdependent or interrelated.
>
> ii. For resources or projects that meet the criteria of (21)(i), Avista will include electrification as an NPA.
>
> iii. Non-Energy Impacts must be included as part of the NPA evaluation.

There are some important distinctions between what Avista agreed to in its 2023 general rate case, and the ongoing Gas Facility Replacement Program (GFRP or Aldyl-A Pipe Replacement program) developed in 2011, almost 12 years prior. This program is directly related to a natural gas system risk of natural gas pipe that is prone to premature brittle-like cracking. This initiative is part of Avista's broader effort to enhance the safety and reliability of our natural gas distribution system.

Compare that to the NPA agreement from our last general rate case. That agreement is crystal clear in that such a framework is related to "supply-side resources and for distribution system reinforcements and expansion projects". Such projects driven by a need to serve new customers or continue to serve existing customers where capacity on the system is diminished. In those cases, an NPA might be appropriate to alleviate the demand for natural gas through other methods.

GFRP, on the other hand and as previously mentioned, is a safety related program first and foremost. That information has not only been provided in multiple prior general rate cases, but is also outlined in Avista's "Natural Gas Safety Project Plan – Oregon" filed annually with the Commission (Docket UM 1898).

With all of that stated, no, Avista has not conducted an NPA related to GFRP.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	01/30/2025
CASE NO:	UG 519	WITNESS:	Tia Benjamin
REQUESTER:	CUB	RESPONDER:	Tia Benjamin/Jason Boni
TYPE:	Data Request	DEPT:	Regulatory Affairs
REQUEST NO.:	CUB – 76	TELEPHONE:	(509) 495-2225
		EMAIL:	tia.benjamin@avistacorp.com

REQUEST:

For the new pipe Avista installed to replace Aldyl-A distribution mains as part of the Aldyl-A Pipe Replacement Program in Oregon:

a. What is the useful life of the pipe?
b. What is the book life of the pipe?

RESPONSE:

Avista files with the Oregon Commission a request for approval of depreciation rates through a depreciation study every five years. The purpose of having a periodic depreciation study is to modify the depreciation rates as the assets in service adjust; utilities do not track assets individually, as like-assets are grouped with a rate applied. As agreed to in settlement discussions with Oregon Staff, Attachment B of Docket UM 2277 and approved by the Commission in Order No. 23-318, the Company applies a depreciation rate of 1.94% (book life of approx. 51.55 years) to assets in FERC account 376.0 for Mains and a depreciation rate of 1.99% (book life of approx. 50.25 years) to assets in FERC account 380.0 for Services.

The Company completes a depreciation study every five years, consistent with OAR 860-027-0350, and requests modifications to its depreciation rates. Avista hired Gannett Fleming, Inc. to undertake a depreciation study of its depreciable electric, natural gas, and common plant in service as of December 31, 2021.

Avista does not record a separate useful life of individual assets.

NOTICE OF CONFIDENTIALITY
ATTACHMENTS TO THIS REPORT HAVE BEEN FILED UNDER SEAL.

PUBLIC SERVICE COMPANY OF COLORADO

INITIAL 2023-2028
GAS INFRASTRUCTURE PLAN

PROCEEDING NO. 23M-0234G

May 18, 2023

NOTICE OF CONFIDENTIALITY
ATTACHMENTS TO THIS REPORT HAVE BEEN FILED UNDER SEAL.

Confidential Attachments:
Attachment A: System Safety and Integrity Planned Projects
Attachment B: Capacity Planned Projects
Attachment C: Mandatory Relocation Planned Projects

Colorado PUC E-Filings System

TABLE OF CONTENTS

ATTACHMENTS:

- Confidential & Public Attachment A: System Safety and Integrity Planned Projects
- Confidential & Public Attachment B: Capacity Planned Projects
- Confidential & Public Attachment C: Mandatory Relocation Planned Projects
- Attachment D: 2022 United States Department of Transportation Gas Distribution System Annual Report, Form F7100.1-1
- Attachment E: 2022 United States Department of Transportation Natural and Other Gas Transmission and Gathering Systems Annual Report, Form F7100.2-1

I. STRATEGIC OVERVIEW

Providing heat to our customers is an essential service, and the gas local distribution company ("LDC") system is at the beginning stages of a transformation. Today, approximately 80 percent of our customers receive gas service from us, relying on gas infrastructure during the coldest months of the year. Given this reality, we make foundational investments to ensure the safety, reliability, and affordability of that system for these and future customers. However, we are also aggressively exploring a diversified set of alternatives to traditional investments including electrification, energy efficiency, and demand side management, and the use of lower carbon fuels, including renewable and certified natural gas and hydrogen, that will allow the Company to provide that same service.

We are prepared to break new ground in developing and deploying tools, refined by pilots, analyses, and data as they evolve, to achieve the goal of a low carbon future. At the same time, gas planning directed at achieving emissions reduction for direct use natural gas is new, and none of the reduction options have been achieved at scale. The prudent path forward is taking action in line with state policy while preserving optionality for our customers and taking advantage of cost-effective options to reduce emissions.

Indeed, Xcel Energy's strategy has long focused on greenhouse gas ("GHG") emissions reduction. Since 2005, we have reduced emissions in the electric sector across the eight states where we serve customers by 51 percent, and we are committed to achieving 80 percent GHG emissions reduction by 2030, on the way to 100 percent clean energy by 2050 in the electric utility sector. In 2020, we expanded our GHG focus and established a goal of having one out of every five vehicles on the road be electric in our eight-state service territory by 2030.[1] Thereafter, in November of 2021 we established our *Net-Zero Vision for Natural Gas* with goals establishing a 25 percent GHG emissions reduction by 2030 and achieving net-zero GHG emissions from our natural gas business by 2050. Taken together, these commitments made Xcel Energy the only major U.S. energy provider at that time to announce a comprehensive vision with aggressive goals for reducing GHG emissions across three of the historically largest emitting sectors of the economy: electricity, transportation, and natural gas end use.

Against this backdrop of our overall strategy as a company, our first-of-kind 2023 gas planning filings – Gas Infrastructure Plan ("GIP") and Clean Heat – are the initial steps to chart a course toward a lower carbon future for our LDC while providing safe, reliable, and affordable service—and a process that will take years to unfold, just as it has on the electric side of our business. Nevertheless, deliberate action today will give us more line of sight into the solutions needed for this decades-long transition. In this filing, we demonstrate how alternatives analyses can inform our capital projects and find efficiencies in the gas business itself. While one purpose of the GIP is to address capacity requirements to meet Design Day conditions on the gas system, we will quickly follow this filing with our first-ever Clean Heat Plan to address emissions reductions and the portfolios of strategies to achieve them. These are both initial steps in our transition and will be the first of many such filings.

[1] The Company expanded on this in 2022 with the addition of an aspirational goal of powering all vehicles in our service areas with clean energy by 2050.

There are four tenets that underpin Xcel Energy's commitment to significant GHG emissions reduction across its gas and electric systems: (1) safety and reliability; (2) affordability (3) sustainability; and (4) resiliency (more important now than ever). Thus, while it is important that we focus our efforts on opportunities which maximize emissions reduction, there are also other foundational planning considerations as we move forward. First, it is important to note that the capacity of the natural gas system to serve customers during periods of peak demand on the coldest days is not necessarily closely correlated with GHG emissions. Instead, the volume of GHG emissions is more directly correlated with the actual consumption of fossil-based natural gas over time. As a consequence, the content and annual throughput of the pipe is paramount, not the size of the pipe. Second, just as the electric grid has become cleaner by substituting electrons generated by wind and solar for those previously generated by fossil fuels, the gas system can also become cleaner by substituting low- and zero-carbon alternatives in place of fossil gas. To be sure, we are at the beginning of determining the gas utility's GHG emissions reduction paths. At the same time, our customers continue to need safe and reliable natural gas service. As such, we believe the prudent strategy is to maintain the safety, integrity, reliability, resiliency, and availability of the gas system and to ensure its ability to deliver a low carbon future. Meanwhile, we will work with our regulators, stakeholders, and customers to comprehensively evaluate technologies that hold promise to reduce methane and carbon dioxide emissions.

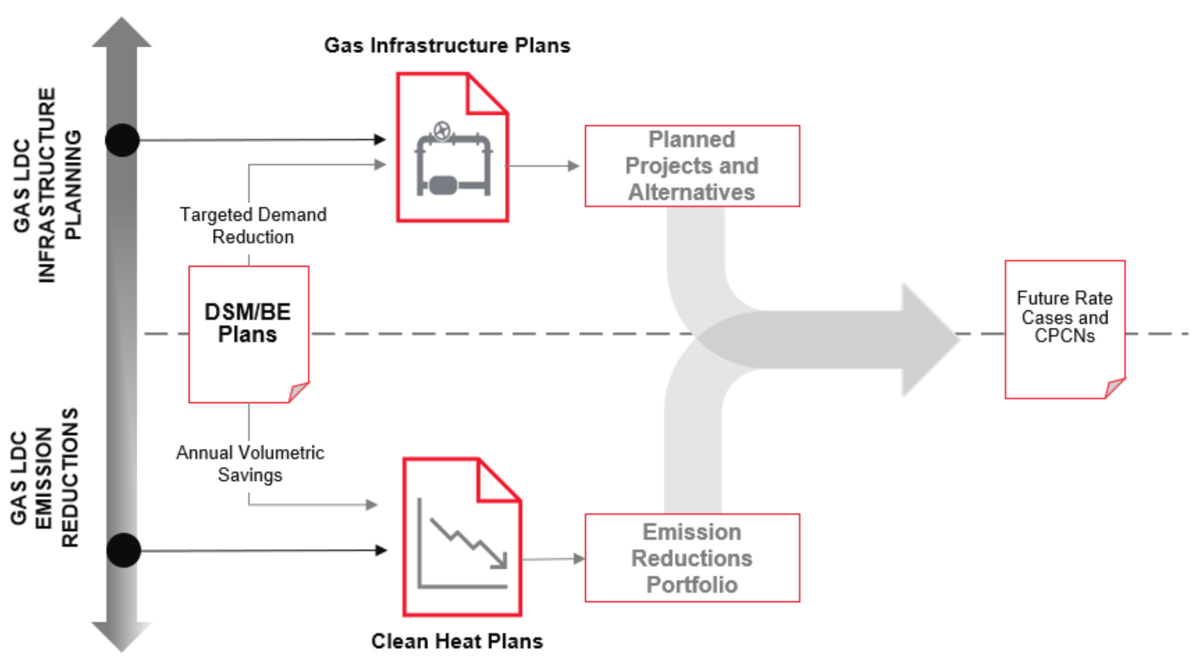
Fifteen plus years ago, the State and utilities, like the Company, were facing a substantial transition for the electric generation portion of the provision of service. Today, we collectively are tackling the conversation for the LDC gas business and the associated customer GHG emissions. As we have learned on the electric side, affordability, reliability, a positive customer experience, and technological innovation will be key to achieving a successful outcome. The General Assembly recognized this in their promulgation of the legislation that is leading to the development of Clean Heat Plans in the State under the oversight and guidance of the Colorado Public Utilities Commission ("Commission").[2] Informed, deliberate, and measured steps forward will need to be taken to achieve successful carbon reductions as well as balance affordability with speed and the foundation of a reliable system for all. This path, which the Company supports, is constructive, and provides a framework to evolve the LDC business over time. To that end, the Commission has overhauled the regulatory framework for LDCs by adopting a new suite of gas rules ("New Gas Rules"),[3] addressing not only Clean Heat Plans ("CHPs")[4] and Demand-Side Management ("DSM")[5] as required, but also enacting new requirements associated with certificates of public convenience and necessity ("CPCNs"), GIPs,[6] and line extensions, among other topics. The New Gas Rules shift and broaden the focus of the rules to include not only regulation of jurisdictional gas utilities and their services, but also their actions to reduce greenhouse gas emissions from the use of gas by their customers and from leaks in their LDC infrastructure.

[2] The Clean Heat Statute (Senate Bill 21-264) recognizes the ongoing role of the gas LDC system and the need to work within that system to reduce GHG emissions, and creates an "evolve and reduce emissions" path.
[3] See final rules adopted in Proceeding No. 21R-0449G, via Decision No. C23-0117. While the rules became final on March 16, 2023, they are not scheduled to become effective until May 15, 2023.
[4] Rules 4725-4734 are hereinafter referred to as the "CHP Rules."
[5] Rules 4750-4761 are hereinafter referred to as the "DSM Rules."
[6] Rules 4550-4555 are hereinafter referred to as the "GIP Rules."

The GIP Rules are intended to work in conjunction with the CHP Rules during the coming years when LDCs will transform their businesses and the services they provide to their customers in order to achieve the substantial reductions in statewide GHG emissions. Having additional insights into system planning, forecasting, and investments as provided by the GIP Rules provides an additional component of the regulatory structure going forward to facilitate Commission oversight of long-term investments in gas system infrastructure. The Commission also stated its expectation that the gas infrastructure plan process "will serve as a venue to: (1) facilitate the Commission's understanding of the current gas system; (2) serve as a place to approve specific projects on a prospective basis, as well as a place to develop both better and more specific project alternative analysis processes, and (3) examine the future use of the system and the economics of the retail service provided over the long term, culminating in the 2050 statewide reductions in emissions as set forth in § 25-7-102(2)(g), C.R.S."[7]

The graphic below displays the interaction of key gas planning regulatory processes on the pathway to emissions reductions. Such processes demand transparency and establish the framework for successful reduction of GHG emissions from our gas system, while also providing regulatory support for ongoing and required gas infrastructure investment.

Figure 1: Key Gas Planning Regulatory Processes



Importantly, the Company itself is evolving along with this framework and State policy. For example, the Company has created a new Integrated System Planning ("ISP") organization, which, over time, will holistically and strategically develop long-term, interrelated plans for our electric and gas systems, while seamlessly serving our customers. ISP is responsible for

[7] Decision No. C22-0760 at ¶167.

coordinating long-term plans and strategies to stay ahead of a fast-changing, and increasingly complex, business environment that is being driven by the accelerating clean energy transition. Our ISP organization is at the intersection of utility generation, transmission, and distribution – electric and gas – across our service areas. With a more holistic ability to innovate during this clean energy transition, we expect increased visibility into capital and technology investments and a better ability to serve our customers well into the future. ISP plans will help us drive the transition and also achieve GHG emissions reduction sustainably, reliably, and affordably. The ISP organization is one of the first of its kind in the utility industry and will help keep Xcel Energy at the forefront of the nation's clean energy transition.

We have advanced aggressive DSM and BE goals in our Strategic Issues filing, along with cutting-edge policy recommendations, such as programs to address targeted demand areas, in the interest of avoiding or deferring capacity investments on the gas system. Through this initial 2023-2028 Gas Infrastructure Plan ("Initial GIP" or "Report") which, by necessity from a timing perspective, is based on previously-planned capital investment, we have engaged in robust alternatives analyses and conducted stakeholder outreach to promote transparency. Our first CHP is under development and we anticipate that subsequent GIP reports will be an evolutionary process as we work with our stakeholders to refine our approach to system planning.

There is no dispute that GHG emissions reduction in the LDC sector is a large challenge and is in its early stages relative to the established and economical clean energy options developed by the power sector to date. As we engage in this transition, we need to understand realistic limitations in regard to both technologies and circumstances, maintaining and honoring a voluntary approach for our customers, with a balanced set of options provided to existing and new customers. But, as we have done throughout the clean energy transition, we need to meet our customers where they are and evolve the business from there. Foundational to that approach is ensuring customers that select gas for their energy needs can do so safely, affordably, and reliably; facilitating electrification in a robust, cost-effective manner; and steady advancement of the emissions reduction objectives set forth in state law.

We support a multi-faceted and flexible approach to achieve emissions reductions and look forward to implementing that Colorado policy in this and other appropriate forums as we learn and reduce emissions—together.

II. PUBLIC SERVICE'S GAS INITIAL 2023-2028 GAS INFRASTRUCTURE PLAN

While the strategic overview details the Company's vision and policy approach to the future of the LDC business holistically, this Initial GIP is focused on providing transparency into the processes for how the Company evaluates investments to ensure the safety and reliability of the gas system. Coloradans continue to choose and depend on natural gas for critical heat during some of the coldest months of the year, and continuing to meet these customer choices while establishing a pathway for long-term gas LDC emission reductions are not mutually exclusive outcomes.

The planning and analysis which ensures the Company can safely, reliably, and cost-effectively meet its obligation to serve has evolved over decades of annual planning cycles and as industry best practices and tools have improved. It is important to recognize that further evolution of the LDC planning processes will not occur overnight. Nevertheless, this plan provides significant transparency into these processes and takes initial strides in that direction in the limited time since final approval of the GIP Rules to formulate this inaugural 2023-2028 Gas Infrastructure Plan. The Company has applied the GIP Rules, identifying the larger individual planned projects over the next six years within the required categories, undertaking a robust non-pipeline alternatives ("NPA") analysis process that continues to evolve, and addressing requirements that do not necessarily apply to this non-adjudicated filing, such as those involving stakeholder outreach.[8] Increasing federal and state mandates and industry best practices continue to govern our obligation to make capital investments to ensure the safety and reliability of our system. As infrastructure ages, is damaged by third-parties, or is subject to potential detrimental effects of severe weather events, investments are needed to ensure safety, resiliency, and service continuity. These investments, along with investments in integrity work and traditional gas investments, continue to occur alongside investments in our Clean Heat future, such as the hydrogen blending project presented later in this Initial GIP.

Planned gas infrastructure projects are on a fluctuating continuum of planning and construction, adapting to the needs of our customers and the system, providing safe and reliable service during the coldest days of the year when customers need their gas heat the most. Thus, the Company, consistent with the GIP Rules, formulated the following parameters to guide development of the Initial GIP and to determine the scope of planned projects included therein:

- First, this Initial GIP – like all planning filings – represents a snapshot in time of the Company's evolving gas infrastructure planning processes, relying primarily on the November 2022 five-year forecasted and budgeted investment for the 2023-2027 portion of the 2023-2028 GIP period ("Plan Period") for its foundational elements. It is expected that future regulatory proceedings for gas infrastructure projects, such as the Company's 2024 interim GIP report and the 2025-2030 GIP will continue to show the progression of planned projects presented in this Initial GIP and the development of any new projects identified after this GIP.

[8] In Decision No. C22-0760 at ¶ 200 (Proceeding No. 21R-0449G), the Commission contemplated that such outreach is not required for the Initial GIP (Decision No. C22-0760).

- Second, the planned projects fall within the categories of work contemplated by Rule 4553(a)(III)(system safety and integrity, new business, capacity expansion, mandatory relocation, and defined programmatic expenses).

- Third, the planned projects involve planned facilities or an extension of existing facilities with a defined scope of work and an associated cost estimate that exceeds $3 million in utility capital investment in 2023 dollars.[9] Due to the GIP Rule reporting requirements, the capital investment contained in this Report only represents a portion of the Company's annual investment in the gas system.

- Fourth, planned projects "start" during the Plan Period in alignment with Rule 4553(a)(VIII),[10] however, projects with *de minimus* capital expenditures in 2022 were included if the total project capital cost is expected to exceed $3 million; and likewise, projects anticipated to start in 2028 were included if the total project capital cost is expected to exceed $3 million.

- Fifth, planned projects in the informational period of 2026-2028, particularly those outside of the Company's five-year capital budgeting period, provide directional information as required by the GIP Rules, but in some instances limited project information is available.

The Table below summarizes the number of planned projects, by category, and associated capital expenditures presented in this Initial GIP. As reflected in the
, there are no new business planned projects.

[9] Rule 4551(f). While the Rule allows for the $3 million threshold to be calculated in 2020 dollars and adjusted annually for inflation, the Company used a $3 million threshold in 2023 dollars for this Initial GIP since there is not yet a Commission notice adjusting the inflation for 2023.
[10] Rule 4553(a)(VIII) provides, in part, that "[t]he utility shall provide project-level information consistent with the requirements in paragraph 4553(c) for all projects with an expected construction start date during the gas infrastructure plan action period and the gas infrastructure plan informational period, where available."

Table 1
Public Service 2023-2028 GIP Planned Project Capital Expenditures by Category
($ Millions)

Planned Project Category	2023-2025 Action Period Projects	Action Period Projects - Estimated Capital Expenditures	2026-2028 Informational Period Projects	Informational Period Projects - Estimated Capital Expenditures*
System Safety & Integrity	6	$26.2	0	$0.0
Capacity Expansion[11]	5	$24.2	3	$34.1
Mandatory Relocation	1	$4.2	0	$0.0
New Business	0	$0	0	$0.0
Total	**12**	**$54.6**	**3**	**$34.1**

* Includes capital expenditures for included planned projects before and after the GIP total period. Differences in sums due to rounding.

As noted above, identification of planned projects as part of the Company's processes is not a static proposition, and the Company primarily used the November 2022 forecast as the foundation for determining the planned projects to be included in this Report. However, it is important to recognize that any plan is part of an iterative process and, as a result, priorities for planned projects are subject to change. This is particularly true for projects in the informational period, especially those outside of our five-year budgeting process, which are expected to evolve over time. Additionally, a number of other factors, including but not limited to the following, can result in shifting priorities, timelines, and costs for planned projects: (a) scheduling work with the least amount of disruption for our customers and communities, including bundling work with municipal improvement projects; (b) allocating resources where they will provide the best value to customers in terms of both safety and cost; (c) changing circumstances, such as those resulting from changing system conditions, field verification, new developments, and modeling updates; and (d) outside factors, such as permitting, weather, and availability of required contracted resources.

Turning to the contents of the Initial GIP itself, we initially provide some general information about the Company's gas business before launching into the GIP-specific requirements. The Report is then segregated into the following major components, in general

[11] Two capacity expansion projects identified in the GIP to commence in the Informational Period are estimated to begin in 2028 and carry over past the GIP total period. Those projects are the Fort Lupton Compressor Station and the Mead to East Longmont Reinforcement. Both of these projects have not been through the Company's stage gate, financial governance, or budgeting processes. As expected for such planned projects in the informational period, particularly late in the informational period, these planned projects are in the pre-initiation phase and are subject to change over time. For purposes of this Report, these projects are reflected as having greater than $12 million in estimated capital expenditures, which is reflected in the "total" capital expenditures in this Table.

sequence with the requirements of GIP Rule 4553. The below listing also provides a summary of the topics covered in each section.

> Required General Information: General information is provided on the planned projects presented herein. The Company further provides details on its modeling processes for each of the planned project categories, discusses the capital budgeting and cost projections processes, and provides an overall map and the PHMSA[12] Gas Distribution Annual Report. We conclude this section with a discussion of outreach conducted in connection with this Report, as well as an overview of the Company's Design Day temperatures and associated Design Day methodology.
>
> Forecasts and Conceptual Incremental Investment: Provides low, reference, and high forecasts, as well as incremental investment based on the low and high scenarios.
>
> Planned Project Information: Contains detailed information required by the GIP Rules regarding the planned projects themselves.
>
> System Safety and Integrity Risk Ranking Methodology: Explains the Company's system safety and integrity risk ranking methodology for the safety category of planned projects included in the Report.
>
> Alternatives Analysis: Presents the Company's alternatives analysis methodology as applied to the selected planned projects.
>
> Other Gas Infrastructure Investments: Provides additional context for this Report regarding investment in gas infrastructure.
>
> Existing Infrastructure Reporting: Addresses existing infrastructure issues as required by GIP Rule 4553(d), specifically as related to customer-owned yard lines ("COYLs"), hydrogen, and advanced leak detection.

The Report concludes with some summary remarks.

[12] "PHMSA" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration.

III. PUBLIC SERVICE'S GAS BUSINESS

Having proudly served Colorado communities and their natural gas needs for over 150 years,[13] Public Service is the largest LDC in Colorado serving approximately 1.5 million customers. We operate an extensive gas delivery system that offers a great deal of complexity. Our gas system includes approximately 23,500 miles of distribution mains and over 2,000 miles of transmission pipeline, over 1.2 million services, 18 compressor station locations with over 40 compressors totaling approximately 38,000 horsepower, roughly 2,000 regulator stations, and other supporting infrastructure, all of which help us move gas safely and reliably throughout Colorado to our customers. The Company has direct access to major gas supply areas in Colorado, which includes underground storage and gas transportation capacity on upstream interstate pipelines. We are also able to access other major gas suppliers from Wyoming, Utah, Texas, Kansas, and Oklahoma. A map of our gas service territory is below:

Figure 2:
Public Service Gas Service Territory Map

As reflected on the above map, our system is diverse, spanning rural, suburban, urban, and mountainous environments, and we operate facilities in 33 of the 64 counties within the State. In addition to providing essential gas service to its own customers, the Company also provides

[13] The original predecessor of Public Service, the Denver Gas Company, was founded on November 13, 1869. Public Service began operating its natural gas distribution and transmission systems in the 1920s.

transportation services to the other Colorado LDCs. Thus, the Company maintains an essential backbone relied upon by Coloradoans for the safe and reliable delivery of natural gas.

Gas Operations and Integrated System Planning provide all the major functions to deliver natural gas from upstream interstate pipelines, such as Colorado Interstate Gas Company, via the Company's transmission and distribution systems to the customer's meter and ensures public safety through compliance with state and federal pipeline safety regulations. These functions include: planning, engineering, design, metering, compliance, responding to gas emergencies, locating underground gas facilities, construction and maintenance on the system, coordinating with communities to relocate our facilities when necessary for municipal projects like water and sewer projects, providing new gas service when requested by our customers in satisfaction of our obligation to serve, complying with all state and federal regulations, and operating and maintaining gas peaking facilities, just to name a few.

Public Service works hard to provide safe and reliable service to our customers, who request and rely on natural gas service from the Company, keep gas in the pipes for the good of all, and continue to lead the clean energy transition through prudent management and development of the natural gas business. Fundamental investments in our assets and our people to mitigate risk to public safety and the environment, undertake programmatic efforts to keep gas in the pipes, and ensure our system is resilient all enable us to successfully provide service that is clean, safe, reliable, and affordable. These efforts are also critical to preparing Public Service's gas system and infrastructure to support clean energy technologies that may heat customers' homes and businesses in the future. We look forward to continuing that partnership as the technology and regulatory structures continue to evolve.

IV. REQUIRED GENERAL INFORMATION (4553(a))

As noted earlier, the GIP is required to provide certain general and detailed information relative to, among other things, planned projects for this GIP total period (2023-2028). The term "planned projects" is defined by the GIP Rules for Public Service as "any planned facility or an extension of an existing facility, or a defined programmatic expense with a defined scope of work and associated cost estimate that exceeds $3 million in utility capital investments in 2020 dollars.[14] This portion of the Report provides the general information regarding the contents of the GIP as required by Rule 4553(a), and the details of the planned projects included in the GIP are provided in Section VI of this Report.

Generally, the Company identified and classified the planned projects presented in this Report in accordance with the categories listed in Rule 4553(a)(III), which are replicated below for convenience.

- "System safety and integrity projects" shall include but are not limited to pipeline and storage integrity management programs; exposed pipe inspection and remediation; pipe or compressor station upgrades; projects undertaken to meet U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration requirements; and Supervisory Control and Data Acquisition (SCADA) upgrades.[15]

- "Capacity expansion projects" shall include both individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need. Within the category of capacity expansion projects, the utility shall further separate appropriate projects into the following subcategories:

  (i) capacity expansion projects needed for reliability or growth in sales by existing customers, structures, and facilities; and

  (ii) capacity expansion projects needed for growth in sales due to new customers, structures, and facilities, that are not otherwise new business planned projects.[16]

- "Mandatory relocation projects" means a project to relocate the utility's gas infrastructure as required by a federal, tribal, state, county, or local governmental body.[17]

- "New business projects" shall include utility investment and spending needed to provide gas service to new customers or customers requiring new gas service.[18]

- "Defined programmatic expenses" as defined in paragraph 4551(b), means the following, or as otherwise ordered by the Commission:

[14] Rule 4551(f).
[15] GIP Rule 4553(a)(III)(A).
[16] GIP Rule 4553(a)(III)(C).
[17] GIP Rule 4553(a)(III)(D) and Rule 4001(dd).
[18] GIP Rule 4553(a)(III)(B).

(i) "relocation or replacement of meters" shall include the utility's investment and expenditure to replace or relocate customer meters, including at-risk meters, not otherwise covered by other projects; and

(ii) "replacement of customer-owned yard lines" shall include the investment and expenditure to replace customer-owned yard lines and associated infrastructure with utility-owned pipelines and associated infrastructure.[19]

Any deviation from this categorization, as well as any interrelationship of planned projects, is identified in the Project Packet for that particular project attached to this Report, and as presented in and further discussed in Section VI below.

Based on the foregoing, and as required by Rule 4553(a)(IV), the below table provides, for each year of the GIP total period, the total number of planned projects, and the total annual capital investment for those planned projects, by category.[20] As discussed later in this Report, this does not reflect the total annual gas capital investment, but is limited to planned projects as required by the GIP Rules.

Table 2: 2023 GIP Report Planned Projects

		Action Period			**Informational Period**					
Planned Project Category	**Number of Projects**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**Estimated Total GIP Expenditures**	**Estimated Total Project Expenditures***
System Safety & Integrity	6	$22.8	$3.1	$0.0	$0.0	$0.0	$0.0	$0.0	$25.9	$26.2
Capacity Expansion[21]	8	$5.4	$10.0	$6.4	$2.9	$2.7	$11.8	$19.0	$39.2	$58.3
Mandatory Relocation	1	$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.1	$4.2
New Business	0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Planned Projects Total:	**15**	**$32.3**	**$13.1**	**$6.4**	**$2.9**	**$2.7**	**$11.8**	**$19.0**	**$69.2**	**$88.7**

* Includes capital expenditures for included planned projects before and after the GIP total period. Differences in sums due to rounding.

In the remainder of this section, the Company addresses the system planning and infrastructure modeling process, the capital budgeting process, the cost projections process, and

[19] GIP Rule 4553(a)(III)(E).

[20] There are also no reportable defined programmatic expenses, as addressed in Section VI of this Report.

[21] As mentioned earlier in the Report, two capacity expansion projects identified in the GIP to commence in the Informational Period are estimated to begin in 2028 and carry over past the GIP total period. Both of these projects have not been through the Company's stage gate, financial governance, or budgeting processes. For purposes of this Report, these projects are reflected as having greater than $12 million in estimated capital expenditures, which is reflected in the "total" capital expenditures in this Table.

also provides a system map of the 2023-2028 planned projects. This section concludes with the provision of the Gas Distribution Annual Report (Form F7100.1), a summary of outreach undertaken as part of this GIP, and required information on current capacity planning Design Day temperatures.

A. System Planning and Infrastructure Modeling Process (4553(a)(I))

This section focuses on the Company's system planning and infrastructure modeling process for each of the planned project categories, including the assumptions and variables that are inputs into the process, as contemplated by Rule 4553(a)(I).[22]

1. Safety

Public Service's natural gas system is the result of decades of infrastructure build-out, the majority of which occurred during a lengthy period of time absent of today's industry knowledge regarding construction materials and practices, and lacking regulation. Due to the natural evolution of expertise and technology, for decades the industry had a different understanding about safe gas system materials and practices than is known today. And while Public Service began operating its natural gas distribution and transmission systems in the 1920s, federal legislation and PHMSA regulations requiring integrity management have only been in existence since the early 2000s. To put things in perspective, as of December 2022 nearly 25 percent of the Company's gas distribution main miles were installed either prior to 1970 or in an unknown decade. The same is true of more than 41 percent of gas transmission miles and over 19 percent of gas distribution services.

A complex set of rules and regulations govern our work at the federal, state, and local level. At a federal level, PHMSA is the primary federal administration for ensuring that pipelines are safe, reliable, and environmentally sound. PHMSA oversees the development and implementation of regulations concerning pipeline construction and maintenance and operations. These responsibilities are shared with the State of Colorado. The Company is dedicated to operating a safe and reliable gas system for our customers, and we are required to comply with all applicable safety requirements and regulations for active pipeline segments, unless permanently abandoned. With aging infrastructure and prescriptive requirements within federal regulations, it is of critical importance that the Company invests in the safety and integrity of our system by assessing, repairing, and replacing problematic pipe and equipment. Since Public Service operates a highly integrated gas system consisting of interconnected distribution and high pressure systems at multiple locations and can flow in multiple directions, with many interdependent segments that operate together in order to ensure the provision of gas service to our customers, the Company will not be relieved of its obligations to make safety investments.

Thus, the Company's integrity management efforts are primarily conducted in light of the applicable federal rules. Within 49 C.F.R. § 192 are Subpart O, Gas Transmission Pipeline Integrity Management regulations, and Subpart P, Gas Distribution Pipeline Integrity Management regulations, both of which contain rules for integrity management programs. Operators are

[22] The Commission has also included within the definition of "Planned Projects" certain defined programmatic expenses. That category will be addressed later in Section VI of this Report.

expected to take prudent measures to know their assets, identify the risks and threats to their assets, and be proactive in mitigating those risks and threats. Consistent with this mandate, the entire gas industry has transitioned from a historically reactive mode to a more proactive mode. A successful progression to "best in class" status requires comprehensive system-wide compliance with the three fundamental directives mentioned above: know your assets; identify the threats and risks to those assets; and proactively mitigate those threats and risks.

The Company stresses that federal requirements and the three directives cited above cannot and should not be pursued sequentially, but rather pursued continuously and simultaneously. At the same time, the Company is gathering data on its assets, and must also actively assess the risks and threats to the assets for which data is available (*e.g.*, TIMP and DIMP assessments).[23] Moreover, the Company must take steps to mitigate risks through repairs, renewals, or new program development based on the knowledge it has gained to date and the results of its ongoing assessments.

One significant challenge in the integrity management programs process is that the Company's plans must ensure that all specific federal requirements are satisfied. One such example is the TIMP requirements regarding the scope and timing of initial and subsequent assessments. This creates the need to plan initial assessments at the same time as developing subsequent assessment plans for assets that have been assessed.

A second major challenge is the timing and prioritization of both internal and external resources. Resource allocation must be designed to provide the right value to customers in terms of cost, while also ensuring safety. This resource allocation, in turn, requires considerable analysis and judgment. The result is some projects are completed within a short period, while others may be completed over a number of years.

A third major challenge is that the plans must be flexible enough to account for uncertainties and new developments. The litmus test of effective planning is not whether the activities are executed as forecasted, but whether the plans were based on the best information known at the time and were flexible enough to adapt successfully to unforeseen changes. As new information becomes available, the short-term and long-term plans should be modified to capture this knowledge. For example, the Company's assessments, repairs and renewals must be coordinated with the communities in which the work occurs. This might include other planned utility work or street reconstruction or paving activities. When scheduling and executing projects in the field, the Company strives to minimize impacts on the affected communities; however, the requirements of local governmental bodies might change the scope, cost, and/or timing of various projects.

A variety of factors impact resource needs in any given year. While the Company uses its experience to forecast potential repairs, remediation and replacements, the results of the assessments themselves will drive the amount of repair, remediation and renewal work during the year. In addition, unforeseen weather and natural disasters, such as the 2013 floods or various wildfires, will also affect our ability to complete planned integrity work.

[23] "TIMP" means Transmission Integrity Management Program. "DIMP" means Distribution Integrity Management Program.

Another fundamental uncertainty is emerging or pending regulations. Such changes, particularly if they entail the completion of specific activities by certain dates, will usually require the Company to modify its long-term plans. The Company regularly reviews communications received from PHMSA in the form of Notices of Proposed Rulemaking, final rules, and advisory bulletins published in the Federal Register and considers this information when stepping through the phases of know your system, identify threats and risks, and proactively mitigate them.

Within this framework, the Company plans for safety work in several different ways, which will continue to evolve as we transition away from the Pipeline System Integrity Adjustment ("PSIA"). The Company, however, considers all of the aforementioned challenges when developing its plan for safety projects, including relative risk assessments, known or anticipated federal regulations, resource availability, and the requirements or preferences of local communities. We modify the plans during the year in response to the circumstances described above. Notably, while there are some larger, discrete individual planned projects, the Company's capital investment in this category is driven primarily by programmatic work. Due to the nature of planning for these projects, individual planned safety projects are not typically identified beyond the current or following year. As explained later in this Report, a budget is set for safety work, and as discrete planned safety projects are identified, they are funded from that budget. For these reasons, there are no planned safety projects meeting GIP criteria beyond 2024 in this Report.

Planning for TIMP and Maximum Allowable Operating Pressure ("MAOP") reconfirmation projects, for example, typically follows a very prescriptive process. For TIMP projects, we continually assess our system in order to meet PHMSA baseline and continual assessment requirements. This means that we assess a portion of the system every year, and as a result of those assessments, integrity concerns and future project needs are identified for the following year and the near-term. For MAOP reconfirmation projects, the applicability, completion date, and remediation options are prescribed by PHMSA regulations. Therefore, MAOP reconfirmation projects will take place annually until 100 percent of the applicable pipeline system has been remediated, in adherence with mandated deadlines. Planning for DIMP and other safety projects not falling within either TIMP or MAOP is somewhat less prescriptive. This is a very fast-paced process focused on maintaining the safety of our system for the benefit of our customers and the environment.

Other individually planned safety projects required to ensure safe and reliable operation of the pipeline system, including, but not limited to, those associated with inoperable/obsolete equipment, compressors, and SCADA, are often identified as a result of integrity management programs, or engineering and operations concerns. For individual planned projects, once risk has been identified and the project has been deemed necessary, the project goes through Stage Gate approval[24] for funding in the current and/or following plan year. Alternatively, programs of work are approved from Stage Gate and discrete projects within the program are thereafter identified and prioritized utilizing a program-specific risk ranking methodology (refer to Section VII of this Report).

[24] The Stage Gate process is discussed in Section IV.B of this Report.

2. Capacity Expansion

As noted above, the Commission defines capacity expansion as encompassing individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need.[25] The Commission also segregates this category of investment into those needed for reliability or growth in sales by existing customers, structures, and facilities, and those needed for growth in sales due to new customers, structures, and facilities, that are not otherwise new business planned projects.

Our customers need reliable service. Customers depend upon natural gas to heat their homes and water, cook their meals, dry their clothes, and support commercial and industrial activities within the state. Consistent with our obligation to serve, Public Service must stand ready to provide our customers with safe and reliable natural gas service. In order to do so, Public Service must adequately maintain, renew, and operate its pipelines, compressor stations, regulator stations, meters, and every other aspect of the system. When our assets are no longer adequate to reliably serve existing and/or new customers, the Company must replace, reinforce, rebuild, or expand the affected portions of our system. This area of our capital investment is very routine and programmatic, but it also has the highest number of individual planned projects.

The Company's gas system is modeled and designed to ensure reliable service can be provided to firm gas customers[26] under Design Day conditions.[27] At a high level, identification of a "capacity expansion" project, regardless of whether it is for the Company's high pressure/intermediate systems[28] or the Company's distribution systems,[29] requires a review of any changes to the gas systems' infrastructure, changes in customer consumption patterns, as well as the utilization of forecasted growth rates. When modeling the gas system for capacity planning and infrastructure needs, there is no added reserve margin of capacity on a pipe by pipe or regional basis. The result of this planning process is an identification of capacity projects that will be required in the future to maintain reliable service to our firm gas customers. Below is an overview of the current planning process:

[25] Rule 4553(a)(III)(C).

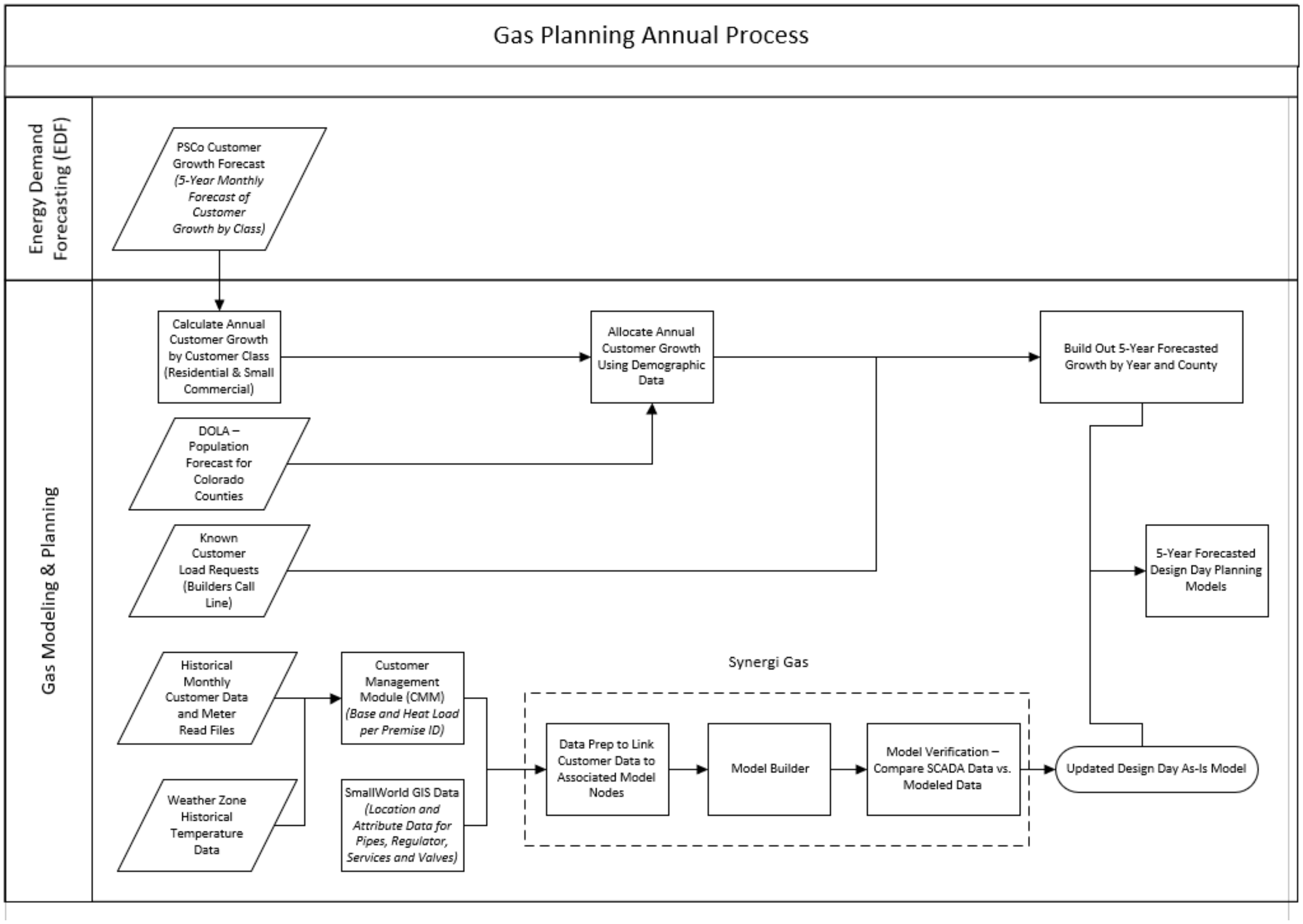
[26] Interruptible gas service customers utilize available capacity, if it exists, on the system that firm gas service customers are not utilizing at a specific time. The Company does not use interruptible gas service customers' estimated peak hour load demand to determine capacity requirements for the system to meet Design Day conditions.

[27] As discussed later in this Report, a Design Day temperature is based on the 1-in-30-year low temperature in a given weather zone. A weather zone is a geographic area, determined internally, with an associated permanent weather station that is reflective of the temperatures to be experienced across the area.

[28] Generally, intermediate and high-pressure systems are greater than 60 pounds per square inch gauge ("PSIG") MAOP.

[29] Generally, distribution systems are 60 PSIG or less.

Figure 3:
Overview of the Current Planning Process



On an annual basis, beginning after conclusion of the heating season, the hydraulic models are calibrated with system operating data from that heating season to confirm whether the gas system is continuing to meet our system-specific Design Day conditions. In its annual system planning model, the Company includes, without limitation, the following factors: upstream supply entitlements, addition or changes of system infrastructure, firm growth rate forecasts, system configurations, and customer and meter read data points. We rely on historical data (monthly customer meter reads), current data (existing system infrastructure and configurations), and projections (forecasted firm customer peak hour growth rates).

Because gas planning needs to account for pressure to maintain reliability and support the efficient operation of the system, the Company uses the Synergi® software package to model the hydraulics of the system. The variables that are in the hydraulic model include temperature, volume, flow, and pressure. These variables are impacted by the size and location of load demands added to the model. There are two sources of data that support model build/verification: the geographic information system ("GIS") and customer billing. The Company's GIS database houses the location and attributes data for the gas system infrastructure (which includes pipe size, material, and roughness, regulators, services, valves, etc.). This is a critical step in the model build process as imported infrastructure and asset attributes, reflective of actual field installed equipment and facilities, will accurately capture the status of the system's infrastructure at the time of model verification. Customer billing provides customer data and monthly meter reads which are utilized to calculate and assign weather dependent loading for each customer.

Historical firm end use consumption is analyzed, to determine respective base and heating loads, in the modeling package through the Customer Management Module ("CMM"). The model is calibrated each year against observed Supervisory Control and Data Acquisition ("SCADA") gas flows/pressures.[30] Below is a more detailed step-by-step explanation of how the Company annually updates its Design Day As-Is model:

- Update the CMM inputs: Import monthly customer data and meter read files.
    - Import weather data for each weather zone from the previous heating season;
    - Run the CMM algorithm to update the existing base and heat demand per customer (i.e., premise ID) to develop a current peak hour load demand for each customer; and
    - Create a new load file for the verification process.
- Extract updated gas infrastructure facility data from SmallWorld GIS.
- Conduct a DataPrep to assign customer data and associated loads to specific nodes within the model.
- Import the new load file from CMM into the model.
- Select gas day(s) from the previous heating season to verify against and pull SCADA data for the specific peak hour of the selected gas days.
- Verify the model against SCADA data.
- Extrapolate verified model to an updated Design Day As-Is Model.

This CMM loading data includes historical reductions achieved through the Company's Demand-Side Management ("DSM") program, since the hydraulic models use actual customer data. As customer usage changes due to appliance efficiency increase, DSM or other drivers, the impacts of these will be reflected in the gas usage which is what CMM provides. The Company uses its SCADA and pressure monitoring data recorders to complete its verification process where actual field data is obtained and compared to the model results.

This verified model is then coupled with forecasted firm customer growth rates and known capacity checks to determine the impact on system pressures over the next five years. If a capacity constraint exists in this five-year period, then the proposed project to address the constraint is reviewed to see if it is adequate to meet at least ten years of forecasted firm growth from the in-service date of the project. The Company determines forecasted Design Day peak hour load

[30] The actual end-uses for gas are not disaggregated for capacity planning. However, aggregate firm individual customer demand (covering all customer types, excluding interruptible load) is factored in based upon observed demand. The model calibration process ensures that our baseload forecast accurately reflects the actual demand from our customers regardless of appliance type.

demand for its gas piping systems using base system load, natural system growth (captured in the forecasted growth rate) and known capacity checks. Capacity checks can vary in size and tend to be standalone requests for gas service. These requests typically are submitted through the Builder's Call Line and added to the model as discrete inputs per the desired in-service date and requested maximum peak hour load. While not all capacity checks move forward as completed projects with associated added contributions to peak hour demand growth, many of them do, and there would be significant repercussions if they were to be excluded from our predictive future peak demand forecasts. Below is a more detailed step-by-step explanation of how the Company determines the forecasted customer growth rate to build out the five-year forecasted Design Day Models:

- The Sales, Energy, and Demand Forecasting department publishes a bi-annual five-year monthly forecast of customer count by class for the State of Colorado. At a high-level, this forecast is developed using an econometric model based on population, multi-family housing units, and historical customer counts.

- Gas planning uses the five-year monthly forecast to calculate an annual statewide customer growth rate for residential and small commercial customers.

- The statewide forecasted customer growth rate percent for residential and small commercial customers is then allocated by county based on the weighted population forecast from the Colorado Department of Local Affairs ("DOLA") demographic data.

- This process results in a five-year forecasted customer growth rate per year per county by customer class (residential and small commercial customers).

- Gas planning also incorporates known capacity checks obtained through the Builder's Call Line.

- Lastly, the forecasted growth as well as known capacity checks are added to the Updated Design Day As-Is Model and built out to develop the five-year forecasted Design Day planning models.

Through all of these efforts, which are repeated annually, the Company can identify, and scope proposed system reinforcements and capacity needs to maintain system reliability for firm service customers under Design Day conditions. For firm gas service customers, if system modeling determines that there will be insufficient pressures on any portion of the Company's gas system under Design Day conditions, then the Company will evaluate feasible and economical mitigative solutions to remediate the capacity constraint for that specific area.[31]

[31] The results of this modeling process also help the Company operate the entire system during the upcoming heating season.

3. Mandatory Relocations

Pursuant to Rules 4553(a)(III)(D) and 4001(dd), the purpose of mandatory relocation projects is to relocate the utility's gas infrastructure as required by a federal, tribal, state, county, or local governmental body. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. Public Service is required by state, county, and local government bodies to relocate its gas infrastructure that resides in road rights-of-way when that entity's work conflicts with its facilities. Public Service's franchise agreements with the communities it serves also require the Company to move or relocate its infrastructure when requested by the government body. This includes, but is not limited to, infrastructure work on water, sewer, transportation, or other major infrastructure. The costs associated with relocating its natural gas infrastructure are typically born by Public Service and ultimately impact its customers through cost-of-service ratemaking.

The Company does not plan for mandatory relocation projects in the same manner as it plans for other projects. Mandatory relocations are requested by a city, municipality, or government agency. Franchise agreements, or applicable law, govern whether the Company is required to, at Company expense, relocate gas assets when requested. Typically, these are public works improvement projects, and the Company does not have latitude on whether or when the project is done. The Company typically plans these projects in cooperation with the requesting authority.

4. New Business

Consistent with its obligation to serve, the Company must serve any new customer that requests gas service within its service territory. This includes not only laying the service line and setting the meter to a customer's facility, but also the gas main to which the service line connects. And it does not stop there. Public Service operates an integrated system of both distribution and transmission assets. Customer growth on the distribution system can cause a capacity shortage on upstream distribution and transmission pipelines and regulating facilities. In order to ensure firm gas service to that customer during a cold peak hour or design day, the Company must have adequate capacity across its entire integrated system.

With regard to new business, Public Service plans for these projects as the requests for service come in. The Company receives requests from individuals and developers for new gas service through the Company's Builders Call Line. The Builders Call Line is the customer's first point of contact when requesting new gas and electric service from the Company and is intended to be a single call department to simplify the customer's experience. The Company supports new business customers through five key phases of installing and connecting new service through the Builders Call line: 1) application; 2) design; 3) payment; 4) scheduling; and 5) construction and meter set. The Builders Call Line delineates which tasks within the five phases are the customer's responsibility, the Company's responsibility, and joint responsibility between the customer and the Company.

The design phase begins when a customer submits building plans and a request for service to the Company's Builders Call Line. During that initial call, information such as address, customer contact information, building type, and any available load data is collected by the Company and compiled into a standardized form. That data is then assigned to a designer, who will contact the customer and arrange a meeting to cover any specifics related to the project.

After that initial meeting, the designer uses a program called GE Design Manager to start outlining the project scale, route, and materials required to meet the customer's needs. GE Design Manager allows the designer to determine the pipeline route, select the required materials, and factor in installation and restoration costs. If the request for new gas service is large in nature, and served from our high-pressure system, the request for new business is transferred from the designer to a gas engineer. That list of materials and labor is then populated into the Company's Work and Asset Management system and sent to local design and engineering management for review and approval before a quote is issued. From that point, the system generated cost estimates are valid for 90 days before a refresh is required. If the customer accepts the quote by signing the service agreement, the customer's payment is collected, and the project is moved to construction.

Since GE Design Manager is built into the Company's Geographic Information System, all location and material information is captured and added to the Company's mapping system and serves as the Company's asset system of record. The design process is the same for both gas and electric and a customer can start the process for both gas and electric services concurrently, with one application.

B. Capital Budgeting Process and Cost Projections (4553(a)(II)) and 4553(c)(I)(G))

In this section, the Company provides information on its capital budgeting process, as well as the expected level of accuracy in its cost projections, as required by Rule 4553(a)(II). As related to cost projections, a discussion of the Company's cost estimate classification index, and support of that methodology, is also included herein, in compliance with Rule 4553(c)(I)(G).[32]

1. Capital Budgeting Process

Each of the planned project areas of investment has its own, unique planning process, as summarized in the subsections above. Proposed projects and categories of work need to be funded, however, and thus need to be approved as part of our corporate-wide budget approval process. For many projects, it is not until after the budget approval process has been completed that project approval is obtained and execution begins. This results in an overlapping annual cycle of project execution, project planning, and budget creation. The practical realities of these processes and corporate budgeting requirements present challenges when trying to develop a GIP that facilitates visibility into the most current possible information, while at the same time being compatible with well-defined corporate processes and governance.

Not all gas operations projects are individual planned projects subject to GIP reporting, in fact the majority are not. Much of our work comprises "routine" project types, which are not subject to the GIP Rules. Routines are budgets used to fund small projects that are typically less than $300,000 each and are of a nature and type that are typical or common for a LDC to perform

[32] As required by Rule 4553(c)(I)(G), the cost estimate classification for each Planned Project will be provided as part of each Project Packet.

regularly. The Company currently has four Routine budgets: Asset Health (Reliability/Safety), New Business, Mandatory Relocations, and Capacity (Reliability). Because projects that are funded under routines are generally not defined until the current year, the budget is determined based largely on historical actuals. More specifically, routine budgets are based on historical spend and forward-looking customer growth projections for new business, while also taking cost escalations into account. Other individual routine projects, such as for new business growth, reinforcements, or rebuilds, are budgeted based on a two-year expenditure history and estimated in-service date. This routine grouping of projects serves to allocate funding for performing core business functions, such as connecting new customers, reconstructing facilities, and purchasing new meters, regulators, and fleet.

We also have discrete projects, which are often multi-year in nature, and can be either programs of work or individually planned projects.[33] These projects or programs of work are typically greater than $300,000, in which the Company sets up a discrete work order to track the specific cost of the project or program of work. Discrete projects are identified through the Company's Builder's Call Line (New Business), requests from municipal or government agencies (Mandatory Relocations), or through the Company's planning processes (Safety and Capacity Expansion). During the Company's annual budget cycle, we follow a rigorous budgeting process that identifies the optimal mix of projects and expenditures for a given year. If a discrete project is known and of high enough priority to be included separately in the annual budget, it is added to the budget during the regular budget cycle. In other instances, a budget is set for a particular kind of work, and discrete projects are pulled from that budget for execution once identified; these are typically within the first year or two of the five-year budget. In addition, discrete projects can arise outside of the Company's normal budgeting process. In order to account for these projects that arise outside of the normal budget process, the Company reviews historical spend and will place funding in a working capital fund.

There is a well-defined process for identifying, ranking, and budgeting gas capital projects. The key steps necessary to ensure the preparation of a comprehensive five-year capital budget are summarized below.

Step 1: Engineering and operations personnel identify potential risks (issues) and mitigations (solutions).

Step 2: Each risk and mitigation is reviewed for accuracy, completeness, and reasonableness.

Step 3: As each risk and mitigation is considered, it is scored based on certain criteria, such as the likelihood of occurrence, and the consequences of not addressing it.

[33] It is these larger, individually planned discrete projects that are subject to GIP reporting, if they applicable monetary threshold is met. Under Rules 4551(b) and 4553(a)(III)(E), defined programmatic expense is limited to relocation or replacement of meters, replacement of customer-owned yard lines, or as otherwise ordered by the Commission.

Step 4: All potential mitigations are ranked or prioritized. Historically, the PSIA had its own risk ranking criteria to determine eligibility for PSIA recovery. Going forward, former PSIA projects will be prioritized in the ordinary course of business along with all other Gas Operations capital projects.

Step 5: After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as overall capital levels based on financial criteria.

Step 6: Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are also classified as either "specific" (*i.e.*, "discrete") or "routine."

Step 7: Capital projects for large pools of small projects (e.g., main installations, service renewals, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date.

Step 8: All capital projects that are included are reviewed at both the business area level and at the corporate level to create an approved list.

Step 9: Work is deployed during the year, as efficiently and cost-effectively as possible.

The estimated in-service date of each large project and the closing patterns associated with different types of work pools (noted in Step 7 above) determine the date the project goes from Construction Work in Progress to Plant-In-Service on the Company's books and becomes a plant addition. Information specific to each of the primary planned project categories is below.

a. Safety

The budget for system safety and integrity projects is set in one of two primary methods: (1) planned program of prescriptive or regulatory required work (examples include, but are not limited to, MAOP reconfirmation and TIMP assessments) (Method 1); and (2) other safety or integrity work that is not prescriptive but necessary to ensure safe and reliable operation of the system (Method 2). When utilizing Method 1, the program budget is identified during the normal five-year budget cycle. The budget for prescriptive work is based on a combination of historical spend and prescriptive regulatory deadline requirements. Discrete projects are later identified with the program funding reallocated towards each discrete project. When utilizing Method 2, which is applicable to other safety and integrity programs or projects, the Company follows the well-defined process for identifying, ranking and budgeting gas capital projects, as described herein. Safety and integrity programs and projects budgets are set based on the Company's cost estimating process, discussed in the next subsection of this Report. As a consequence of this budgeting and project identification process, there are no planned safety projects meeting GIP criteria beyond 2024 in this Report.

b. Capacity Expansion

The process outlined earlier is generally used for capacity expansion projects. Annually, after completion of the system planning process for capacity expansion projects (discussed earlier in this Report), identified capacity expansion projects are entered into the budgeting process. Throughout the budgeting and planning processes, the Company also identifies other opportunities, such as bypassing regulator stations or the use of compressed natural gas/liquefied natural gas, when prioritizing which projects need to be undertaken, and when. The Company also evaluates non-pipeline alternatives for certain capacity expansion projects. This proactive approach allows us to be prepared to meet customer needs throughout the heating season, down to Design Day temperatures.

c. Mandatory Relocations

The Company does not typically receive information about mandated relocations ahead of any given calendar year. Unless there is an identified discrete project, the budget for mandatory relocations is set based on an average of the two years' prior actuals, escalated by the then-existing corporate-wide inflation rate. The inflation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases. The Company budgets for known discrete relocation projects if they are identified ahead of budget creation; emerging discrete relocation projects that arise after budget creation utilize funding from the mandated relocation working capital fund. The reason emerging discrete mandated relocation projects are not loaded into the budget is that the Company does not have control of when or where relocations will occur. The projects are driven by outside entities such as state, county, and local government agencies, developers, and others holding land rights. The Company partners with those outside entities, where possible, to limit impact on the budget and be more forward-looking. The budget for known discrete relocation projects is set based on the Company's cost estimating process, discussed in the next subsection of this Report.

d. New Business

Similar to mandatory relocations, the majority of new business work, as discussed earlier, consists of smaller projects that are not identified prior to the budget cycle. Thus, consistent with other gas projects, there are two types of capital project funding types for new business: 1) discrete projects, and 2) routines. Discrete projects typically are more complex projects that may include transmission mains, transmission regulator stations, larger diameter distribution mains, distribution regulator stations, and land or easement purchases. New business discrete projects are tracked individually under separate work orders and have a high likelihood of having expenditures in more than one budget year. It is these discrete projects that could potentially qualify as new business planned projects under the GIP.

New business projects funded under routines are generally simpler in nature, like a new service or short new main extension. In any given year, the Company receives many requests for a new service but cannot necessarily predict exactly when those requests will be received. Therefore, new services are not defined until the current year. Thus, unless there is a discrete new business Planned Project, the budget for new business is set as follows: (i) first, the forecast for the number of customers that are expected to request new gas service for the following calendar year is obtained from the Company's Sales, Energy, and Demand Forecasting department; and (ii) second, the budget for new business routines is then developed using a cost-per-customer from historical actuals in addition to corporate escalation factors including, but not limited to labor, non-labor, contractor, materials, equipment and fleet escalation rates, and bargaining labor increases. The Company only budgets for known discrete new business projects if they are identified ahead of budget creation; emerging discrete new business projects that come up after budget creation utilize funding from the new business routines.

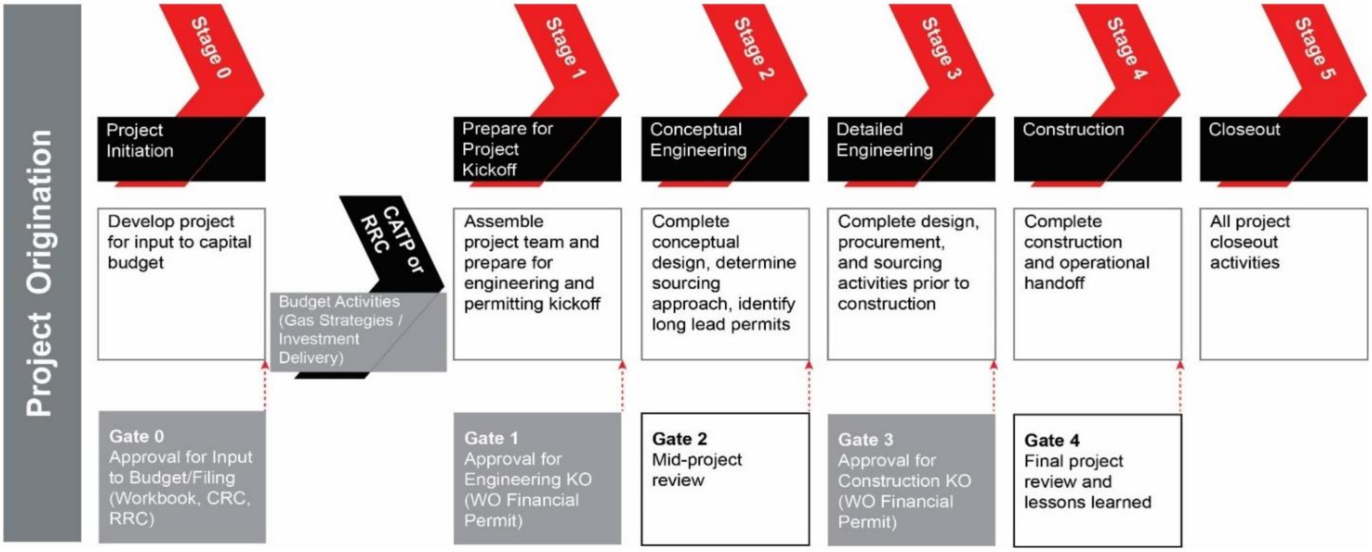
The budget for individual, known discrete new business projects is set based on the Company's cost estimating process, discussed in the next subsection of this Report. Also, as mentioned earlier, during the planning process, the Company determines, consistent with its tariff, the extent of any required customer contributions. The reason emerging discrete new business projects are not loaded into the budget is that the Company does not have control of when discrete new business projects will occur. The projects are driven by outside entities such as large customers and developers. The Company partners with those outside entities, where possible, to limit impact on the budget and be more forward-looking.

2. Planned Projects - Capital Cost Projections/Cost Estimate Classification Index

Public Service is developing and maturing industry best practices guidelines for budgeting and planning for its Planned Projects that align with American Association of Cost Engineers ("AACE") standards. To manage the scope and costs of its Planned Projects, the Company uses a Stage Gate process. This process is a guideline for best practices and, as noted, continues to be refined and incorporated into the Company's cost estimating processes for all projects. The Stage Gate methodology is a scalable process intended to apply increasing rigor and consistent governance throughout the lifecycle of the project. In each Stage, the Company performs a particular scope of work necessary to bring the project to the next Gate, or milestone, that determines whether and how the project will proceed. The estimating process increases in rigor as the project matures and reaches each of the Gates, because the scope of a project matures and becomes more detailed as the project moves closer to implementation and then completion.

At a high level, projects move through various stages of development, the beginning of which is marked by a governance point known as a "Gate" that would determine whether the work proceeds to the next Stage. In the project Stages, projects make their way from initiation, to preparation for kick-off, to conceptual engineering, to detailed engineering, construction, and closeout. As explained below, the budget for a project is also refined at each gate. Figure 4 below depicts each of the Stages and Gates within the process, the cascading relationship of each stage, a high level description of each Stage, and major project milestones. Importantly, the impact that cost estimating provides diminishes through the project lifecycle as estimated values become specific, quotable values provided by contractors and vendors.

Figure 4: Stage Gate Process



The Company assigns work of different dollar amounts to one of four Tiers – Tier 1: Greater than $5 million; Tier 2: $1 million - $5 million; Tier 3: $300,000-$1 million; and Tier 4: Less than $300,000. The Tier to which a project is assigned determines how the project is managed, including the anticipated range of project cost estimate accuracy (the cost estimate Class per AACE standards, or "Estimate Class") at each Gate. Tier 1 projects follow the most strenuous estimating process, and Tier 4 the least. And, in turn, Tier 1 projects are expected to have the most precise project scope definition and Estimate Class at the advanced Gates. Planned Projects, by definition, all fall within either Tier 1 or Tier 2. The Stage Gate process for Tier 1 and Tier 2 projects requires a material allocation of internal and external resources that are managed by a dedicated project lead.

For example, at Gate 3 (Approval for Construction) at the end of Stage 3 (Detailed Engineering), a Tier 1 project (greater than $5 million) will have an expected cost estimate accuracy range of +/- 5 percent, whereas a Tier 2 project ($1 million - $5 million) will have an expected cost estimate accuracy range of +/- 10 percent. Table 3 below depicts Tier 1 and Tier 2 Project cost estimate milestones by Stage and Gate, corresponding to increasing design maturity based on AACE's estimate classification. The estimate accuracy range corresponding with a given Estimate Class is also provided.

Table 3:
Tier 1 and Tier 2 Project Estimate Classification Application*

Estimate Accuracy Application				
Gate	**Tier 1 (> $5M)**	**Tier 1 Estimated Accuracy Range**	**Tier 2 ($1M - $5M)**	**Tier 2 Estimated Accuracy Range**
Gate 0	Class 5	+/- 50%	Class 5	+/- 50%
Gate 1	Class 4	+/- 30%	Class 5	+/- 50%
Gate 2	Class 3	+/- 20%	Class 3	+/- 20%
Gate 3	Class 1	+/- 5%	Class 2	+/- 10%
Gate 4	Class 1	+/- 5%	N/A	N/A
Gate 5	N/A	Costs Realized	N/A	Costs Realized

*This table is a guideline for best practice.

Tier 1 projects do not have a Class 2 +/- 10 percent estimate as part of the AACE process because at Stage 3, as compared to lower Tier projects, they are required to have the tighter Class 1 estimate of +/-5 percent. Similarly, Tier 2 projects do not have either a Class 4 +/- 30 percent estimate or Class 1 +/- 5 percent estimate.

Table 4 below provides more detail for all five Estimate Classes.

Table 4:
Cost Estimate Classification Matrix*

	Primary Characteristic	Secondary Characteristic		
Estimate Class	**Maturity Level of Project Definition Deliverables** **Expressed as % of complete definition**	**End Usage** **Typical purpose of estimate**	**Methodology** **Typical estimating method**	**Expected Accuracy Range** **Typical variation in low and high ranges at an 80% confidence interval**
Class 5	0% to 2%	Concept screening	Cost/length factors, parametric models, judgment, or analogy	+/- 50%
Class 4	1% to 15%	Study or feasibility	Cost/length, factored or parametric models	+/- 30%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly-level line items	+/- 20%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	+/- 10%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	+/- 5%

*This table is a guideline for best practice.

The Stage Gate process, designed in concert with AACE principles and aligned with AACE cost estimation standards, has several benefits for planned projects, and for our customers. First, it demonstrates a formalized manner of managing these projects that aligns with industry-leading practices and standards. Second, it explains from an objective industry perspective why individual projects will have varying degrees of cost certainty at different points in the process (consistent with AACE International Recommended Practices 97R-19 – Cost Estimate Classification System – As Applied in Pipeline Transportation Infrastructure Projects). For example, permitting requirements, restoration requirements, field conditions and other circumstances can impact the initial estimate, scope, and timing of any particular piece of work. Given this unavoidable fact, the Company believes it is valuable to have guidelines for application of established practices and procedures to manage the work. Third, it illustrates that planned projects receive detailed scrutiny from multiple angles and project performance transparency subject to oversight within the Company.

C. Map(s) of 2023-2028 Planned Projects (4553(a)(V))

Rule 4553(a)(V) requires the following:

> The utility shall provide one or more maps indicating locations of individual planned projects, pressure district[34] or geographic area served by the individual planned projects or that would otherwise lead to a foreseeable lack of system reliability, if applicable, and other distinct zones identified for planning purposes in the utility's most recently approved clean heat plan pursuant to subparagraph 4731(a)(I)(B) with sufficient geographical detail such that the Commission can evaluate and fully comprehend the extent and purpose of the overall gas infrastructure plan. The utility shall also indicate whether the planned projects are located within disproportionately impacted communities

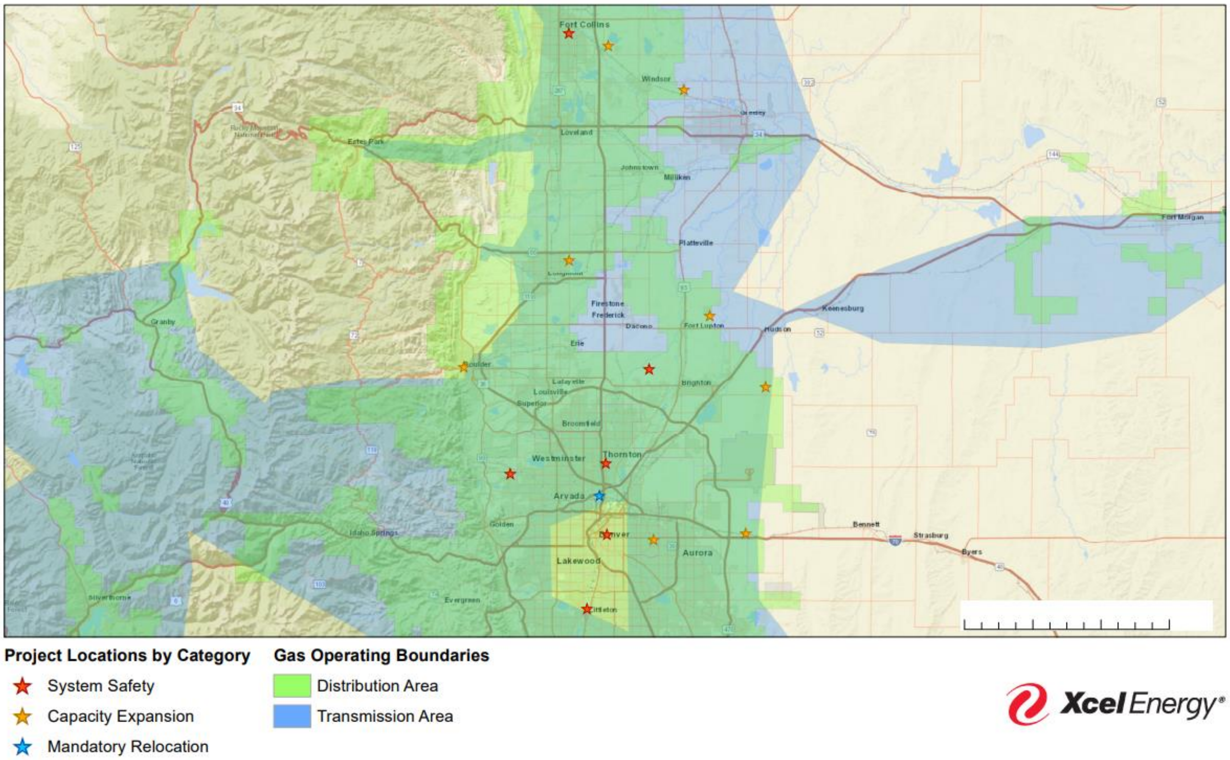
Along those same lines, Rule 4553(c)(I)(J) requires, for each planned project in the GIP, an illustrative map of the facilities including:

> (i) the pressure district or geographic area that requires the proposed facilities;
>
> (ii) the existing and proposed regulator stations and existing and proposed distribution piping and higher capacity pipelines served by or representing the proposed facilities;
>
> (iii) the locations of any disproportionately impacted community;[35]
>
> (iv) identification of the electric utility service provider(s) at that location; and
>
> (v) any other information necessary to allow the Commission to make a thorough evaluation.

In compliance with these requirements, below is a map indicating, at a very high level, where all of the planned projects reported in the GIP are located, geographically, and by planned project type.

[34] The Commission also provides a definition of "pressure district" to mean "a localized area within a utility's service territory whereby an established minimum and maximum pressure range is intended to be maintained and is distinct from neighboring regions" (Rule 4001(nn)).
[35] "DI Community" refers to a disproportionately impacted community.

Figure 5: 2023-2028 GIP Planned Project Overview Map



More detailed maps meeting the remaining rule requirements are provided for each planned project as part of its Project Packet, which also contains detailed project information and other data required by the GIP Rules. The mapping parameters used by the Company are further discussed in Section VI of this Report.

D. Gas Distribution Annual Report, Form F7100.1 (4553(a)(VI))

The Company's 2022 United States Department of Transportation Gas Distribution System Annual Report, Form F7100.1-1 is included as Attachment D. Although not required by rule, we are also including the Company's 2022 United States Department of Transportation Natural and Other Gas Transmission and Gathering Systems Annual Report, Form F7100.2-1, as Attachment E.[36]

E. Summary of Outreach (4553(a)(VII))

The GIP Rules do not appear to require public workshops or outreach to DI Communities as part of the Initial GIP, but such requirements do apply in conjunction with litigated GIPs filed as an application.[37] This logic is supported by the Commission's discussion in Decision No. C22-

[36] See GIP Rule 4553(a)(VI).
[37] See GIP Rule 4552(d)(IV), which provides, in part: "[p]rior to the filing of the application, the utility shall hold one or more public workshops to educate, and facilitate feedback from, stakeholders and potential intervenors on the projects selected . . ." See also GIP Rule 4553(a)(VII).

0760 in Proceeding No. 21R-0449G (the "Clean Heat NOPR"), where it stated in pertinent part, as follows:

- "Adopted Rule 4552(d)(III) requires utilities, prior to filing an application, to hold one or more public workshops to educate, and facilitate feedback from, stakeholders and potential intervenors on the projects selected, the utility's approach to alternatives analyses for the projects selected, and the results of the utility's alternatives analyses, pursuant to Rule 4553(c)(I)(P) with the goal of facilitating a robust and broadly supported set of alternatives analyses upon the filing of the application."[38]

- "[W]e adopt a minor modification to the rules to clarify that the nature of the [DI Communities] outreach should be appropriate to the filing and that should be described as part of relevant applications."[39]

The foregoing rationale makes sense with respect to the Initial GIP as the Company has had truncated time to prepare it, and the effective date of the GIP Rules is May 15, 2023.

Notwithstanding the foregoing, the Company understands and appreciates the importance of outreach in the context of the Initial GIP. While specifically engaging with DI Communities about this Initial GIP prior to its filing was not feasible for a variety of reasons, including timing, as discussed below, the Company was able to engage in two limited public workshops including those who participated in the Clean Heat NOPR. During the first public workshop, which was held on April 10, 2023, the Company provided a preliminary (and draft) overview of the requirements for the Initial GIP and anticipated contents. The Company also provided, at a high level, information on projects anticipated to be included in the Report, by category, including, among other things, estimated expenditures, project descriptions, and project locations. Finally, the Company provided general information on the alternatives analyses process being undertaken (which was still in progress at that time). The Company fielded questions regarding several topics, including estimated expenditures, planning, like-for-like replacements in connection with safety projects, and the alternatives analyses. Aside from Company representatives, there were approximately 40 participants in this first workshop, representing, among others, regulatory stakeholders, environmental advocates, communities, labor, LDCs, and other interested parties.

The Company held the second public workshop on April 27, 2023. In this workshop the Company provided information regarding the framework and components of the planned Report, and planned projects anticipated to be included therein, by category. Additionally, the Company provided the framework and criteria being used for evaluating NPAs, as well as information on the preliminary results of the NPAs to be presented in the Initial GIP. The Company fielded questions regarding several topics primarily related to the alternatives analyses and related considerations. Aside from Company representatives, there were approximately 30 participants in this second workshop, representing, among others, regulatory stakeholders, environmental advocates, communities, labor, LDCs, and other interested parties.

[38] Decision No. C22-0760 at ¶200 (emphasis added).
[39] Decision No. C22-0760 at ¶213 (emphasis added).

Separately, the Company has determined that nine of the planned projects are within or near DI Communities in our service territory, affecting approximately 5,200 customers. This is a large number of customers to contact, particularly given the timing, and the need to develop an appropriate outreach plan. As a result, the Company, in alignment with the GIP Rules, chose not to engage in what could only be partial outreach to DI Communities prior to the filing of this Initial GIP. In Decision No. C22-0760, the Commission recognized the need for flexibility and careful consideration of these touchpoints, stating the following:[40]

> These rules are only one of potentially many settings in which appropriate community engagement must be considered as the Commission implements SB 21-272, and regulated entities may need flexibility, especially in the first stages of implementing new rules, to define appropriate engagement. Without taking a holistic view of what constitutes appropriate community engagement across industries and cases, the Commission risks establishing overly prescriptive requirements that burden communities with excess case-specific meetings rather than lead to meaningful engagement.

Further, we anticipate that more concrete parameters regarding such outreach will be in place prior to the adjudicated GIP required to be filed in 2025. As explained in Decision No. C22-0760, the Commission has initiated a pre-rulemaking regarding SB 21-272, Proceeding No. 22M-0171ALL, which will gather information about best practices regarding community engagement and appropriate roles for the Commission and other entities, including state agencies and regulated applicants, among other objectives. As acknowledged by the Commission, ". . . that proceeding may be the best venue to consider important questions such as what information is most critical to understand in which types of proceedings, and whether outreach-related rules should be specific to applications or rather, whether rules specific to outreach requirements should be crafted and applied in varying ways depending on the nature of the proceeding."[41] Notwithstanding the foregoing, it is the Company's general practice to reach out to communities, in general, when significant gas projects will impact their community. We will continue to do this in the interim, while an actionable outreach plan for DI Communities is developed for the first litigated GIP.

F. <u>Design Day Temperature (4553(a)(IX))</u>

Pursuant to GIP Rule 4553(a)(IX), the Company is required to "provide the then-current Design Day temperature assigned to unique segments of the utility system used for capacity planning, and data to support such design temperatures." This section of the Report is intended to address this requirement.

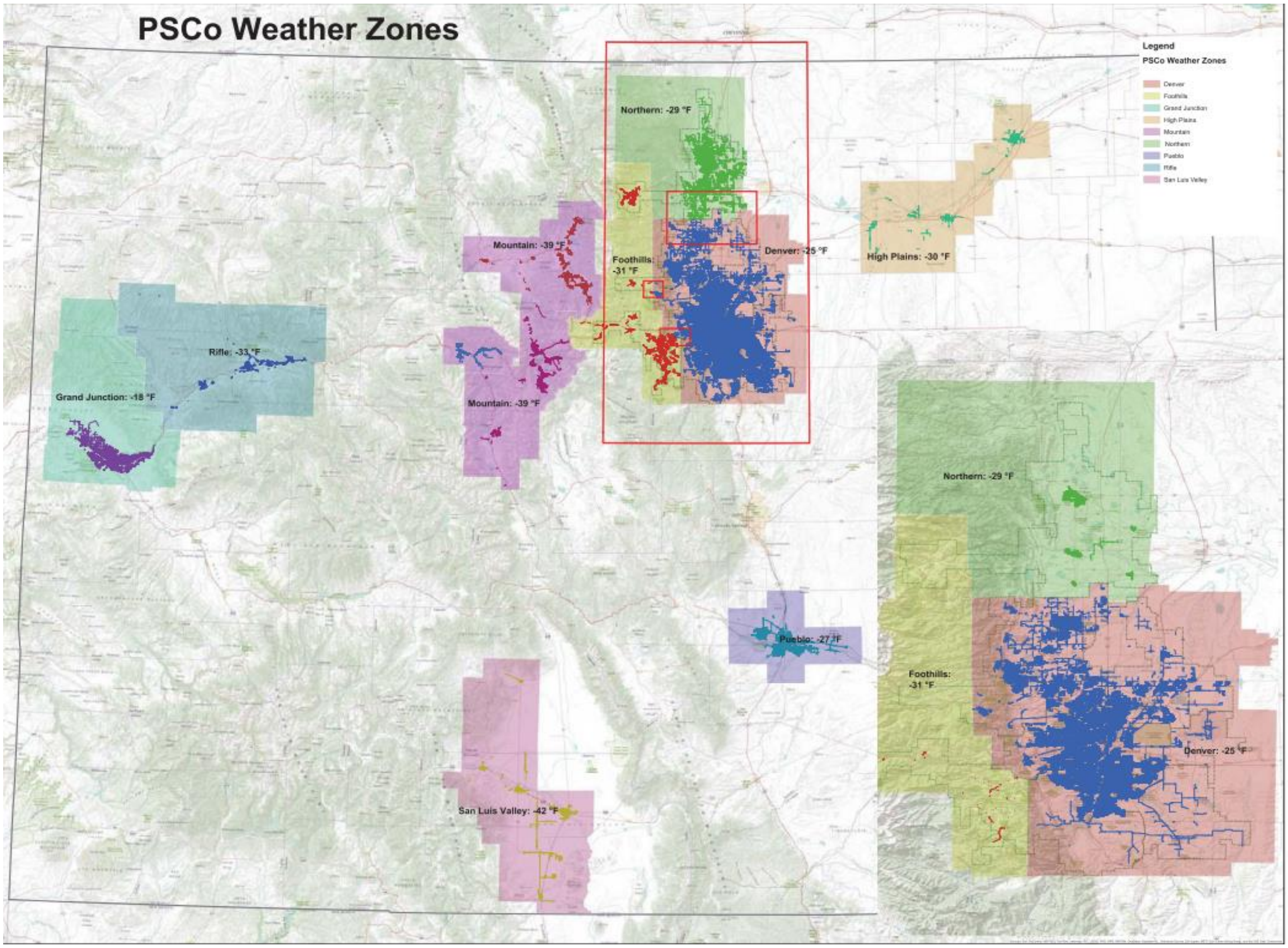
The Company utilizes the concept of a Design Day to ensure that its existing gas infrastructure and assets can handle firm customer load during an extreme cold weather day, when demands on our system are greatest. As relevant to the Company, Design Day is determined based on the concept of a peak-day, which refers to a probabilistic occurrence of a temperature occurring over a given heating season. The Company has established its Design Day temperature based on

[40] Decision No. C22-0760 at ¶212.
[41] Decision No. C22-0760 at ¶213.

a 1-in-30 year cold weather event occurring within an associated weather zone. That is to say, Design Day is based on the coldest temperature we would expect to see once every 30 years. That does not mean that we *will* see that temperature exactly once every 30 years; rather, it means that based on historical weather temperature data, there is a 1-in-30 probability of experiencing a Design Day temperature in any given heating season.

Because temperatures can vary across different portions of the Company's distribution system within its Colorado service territory, the Company's service territory is divided geographically into nine distinct weather zones across the State based on historical common weather patterns. The map below reflects the Company's nine separate weather zones and associated current Design Day temperatures.

Figure 6: PSCO Weather Zones



The process of calculating a Design Day temperature in a weather zone is outlined below:

- Annually, weather data for the past 12 months is collected at specified National Oceanic and Atmospheric Administration ("NOAA") weather stations that are located within the associated weather zones.
- Collected data is then added to supplement the existing historical temperature data for each specified weather station in each weather zone.
- The historical weather data used to determine Design Day is updated to reflect the newly acquired additional 12 months.
- The number of occurrences for each temperature over time is tracked and documented and the probability of occurrence is determined.
- The probability that is closest to a 1-in-30 year is ascertained without exceeding the probability of 0.033 (3.3 percent).
- The closest value is then considered the Design Day temperature for that distinct weather zone. If that value differs from the existing Design Day temperature, then the Design Day temperature is updated. If not, the Design Day temperature does not change.

As a result of this process, which is repeated each year to determine whether there are any changes to Design Day temperatures, the Company has currently established the Design Day temperatures reflected on the table below, by weather zone.

Table 5:
Design Day Temperatures by Weather Zone

Public Service Weather Zones	Design Day Temperature (°F)
Denver	-25
Mountain	-39
Pueblo	-27
Grand Junction	-18
Rifle	-33
San Luis Valley	-42
Northern	-29
Foothills	-31
High Plains	-30

A review of the past weather events experienced in each of the Company's distinct weather zones during the past 15 years supports the aforementioned Design Day temperatures, as shown in the table below.

Table 6:
Weather Events During the Past 15 Years

Public Service Weather Zones	Design Day Temperature (°F)	Year Design Day Last Experienced	Coldest Temp Experienced in Last 15 Years (°F)	Month/Year of Coldest Temp Experienced in Last 15 Years
Denver	-25	1990	-24	Dec 2022
Mountain	-39	1962	-32	Feb 2011
Pueblo	-27	1996	-21	Jan 2011
Grand Junction	-18	1989	-16	Dec 2009
Rifle	-33	1989	-19	Dec 2013
San Luis Valley	-42	1978	-36	Jan 2017
Northern	-29	1984	-16	Jan 2017
Foothills	-31	1982	-23	Feb 2011
High Plains	-30	1989	-22	Feb 2022

Designing a gas distribution system based on this Design Day concept is a typical utility best practice, and for the Company, it is important to recognize that gas demand is correlated to the ambient temperature. Therefore, as temperatures decrease, the demand for gas increases thus causing reduced pressures across the system. The colder the weather gets, the more the pressure loss is experienced within the system as a result of increased firm customer gas consumption. Inadequate pressures on the gas system can cause interruption in gas service to firm customers; and it is important that we design the system to withstand weather events when they occur.

V. FORECASTS (4553(b)) AND CONCEPTUAL INCREMENTAL INVESTMENT (4553(c)(II))

Rule 4553(b) directs gas utilities to present reference, low, and high forecasts incorporating various factors such as "design peak demand, customer count, sales and capacity requirements, gas content including expected mixtures by volume of hydrogen and recovered methane, and system-wide greenhouse gas emissions, consistent with the utility's approved portfolio of clean heat resources…" The Company does not, however, at this time have an approved portfolio of clean heat resources, nor is hydrogen currently being blended on the system. Additionally, Rule 4553(c)(II) requires identification of incremental investment over the GIP action period and informational period based on the reference, low, and high forecasts, as well as identification of capacity expansion project movement.[42]

In compliance with the GIP Rule requirements related to forecasting, the Company first addresses the reference forecast methodology. The conceptual low and high forecast scenarios, along with associated avoided or incremental capacity expansion investment based on those scenarios, are also provided herein.

A. "Reference" Forecasts

"Reference forecasts" determine whether capacity expansion projects are required, such as those included in this GIP Report, and such forecasts are determined in the manner discussed in Section IV.A.2 above.[43] In this case, the reference forecast is based on the 2021-2022 heating season, and the associated 2021-2022 Design Day As-Is model. The 2021-2022 Design Day As-Is model was used to determine capacity constraints on the system, and served as the foundation for identification of the capacity expansion planned projects in this Report. The state-wide customer count growth rate received from the Company's Sales, Energy and Demand Forecasting department is reflected in the table below. This data is further stratified at the county level based on DOLA, and areas of the State may experience higher or lower growth rates than reflected on the Table.

[42] As forecasts are prepared in connection with capacity expansion projects, the Company assumed these requirements apply to that category of planned projects.
[43] Planned projects in the remaining categories are driven by PHMSA regulations/safety and integrity needs, new business requests, and mandatory relocation requirements.

Table 7: Customer Count Growth Rate

Rate Class	2023/2024 Heating Season	2024/2025 Heating Season	2025/2026 Heating Season	2026/2027 Heating Season	2027/2028 Heating Season	2028/2029 Heating Season
Residential Growth	0.91%	0.95%	0.98%	0.97%	0.96%	0.95%
Small Commercial Growth	0.27%	0.25%	0.26%	0.25%	0.25%	0.24%
Combined Residential and Small Commercial Growth	0.87%	0.91%	0.93%	0.92%	0.91%	0.91%

B. Low and High Forecasts

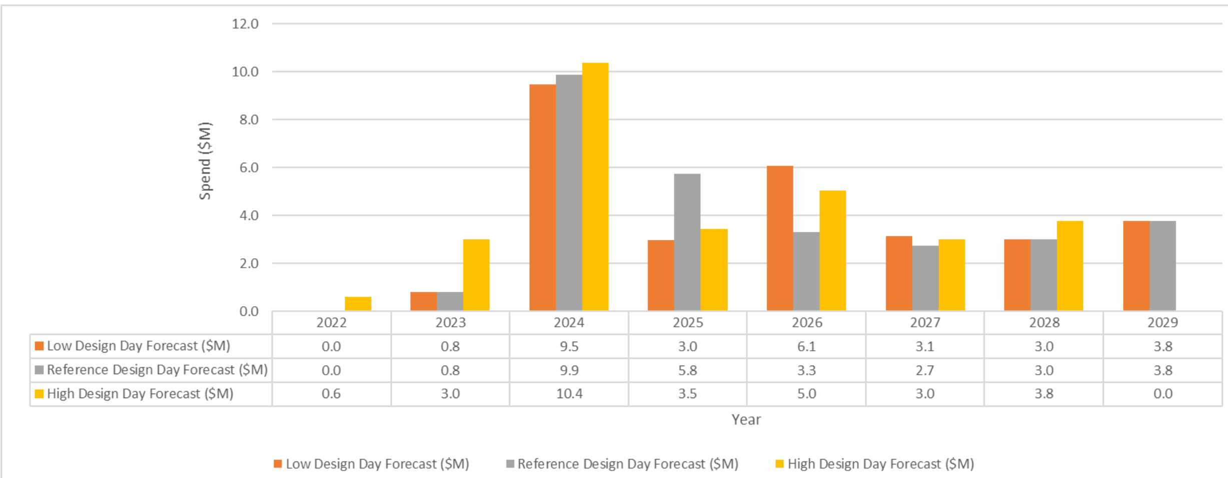
Although not included as part of the Company's existing forecasting methodology, the Company developed conceptual low and high forecasted sensitivity scenarios of the reference forecast as required by Rule 4553(b)(II). For both the low and high forecast scenarios in this Initial GIP, the Company's Sales, Energy and Demand Forecasting department reviewed the past 10 years of data for residential and small commercial customers to identify the actual annual high and low customer count growth experienced by the Company. As a result of that review, the Company used a low customer count growth forecast of 0.83% for residential customers and –0.04% for small commercial customers; and a high customer count growth forecast of 1.28% for residential customers and 0.32% for small commercial customers. Similar to the "reference" forecast analysis mentioned above, the Company then used the 2021-2022 Design Day As-Is model, adjusting the forecasted customer count growth rate inputs (1) for the low customer count growth forecast in order to generate the low capacity expansion project forecast; and (2) for the high customer count growth forecast in order to generate the high capacity expansion project forecast. Through this analysis, the Company was able to determine the impacts on capacity expansion planned project-level investment in both scenarios. The results are discussed below.

C. Incremental Investment Based on Low and High Forecasts

The Company emphasizes that the low and high forecasts are conceptual and hypothetical in nature and do not reflect the Company's actual forecasted load growth. The Company's actual forecasted load growth is the "reference" forecast. Nevertheless, to the extent projects are shifted to the informational period through this exercise, it increases the likelihood that they could eventually become unnecessary due to changes in load growth or specifically avoided with an NPA or other alternative. Just as importantly, however, the projects will be needed regardless of the forecast. For example, if the firm peak demand growth rate for the area served by the Powhaton Station is zero percent for Residential and Small Commercial customers, the project will still be needed as it supports other components of the interconnected high-pressure system.

Figure 7 below shows the GIP annual capital spend impacts of the low and high forecasts on capacity expansion planned projects presented in this GIP, as compared to the reference forecast. This Figure does not include the Hydrogen Blending Demonstration project as no high/low conceptual forecast is applicable to the project. Further, the 2028 Mead to East Longmont Reinforcement and Fort Lupton Compressor Station projects were excluded as the cost estimates and project scopes are still being refined, and the estimated in-service dates are outside of the GIP Period.

Figure 7: Capacity Expansion Project Spend – Forecast Sensitivity Analysis



Rule 4553(c)(II) also requires "an identification of the primary individual new projects avoided in the low design peak demand forecast and an identification of the primary individual new projects and capital spend added in the high design peak demand forecast." As depicted on Table 8 below, application of the conceptual low and high forecast analyses did not result in any newly identified or avoided capacity expansion planned projects. However, the low and high forecast did cause several of the analyzed capacity expansion planned projects' in-service dates to shift when compared to the reference forecast.

Table 8: Planned Projects Avoided/Added[44]

	In-Service Date (Calendar Year)		
Capacity Expansion Project Name	***Low Forecast***	***Reference Forecast***	***High Forecast***
Harmony High Pressure Pipeline Project	2029	2029	2028
Powhaton Station	2024	2024	2024
F-3 Reinforcement	2026	2025	2024
Windsor Severance Reinforcement	2024	2024	2023
Pearl Street Mall	2026	2026	2026

[44] This Table does not include the Hydrogen Blending Demonstration project as no high/low conceptual forecast is applicable to the project. Further, the 2028 Mead to East Longmont Reinforcement and Fort Lupton Compressor Station projects were excluded as the cost estimates and project scopes are still being refined, and the estimated in-service dates are outside of the GIP Period.

VI. PLANNED PROJECT INFORMATION (4553(A)(VIII) AND 4553(c)(I))

In this section of the Report the Company provides an overview of the Planned Projects with expected start dates during this Initial GIP Plan Period (2023-2028)[45] for which it provides the project-specific information required by Rule 4553(c)(I).[46] The project-specific information for each Planned Project is provided in a "Project Packet" within the applicable Project Category attachment to this Report. The contents of the Project Packets are explained in more detail later within this section.

A. Planned Project Overview by Category

1. System Safety and Integrity Planned Projects

The Company has identified six System Safety and Integrity Planned Projects that are expected to start during the Initial GIP Plan Period. These planned projects are identified in the Table below, and further described in the Safety Project Packets found in Attachments A-1 through A-6. As indicated in the Table, most of the projects are part of the Programmatic Pipe Replacement Program ("PPRP") for vintage/problematic pipe and coupled intermediate pressure ("IP") pipe, with two projects associated with inoperable/obsolete equipment. The listed projects have an estimated total capital expenditure of $26.0 million throughout the Initial GIP Plan Period and an overall estimated total project capital expenditure of $26.2 million. All six System Safety and Integrity projects have start dates during the Action Period (2023-2025) with initial project spend occurring in either late 2022 or expected to occur at some point in 2023, and all six projects are expected to be in-service by the end of 2024. As explained earlier in this Report, a budget is set for safety work, and as discrete planned safety projects are identified, they are funded from that budget. For these reasons, there are no planned safety projects meeting GIP criteria beyond 2024 in this Report.

[45] Rule 4551(e) establishes the "gas infrastructure total plan period" through incorporation of Rule 4551(c) ("gas infrastructure plan action period") and Rule 4552(d) ("gas infrastructure plan informational period"). Essentially the action period is the first three years of GIP, or years 2023-2025 for the Initial GIP; while the informational period is the later three years of the GIP, or 2026-2028 for the Initial GIP.
[46] Rule 4553(a)(VIII) and Rule 4553(c)(I). See Section II of this Report for the parameters used to scope projects as Planned Project to establish a starting point for detailed gas infrastructure reporting in this Initial GIP.

Table 9: Public Service 2023-2028 System Safety and Integrity Projects ($ Millions)

	Action Period			Informational Period					
Project Name/Location	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Estimated Total GIP Expenditures**	**Estimated Total Project Expenditures ***	**Project Description**
Washington & 76th Phase 2/ Thornton	$5.7	$0.0	$0.0	$0.0	$0.0	$0.0	$5.7	$5.7	Pipeline Replacement (PPRP-Coupled IP)
Clarkson St. Main Renewal Phase 2/ Denver	$5.4	$0.0	$0.0	$0.0	$0.0	$0.0	$5.4	$5.4	Pipeline Replacement (PPRP – Vintage/Problematic Pipe)
Fort Collins 8" Intermediate Pressure/ Fort Collins	$4.9	$0.0	$0.0	$0.0	$0.0	$0.0	$4.9	$4.9	Pipeline Replacement (PPRP- Vintage/Problematic Pipe)
W. Belleview Ave. Coupled Intermediate Pressure/ Littleton	$3.3	$0.0	$0.0	$0.0	$0.0	$0.0	$3.3	$3.3	Pipeline Replacement (PPRP-Coupled IP)
Rebuild F-808/ Arvada	$3.1	$0.0	$0.0	$0.0	$0.0	$0.0	$3.1	$3.3	Regulator Station Rebuild (Inoperable/Obsolete Equipment)
Yosemite Air Dryer/ Brighton	$0.5	$3.1	$0.0	$0.0	$0.0	$0.0	$3.6	$3.6	Air Dryer (Inoperable/Obsolete Equipment)
Total	**$22.9**	**$3.1**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$26.0**	**$26.2**	

* Includes capital expenditures for planned projects before the GIP Plan Period. Differences in sums due to rounding.

2. *Capacity Expansion Planned Projects*

The Company has identified eight Capacity Expansion Planned Projects that are expected to start during the Initial GIP Plan Period, and which are identified in Tables 10 and 11 below, and further described in the attached Project Packets. These projects are generally needed to maintain reliability for existing customers and/or growth on the system due to new customers.[47] Table 10

[47] The Capacity Expansion subcategories as defined in Rule 4553(a)(III)(C) are identified in the attached Project Packets for each of the listed Capacity Expansion Planned Projects.

contains projects with start dates within the Action Period. As noted, three of these projects require regulator station work, and two of the projects involve pipeline reinforcement/renewal.

Table 10
Public Service Capacity Expansion Projects Beginning in the Action Period
($Millions)

	Action Period			Informational Period					
Project Description/Location	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Estimated Total GIP Expenditures**	**Estimated Total Project Expenditures***	**Project Description**
Powhaton Station / Wattenburg	$0.0	$5.2	$0.1	$0.0	$0.0	$0.0	$5.3	$5.3	Install Regulator Station - Reinforcement
Hydrogen Blending Demonstration / Unincorporated Adams County	$4.8	$0.1	$0.0	$0.0	$0.0	$0.0	$4.9	$5.0	Upgrade Regulator Station
F-3 Reinforcement / Aurora	$0.0	$0.0	$4.0	$0.0	$0.0	$0.0	$4.0	$4.0	Pipeline Reinforcement
Windsor Severance Reinforcement / Windsor	$0.6	$2.5	$0.0	$0.0	$0.0	$0.0	$3.2	$3.2	Install Regulator Station - Reinforcement
Pearl Street Mall / Boulder	$0.0	$2.1	$2.3	$2.3	$0.0	$0.0	$6.7	$6.7	Pipeline Renewal
Total	**$5.4**	**$10.0**	**$6.4**	**$2.3**	**$0.0**	**$0.0**	**$24.1**	**$24.2**	

* Includes capital expenditures for planned projects before the GIP Plan Period. Differences in sums due to rounding.

Separately, three Capacity Expansion projects are currently anticipated to commence during the Informational Period, as reflected on the Table below.

Table 11
Public Service GIP Capacity Expansion Projects Beginning in the Informational Period ($Millions)

	Informational Period					
Project Description/Location	**2026**	**2027**	**2028**	**Estimated Total GIP Expenditures**	**Estimated Total Project Expenditures***	**Project Description**
Mead to East Longmont Reinforcement / Longmont	$0.0	$0.0	$2.4	$2.4	>$12.0	Pipeline Reinforcement
Harmony High Pressure Pipeline Reinforcement / Ft. Collins	$0.6	$2.7	$3.0	$6.3	$10.1	Pipeline Reinforcement
Fort Lupton Compressor Station / Fort Lupton	$0.0	$0.0	$6.4	$6.4	>$12.0	Install Compressor Station - Reinforcement
Total	**$0.6**	**$2.7**	**$11.8**	**$15.1**	**>$34.1**	

* Includes capital expenditures for planned projects after the GIP Plan Period. Differences in sums due to rounding.

As noted on the Table, the Fort Lupton Compressor Station project and the Mead to East Longmont Reinforcement project are estimated to begin in 2028 and carry over past the GIP Plan Period. For purposes of this Report, these projects are reflected as having greater than $12 million in estimated capital expenditures. Both of these projects have not been through the Company's stage gate, financial governance, or budgeting processes. As expected for such planned projects in the informational period, particularly late in the informational period, these planned projects are in the pre-initiation phase and are subject to change over time as the project develops and the need for and cost associated with the project is refined. It is possible that the need for these projects could be resolved, mitigated, or delayed for a variety of reasons. The Company did, as explained in more detail below and in the Project Packet, choose both of these projects for an alternatives analysis.

3. Mandatory Relocation Planned Projects

The Company has identified one Mandatory Relocation planned project that has a start date within the Initial GIP Plan Period. This planned project is identified in the Table below and is further described in the Mandatory Relocation Project Packet found in Attachment C-1. This project had a minimal amount of initial project spend in late 2022 just prior to the Initial GIP Plan Period, with most of the spend expected to occur in 2023. Accordingly, the associated estimated total GIP expenditure is $4.1 million, while the estimated total project expenditure is $4.2 million. It is expected to be in-service in 2023.

Table 12
Public Service 2023-2028 Mandatory Relocation Projects

	Action Period			Informational Period				
Project Name/Location	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Estimated Total GIP Expenditures**	**Estimated Total Project Expenditures***
62nd Ave. Main Relocation / Unincorporated Adams County	$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$4.1	$4.2
Total	**$4.1**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$4.1**	**$4.2**

* Includes capital expenditures before the GIP total period. Differences in sums due to rounding.

4. New Business

Pursuant to Rule 4553(a)(III)(B), New Business projects include utility investment and spending needed to provide gas service to new customers or customers requiring new gas service. Such projects are also not subject to GIP reporting requirements unless the associated cost estimate exceeds $3 million in utility capital investment in 2020 dollars. For the Company, the majority of new business work consists of smaller projects that are not identified prior to the budget cycle. As mentioned earlier, during the planning process, the Company determines, consistent with its tariff, the extent of any required customer contributions. The reason emerging discrete new business projects are not loaded into the budget is that the Company does not have control of when discrete new business projects will occur. The projects are driven by outside entities such as large customers and developers. The Company partners with those outside entities, where possible, to limit impact on the budget and be more forward-looking. For this Initial GIP, the Company has not identified New Business planned projects that have a start date within the Initial GIP Plan Period, and that otherwise meet GIP reporting requirements.

5. Defined Programmatic Expenses

As noted earlier in this Report, Commission Rule 4553(a)(III)(E) provides that "Defined programmatic expenses" as defined in paragraph 4551(b), means the following, or as otherwise ordered by the Commission:[48]

(i) "relocation or replacement of meters" shall include the utility's investment and expenditure to replace or relocate customer meters, including at-risk meters, not otherwise covered by other projects; and

(ii) "replacement of customer-owned yard lines" shall include the investment and expenditure to replace customer-owned yard lines and associated infrastructure with utility-owned pipelines and associated infrastructure.

[48] GIP Rule 4551(b) further defines "defined programmatic expense" to mean "a a programmatic expense that, in the aggregate, falls within the oversight of a utility's application for issuance of a certificate of public convenience and necessity or approval of a gas infrastructure plan. Defined programmatic expense means company-wide programmatic investment in activities related to relocation or replacement of meters and customer-owned yard lines, or as otherwise ordered by the Commission."

With respect to meters, the Company has a Commission-approved meter sampling and periodic testing program that has been in place since 2008 ("Meter Program"). As part of that Program, the Company tests the various types of meters on its system as required, and, under the sampling portion of the Program, replaces meters in failed lots. The Company, as directed by the Commission in Proceeding No. 22AL-0046G, recently filed an Application for "Approval of a Modified Gas Meter Sampling and Periodic Testing Program, Process for Exchange of Meters in Failed Lots, and Waiver of Commission Rules 4304(D)(I) – (IV) and (VI) as Necessary."[49] The Company does not otherwise have a Company-wide program to replace or relocate customer meters at this time.

With respect to COYLs, the GIP Rules separately require the Company to provide COYL-related information under Rule 4553(d), under existing infrastructure assessment reporting. While the Company does not have a program for replacement of COYLs, additional information on the topic can be found in Section X of this Report.

B. Planned Project Specific Information – Project Packets

The project-specific information required by Rule 4553(c)(I) is provided for each Planned Project within a Project Packet. These Project Packets are organized by project type within the following attachments:

- Attachment A: System Safety and Integrity Projects;
- Attachment B: Capacity Expansion Projects; and
- Attachment C: Mandatory Relocation Project.

Each Project Packet includes an Introduction Page that provides general high-level information about the Planned Project, a project-specific map, a narrative offering further detail about the applicable rule criteria, and project specific revenue requirements. Additionally, an alternatives analysis is included for each of the five capacity expansion projects chosen for the analysis.

While the majority of reporting requirements are straightforward, several require further explanation regarding how the Company applied them across the Project Packets, as reflected below by rule reference:

- *Rule 4553(c)(I)(D): Projected life of project*. This Rule requires, for each planned project, the "projected life." The Company has interpreted this to mean the depreciable book life for the major components of a project based on the proper asset class. Depreciable book life refers to the number of years that an asset is considered as usable before the total cost of the asset is fully depreciated. This projected life is provided in each of the Project Packets.

[49] This Application is pending in Proceeding No. 23A-0204G, and is currently in the intervention period.

- *Rule 4553(c)(I)(G): Cost estimate classification*. This Rule requires the Company to provide, for each planned project, "the cost estimate classification using the utility's or an industry-accepted cost estimate classification index, and support of the methodology." In satisfaction of this requirement, the Company's cost estimate classification methodology is addressed, generally, in Section IV.B of this Report. The cost estimate, along with the classification, for each project is provided in the accompanying Project Packet.

- *Rule 4553(c)(I)(I): Total project cost estimate and associated annual revenue requirements*. This Rule requires, among other things, a presentation of the associated annual revenue requirements for each project during the GIP Plan Period, "assuming both conventional and accelerated depreciation in accordance with the forecasts submitted or developed pursuant to paragraph 4553(b)." In satisfaction of this requirement, the Company is presenting annual revenue requirements associated with each Planned Project through 2033, so that we are providing a 10-year view. For conventional depreciation we are using a composite rate that is assigned to assets in the budgeting process, intended to reflect an estimate of the depreciation rates. For accelerated depreciation, we assumed a shorter 30-year depreciation life.

- *Rule 4553(c)(I)(J): Project maps*. This Rule requires that the project location and an illustrative map of the facilities be provided for each planned project. At a minimum, the maps are required to include the pressure district/geographic area, existing and proposed regulator stations and piping, locations of any DI Community, and identification of the electric utility service provider at the project location. Each Project Packet includes a confidential and public map for the planned project at issue in order to protect more sensitive gas infrastructure, such as regulator stations, MAOP, and locational information. In addition, the following assumptions were used in building each map:

    - "Pressure district" is defined in Rule 4001(nn) as "a localized area within a utility's service territory whereby an established minimum and maximum pressure range is intended to be maintained and is distinct from neighboring regions." Based on the configuration of the Company's system, in satisfaction of this requirement the pressure district is depicted as the unique distribution and/or transmission system in the project area, as applicable; and

    - To identify the DI Communities located within the area shown on a project map, the Company used a dataset provided by Colorado Department of Public Health and Environment. This dataset includes Colorado EnviroScreen data at the census block group level from version 1 of the tool, published in June 2022.[50] Colorado EnviroScreen is an environmental justice mapping tool that uses population and environmental factors to calculate an EnviroScreen Score. It was developed for the Colorado Department of Public Health and Environment (CDPHE) by a team from Colorado State University. The tool enables users to

[50] Colorado EnviroScreen v1 BlockGroup | Colorado EnviroScreen v1 BlockGroup | Colorado Department of Public Health and Environment (arcgis.com)

identify disproportionately impacted communities based on the definition in Colorado's Environmental Justice Act (HB21-1266). The Company's maps reflect CDPHE's dataset showing the location of DI Communities by census block, they do not depict differences in the EnviroScreen Score but rather if the census block is in a DI community.

- *Rule 4553(c)(I)(K): Customers, Annual Sales, and Design Peak Demand Requirements*. This Rule requires "to the extent practicable, the number of customers, annual sales, and design peak demand requirements, by customer class, directly impacted or served by the project." The Company interprets the rule language as requesting Design Day firm peak hour load demand and firm annual sales (throughput) associated with the number of firm customers for each of the following customer classes: Residential, Small Commercial, Large Commercial, Small Firm Transportation, and Large Firm Transportation.[51] The Company's system is very dynamic and integrated so the provided figures represent, to the extent practicable, the customers most directly impacted or served by the project assuming normal operations.

  Additionally for capacity expansion projects, the Company evaluated the potential of customer loss occurrence if the proposed capacity expansion project is not in-service for the required heating season to maintain system reliability and continue taking on forecasted growth. While determining customer loss impact on an integrated gas system that is dynamic in nature can be challenging, the Company undertook a supply side approach to determine a representative count of customer loss for each capacity expansion project area. This approach consisted of looking at the supply surplus and deficiency that is available before and after the in-service date of a proposed capacity expansion project to meet customer peak hour load demand while maintaining system minimum design pressures.

- *Rule 4553(c)(I)(N): Change in projected GHG emissions*. This Rule requires the Company to provide, for each planned project, the change in projected greenhouse gas emissions due to the planned project. Similarly, Rule 4102 regarding Certificates of Public Convenience and Necessity for Facilities requires the following for such projects: "the change in projected utility-wide greenhouse gas emissions due to the proposed facilities, as calculated relative to the utility's most recently approved clean heat plan greenhouse gas emission forecast or subsequent interim-year update . . ." As the Company does not at this time have an approved clean heat plan, for this Initial GIP the Company has interpreted the rules as requiring the projected change in GHG emissions resulting from the project in the form of methane emission estimations (and the carbon dioxide equivalent) from pipelines consistent with the reporting methodology under EPA's Greenhouse Gas Mandatory Reporting Rule, 40 CFR Part 98, Subpart W.

[51] Interruptible gas service customers utilize available capacity, if it exists, on the system that firm gas service customers are not utilizing at a specific time. The Company does not use interruptible gas service customers' estimated peak hour load demand to determine capacity requirements for the system to meet Design Day conditions.

The EPA's current methodology estimates methane emissions based on two factors – activity count (e.g., pipeline miles, number of services)[52] and material of construction. This is the only calculation methodology for pipeline methane emissions that is codified in either Federal or Colorado regulations at this time. There is concern that use of the EPA methodology does not accurately represent methane emissions reductions for specific projects, especially in scenarios where a new pipeline is replacing a problematic or outdated pipeline of essentially the same length and categorical material. While the EPA reporting methodology is used to estimate project specific methane emissions for the Initial GIP, the Company is working with industry groups to develop a more thorough and accurate protocol to calculate methane emissions from natural gas distribution systems. Consistent with the foregoing, customer end use (or throughput) consisting of combined carbon dioxide and methane emissions for projects are not included in this Initial GIP. Accurate forecasted calculation of emissions from customer end use for individual projects are not yet possible without an understanding of customer adoption and acceptance of approved clean heat resources and portfolios in the Clean Heat Plan. The Company will continue to evaluate incorporating customer end use emissions in future GIP filings once the Clean Heat Plan is approved and as emission estimation procedures evolve.

- *Rule 4553(c)(I)(P) and (Q): Alternatives Analysis for Selected Projects*. These Rules require that an alternatives analysis be provided for selected new business and capacity expansion requirements, and set forth certain required criteria. The Company satisfies these requirements by providing an overview of the Company's alternative analysis selection process and methodology in Section VIII of this Report. Each capacity expansion Project Packet indicates whether an alternatives analysis was conducted for the project and, if so, the full analysis is included.

- *Rule 4553(c)(I)(R): System Safety and Integrity Projects Risk Ranking Methodology*. The Company's risk ranking methodology for system safety and integrity projects included in this Initial GIP is provided in Section VII of this GIP Report, while the output of the methodology in the format of a project's risk ranking is in the safety Project Packets.

[52] Since capacity expansion projects contemplate growth, the estimated incremental number of new services over a ten-year period was factored into the calculation for these projects.

VII. System Safety and Integrity Risk Ranking Methodology (4553(c)(I)(R))

Pursuant to GIP Rule 4553(c)(I)(R):

> For system safety and integrity projects, the utility shall provide the applicable federal regulation, the planned project's risk ranking and the utility's risk ranking methodology including but not limited to the material, age, maximum allowable operating pressure, density of surrounding residences and businesses, and any other physical and operating characteristics relevant to the risk ranking of the planned project and the risk ranking methodology. The utility should also identify, discuss in detail, and provide the output to any risk-related models developed or employed by the utility in conducting risk analyses to support planned system safety and integrity projects or other projects.

In accordance with the Company's integrity management programs the Company identifies and evaluates the threats to its gas transmission and gas distribution systems. Public Service's risk assessment methodology is a process used to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. Importantly, the risk ranking methodology used for safety projects has a long-standing history with the Commission. For example, the risk ranking methodology used for Pipeline System Integrity Adjustment ("PSIA")-related work, which encompasses the PPRP safety work presented herein, was developed consistent with Staff's proposal in Proceeding No. 15AL-0135G, and approved by the Commission in Decision No. C16-0123 (adopting with modification Recommended Decision No. R15-1204). Exemptions to the requirement for risk ranking assessments were also set forth therein, and were generally applicable to TIMP work and the Accelerated Main Replacement Program. Consistent with the foregoing, the Company utilizes a combination a various risk model methodologies based on the program or individual project need and the federal requirements within 49 CFR Part 192. The Company may also, for certain types of projects, elect to utilize a quantitative, semi-quantitative, index/relative, or subject matter expert ("SME") based risk ranking methodology. At its core, the risk ranking methodologies facilitate a process to evaluate consequence and likelihood of an event taking place on the Company's natural gas infrastructure, as well as help determine the prioritization of projects when compared within the various programs. The goal of the Company's system safety and integrity work is to protect the public, property and the environment from pipeline and equipment failures.

System Safety and Integrity projects included in this Initial GIP involve: DIMP PPRP for Coupled IP, and Vintage/Problematic pipe, as well as inoperable/obsolete equipment. The risk methodology used for each of these programs or project categories is described below.

A. Distribution Integrity Management Programs

Distribution Integrity Management Programs (DIMP) utilizes a quantitative risk assessment methodology to develop a quantitative risk score and assign a risk category (high, medium, low) for identified initiative. These initiatives may include gas distribution PPRP (vintage/problematic pipe and coupled IP), and gas distribution valve replacements. Potential projects are initially identified utilizing commercial risk software and/or SME feedback.

Quantitative risk scores are then developed for each project by assigning numeric values to likelihood and consequences utilizing empirical data, quantifying assessments, and SME input. Based on the resulting risk score each project is assigned a risk category (high, medium, low) in accordance with the methodology outlined below.

For those safety projects utilizing a quantitative risk assessment, the Company's goal is to execute on them to programmatically address the highest priority system risks in an efficient and cost-effective manner. However, it is important to recognize that any plan is part of an iterative process and, as a result, priorities for these risk-ranked Projects are subject to change, as explained earlier in this Report. Below is a summary of the risk-ranking methodology applicable to the following:

- DIMP PPRP for Vintage and/or Problematic Pipe;
- DIMP Programmatic Risk-Based Pipe Replacement Program for Coupled IP; and
- Inoperable/Obsolete Equipment

B. <u>DIMP PPRP – Vintage and/or Problematic Pipe Risk</u>

Uses Commercial Software: J-DIMP™ by JANA ("J-DIMP™"). The J-DIMP™ software was implemented as part of the Company's DIMP and utilizes a probabilistic form of risk modeling. This model allows the Company to better utilize the detailed data available in the SAP work and asset management system and the Company's Geographic Information System ("GIS").

Data Inputs include data such as Leak Date, Leak Class, Leak Cause, Pipe Length, Pipe Material, Pipe Pressure, Pipe Diameter, Pipe Coating, Year Installed, Cathodic Protection, Presence of Excess Flow Valve on Service, Building Class and proximity to pipeline, and Population Density.

A bundle (as used in J-DIMP™) is a grouping of mains and services with similar material, diameter, pressure, cathodic protection status, and installation year. Typical projects will consist of one or more bundles, whose length is approximately 1500 feet of main and associated services and risers. Bundle lengths can vary significantly from project to project and can serve as a starting point for establishing the scope of various projects.

Under J-DIMP™, the risk score used to rank the risk associated with each bundle is calculated using the risk scores of each asset within the bundle and is then normalized by the length (in feet) of the assets within the bundle.

$$Bundle\ Risk/length = \frac{\sum Main, Service, Valve, and\ Riser\ Asset\ Risk}{\sum Length\ of\ all\ Assets\ in\ Bundle}$$

An asset risk such as main, service, valve or a riser risk is calculated by multiplying the likelihood of failure by the consequence of failure for each threat and summing the associated threat risks. The risk scores are recalculated every year to allow for an understanding of the rate of change of the risks associated with the bundles and their respective assets.

Asset Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each respective threat

Likelihood of failure in the J-DIMP™ model is calculated utilizing a Weibul Proportional Hazard Model for 25 specific threat types derived from the 8 primary threat categories established by PHMSA in 49 C.F.R. §192.1007.

Consequence of failure in the J-DIMP™ model is calculated for each threat for each individual asset and is based on the probability and magnitude of a number of loss of function or loss of containment scenarios that may come about due to each threat, and considers consequence factors such as Health and Safety, Property Damage, and Economic Loss.

As can be noted from the calculation above, Main & Service project risk scores (i.e. the Bundle Risk / Length scores) are calculated on a per foot basis. This allows for a direct comparison of projects that may vary significantly in length. The projects are grouped into high-, medium- and low-risk categories based on the resulting Bundle Risk / Length scores generated by the model.

As the J-DIMP™ model is primarily used to rank and evaluate potential replacement projects, it is important to calculate not only the inherent risk presented by an asset in the Company's gas distribution network, but also the risk reduction achieved by replacing the asset, or mitigated risk. Mitigated risk is calculated as the difference in risk between a current asset (the baseline risk condition) and a hypothetical new asset in the same location and subject to the same operating conditions.

The two risk profiles needed to calculate the mitigated risk for every bundle (or project) are evaluated in the same way as the baseline bundle risk score, and the resulting mitigated bundle risk score is provided on a per foot basis to allow for a direct comparison of assets and bundles that may vary significantly in length. The projects are grouped into high-, medium- and low-risk reduction categories based on the resulting mitigated bundle risk per length scores by the model.

Projects may also be designated as high or medium risk via engineering judgment provided by subject matter experts (SMEs) who evaluate factors such as recent leakage which is not yet in the J-DIMP™ model, field observations that the pipe has significant corrosion, or emerging risk factors based on industry incidents or findings.

C. <u>DIMP PPRP – Coupled IP Risk</u>

Data inputs:

- Construction Risk Factor - Presence of Mechanical Joint Joining Method
- Construction Risk Factor – Welding Method Modern Pipe (Oxyacetylene or Arc)
- History of Corrosion, 3rd Party Damage and other leakage
- Pipeline Diameter and Operating Pressure

Risk Score = Likelihood of Failure x Consequence of Failure
Likelihood of Failure = (Mechanical Joint Risk Factor + Welding Risk Factor) x Maximum Score of (Corrosion Risk Factor, 3rd Party Damage Risk Factor, Other Leak History Factor)

Consequence of Failure = Potential Impact Radius ("PIR") of downstream pipeline

$$PIR\ (ft) = .69 * \sqrt{Pressure(psig) * Diameter(in)^2}$$

Table 13: Mechanical Joint Risk Factor Lookup Table

Condition	Score
Pipeline Segment Contains Mechanical Joints	3.5
Does Not Include Mechanical Joints	0.5

Table 14: Welding Risk Factor Lookup Table

Condition	Score
Includes Acetylene Welds (Pre 1932)	0.5
Does not Include Acetylene Welds (Pre 1932)	0

Table 15: Corrosion Risk Factor Lookup Table

Condition	Score
History of Corrosion Leakage	2
Presence of Corrosion Pitting	2
No history of Corrosion leakage or pitting	1

Table 16: 3rd Party Damage Risk Factor Lookup Table

Condition	Score
Presence of 3rd Party Damage	2
No Presence of 3rd Party Damage	1

Table 17: Other Leak History Risk Factor Lookup Table

Condition	Score
History of Leakage due to Causes other than corrosion or 3rd Party Damage	2
No History of Other Leakage	1

Table 18: Consequence of Failure Lookup Table

Condition	Score
PIR > 100 ft.	4
40 ft. < PIR ≤ 100 ft.	3
PIR ≤ 40 ft.	1

Table 19: Risk Matrix

			Consequence Score		
			PIR ≤ 40 ft.	40 ft. < PIR ≤ 100 ft.	PIR > 100 ft.
			1	**3**	**4**
Likelihood of Failure	Mechanical Coupled AND Acetylene Welded AND Corrosion or 3rd Party Damage	**8**	8	24	32
	Mechanical Coupled AND Corrosion or 3rd Party Damage	**7**	7	21	28
	Mechanical Coupled AND Acetylene Welded and NO Corrosion or 3rd Party Damage	**4**	4	12	16
	Mechanical Coupled and no other risk factors	**3.5**	3.5	10.5	14
	No Mechanical Couplings	**≤ 2**	≤ 2	≤ 6	≤ 8

High Risk, Risk Score ≥ 21
Medium Risk, 10 ≤ Risk Score < 21
Low Risk, Risk < 10

D. <u>Inoperable/Obsolete Equipment</u>

Replacement of inoperable/obsolete equipment is based on SME input, and does not rely upon a risk-ranking methodology. Consideration is given to consequences of not addressing the issue, such as gas volume, number of customers impacted in an outage scenario, and estimated frequency of outages per year. The identified projects are then submitted through the Capital Budgeting Process described earlier in this Report.

VIII. Alternatives Analysis for Selected Capacity Expansion Projects (4553)(c)(I)(P) and (Q))

As noted earlier in this Report, GIP Rules 4553(c)(I)(P) and (Q) require that an alternatives analysis be provided for selected new business and capacity expansion requirements and set forth certain required criteria. For this Initial GIP, Public Service is required to select five new business and/or capacity expansion projects for an alternatives analysis that includes NPAs, costs for the alternatives, and criteria to rank or eliminate the alternatives.[53] For those selected planned projects, the GIP Rules further require the alternatives analysis to consider: [54]

1. one or more applicable clean heat resources consistent with the utility's most recently approved Clean Heat Plan, Demand Side Management plan, or beneficial electrification plan, as applicable;

2. a cost-benefit analysis including the costs of direct investment and the social costs of methane for emissions due to or avoided by the alternative[55]; and

3. available best value employment metrics for each alternative as further detailed in the rule.

The alternatives analysis must also include the technologies and/or approaches proposed and evaluated, the projected timeline and annual implementation rate for the technology or approaches evaluated, the technical feasibility of the alternative assuming full adoption, the strategy to facilitate the alternatives, and an explanation of the methodology used to select the projects presented with an alternatives analysis.[56]

The Company is focused on developing a data-driven robust alternatives analysis that evaluates an NPA portfolio of approaches that includes interim mitigations (such as bypassing a regulator station, compressed natural gas, or liquified natural gas) as well as alternative technologies and approaches encompassing interruptible service and energy efficiency and electrification programs (including targeted incentives). Thus, in addition to the aforementioned rule requirements, the Company continues to evolve its own NPA processes, implementing a number of enhancements based on Commission feedback, including the following, which have been incorporated into the analyses presented herein:

- Review of the underlying conditions driving the project need to determine if an NPA portfolio could provide the necessary mitigation, including consideration of projects driven solely by reliability such as the Pearl Street Mall project.
- Initiate an NPA analysis early in the planning process to allow for sufficient time to implement an NPA portfolio, focusing on projects in the GIP informational period.

[53] Rule 4553(c)(I)(P).
[54] Rule 4553(c)(I)(P)(i).
[55] Refer to Section VI.B of this Report for explanation of social costs of emissions.
[56] Rule 4553(c)(I)(P)(ii). Additionally for adjudicated GIP proceedings, a discussion of the public review process will also be required. *See* Rule 4553(c)(I)(P)(ii)(6).

- Model incremental incentives and alternative delivery models that would likely be required to increase annual participation rates in electric and gas DSM and BE measures in order to achieve quantifiable reductions to the Design Day peak hourly gas demand.
- Analyze a variety of NPA technologies and methods including a multitude of energy efficiency and electrification programs as well as interruptible service conversion.
- Review of the electric distribution system to identify targeted areas where capacity is available to support conversion from gas to electric appliances without significant delays and costs associated with electric distribution system upgrades.
- Implement a cost-benefit analysis tool to quantify and compare the total costs and benefits of pursing an NPA portfolio in lieu of a gas infrastructure project.
- Consider best value employment metrics to offer informational insight regarding impacts to the workforce associated with pursing an NPA portfolio in lieu of a gas infrastructure project.

The Company will continue to develop the alternatives analysis paradigm based on emerging technologies and approaches, lessons learned, and consideration of stakeholder feedback. For example, the Company is exploring community geothermal technologies and gas demand response offerings for future alternatives, although these technologies are not yet market ready as an alternative for the analyzed projects.

In the following subsections, the Company describes its NPA methodology, the planned project NPA selection process, alternative technologies and approaches evaluated, and the criteria used to rank or eliminate alternatives.

A. NPA Methodology

As noted above, the Company developed an NPA methodology to comprehensively evaluate proposed new business and capacity expansion projects for this Initial GIP in accordance with the rule requirements.[57] The Company's methodology includes an initial suitability framework used to select planned projects for an NPA analysis, a review of the alternative technologies and approaches proposed and evaluated including NPAs, and criteria used to rank or eliminate such alternatives. A visual of the methodology is presented in Figure 8 below and described in the following subparts. For each planned project selected for an NPA analysis, the results are presented as part of the Alternatives Analysis Report ("NPA Report") included as an attachment to the Project Packet.

[57] Rules 4553(c)(I)(P) and (Q).

Figure 8: Overall NPA Methodology

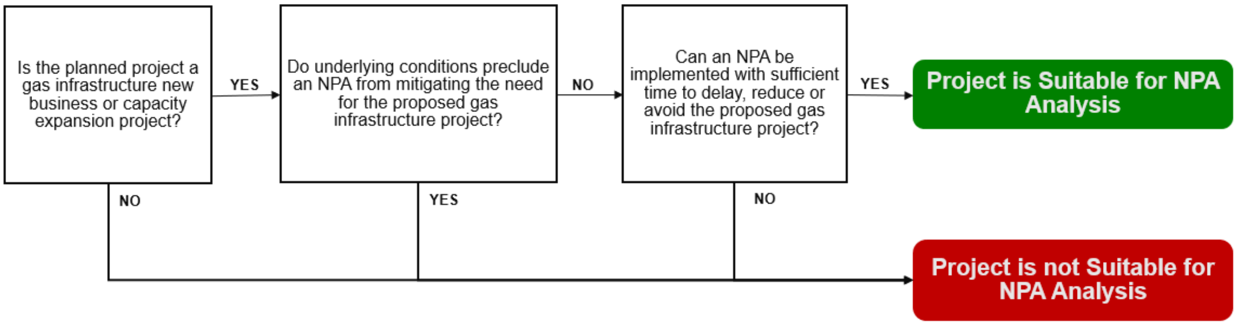
Methodology to Select Planned Projects for NPAs	• NPA Initial Suitability Criteria Framework
Alternative Technologies and Approaches Evaluated	• Capacity Shortfall / Project Area • Interim Mitigative Approaches • Alternative Technologies and Approaches Evaluated
Criteria Used to Rank or Eliminate Alternatives	• Technical Potential • Achievable Potential • Cost Benefit Analysis • Best Value Employment Metrics

B. Methodology to Select Planned Projects for NPAs

This section explains the methodology used by the Company to select capacity expansion planned projects for the NPA analysis as required by Rule 4553(c)(I)(P)(ii)(6).[58] Pursuant to Rule 4001(ii), NPA means "programs, equipment, or actions that avoid, reduce, or delay the need for investment in certain types of new gas infrastructure and may include energy efficiency, demand response, and beneficial electrification." The Company's alternatives analysis therefore concentrated on NPA solutions to reduce Design Day peak hour gas demand for capacity expansion planned projects. The Company created and applied the following NPA Suitability Screening Criteria ("Suitability Criteria") to the capacity expansion planned projects within the GIP Plan Period, the results of which appear in each capacity expansion Project Packet. To be further considered for an NPA analysis, the answer to all "Suitability Criteria" questions had to indicate that the project was suitable for an NPA analysis as illustrated in the process flow contained in the Figure below.

[58] There are no new business planned projects identified in this Report.

Figure 9: NPA Initial Suitability Criteria Framework



Based upon application of the Suitability Criteria, the Company arrived at a final list of the following five capacity expansion projects for the required NPA analysis:

- Mead to East Longmont Reinforcement
- Harmony High Pressure Pipeline Reinforcement
- Fort Lupton Compressor Station
- Pearl Street Mall
- F-3 Reinforcement

The results of the NPA analyses on these projects are discussed below and in the applicable Project Packet.

C. Alternative Technologies and Approaches Evaluated

Pursuant to Rule 4553(c)(I)(P)(ii)(1) and (2), the Company proposed and evaluated the same set of alternative technologies and approaches for each of the selected capacity expansion projects as they represent the pathways currently available to alleviate the capacity shortfall for the identified capacity expansion planned projects. More specifically, after first determining the projected capacity shortfall and project area, the Company proposed and evaluated non-pipeline alternatives including:

- Increased participation in energy efficiency;
- Electrification programs; and
- Customer conversion from firm to interruptible service.

The Company also evaluated interim mitigation options to ensure reliable gas service could be maintained to either address operational risk in the event customer annual adoption rates were less than forecasted or to temporarily address the capacity shortfall while the NPA technologies and approaches become fully implemented. These interim measures are intended to be temporary and therefore not considered to be an alternative to the proposed gas infrastructure project. The interim mitigation measures were only included in the NPA portfolio if they were determined to be required to temporarily address the capacity shortfall until the NPA technologies and approached become fully implemented. The capacity shortfall/project area determination and interim mitigation approaches are addressed first in the Report, followed by the NPA technologies and approaches evaluated.

1. Capacity Shortfall/Project Area Determination

Determining the required reduction in Design Day peak hour gas demand by heating season ("capacity shortfall") is critical when evaluating whether an NPA portfolio can delay, reduce the scope of, or avoid the proposed gas infrastructure project. For each chosen capacity expansion planned project, the Company determined the capacity shortfall that needs to be eliminated in order to avoid the proposed gas infrastructure project in its entirety. For example, within the forecasting period, a capacity shortfall occurs when Design Day peak hour gas demand exceeds supply and/or available system capacity for the project area. The projected capacity shortfall may increase each heating season dependent on the level of forecasted growth.

In the NPA Report for each capacity expansion planned project chosen for an NPA assessment, the Company presents the estimated Design Day capacity shortfall per heating season along with the equivalent electric load (kW) to convert the entire capacity shortfall from gas to electric as comparative data.[59] The Company also identifies (to the extent possible) the customers directly served or impacted by the project, which represents the existing gas demand load and the customers potentially eligible for NPA measures and methods. The Company used the foregoing information as a proxy for the project area.

2. Interim Mitigation Approaches

The Company focused on mitigating the capacity shortfall with NPA technologies and approaches as explained later in this section. However, the Company determined it was necessary to also identify potential interim mitigation measures to account for the operational risk associated with non-attainment or adoption of NPA technologies and approaches, which would avoid, reduce, or delay the gas infrastructure project should an NPA portfolio be pursued. Operational risk is introduced to the system if the Company relies on an NPA portfolio to address the capacity shortfall because the effectiveness of an NPA portfolio is dependent on customer participation and implementation, among other things. An interim mitigation measure may also be included in the NPA portfolio to temporarily address the capacity shortfall while the NPA technologies and methods become fully implemented. The Company reviewed the three interim mitigative measures as summarized below, each of which are intended to be temporary and therefore not considered to be an alternative to the proposed gas infrastructure project. If an interim measure is determined necessary to bridge the gap in NPA implementation, it would be included in the implementation costs for the NPA portfolio. Otherwise, these costs are not included.

a. Operational Measures: Bypassing

The first mitigation measure considered by the Company was an operational measure - bypassing a regulator station. Bypassing a regulator station involves opening the bypass valves within the regulator station to circumvent the regulator, which reduces the amount of pressure loss

[59] The equivalent electric load (kW) was calculated assuming an Air Source Heat Pump ("ASHP") with electric resistance backup would be installed in lieu of a natural gas furnace.

through the station. This was considered viable if the system was experiencing insufficient inlet pressure at a regulator station and if the reduction in pressure loss through the station would result in sufficient downstream pressure to maintain service reliability. Bypassing a regulator station is generally a manual operation and therefore the Company would deploy a station operator during cold weather events when the inlet pressure drops below the minimum required inlet pressure to perform the operation. Bypassing a regulator station may be sufficient to sustain the system at Design Day or could be used as a preliminary measure before supplemental supply would be required. This would require coordination from the Company to reallocate the appropriate personnel from other operational responsibilities. Additional costs are not expected to be associated with this approach.

b. Supplemental Supply: Compressed Natural Gas ("CNG") and Liquified Natural Gas ("LNG")

If the downstream pressure could not be maintained by bypassing a regulator station, the Company evaluated supplemental supply as the next mitigative measure. Supplemental supply is available in the form of CNG or LNG. This involves injecting supplemental supply into the piping system to increase the pressures to maintain service reliability.

Supplemental supply of natural gas comes in one of two states: CNG or LNG. CNG and LNG each have distinct properties which were considered by the Company when determining the preferred supplemental supply solution. The Company generally considered CNG as the primary supply solution for supplemental supply, with LNG as a secondary option. Both options for supplemental supply are considered to be temporary solutions deployed during the heating season during periods of high peak hour gas demand. Once the trailers are deployed, CNG / LNG would be injected only if the system pressures fell at or below site specific threshold values, which may or may not occur during the heating season dependent on actual minimum temperatures and customer demand on the system. If determined necessary, for purposes of this analysis the Company assumed it would lease CNG or LNG through a third-party supplier because the Company has limited amount of Company owned CNG trailers and no Company owned LNG trailers at this time. The associated cost to lease would include the commodity, mobilization of equipment, site preparation, storage, and in the case of LNG, operations personnel.

When determining whether to use CNG versus LNG, the Company considered the hourly flowrate, onsite storage volume required, and land/siting size. The Company utilized the gas planning hydraulic model to determine the required hourly and daily flowrate at Design Day, which subsequently was used to determine the onsite storage volume required. The Company calculated the amount of onsite storage volume to be equivalent to three days of the daily flowrate at Design Day. LNG can accommodate higher hourly flowrates and onsite storage volumes, therefore may be required in lieu of CNG for the project area. More detailed information regarding the use of CNG versus LNG is provided below.

CNG is formed by compressing natural gas to a 1/100 volume ratio at standard atmospheric pressure. CNG is stored around 3000 – 3600 psig in fuel tanks or cylinders, which are available in various sizes depending on the onsite storage required. Depending on the third-party supplier, the largest CNG tube trailer could provide approximately 900 mscf of total storage. When injecting into the pipeline, a decompression unit is required to reduce the pressure to the pipe while ensuring that the natural gas does not get too cold due to the pressure drop. If CNG was determined to be the preferred mitigative measure, the Company assumed the following total costs for the heating season based on the size of the CNG storage trailer:

Table 20: Estimated Temporary CNG Costs

CNG Storage Trailer (Total Storage Volume)	Cost per Trailer
≤ 50 mscf	$20,000
50 mscf to 84 mscf	$140,000
85 mscf to 240 mscf	$280,000
241 mscf to 900 mscf	$420,000

LNG utilizes natural gas converted to liquid form through liquefaction to a volume ratio of 1/600. LNG is stored around 0.5 - 100 psig and -260°F in vacuum insulated storage cryogenic tanks to maintain its super-cooled properties. When injecting into the pipeline, a vaporizer and pump are needed, although some of the trucks have pumps as part of the trailer. If LNG was determined to be the required in lieu of CNG, the Company assumed the following total costs based on the LNG equipment required:

Table 21: Estimated Temporary LNG Costs

LNG Equipment	Cost per Equipment
Queen	$140,000
Smart Queen	$190,000
Transport	$115,000
Triplex Pump	$175,000
Generator	$155,000
Odorizer	$65,000
Vaporizer (350 mcfh)	$247,500
Vaporizer (500 mcfh)	$325,000

Additional information regarding the advantages and disadvantages of CNG versus LNG are summarized below.

Table 22: Advantages/Disadvantages of CNG versus LNG

	CNG	LNG
Advantages	• Smaller Staging Footprint • Easier to Produce CNG • Does not require specialized equipment or training to operate • Odorized	• Higher Flowrates • Higher Storage Volumes
Disadvantages	• Lower Flowrates • Lower Storage Volumes	• Larger Staging Footprint • Requires special equipment, protective gear, and training to operate • Requires Odorization

3. *Alternative Technologies and Approaches Evaluated*

As previously explained, the Company focused on evaluating technologies and approaches including conversion of customers from firm to interruptible gas service, energy efficiency, and electrification programs as NPAs. An overview of each of the NPA measures and approaches evaluated is summarized in the table below with additional information in the following subparts. For the selected planned projects, the Company considered all NPA technologies and approaches detailed herein unless otherwise described in the NPA Report. For purposes of this analysis, electrification programs were only considered if the Company was the electric service provider for some, or all of the customers directly served by or impacted by the project.[60] This has minimal impact on the outcome of the analyses because the NPA portfolio includes a variety of technologies approaches outside of electrification programs to alleviate the capacity shortfall.

Table 23: NPA Technologies and Approaches

Energy Efficiency	Electrification	Interruptible Gas Service
• High Efficiency Natural Gas Furnace • Attic Insulation • Wall Insulation • Air Sealing • Commercial New Boiler • Ancillary Boiler Efficiency Measures	• Ground Source Heat Pump (GSHP) • Electric Heat Pump Water Heaters (HPWH) • Air-Source Heat Pump (ASHP) with Electric Resistance Backup	• Transport Firm Large • Large Commercial Firm Sales

a. *Interruptible Gas Service*

As a first step for evaluating long-term NPA approaches, the Company considered the potential conversion of eligible firm gas customers to interruptible service. The Company does not design and engineer its gas system to service interruptible customers on a Design Day. Thus, if firm customers become interruptible customers, this may reduce the estimated capacity shortfall for the project area. Interruptible gas service is subject to availability of capacity on the Company's system and is interruptible and subject to curtailment to ensure service to firm customers. While interruptible customers pay lower rates than customers taking firm service, this option is limited in terms of suitability and appeal. Furthermore, the Commission recently approved certain changes to the Company's P.U.C. No. 6 Gas Tariff to ensure that transportation and sales customers taking interruptible service are adequately prepared and incentivized to comply with curtailment orders, as set forth therein. This includes requirements regarding curtailment demonstration tests, where interruptible customers must establish that they have the ability to comply with interruptions and providing for removal from interruptible service when they fail to do so. Interruptible customers must comply with the terms and conditions of the Gas Tariff regarding interruptible service (and agree to remain on interruptible service for an extended period of time) in order for conversion from firm to interruptible gas service to be feasible as an NPA approach. Notably, the Company

[60] This framework was adopted for purposes of this analysis because under our currently-approved DSM Plans, a customer is required to get both electric and gas service from the Company in order to qualify for electrification rebates.

cannot compel customers to either switch to interruptible service or remain on interruptible service, and there are very good reasons that many customers prefer firm service.

b. Energy Efficiency/ Electrification Programs

Secondly, the Company reviewed the energy efficiency and electrification programs presently offered to our customers through the 2021/2022 DSM Plan, as approved by the Commission in Proceeding No. 20A-0287EG.[61] Specifically, the Company identified technologies with proven reductions in Design Day peak hour gas demand in contrast to an average annual reduction in natural gas throughput and customer end usage. For example, dual fuel heat pumps contribute to a reduction in natural gas annual throughput and customer end usage but because gas is the primary fuel used at Design Day temperatures, such heat pumps provide no notable reductions to Design Day peak hour gas demand. Therefore, dual fuel heat pumps are not included in the NPA portfolio. Alternatively, ground source heat pumps, and cold climate air source heat pumps with electric resistance backup utilize electricity at cold temperatures thereby significantly reducing Design Day peak hour gas demand. Evaluating technologies and approaches with proven reductions to Design Day peak hour gas demand allowed the Company to perform a quantitative analysis of the amount of energy efficiency/electrification program participation that would be required to address the capacity shortfall. The implementation of additional energy efficiency/electrification programs will continue to be pursued and the Company's NPA analysis will evolve to make best use of new and available technologies as quantitative data becomes available on the associated Design Day peak hour gas demand reductions. This includes demand response programs that are currently in the pilot phase.

A summary of the identified energy efficiency/electrification programs, the estimated implementation costs and peak demand reductions considered as part of the Company's NPA analyses are provided below. Both the implementation costs and peak demand reductions in the Table below are estimated based on the historical implementation information for the applicable equipment but may vary based on the individual customers' premises. Additional information including the existing marketing objectives and strategies can be found in the Company's currently approved DSM Plans.

[61] *See* Rule 4553(c)(I)(P)(i)(1).

Table 24: Energy Efficiency/Electrification Programs

Program	Description	Estimated Implementation Cost	Estimated Peak Demand Reduction (PD)
Energy Efficiency			
Natural Gas Furnaces	Upgrade existing gas furnace to a high efficiency gas furnace with a minimum furnace efficiency of 95% Annual Fuel Utilization Efficiency ("AFUE")	$9,000	17%
Attic Insulation	Upgrade Attic Insulation to a minimum R-60 value	$1,800	5%
Wall Insulation	Upgrade from no wall insulation to a minimum R-14 value with blown in fiber glass	$3,000	5.5%
Air Sealing	Perform air sealing to a home without air sealing with a 20% minimum reduction in are leakage based on CFM 50 blower door results	$1,000	6%
Commercial New Boiler	Upgrade existing boiler to a high efficiency boiler	$12,500[62]	4%
Ancillary Commercial Boiler Efficiency Measures	Upgrade existing ancillary boiler efficiency control including: Average of Outdoor Air Reset, Stack Dampers, Modulating Burners, Turbulators, O2 Trim Control, Linkageless Control	$5,000[63]	3%
Electrification			
Ground Source Heat Pump with Quality Installation ("GSHP")	Replace existing gas furnace with an ENERGY STAR® certified Ground Source Heat Pump	$35,000	80%
Electric Heat Pump Water Heaters ("HPWH")	Replace existing gas water heater with an ENERGY STAR® certified electric heat pump water heater	$5,500	20%
Air-Source Heat Pump ("ASHP") with Electric Resistance Backup	Air Source Heat Pump with ER backup replacing existing gas furnace	$25,000*	80%

Estimated implementation cost is the per unit equipment cost associated with upgrading customer equipment beyond the service meter. Implementation costs do not include service transformers or conductor upgrades which may be required based on the customers' existing panel

[62] Estimated Cost = Average Boiler Size (MMBH)*Average Boiler ($/MMBH)*Installation Cost Factor of 1.5
[63] Estimated Cost = Average Cost of Upgrades*Installation Cost Factor of 1.5

size. Implementation costs also omit costs associated with electric distribution system upgrades required to support the increase in electric loads.

Estimated peak demand reduction (PD) was used to determine the per equipment reduction in Design Day peak hour gas demand for both the technical potential and achievable potential using the following equation. The existing customer design day peak hour gas demand (D_E) was determined for each premise using CMM. The reduction in design day peak hour demand per equipment is project specific and provided within the technical potential and achievable potential for each NPA.

Equation 1: Reduction in Design Day Peak Hour Gas Demand

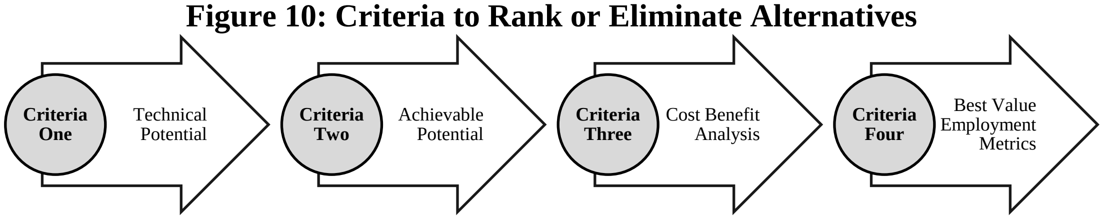
$$D_R = \sum_{Eligible\ Customers} D_E * PD$$

$D_R = Reduction\ in\ Design\ Day\ Peak\ Hour\ Gas\ Demand$
$D_E = Existing\ Customer\ Design\ Day\ Peak\ Hour\ Gas\ Demand\ (varies\ per\ customer)$
$PD = Estimated\ Peak\ Demand\ Reduction$

D. Criteria Used to Rank or Eliminate Alternatives

To evaluate the feasibility of an NPA portfolio, the Company considered four criteria, including technical potential, achievable potential, cost benefit analysis, and best value employment metrics. As explained in more detail below, an identified achievable NPA portfolio is evaluated against the infrastructure planned project in a cost benefit analysis. Further insight comparing best value employment metrics between the NPA portfolio and the infrastructure planned project are also provided as an initial glimpse into the types of metrics weighed between options, but are not necessarily used in this Initial GIP to rank or eliminate NPAs. The process for each of the criteria was applied in sequence as illustrated by the figure below.

Figure 10: Criteria to Rank or Eliminate Alternatives



1. *Criteria 1: Technical Potential*

Technical potential is the theoretical maximum amount of peak demand that could be deferred or avoided by NPAs within the project area assuming full adoption of the technologies and approaches by disregarding all non-engineering constraints such as cost-effectiveness and the willingness of customers to adopt the measures. The Company used the technical potential to establish an upper-boundary estimate of the potential Design Day peak hour gas demand reduction for each NPA technology and approach, which provided the dataset necessary to determine achievable potential. However, because technical potential does not consider implementation strategies, the willingness of customers to adopt the NPA technologies and measures, or cost, the Company did not use this as an indication of actual results.

The technical potential is addressed in each NPA Report. The Company determined the technical potential of the NPA portfolio assuming full adoption of the NPA technologies and approaches evaluated.[64] Technical potential was developed by determining the following for each NPA measure and technology:

- Number of Eligible Customers;
- Reduction in Design Day Peak Hour Gas Demand; and
- Associated Implementation Cost.

The number of eligible customers for each NPA measure and technology was determined for the project area by reviewing the customers directly impacted/served by the project. For firm to interruptible customer conversion, the Company reviewed the large firm transport and large commercial sales customers within the project area. If any large commercial sales customers were determined to be apartment/condominium buildings, they were not considered eligible for interruptible service. For technical potential, the Company assumed that customers interested in interruptible service would convert their entire gas demand to interruptible service and remain on interruptible service indefinitely.

For energy efficiency and electrification programs, the Company reviewed the residential and commercial customers within the project area. The Company omitted customers known to have already implemented the program at issue. Additionally, for natural gas furnace upgrades, residential customers with a peak hourly gas load of 0.03 mscfh or less were not considered eligible because peak gas loads of that magnitude are generally not natural gas furnaces and condensing furnaces are not readily available to serve a gas demand that small. Similarly, for attic insulation, wall insulation, and air sealing, residential addresses with four meters or more were not considered eligible. This is because a residential customer with more than four meters is assumed to be a multi-family building. Multi-family residencies are not eligible for prescriptive attic insulation, wall insulation, or air sealing measures and the prescriptive assumptions derived from the DSM plans are only applicable to single family homes. Accurately quantifying the potential demand reductions from multi-family projects would require a more in depth, possibly building by building, assessment of the savings which was beyond the scope of this analysis. No consideration was given to space requirements for equipment, as it was assumed that sufficient space is available.

Based on the number of eligible customers for each energy efficiency/electrification program, the Company determined the estimated Design Day peak hour gas demand reduction for the technical potential using the equation above. Results for each selected project are shown in the NPA Report. It should be noted that the technical potential for each measure was calculated separately without regard for interactive effects. Therefore the total technical potential for all measures in a given area is less than the summation of the measure level technical potentials for a

[64] Rule 4553(c)(I)(P)(ii)(4).

given area. As an example, the electrification measures eliminate all peak hour gas demand for a premise. The same premise may also be counted in the technical potential for insulation measures where a portion of the peak hour gas demand would be reduced. Adding the technical potential for the electrification measure and the insulation measure for the same premise would result in a technical potential greater than the actual current peak hour gas demand for the example premise.

Additionally, for energy efficiency and electrification programs, the Company assumed that the implementation costs would be incurred by the customer, with no additional incremental incentives above those included in the currently approved DSM plans. Infrastructure costs associated with electric distribution and transmission upgrades to support the increased electric load were not considered for the technical potential, however significant infrastructure costs would be expected.

2. Criteria 2: Achievable Potential

Achievable potential is a subset of the technical potential. Achievable potential is the realistic amount of peak demand that could be reduced with NPAs, including customer financial incentives and the willingness of customers to adopt the alternative technologies and approaches by the date needed to address the capacity shortfall. The achievable potential was used by the Company to determine the NPA portfolio that could be pursued in lieu of the proposed gas infrastructure project, pending Commission approval.

Achievable potential is addressed in each NPA Report. The Company determined the achievable potential of the NPA portfolio assuming the achievable annual implementation rates of the NPA technologies and approaches evaluated. Achievable potential was developed by determining the following for each NPA measure and technology:

- Number of Eligible Customers (Determined from Technical Potential);
- Strategy to Facilitate Implementation (NPA Incentive Strategy);[65]
- Achievable Annual Implementation Rates;[66]
- Reduction in Design Day Peak Hour Gas Demand;
- Associated Implementation Cost; and
- Associated Infrastructure Cost.

a. Number of Eligible Customers

As discussed above, the number of eligible customers for each NPA technology and approach was determined for the project area in the technical potential, which established the dataset for achievable potential for the planned project. From the dataset of eligible customers, the Company was able to identify the achievable potential of the NPA portfolio with consideration of the strategy to facilitate implementation.

[65] Rule 4553(c)(I)(P)(ii)(5).
[66] Rule 4553(c)(I)(P)(ii)(3).

b. Strategy to Facilitate Implementation (NPA Incentive Strategy)

For interruptible gas service, a list of the eligible large commercial firm sales and transport firm large customers was developed and provided to the Company's account management and natural gas services departments, respectively. Each customer was contacted via email to determine interest in converting from firm to interruptible service. This allowed the Company to have an accurate understanding of the annual implementation rates. However, in each instance there were no customers in the project areas that expressed an interest in converting from firm to interruptible service. This is addressed in more detail in the applicable NPA Report.

For the energy efficiency/electrification programs, the Company developed a strategy to facilitate implementation referred to as the "NPA Incentive Strategy", which includes incremental incentives for each technology and approach beyond those included in the administration of the currently approved electric and gas DSM Plans and specific to the project area.

The NPA Incentive Strategy was critical in determining the achievable NPA potential for the following reasons. Historical participation rates in the Company's energy efficiency and electrification programs and the impact of these approaches, as they are incentivized in the currently approved DSM Plan, are already observed in the gas forecasting modeling and therefore are already accounted for when estimating the capacity shortfall. The Company believes that incremental incentives are necessary to promote annual adoption rates to the levels required to propose an achievable NPA portfolio that eliminates the need for the proposed gas infrastructure project. The NPA Incentive Strategy includes company funded incentives to offset the implementation costs incurred by the customer. Offering incremental incentives will also result in a 20% administrative fee associated with targeted marketing, customer recruitment, and enrollment. For Commercial premises, the Company developed the amount of the Company funded incentive with input from account management representatives. It should be noted that the NPA Incentive Strategy should be reviewed and adjusted for each area as the work progresses, taking into consideration the actual customer adoption rates and current market conditions. A method for cost recovery for the incremental costs incurred will be pursued by the Company for each project that an NPA Portfolio implements in lieu of the proposed gas infrastructure project. The NPA Incentive Strategy was developed for each planned project as reflected in each NPA Report.

c. Achievable Annual Implementation Rates

After contacting eligible customers for interruptible gas service and establishing the NPA Incentive Strategy, the Company was able to determine the anticipated achievable annual implementation rates for each NPA technology or approach to meet the capacity shortfall estimated per year. The annual implementation rate included consideration of the achievable customer participation rates, product impact, implementation timeline including procurement and construction lead-times. Achievable annual implementation rates are provided in the NPA Report for each selected planned project.

d. Reduction in Design Day Peak Hour Gas Demand / Associated Implementation Costs

Understanding the achievable annual participation rates for each NPA technology and approach allowed the Company to calculate the estimated reduction in Design Day peak hour gas demand per year and the associated implementation cost, split between the Company and the customer. The reduction in Design Day peak hour gas demand was calculated using the same methodology described in the Technical Potential section of this Report. The associated implementation cost of the customer and the Company was calculated through the 2028-2029 heating season using the following Equation 2 and Equation 3, respectively. The estimated implementation cost for the Company also included a 20% administrative fee, as noted earlier.

Equation 2: Estimated Implementation Cost for Company

$$Implementation\ Cost\ _{Company}(2023-28) = \sum_{\substack{Units\\ Implemented\\ from\ 2023-28}} Incremental\ Incentive + Administation\ Fee$$

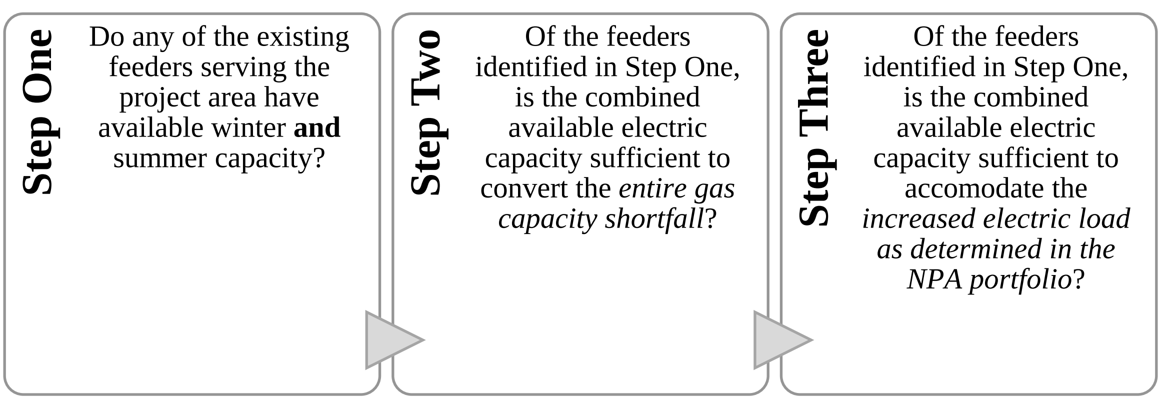
Equation 3: Estimated Implementation Cost for Customer

$$Implementation\ Cost\ _{Customer}(2023-28) = \sum_{\substack{Units\\ Implemented\\ from\ 2023-28}} Implementation\ Cost - Incremental\ Incentive$$

e. Associated Infrastructure Costs

In addition to implementation costs, the Company considered any costs required to upgrade the electric distribution system to accommodate increases in electric load. For each selected planned project, the Company reviewed the existing electric distribution system and corresponding capacity that serves the project area. This analysis was conducting using a 3-step approach as illustrated in Figure 11 below.

Figure 11: Electric Distribution Infrastructure Upgrades



For Step One, the Company evaluated the existing electric feeders that serve the project area to determine the amount of available winter and summer capacity. For a feeder to accommodate any increased electric demand (resulting from gas to electric conversion) available winter and summer capacity must be available. The Company reviewed the capacity available on existing feeders serving the project area through the 2028-2029 heating season, including any planned electric capacity expansion projects. If none of the existing feeders had available winter and summer capacity, electric distribution system upgrades would be required, and no further analysis was done.

For Step Two, the Company evaluated if the existing feeders identified in Step One had sufficient combined winter and summer capacity available to convert the entire gas capacity shortfall to electric. To do this, the Company assumed that the converted electric load would be consumed at 100% in the winter versus 20% in the summer. The assumption for 20% consumption in the summer was used as a conservative assumption in the initial phase of the analysis. If the existing feeders were unable to accommodate this conservative assumption, the summer consumption percentage was further refined and reanalyzed as described in the NPA Report for each planned project. If it was determined that the combined capacity could accommodate the entire gas capacity shortfall to electric, the Company concluded that electric distribution system upgrades would not be required, and no further analysis was done. It was also concluded that the Company would target existing Xcel Energy gas and electric combination customers from those feeders to convert gas appliances to electric appliances. If the existing feeders did not have an available combined capacity to accommodate the entire gas capacity shortfall to electric, the Company proceeded to the third step of the analysis.

For the third and final Step, if needed, the Company evaluated if the existing feeders identified in Step One had the combined winter and summer capacity available to accommodate the increased electric load of converting gas to electric appliances as determined in the achievable NPA portfolio. This was done using the same approach detailed in Step Two. If it was determined that the combined capacity could accommodate the increased electric demand resulting from the achievable NPA portfolio, the Company concluded that electric distribution system upgrades would not be required if the Company targeted customers with existing Public Service gas and electric service from those feeders to convert gas appliances to electric appliances. If the existing feeders did not have an available combined winter and summer capacity to accommodate the increased electric demand resulting from the achievable NPA portfolio, the Company concluded electric distribution infrastructure upgrades would be required.

If electric distribution infrastructure costs were required, the Company included the scope of the electric distribution infrastructure upgrades, associated infrastructure costs, and any notable risks are included in the NPA Report for each planned project.

3. Criteria 3: Cost Benefit Analysis

To evaluate the NPAs, the Company developed a Cost Benefit Analysis (“CBA”) consistent with the rules guiding the NPA process.[67] The purpose of the Company’s developed CBA model is to compare the net present value (“NPV”) economic benefits between the proposed gas infrastructure project and the achievable NPA portfolio. A summary of the CBA results are included in each NPA Report. The NPV Economic Benefits are inclusive of the following metrics, which are explained in more detail below.

[67] See Rule 4553(c)(I)(P)(i)(2).

Table 25: Summary of CBA Costs and Benefits[68]

	Costs	Benefits
Gas Infrastructure Project	• Proposed Gas Infrastructure Costs • Social Costs of Methane (CH4) Emissions	N/A

Achievable NPA Portfolio	• Program Costs
	• Electric Distribution System Infrastructure Costs, if required
	• Increased amount of electric commodity used
	• Electric Capital Expenses, if applicable:
	  o Transmission and Generation Capacity Costs
	  o Energy Generation Costs
		• Avoided Gas Commodity
		• Social Cost of Carbon (CO2e) Emissions Avoided

NPV Economic Benefits is the net value of the associated benefits and costs over the measured life of the technology or approach as defined in the currently approved gas/electric DSM Plan. The NPV Economic Benefits were utilized by the Company to compare the proposed gas infrastructure project to the achievable NPA portfolio. This informed the Company of whether to pursue the achievable NPA portfolio in lieu of the proposed gas infrastructure project. NPV Economic Benefits were calculated using Equation 4 below and included a discount rate of 6.7% from the Company's weighted average cost of capital (WACC). For each of the selected projects, tf the costs are greater than the benefits, the value is shown in parenthesis which indicates a negative value. The costs and benefits for the achievable NPA portfolio and the proposed gas infrastructure project are discussed in the following paragraphs.

Equation 4: Net Present Value of Economic Benefits

$$NPV_{Economic\ Benefits} = Discount\ Rate * (Benefits - Costs)\ (\$)$$

The costs for the planned gas infrastructure project included the proposed gas infrastructure capital costs as well as the social cost of methane emissions. For each planned project, the Company determined the change in projected greenhouse gas emissions due to the planned project as explained in Section VI of this Report. The project specific methane emissions were used as an input into the CBA tool which was multiplied by the social cost of methane emissions. Social cost was derived from the federal technical support document developed by the Interagency Working Group ("IWG") on the Social Cost of Greenhouse Gases, published February 2021. The estimates

[68] See Rule 4553(c)(I)(P)(i)(2). See also Rule 4528(c), where the social cost of emissions reflect cost as published by the Federal Technical Support Document, which is currently Social Cost of Carbon, Methane, and Nitrous Oxide - Interim Estimates under Executive Order 13990 in February 2021.

in the technical support document are reported in 2020 dollars, which were escalated based on a 2% annual rate. The Company selected a discount rate of 2.5% from the three discount rates included in the technical support document.

For the achievable NPA portfolio, the Company included costs as proposed for each of the selected planned projects. This included program costs, electric distribution system infrastructure costs (if required), the increased amount of electric commodity used as a result of the NPA technologies and approaches, and electric system costs. Electric system costs included capacity costs for transmission and generation, as well as costs for energy generation, if applicable. The price of the Company's electric commodity and electric system costs were derived as follows:

- Distribution capacity cost: Estimated by system planning based on available electric distribution capacity.
- Transmission capacity cost: With Public Service's existing approved plans for transmission capacity expansion through the Power Pathway project,[69] it is assumed there is no incremental transmission capacity cost or avoided cost to the NPA measure.
- Generation capacity costs: Currently approved electric and gas DSM Plans.
- Energy generation costs: Provided by Public Service Company Resource Planning consistent with the values in the currently approved electric and gas DSM Plans.

Benefits were only included in the NPV Cost for the achievable NPA portfolio, which incorporated the amount of avoided gas commodity and avoided social cost of carbon emissions. The achievable NPA portfolio is expected to result in avoided combined carbon dioxide and methane emissions from reduced customer end use and thus combustion of natural gas (or throughput). The Company projected the amount of reduced emissions from customer end use for the selected planned projects based on the anticipated customer adoption of the NPA technologies and approaches. The avoided carbon emissions was the net value of the annual gas throughput reduction less the electric energy load impact, if applicable. Social cost was derived as discussed above. The price of the Company's gas commodity is a blended forecast of NYMEX, S&P/IHS, and Wood MacKenzie at the CIG Hub.

The Company intends to continue to develop the CBA tool following the initial GIP Report filing once the Clean Heat Plan is approved and as emission estimation procedures evolve.

4. Criteria 4: Best Value Employment Metrics

In accordance with Rule 4553(c)(P)(i)(3), the Company performed an evaluation of the best value employment metrics ("BVEM") for the NPA analysis, in which the Company is required to consider "available best value employment metrics associated with each alternative, as defined in paragraph 4001(h), including a projection of gas distribution jobs affected by the alternative and jobs made available through the alternative, opportunities to transition any affected gas distribution jobs to the alternative, pay and benefit levels of the affected gas distribution jobs and the jobs available through a transition opportunity, and how employment impacts associated with each alternative could affect disproportionately impacted communities."[70] In the context of the NPA

[69] Proceeding No. 21A-0096E.
[70] BVEM is further defined in Rule 4001(h).

analysis, BVEMs were used to provide a quantitative comparison of the potential impacts to the workforce if a NPA portfolio was pursued in lieu of the planned project. BVEM requirements are addressed in each provided NPA Report. The Company developed BVEMs for the proposed gas infrastructure project and achievable NPA portfolio including the associated electric distribution system upgrades, if required. BVEMs included a projection of incremental workforce with consideration to the job title, number of workers, duration of employment, range of wages, and benefits offered.

If the Company pursues the proposed planned project, for purposes of this analysis the Company assumed that an incremental workforce would be required to perform construction activities. This may include foremen, laborers, equipment operators, welders, welder helpers, fusers, pipe fitters, superintendents, a project manager, and other services not limited to restoration, trucking, traffic control, etc. Activities related to design, engineering, and ongoing operations and maintenance would be absorbed by existing employees, therefore no incremental workforce would be required. The duration of employment would be temporary, and employees would generally receive hourly wages with benefits. The Company estimated the incremental workforce based on each planned project's scope of work at the time of the Initial GIP but may be refined as the scope of work is further developed. If the planned project's scope of work was still under development at the time of the Initial GIP, the Company was unable to provide BVEMs for the planned project. The wages/benefits portion of the analysis was based on publicly available occupational employment and wage statistics published by the Bureau of Labor Statistics, United States Department of Labor ("BLS").[71] The Company relied on the data reported to BLS for the purpose of providing a neutral source of wage data to serve as a metric for each identified position since the incremental workforce resources and thus salary ranges are an unknown variable at this time. The wage data for each position is presented as the Colorado mean hourly wage for the job title as aligned with the best available information for similar job titles as classified by the BLS. The specific job titles, and therefore salary metric, for the identified roles in each NPA are informational data points and subject to change based on determinations made at the time of implementing either option.

Under the NPA portfolio, the Company assumed that incremental product managers would be required to facilitate the implementation. The wages/benefits portion of the analysis was also based on the BLS wage statistics as explained in the prior paragraph. Additionally, if electric distribution system upgrades were determined to be required, the Company assumed that the existing substation, boring, and electric distribution crews would perform the construction activities therefore no incremental workforce would be required. This assumption is dependent on the timing of the electric distribution system upgrades in coordination with already scheduled work. Again, after the scope of work for the electric system upgrades is further developed, the Company may identify a need for an incremental workforce.

E. **Summary of NPA Results for Selected Planned Projects**

A summary of the NPA results for each of the selected capacity expansion planned projects is contained in the Table below:

[71] See Bureau of Labor Statistics, U.S. Department of Labor, Occupational Employment and Wage Statistics, www.bls.gov/oes/. Wage data reported in May 2022.

Table 26: NPA Analysis Results

Project	Program Cost	NPV Cost	NPV Benefits	NPV Economic Benefits	Benefit / Cost Ratio
Mead to East Longmont Reinforcement					
NPA Portfolio	$8,338,710	$4,820,190	$2,649,934	($2,170,256)	0.55
Gas Infrastructure Project	> $12,000,000	-			
Recommendation (with cost recovery support):	Provide Recommendation in future GIP filing				
Harmony High Pressure Pipeline Reinforcement					
NPA Portfolio	$54,730,157	$51,492,599	$7,609,638	($43,882,962)	0.15
Gas Infrastructure Project	$10,126,926	$7,515,568	$27,358	($7,542,926)	0.004
Recommendation (with cost recovery support):	Proposed Gas Infrastructure Project				
Pearl Street Mall					
NPA Portfolio	$3,197,767	$5,730,153	($98,310)	($5,828,463)	0.02
Gas Infrastructure Project	$6,690,235	$5,874,266	$9,396	($5,883,662)	0.002
Recommendation (with cost recovery support):	NPA Portfolio				
F-3 Reinforcement					
NPA Portfolio	$7,458,784	$4,286,373	$2,588,971	($1,697,402)	0.60
Gas Infrastructure Project	$3,945,987	$3,465,905	$9,225	($3,475,130)	0.003
Recommendation (with cost recovery support):	NPA Portfolio				
Fort Lupton Compressor Station					
NPA Portfolio	$85,112,841	$58,848,233	$15,515,994	($43,332,239)	0.26
Gas Infrastructure Project	> $12,000,000	-			
Recommendation (with cost recovery support):	Provide Recommendation in future GIP filing				

F. Cost Recovery

It is important to recognize that to the extent that implementation of alternatives, inclusive of any interim mitigation efforts, come at an incremental cost to the Company that is not currently covered by the demand-side management cost adjustment for either gas or electric, or any other mechanism at this time, the Company would require some form of authorized cost recovery for the gas and/or electric utility, as appropriate. In the event the Commission were to determine, consistent with the Company's analyses as detailed in the NPA Reports, that alternatives should be pursued, authorized Commission recovery in the form of deferred accounting with a full return, would be an important prerequisite to the Company moving forward with implementation. While the Company recognizes that such authorization cannot be fully granted in this non-adjudicated proceeding, the Commission could require the Company to submit an appropriate compliance filing with an expedited schedule for Commission approval to promote near-term implementation and success of the NPA portfolio.

IX. Other Gas Infrastructure Investments

As explained earlier in this Report, the Company invests in its gas infrastructure to maintain safe, reliable, and affordable gas service for its customers as well as to align with statutory and its own emissions reduction goals. The planned projects described in detail in this Report constitute a portion of the Company's overall investment in its gas infrastructure. The remainder of capital expenditures not included in this Report consist of projects that began prior to 2023, routine work associated with all categories of investment, discrete projects under $3 million, and larger projects that have emerged since the November 2022 budget for 2023-2027. Some examples of the foregoing that fall within the safety and capacity expansion investment categories, but are not included in this Report, follow.

For example, several safety projects with aggregate expenditures over $3 million were initiated under the PSIA Deferral authorized by the Commission as part of Proceeding No. 21A-0071G, and will continue to have expenditures in 2023. Those projects, which are discussed in more detail in the Company's 2022 PSIA Deferral Actuals filing submitted on April 3, 2023, include the following:

Table 27: System Safety and Integrity Projects >$3M Started Prior to 2023

Project Name	2022 Actuals	2023 Forecast
CO/MAOP/6in Estes Park (Line Loop 8) PSIA	$15.2	$0.2
CO/MAOP/10" Mesa to Boulder (Line l) PSIA	$11.3	$0.5
CO/DMR/Rebuild F-524	$1.8	$1.6
CO/HPGE_MAOP_12in Fossil Creek PSIA	$1.2	$1.2
Total	**$29.5**	**$3.5**

As noted earlier in this Report, individual planned safety projects are often discretely identified for the near term. One such recently authorized safety project is the MAOP EDC to H-Y 20-inch Spike Test Project. The affected portion of the pipeline, which is in the vicinity of Mississippi Avenue and Chambers Road, does not have sufficient pressure test records to support the current MAOP and testing is therefore required by PHMSA regulations. The pressure test will be paired with material verification to meet the requirements of 49 C.F.R. 192.624, and comply with traceable, verifiable, and complete record ("TVC") requirements. This project currently has an estimated total project cost of $7.7 million with an anticipated construction project start date in 2024 and an in-service date of October 1, 2024.

An example of a capacity expansion project not included in this Report is the West Metro project. Effective late December 2022,[72] the Commission granted the Company's Verified

[72] See Decision Nos. R22-0457 and C22-0780 in Proceeding No. 21A-0472G. Decision No. C22-0780, which is the Commission's decision denying exceptions to the Administrative Law Judge's Recommended Decision, was mailed on December 6, 2022.

Application for a certificate of public convenience and necessity for this project, which was estimated to cost $27.15 million, excluding an allowance for funds used during construction. As a result of the Commission's authorization, this project is underway. The 12" IP line and F-995 regulator station are anticipated to be completed in 2023, with the boosting pounds low system and Highlands system upgrades to be completed by the Fall of 2024.

Separately, while not at planned project status, the Company has identified capacity constraints in its Mountain Gas System ("Mountain System"), driven by forecasted peak hour demand growth that exceeds the available system capacity. The existing Mountain System provides natural gas service to approximately 65,000 customers, plus the remaining three LDCs. The Company's Mountain System includes approximately 975 miles of transmission pipeline, eight compressor stations, and the following three primary supply points:

- Marshall Compressor Station located in Boulder;
- Tiffany Compressor Station located near Durango; and
- Rifle Gas Plant located in Rifle.

The available system capacity of the Mountain System is limited due to the size of the available transmission pipeline as well as available supply from the three supply points. The three supply points are either at their design maximum throughput or maximum available daily contracted amount. Additionally, for the past several years, the Mountain System has experienced abnormal growth rates as compared to the overall Public Service gas territory, specifically in Summit, Grand, Eagle, and Lake counties. As a result of these factors, the Company has identified an existing and forecasted capacity shortfall in several of the Company's load centers. To continue providing reliable service to these load centers, specifically during periods of peak hour gas demand, the Company deployed temporary CNG and LNG solutions during this past 2022/2023 heating season in order to have the ability to provide supplemental supply into the gas system to maintain system reliability. In order to maintain system reliability under Design Day conditions, the Company will continue to identify and implement temporary mitigative solutions over the next few heating seasons until a long-term solution is identified and placed in-service. As part of its long-term gas infrastructure planning approach and aside from traditional gas reinforcement recommendations, the Company is in the process of considering NPA portfolios as potential options for long-term solutions.

To evaluate gas infrastructure projects as a long-term solution, the Company has engaged its Gas Planning and Conceptual Design Engineering teams to identify appropriate, economical, and feasible system reinforcements. The Company is evaluating various solution sets which will be further refined through a financial analysis and input from the NPA analysis. In a parallel path, the Company has partnered with a third-party consultant to evaluate and model NPA portfolios to mitigate the capacity shortfall in the Mountain System. The NPA analysis will include the following core deliverables:

- Portfolio Development, including primary research;
- Full Electrification; and
- Comprehensive Comparison of Potential Alternative Portfolios.

The development of portfolios will include an evaluation of technical, economic, and achievable potential of NPA measures and technologies for Design Day peak hour gas demand reductions. As part of the portfolio development, the Consultant will be reviewing the Company's existing NPA process to evaluate if the set of measures and technologies is comprehensive or whether additional measures should be considered as part of the evaluation of alternatives. The Consultant will also be conducting primary research. Specifically, the primary research will evaluate the building stock, customer economics, building uses (seasonal use, short-term rentals, tenant/landlord relationships), and contractor availability, which are likely to be different in the Mountain System than in other Public Service gas territories. The results of the primary research will directly impact the accuracy of the achievable potential as well as provide input into the necessary incentive levels to drive customer participation. Additionally, the Consultant will be assessing the feasibility of conversion of new and existing gas demands to 100% electric service within the Company's electric service territory. Throughout the analysis, the Company will be hosting Stakeholder Workshops to provide educational opportunities about the process as well as seek stakeholder feedback and input. Details regarding the Stakeholder Workshops, including the format and timing, are still under determination. Upon conclusion of the analysis, the NPA portfolios will be synthesized into a comparative analysis. The comparative analysis will help inform the Company when selecting an appropriate long-term solution. Once a long-term solution is determined, the Company will share its findings with the Commission through the appropriate regulatory filing channel, and, as appropriate, seek Commission approval.

X. EXISTING INFRASTRUCTURE ASSESSMENT REPORTING (4553(d))

Pursuant to Rule 4553(d), the Report is required to contain existing infrastructure assessment reporting. Specifically, information is required to be provided as related to COYLs, hydrogen compatibility in the Company's distribution system, and advanced leak detection. Each of these topics are addressed below.

A. Customer-Owned Yard Lines (4553(d)(I))

Pursuant to Rule 4553(d)(I), the Company is required to report the following information regarding customer-owned yard lines attached to its distribution system, if applicable:

> (A) an estimate of the number of customer-owned yard lines by municipality served;
>
> (B) the number of customer-owned yard lines replaced by the utility to date and capital investment incurred to do so; and
>
> (C) the estimated gross and net rate-based investment needed to replace all customer-owned yard lines in present dollars through year 2030, through year 2040, and through year 2050.

Rule 4551(a) defines a COYL to mean "any customer-owned gas line running underground from the utility meter to a customer's home, business, or other customer end use

Beginning in 2021, the Company implemented procedures to identify and track COYL piping as part of its three-year leak survey cycle per the terms of a settlement agreement reached in its 2020 Gas Rate Case (Proceeding No. 20AL-0049G), which was approved by the Commission.[73] Specifically, Section III.U.3 of the 2020 GRC Settlement states:

> As part of conducting its rolling three-year leak survey cycle, beginning January 1, 2021, Public Service will identify and track customer owned piping (customer-owned yard lines, or "COYLs") located within the Company's service territory. In addition:
>
> a. On an annual basis over the course of the leak survey cycle, Public Service will file with the Commission in this proceeding a report on its findings including, at a minimum,1) the number of COYLs, 2) the geographic location of such lines, and 3) the prior calendar year system average cost to replace a gas service line. At the conclusion of this three-year cycle, Public Service will provide Staff with a final report on its findings through a filing in this proceeding; and

[73] An Unopposed Comprehensive Stipulation and Settlement Agreement (the "2020 GRC Settlement") was approved in Decision No. R20-0673 in Proceeding No. 20AL-0049G on September 22, 2020, which thereafter became the decision of the Commission.

b. On an annual basis over the three-year leak detection cycle, Public Service shall notify individual customers of the existence of a COYL on their premises, notify customers that Public Service does not provide leak detection or maintenance for such lines, and provide customers information regarding the Company's terms and conditions in its existing line extension policy related to a customer's request for a change in service.

This will result in the Company surveying roughly one-third of its system annually, with the entire system surveyed by the end of 2023, after which a final report will be filed with the Commission. Field personnel conducting leak survey activities can ascertain whether a COYL is present on a customer's property because they are physically at the meter, and they know whether the line from the meter to the customer's home or business is part of the system owned by the Company. In cases where the line from the meter to the point of use is not owned by the Company, field personnel then record this piping as a COYL.

In 2021, the first year of our three-year leak survey cycle, we identified 2,750 COYLs. Given that there are approximately 1.5 million total customer meters on the Company's system, the 2,750 COYLs identified in 2021 represent less than 0.2 percent of all of the customer meters. COYLs were identified in various areas across our service territory, based on where leak survey work was conducted in 2021, as also reflected in the table below, by municipality:

Table 28: COYLs by Municipality – 2021 Results

Municipality	No.	Municipality	No.	Municipality	No.
Alamosa	2	Englewood	133	Louisville	6
Arvada	1	Erie	4	Loveland	5
Aurora	140	Evergreen	110	Mead	3
Beaver Creek	1	Fort Collins	43	Milliken	21
Berthoud	21	Frisco	10	Morrison	11
Black Hawk	5	Golden	185	Nederland	29
Boulder	19	Grand Junction	9	Northglenn	6
Breckenridge	17	Greenwood Village	308	Parachute	1
Brighton	8	Henderson	50	Parker	43
Broomfield	9	Hot Sulphur Springs	22	Parshall	1
Brush	2	Hygiene	1	Rifle	1
Centennial	146	Idaho Springs	17	Sheridan	1
Central City	11	Idledale	17	Sterling	58
Cherry Hills Village	139	Indian Hills	5	Thornton	209
Columbine Valley	33	Johnstown	2	Vail	1
Commerce City	48	Keystone	8	Wellington	2
Conifer	11	Kittredge	3	Westminster	2
Denver	620	Lafayette	2	Wheatridge	1
Dillon	12	Lakewood	5	Wiggins	9
Eaton	2	Littleton	95	Windsor	2
Empire	12	Longmont	50		
Subtotal:	**1,259**		**1,079**		**412**
Total:	**2,750**				

The results from 2022, the second year of our three-year leak survey cycle are in the process of being finalized as of the date of this Report. Those results will be filed in Proceeding No. 20AL-0049G when complete.

The Company sent letters to customers identified as having a COYL in 2021. The letters advised that repair and maintenance of the COYL are the responsibility of the owner, and that the Company does not provide leak detection or maintenance for such customer-owned lines. Customers were advised to contact the Company if they had questions or wanted information to help determine if the COYL could be replaced with a company-owned service line. The costs assessed for this service would be determined by the Company's Gas Extension Policy. To date, no customers have requested that their COYL be replaced.

The Company does not have a COYL replacement program, and is still in the process of identifying all the COYLs on its system, as noted earlier. Thus, for both residential and commercial customers, any costs associated with moving or removing Company facilities necessary to modify the customer's service, as well as costs associated with removing any customer-owned facilities, would be the responsibility of the customer. Thus, the Company must make assumptions based on known data of what the cost to replace a COYL would be. The Company anticipates the average cost to remove and modify Company and Customer owned assets and replace a COYL to be approximately $8,728. This average cost of $8,728 was determined utilizing the average cost to replace a Company owned gas service line plus 20 percent added assuming the service length will be longer than 58' (which is the average length of a Company-owned service line) and efficiencies in traffic control, permitting, restoration, and mobilization may not be present. Additionally, the Company's cost estimate includes an average cost to perform a gas service demolition for customers. Actual costs to replace COYLs with Company-owned service lines will vary. It is estimated that approximately $24 million in investment would be required to replace the 2,750 COYLs identified through 2021.

B. Hydrogen ((4553)(d)(II))

Pursuant to Rule 4553(d)(II), the Company is required to report the following information regarding hydrogen compatibility throughout its distribution system to the extent known:

> (A) estimate the percentage of distribution system components known to be compatible with safely carrying varying concentrations of hydrogen, including but not limited to:
>
> (i) piping;
> (ii) fittings; and
> (iii) non-pipe system components.
>
> (B) The utility shall identify any areas of the system with unknown materials or materials known to be not compatible with hydrogen mixtures up to 20 percent by volume.

The Company, as part of its clean energy vision for its natural gas systems, has outlined a strategy, where the Company will (1) expand conservation programs, (2) encourage gas to electric appliance switching, and (3) offer low-carbon gas alternatives such as hydrogen and renewable natural gas. As a part of this vision, the Company is working to utilize low carbon fuels such as certified natural gas, renewable natural gas and hydrogen blending. Studies and research are ongoing across the industry regarding the effects of hydrogen on existing natural gas systems. As a result, knowledge regarding various hydrogen blends and technologies in the industry will continue to evolve.

The Company intends to continue and study through engineering analysis the effect of hydrogen blending on both Company facilities as well as customer equipment. The engineering analyses will include, among other things, material evaluation, customer interchangeability review and changes to company standards and practices resulting from hydrogen blending. Moreover, these studies will begin to determine the future long-term strategy of utilizing hydrogen in the existing natural gas system as a low carbon alternative to support greenhouse gas emissions reduction. To that end, the Company is currently working on setting up a demonstration project for hydrogen blending into natural gas in an existing distribution system in Adams County, Colorado.

This project, which is reported as a capacity expansion project in this Report, is set to deliver a blend of hydrogen and natural gas to customers, located in an isolated distribution system, at volume blend ratios of 2 percent, 5 percent and 10 percent over a two-year period. As part of the demonstration, the Company will also look into the compatibility of the materials used in its natural gas systems with hydrogen. This will allow for the Company to adjust its material inventory and future material purchases to be compatible with hydrogen blended natural gas. It will also allow the Company to update its Process and Compliance Manual, Integrity Management Programs and Manuals and Operator Qualification training programs to include work around hydrogen blending. In combination with the results from the demonstration project and information regarding materials compatibility with hydrogen, the Company will work to develop a roadmap for the future use of hydrogen blending in a broader spectrum across its gas systems. As the Company is in the process of evaluating the specific reporting elements outlined in Rule 4553(d)(II), it is premature to provide more specific information.

C. <u>Advanced Leak Detection ((4553)(d)(III))</u>

Pursuant to Rule 4553(d)(III), the Company is required to report the following information regarding advanced leak detection:

(A) identification of equipment, survey method, percentage of system surveyed in each year, and interval in which additional advanced leak detection occurred on the same areas of the system;

(B) any updates to anticipated system-wide methane emissions based on most recent advanced leak detection surveys; and

(C) [the] extent to which leakage sources identified are within DI Communities.

The term "advanced leak detection" is not defined in Commission rules, and is an evolving concept. Regardless of the definition, the Company is not currently utilizing any form of advanced leak detection methods as part of formal leak survey operations. The Company is currently evaluating advanced leak detection for use on an annual basis for the entire gas distribution system and may propose the Advanced Leak Detection projects in a future gas filing. Because we do not use advanced leak detection methods, they are not currently employed to determine and/or update systemwide methane emissions.

At this time, the Company conducts leak surveys by "traditional" methods utilizing CGI (Combustible Gas Detector) equipment and a combination of both walking and mobile (vehicle) survey techniques. The Leak Survey department performs the following leak surveys: whole map survey, business district survey, and accelerated survey. Handheld infra-red leak detection units such as the DP-IR are used. The whole map leak survey is performed on a three-year cycle, with approximately one-third of the distribution system surveyed annually. Business district, accelerated, bridge crossings and shorted casing surveys are performed on an annual basis, with distribution high pressure systems surveyed quarterly. Finally, there is not current tracking of leakage sources identified within DI Communities. All areas of the gas distribution system are leak surveyed on the intervals above with all known leaks identified and scheduled for repair in accordance with applicable timeline requirements.

XI. CONCLUSION

The Company is pleased to present this Initial GIP. This robust Initial GIP provides new levels of transparency into how the Company plans for, invests in, and operates its gas LDC business. Additionally, this GIP also advances new, alternative approaches to planning, including extensive evaluation and consideration of alternatives for capacity expansion projects. While we are at the beginning of developing and implementing these frameworks, we look forward to evolving these approaches with the Commission's and other stakeholders' input. It is also important that we balance the objectives of these new approaches to planning with the Company's obligation to serve new customers and to maintain a safe, reliable, and affordable gas system. which serves approximately 1.5 million customers in Colorado, as well as all the other Colorado LDCs. Since our system is an essential backbone upon which millions of Coloradans rely for their heating needs, foundational investment in the system for all planned project types is a necessity, as explained herein, even as we embark on the transition to a Clean Heat future. We look forward to engaging in a robust and collaborative conversation with the Commission and interested stakeholders not only during this Initial GIP, but as the new regulatory paradigm unfolds.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on November 18, 2021

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
Diane X. Burman, dissenting
James S. Alesi
Tracey A. Edwards
John B. Howard
David J. Valesky, dissenting
John B. Maggiore

CASE 19-G-0379 - Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service.

ORDER DENYING PETITION

(Issued and Effective November 19, 2021)

BY THE COMMISSION:

INTRODUCTION

New York State Electric & Gas Corporation (NYSEG) filed a petition on May 17, 2021 (Reallocation Petition). In the Reallocation Petition, the Company requests a limited waiver from a provision of its tariff that addresses the priority of applicants' eligibility for service. The requested limited waiver would allow NYSEG to allocate natural gas on a preferential basis to serve commercial and/or industrial customers in the Lansing moratorium area only for reasons of economic development and where such customers have no practical alternatives. By this Order, the Reallocation Petition is denied.

BACKGROUND

On February 9, 2015, NYSEG notified the Secretary to the Commission that the Company was no longer able to accept any applications for gas service from new or existing customers in the Town of Lansing, located in Tompkins County, New York.[1] Prior to issuing its moratorium, NYSEG developed and proposed traditional infrastructure solutions which eliminated reliability concerns in the Lansing area for existing customers and allowed for the addition of new customers. Since the declaration of the Lansing gas moratorium, NYSEG has been actively working on potential pipeline and non-pipeline solutions to address localized low gas operating pressures on the gas system during peak days. Specifically, on July 19, 2017, NYSEG filed a petition for authorization to construct a natural gas compressor pilot project.[2] NYSEG indicated that it would issue a Request for Proposals seeking Non-Pipe Alternatives (NPAs) to address the pressure/reliability issues present in the moratorium area and to address the pending demands for additional natural gas in the area. The Commission authorized the natural gas compressor pilot in November 2017.[3]

In July 2019, the Alliance for Non-Pipe Alternatives (ANPA) submitted a filing stating that commercial non-

---

[1] A copy of the signed letter is attached as Appendix A.

[2] Case 17-G-0432, Petition of New York State Electric & Gas Corporation for Authorization to Construct a Natural Gas Compressor Pilot Project in Tompkins County, NY.

[3] Id., Order Authorizing Natural Gas Compressor Pilot Project (issued November 16, 2017).

residential growth has stagnated in the Lansing moratorium area.[4] In its filing, ANPA requested that the Commission allow NYSEG to reallocate natural gas for commercial and industrial processes as gas supply becomes available due to achieved demand reductions.

On June 22, 2020, NYSEG and other parties submitted a joint proposal in the then-on-going rate proceedings, that included, as part of Appendix M, 17 commitments by NYSEG related to its natural gas business.[5] These commitments required, among other things, NYSEG to file a petition regarding the potential preferential reallocation of natural gas to serve commercial and industrial customers for reasons of economic development in the Lansing moratorium area. On November 19, 2020, the Commission issued a rate order[6] adopting the terms of that joint proposal.

On September 1, 2020, NYSEG filed a petition for the approval to implement an NPA portfolio designed to eliminate the need for the Compressor Project. As part of its petition, the Company proposed a portfolio of seven projects with a projected demand reduction of 56.34 MCFH (thousand cubic feet per hour). On June 21, 2021, the Commission approved the NPA portfolio, with modifications.[7] In the Reallocation Petition, the Company

---

[4] Case 17-G-0432, Petition of the Alliance for Non-Pipe Alternatives pertaining to the Lansing Gas Moratorium and NYSEG's Non-Pipe Alternative Request for Information, filed July 15, 2019, p. 6.

[5] Cases 19-G-0379, et al., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation – Electric and Gas Rates, Joint Proposal (filed June 22, 2020).

[6] Cases 19-G-0379, et al., supra, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, with Modifications (issued November 19, 2020) (2020 Rate Order).

[7] Case 17-G-0432, supra, Order Approving Petition for Non-Pipe Alternative Projects (issued June 21, 2021), Confirming Order (issued July 20, 2021).

stated that the NPA portfolio solution may moderate, but will not eliminate, peak-day reliability concerns and will not be sufficient to lift the moratorium in the Lansing area. According to NYSEG, the NPA portfolio as approved by the Commission will increase reliability for existing gas customers, allow NYSEG to make progress toward Climate Leadership and Community Protection Act (CLCPA) goals, support the Company's commitment of no net new increase in gas utilization, and has garnered community support of the solutions which do not increase gas utilization.

To the extent the Commission were to allow a limited number of new non-residential economic development gas customers (or increased gas supply to current non-residential gas customers) to be added, the Company would require a waiver from a provision of P.S.C 90 - Schedule for Gas Service, Leaf 86, Section 10(J), which states: "The applicant's priority eligibility for service shall be based upon the date the Company receives the Customer's application for gas service." The limited waiver would allow the Company to allocate newly available gas system capability to provide new or incremental gas service to commercial and industrial customers in the Lansing moratorium area.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on June 9, 2021 [SAPA No. 19-G-0379SP2]. The time for submission of comments pursuant to the Notice expired on August 9, 2021. No comments were received.

LEGAL AUTHORITY

Under PSL §§65 and 66, the Commission has general supervision of all gas corporations in New York State, which includes the ability to regulate the terms under which gas corporations provide gas service to their customers and the authority to make ratemaking determinations.

DISCUSSION AND CONCLUSION

NYSEG's petition comes to us at a time when the Company's NPA projects are at the very beginning stages of implementation in the Lansing gas moratorium area. The NPA projects, as authorized, have yet to demonstrate their effectiveness and provide sufficient data to illustrate that the Lansing service area peak-day reliability concerns will be addressed. The NPA portfolio is comprised of mostly heat pump and energy efficiency solutions, which may require up to three years to fully realize the expected load reduction. More importantly, even if the projected load reduction is realized sooner, the Company has stated the proposed NPA portfolio solution may moderate, but will not eliminate, peak-day reliability concerns and will not be sufficient to lift the moratorium in the Lansing service area. Further, the risk of potential increased customer load among existing customers offsetting the load reduction realized from the NPA projects cannot be ignored. As proposed, NYSEG's Reallocation Petition could exacerbate the peak-day reliability concerns that already exist on the gas distribution system in the Lansing gas moratorium area. As such, authorizing increased customer demands on the Lansing service area gas system now would be imprudent.

For these reasons, we deny NYSEG's Reallocation Petition. However, NYSEG may file a new petition for Commission consideration once the Company's NPA portfolio of the seven projects has been fully implemented and the Lansing service area peak-day reliability concerns have been addressed.

The Commission orders:

1. The petition filed by New York State Electric & Gas Corporation is denied, as discussed in the body of this Order.

2. This proceeding is continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

Appendix A – Lansing Gas Moratorium Letter

IBERDROLA USA

Mark O. Marini
Director - Regulatory

February 9,
2015

VIA ELECTRONIC SERVICE

Honorable Kathleen H. Burgess, Secretary
New York State Department of Public
Service3 Empire State Plaza, 19th Floor

Albany, NY 12223

Dear Secretary

Burgess:

In accordance with the New York State Electric & Gas Corporation ("NYSEG" or the "Company") Gas Tariff (PSC 90, Leaf No. 86, Section 10. Conditions of Gas Service, Provision J), the Company hereby advises the New York State Public Service Commission ("PSC" or the "Commission") that it is unable to accept additional applications for gas service from new or existing customers in portions of the Ithacafranchise area.

The Company continues to receive requests for incremental natural gas services from both new and existing customers in its Ithaca franchise area. Due to current pressures on the distribution system on cold weather days and design-day predicted pressures in the Lansing area, NYSEG cannot provide the requested incremental natural gas service at this time. The area where NYSEG cannot provide incremental service is in the Town of Lansing as bounded by the lake on the west and NYS Route 13 on the south. This area is shown on the attached figure. NYSEG started work in 2014 on the Lansing/Freeville reinforcement project along West Dryden Road. NYSEG is actively working on obtaining easements from residents along West Dryden Road. To date, NYSEG has obtained approximately half of the required 100 easements. The residents own to the centerline of the road and many residents have denied NYSEG the requested 15' wide easement. The project includes 7 miles of 10" distribution main along West Dryden Road, a new regulator station at Warren Road to connect to NYSEG's existing distribution system, and a rebuild of Dominion Transmission's Freeville Gate Stationserving NYSEG. NYSEG did consider other reinforcement options prior to this project and is currently re-evaluating based on the possible need for condemnations along West Dryden Road. NYSEG will continue to consider all available options in an effort to accommodate future service requests.

Appendix A - Lansing Gas Moratorium Letter

89 East Avenue, Rochester, NY 14649-0001
Telephone 585.771.4692, Cell 585.750.1666
Mark_Marini@rge.com

An equal opportunity employer
Printed on recycled paper

The Company will keep PSC Staff informed of any further developments regarding requests for newor increased gas service.

Respectfully submitted,

Mark O. Marini

Mark O. Marini

Attachment

CC: Cindy McCarran - Deputy Director, Gas and Water

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	**Case 17-G-0460**

Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report

December 2, 2024

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

People. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

Central Hudson Gas & Electric Corporation
Case 17-G-0460
Non-Pipeline Alternatives – Annual Report

Table of Contents

Background

Non-Pipeline Alternatives ("NPAs") are projects designed to displace the need for traditional gas infrastructure investment. Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") proposed to incorporate NPA projects into its system planning process within its 2017 Rate Case.[1] On June 14, 2018 the Commission issued an Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Order"). The Order adopted proposed NPA strategies and required the Company to submit an implementation plan and subsequent annual report for each identified NPA project. Central Hudson provides this annual report on the progress of each of its NPA projects.

Non-Pipeline Alternative Projects

The Company is pursuing two categories of NPA projects, both of which employ non-traditional solutions to avoid traditional infrastructure construction.

1) *Transportation Mode Alternatives*

Central Hudson's transportation mode alternatives projects are designed for strategic abandonment of leak-prone pipe ("LPP") and avoidance of Transmission Service Relocation ("TSR") through electrification where it is more cost effective than replacement or installation and system reliability is not negatively impacted.

2) *Load Growth-Based Projects*

These types of projects would be designed to manage locational constraints that are associated with peak demand.

[1] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.*

Transportation Mode Alternatives

Overview

Central Hudson's current Transportation Mode Alternatives ("TMA") are designed to facilitate strategic abandonment of LPP and avoidance of TSR. LPP is any natural gas distribution piping that is not made of either plastic or "protected"[2] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In order to improve safety and reduce ongoing maintenance costs, LPP that cannot be protected or abandoned must be replaced with new plastic pipe. LPP replacement is costly; in 2019, the Company estimated its cost to be approximately $1.9 million per mile on average.[3]

Central Hudson's Transmission Service Relocation Program was approved through the 2023 Rate Case[4]. The Company is authorized relocate 67 transmission services or "Farm Taps" to nearby distribution network through the extension of main pipeline, comprising a total of 15 cases. The extension of main pipeline to service these Farm Taps is costly and is estimated at approximately $103,990 per service on average.

Approach

Through electrification of customers' heating and appliances, gas pipeline can be retired or avoided permanently in strategic locations. The approach is ideal for low customer saturation areas with high replacement or installation costs. Generally, for a TMA initiative to be successful, all the natural gas customers served by the designated infrastructure must agree to retire their gas service.

To date, the Company has identified over 60 separate TMA project locations throughout its service territory where it is potentially feasible and cost-effective to permanently retire or avoid sections of gas pipeline. Each project location, referred to as a "case", includes two to three customers on average.

The first three cases were submitted in "Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode

---

[2] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[3] Joint Proposal "Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service." Section XVII.E*
[4] Case 23-G-0419*: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*

Alternatives"[5] ("2019 Implementation Plan"), filed in June 2019.

In 2020, the Company broadened its scope for potential projects and identified 37 additional cases as potential TMA candidates. Five of these new cases were identified as "high priority" and included in Central Hudson's "2020 Implementation Plan"[6], filed June 12, 2020. Cases have been designated as high priority when they have heighted time constraints due to concurrent Company or municipal initiatives. Central Hudson pursues TMA cases based on a determined priority, as opposed to their chronological identification.

On September 15, 2021, the Company filed its "2021 Implementation Plan Update."[7] Thirteen additional NPA project opportunities were included in this update; seven cases from 2020 which did not proceed with NPA conversions at that time, and six new cases being initially pursued in 2021.

On October 24th, 2022 the Company filed its "2022 Implementation Plan Update."[8] Six additional NPA project opportunities were included in the update; five cases from the 37 potential projects identified in 2020, and one new case identified in 2022.

On November 1st, 2023 the Company filed its "2023 Implementation Plan Update."[9] Four additional NPA project opportunities were included in the update, all being new cases identified in 2023.

On September 13, 2024 the Company filed its "2024 Implementation Plan Update."[10] Five additional LPP NPA project opportunities were included in the update, two being new cases identified in 2024. Five TSR NPA opportunities we included in the update, all cases identified from the Transmission Service Relocation Program.

---

[5] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives, Filed June 21, 2019

[6] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed June 12, 2020

[7] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed September 15, 2021

[8] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed October 24, 2022

[9] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed November 1, 2023

[10] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Transportation Mode Alternatives, filed November 1, 2023

The Company has partnered with ICF along with its existing HVAC Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, a direct install approach is utilized. The initiative employs a highly targeted marketing strategy, followed by customer education and enrollment. High efficiency cold climate air-source heat pumps and electric heat pump water heaters are utilized to replace the primary natural gas end uses. Air source heat pump installations are performed in compliance with NYS Clean Heat[11] guidelines. Other natural gas appliances such as cooking ranges and clothes dryers are replaced with electric units where applicable. Customers are provided a standard conversion package at no cost[12] and may also receive a financial bonus incentive upon project completion.

Current Status

The Initial Three TMA Cases (2019)

In 2019, The Company initiated its first TMA case shortly after filing its 2019 Implementation Plan.

Case 1: The first LPP case consists of two customers. One customer went forward with the conversion in December 2019 which included converting existing natural gas equipment to efficient electric heating and hot water end uses, appliance replacements, and a financial completion bonus. The second property lies on a corner lot and has received a new, relocated service line as part of a pipeline replacement occurring on the adjacent street. Central Hudson filed for its TMA incentive on May 21, 2024 to Case 17-G-0460.

Case 2: This LPP case also consists of two customers. This case has been eliminated as a potential TMA candidate. After further review, the Company learned that one property had previously retired its gas use. The second property is able to access gas from another nearby gas main. The LPP main targeted as part of the TMA project is still planned for retirement.

Case 3: This LPP case includes approximately 18 customers. This case will be revisited after recruitment efforts are refined through smaller cases and those under tighter timeline constraints.

High Priority Cases (2020)

[11] See https://www.nyserda.ny.gov/All-Programs/Programs/NYS-Clean-Heat.
[12] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.

Five “high priority” cases were included in Central Hudson’s 2020 Implementation Plan. These cases were prioritized to coordinate with local municipal projects such as street repaving.

Case 4: This LPP case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 5: This LPP case involving three properties has successfully moved forward with a TMA strategy. One property received a full TMA conversion which included converting existing natural gas equipment to efficient electric heating and hot water end uses, an appliance replacement, and financial completion bonus. Conversion work was completed in September of 2020. The remaining two properties received new gas service lines since they are within 100 feet of a new main on an adjacent street and could request gas service in the future. Central Hudson filed for its TMA incentive on May 21, 2024 to Case 17-G-0460.

Case 6: This LPP case consists of a single structure that is overseen by a Board of Directors. The Board supports the conversion in concept, however, plans to expand their footprint and does not want to forego access to natural gas. The customer plans to install a gas-fired backup generator. The municipal project initially driving the priority of this case has been delayed until 2021, allowing more time to finalize this case. For the time being, discussions remain open as the Board continues its planning.

Case 7: This LPP case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 8: This LPP case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Additional Cases (2020)

Five cases were pursued in 2020 which did not proceed with NPA conversions. These were included retroactively in the 2021 Implementation Plan update.

Case 9: This LPP case was initially identified as having two customers. Under further investigation, five customers were using the length of gas main. As a result, the preliminary Societal Cost Test (“SCT”) estimate significantly failed with the additional conversion costs associated with the higher customer count.

Case 10: This LPP case has two customers. Under further investigation it was determined that customers agreeing to a TMA conversion would continue to have access to adjacent remaining gas mains and could request new service using the 100-foot rule, requiring little to no additional funding (CAIC[9]) of their own.

Case 11: This LPP case has five customers. The customers were marketed to and offered participation in the program through direct communications. One house was in contract to be sold. Limited response was received from other customers despite a targeted marketing strategy starting in July 2020 and continued customer follow up into the summer of 2021. The Company decided not to continue pursuing this case with a TMA strategy.

Case 12: This LPP case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 13: This LPP case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Unplanned High Priority Cases 14 & 15 (2020)

As part of a broadened strategy in 2020, Central Hudson attempted to apply the TMA strategy to two Unplanned High Priority cases. These opportunities were identified "in the field" when unique challenges arose during traditional pipeline installation efforts. Each case involved a single building. One building was a single-level professional office while the second was a mixed-use multifamily. Central Hudson engaged with each property owner and offered a full TMA conversion at no cost, coupled with sizable monetary incentives. Neither case was able to achieve customer commitment. One offer was declined, noting a preference for natural gas heat and future consideration of a gas-fired backup generator. The offer for the second location exchanged initial communications but failed to achieve response in subsequent efforts. These cases were included in the 2021 Implementation Plan update.

Additional Cases (2021)

Case 16: This LPP case has one customer. The customer has been marketed to and offered participation in the program through direct communications. Initial efforts have not received customer feedback. Additional customer outreach was completed in 2023 and the customer was unwilling to convert from natural gas so this case will be unable to proceed.

Case 17: This LPP case involved five customers and had received signed agreements to move forward with a TMA strategy. The preliminary BCA for this case was estimated to be under the 1.0 SCT threshold which acts as a primary determinant to proceeding with a TMA case. However, NPA conversion costs of the preliminary BCA are done prior to soliciting to and entering the premise. NPA conversation costs are assumed with reasonable conservative estimates and the Company determined this case to have a reasonable opportunity to complete at a 1.0 SCT or above. Each property consists of a single-family home. All homes have received a full TMA conversion including the conversion of existing natural gas equipment to efficient electric heating and hot water end uses, appliance replacements, and financial completion bonuses. Conversion work was completed in April of 2022. Central Hudson filed for its TMA incentive on May 21, 2024 to Case 17-G-0460.

Case 18: This LPP case involved two properties has successfully moved forward with a TMA strategy. As with Case 17, the preliminary BCA for this case was estimated to be under the 1.0 SCT threshold but the Company determined this case to have a reasonable opportunity to complete at a 1.0 SCT or above. Each property consists of a tenant-occupied two-family home. Both properties received a full TMA conversion which included converting existing natural gas equipment to efficient electric heating and hot water end uses, appliance replacements, and financial completion bonuses for the owners and impacted tenants. Conversion work was completed in July of 2021. Central Hudson filed for its TMA incentive on May 21, 2024 to Case 17-G-0460.

Case 19: This LPP case involves two properties and four buildings. One property is a for-profit business while the other operates as a non-profit. The customers have been marketed to and offered participation in the program through direct communications. On-site evaluations for TMA conversions were performed. Both properties showed initial interest in the TMA conversion opportunity, however, each chose not to proceed with ending natural gas service. One property had an obligation for backup generation and expressed concerns in converting their natural gas unit to another fuel or system. The second property received an offer to sell during our marketing efforts and was advised by their council to not change heating equipment while in negotiations.

Case 20: This LPP case has two multifamily properties. As with Case 17, the preliminary BCA for this case was estimated to be under the 1.0 SCT threshold but the Company determined this case to have a reasonable opportunity to complete at a 1.0 SCT or above. Customers were marketed to and offered participation in the program through direct communications. Sufficient customer interest was not obtained so this case was unable to proceed.

Case 21: This LPP case has two customers. Customers were marketed to and offered participation in the program through direct communications. Sufficient customer interest in converting was not obtained prior to a planned municipal paving project and coordinated LPP pipe upgrades so this case was unable to proceed.

Additional Cases (2022)

Case 22: This LPP case has one customer. The customer was marketed to and offered participation in the program through direct communications. Sufficient customer interest was not obtained so this case was unable to proceed.

Case 23: This LPP case has two customers. Customers were marketed to and offered participation in the program through direct communications. Sufficient customer interest was not obtained so this case was unable to proceed.

Case 24: This LPP case has two customers. The case was estimated to result in an SCT score significantly below 1.0 due to a low avoided cost associated with LPP replacement and high estimated conversion costs. Due to a low SCT, this case did not proceed with marketing and solicitation.

Case 25: This LPP case has three customers. The case was estimated to result in an SCT score significantly below 1.0 due to a low avoided cost associated with LPP replacement and high estimated conversion costs. Due to the low SCT, this case did not proceed with marketing and solicitation.

Case 26: This LPP case has two customers. This case was estimated to result in an SCT score significantly below 1.0 due to a low avoided cost associated with LPP replacement and high estimated conversion costs. Due to the low SCT, this case did not proceed with marketing and solicitation.

Case 27: This LPP case has two customers. Customers were marketed to and offered participation in the program through direct communications. Sufficient customer interest was not obtained so this case was unable to proceed.

Additional Cases (2023)

Case 28: This LPP case has six customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case was unable to proceed.

Case 29: This LPP case has one customer. The preliminary BCA for this case was estimated to be a 1.0 SCT but the Company determined this case would complete at below a 1.0 SCT. After an in-person assessment, the property was deemed unsuitable for an NPA due to a lack of sufficient HVAC infrastructure and insulation to support an upgrade to clean heat appliances.

Case 30: This LPP case involving one property has successfully moved forward with a TMA strategy. The property received a full TMA conversion which included converting existing natural gas equipment to efficient electric heating and hot water end uses, and financial completion bonuses. Conversion work was completed in August of 2023. Central Hudson filed for its TMA incentive on May 21, 2024 to Case 17-G-0460.

Case 31: This LPP case has three customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case was unable to proceed.

Additional Cases (2024)

Case 32: This LPP case has one customer. The customer was marketed to and offered participation in the program through direct communications. The customer was unwilling to convert from natural gas so this case will be unable to proceed.

Case 33: This LPP case has one customer. The customer was marketed to and offered participation in the program through direct communications. The customer was unwilling to convert from natural gas so this case will be unable to proceed.

Case 34: This LPP case has one customer. This case was estimated to result in an SCT score significantly below 1.0 due to a low avoided cost associated with LPP replacement and high estimated conversion costs. Due to the low SCT, this case will be unable to proceed.

Case 35: This LPP case involving two properties has successfully moved forward with a TMA strategy. The properties will receive a full TMA conversion which will include converting existing natural gas equipment to efficient electric heating and hot water end uses, and financial completion bonuses. Conversion work is expected to be completed before 2024 year-end. Central Hudson plans to file for its TMA incentive in 2025.

Case 36: This LPP case involving one property has successfully moved forward with a TMA strategy. The property will receive a full TMA conversion which will include converting existing natural gas equipment to efficient electric heating and hot water end uses, and a financial completion bonus. Conversion work is expected to be completed before 2024 year-end. Central Hudson plans to file for its TMA incentive in 2025.

Case 37: This TSR case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 38: This TSR case has two customers. The customers were marketed to and offered participation in the program through direct communications. One or more of customers were unwilling to convert from natural gas so this case will be unable to proceed.

Case 39: This TSR case has one customer. The customers were marketed to and offered participation in the program through direct communications. Although customers have shown interest in moving forward with the TMA strategy, full customer agreement has not been attained and this case is still within the planning phase. Project status will be provided again in the 2025 NPA Annual Report.

Case 40: This TSR case has three customers. The customers were marketed to and offered participation in the program through direct communications. Although customers have shown interest in moving forward with the TMA strategy, full customer agreement has not been attained and this case is still within the planning phase. Project status will be provided again in the 2025 NPA Annual Report.

Case 41: This TSR case has four customers. The customers were marketed to and offered participation in the program through direct communications. Although customers have shown interest in moving forward with the TMA strategy, full customer agreement has not been attained and this case is still within the planning phase. Project status will be provided again in the 2025 NPA Annual Report.

Benefit Cost Analysis

The Company estimates NPA case Benefit Cost Ratios (BCR) based on the three tests included in the BCA Handbook, as reported in more detail within the Implementation Plan.

Central Hudson primarily evaluates the economics of its TMA cases based on the Societal Cost Test

("SCT") prescribed within the Company's BCA Handbook.[13] The Company has partnered with a third-party evaluator, Applied Energy Group ("AEG"), to create a proprietary BCA screening tool to use in case evaluations. This tool provides valuable time savings and an increased ability to adjust for alternative scenario assumptions in initial BCA screenings.

Where applicable, the valuation methodologies from the BCA Handbook, which are primarily intended for electric projects, have been used. Some natural gas specific benefits and costs have been included in a way that is similar to those within the BCA Handbook. Central Hudson is continually refining its benefit cost analysis protocols to most accurately account for all related costs and benefits. Any material changes are done in consultation with DPS Staff.

The SCT calculated within a preliminary BCA is the primary determinant in the cost-effectiveness of an NPA solution. An SCT of 1.0 or greater prompts the Company to pursue a TMA case for solicitation and marketing. While determining the cost inputs of an NPA solution, there are unknowns to the unique requirements of any given property prior to soliciting to and entering the premise. For this reason, the NPA conversion cost are assumed with reasonable conservative estimates. While some cases may have preliminary SCT scores below 1.0, the Company may solicit to those which are deemed to provide a reasonable opportunity to complete at a 1.0 SCT or above. Additionally, the Company may choose to proceed with an NPA solution for reasons beyond achieving a minimum 1.0 SCT such as, but not limited to, those for risk mitigation, supporting reliability, or being cheaper than a traditional project to achieve the same result.

The Company's expectation is to maintain a portfolio of TMA cases with an SCT score of 1.0 or greater.

[13] Central Hudson Gas & Electric Benefit-Cost Analysis ("BCA") Handbook, Version 4.0, revised July 30, 2023.

Table 3: All Cases - BCAs and Project Summaries

Proposed	Case	SCT	UCT	RIM	Customers	Located in a Disadvantaged Community	Status
June 2019	1	1.14	0.93	2.71	2	X	*Completed*
	2	6.54	2.10	2.51	2		Unsuitable for NPA
	3	2.87	1.52	2.23	18		Unsuitable for NPA
June 2020	4	1.94	1.30	1.37	2	X	Insufficient customer interest
	5	5.18	1.97	2.15	1	X	*Completed*
	6	4.66	1.90	2.13	1	X	Insufficient customer interest
	7	1.13	0.90	1.22	2		Insufficient customer interest
	8	2.04	1.31	1.69	2		Insufficient customer interest
	9*	0.42	0.34	0.49	5		Unsuitable for NPA
	10*	0.49	0.40	0.58	3		Unsuitable for NPA
	11*	2.50	1.47	1.81	5		Insufficient customer interest
	12*	0.95	0.80	0.98	3	X	Unsuitable for NPA
	13*	1.16	0.94	1.10	2	X	Insufficient customer interest
	14*	1.66	1.18	1.44	1	X	Insufficient customer interest
	15**	N/A	N/A	N/A	5	X	Insufficient customer interest
August 2021	16	2.01	1.31	1.54	1	X	Insufficient customer interest
	17	0.86	0.72	0.95	5	X	*Completed*
	18	0.81	0.68	1.00	3	X	*Completed*
	19	1.51	1.11	1.35	3	X	Insufficient customer interest
	20	0.90	0.76	0.95	4	X	Insufficient customer interest
	21	1.15	0.93	1.27	2	X	Unsuitable for NPA
September 2022	22	1.27	0.98	1.44	1	X	Insufficient customer interest
	23	1.90	1.28	1.49	2		Insufficient customer interest
	24	0.50	0.42	0.48	2		Unsuitable for NPA
	25	0.77	0.64	0.86	3	X	Unsuitable for NPA
	26	0.65	0.54	0.71	2	X	Unsuitable for NPA
	27	2.20	1.38	1.65	2	X	Insufficient customer interest
September 2023	28	2.10	1.34	1.68	6	X	Insufficient customer interest
	29	1.00	0.85	1.01	1		Unsuitable for NPA
	30	1.34	1.03	1.18	1		*Completed*
	31	1.32	1.01	1.34	3		Insufficient customer interest
September 2024	32	1.43	1.07	1.27	1		Insufficient customer interest
	33	0.87	0.73	0.94	1	X	Unsuitable for NPA
	34	1.87	1.25	1.67	1	X	Insufficient customer interest
	35	1.28	0.99	1.30	2		In Progress
	36	1.71	1.19	1.42	1	X	In Progress
	37	1.88	1.25	2.16	2	X	Insufficient customer interest
	38	1.33	1.00	1.77	2	X	Insufficient customer interest

Central Hudson Gas & Electric Corporation
Case 17-G-0460
Non-Pipeline Alternatives – Annual Report

	39	1.45	1.07	1.64	1	X	Planning phase
	40	5.21	1.95	2.55	3	X	Planning phase
	41	2.09	1.32	2.09	4	X	Planning Phase
Total		1.80	1.10	1.47	111	27	

** A project investigated in 2020 included within the August 2021 Implementation Plan update **Case 15 was an unplanned high priority. The case failed to generate sufficient customer interest. A full Avoided Main Replacement and Services cost estimate for the NPA opportunity was never finalized.*

Project status key:

Planning phase - a case which is in queue for a preliminary site investigation and BCA.

In progress - a case in which customer interest is being solicited and, if applicable, NPA work is proceeding.

Insufficient customer interest - a case which has received solicitation but lacks sufficient customer interest to proceed with an NPA solution.

Unsuitable for NPA - a case initially identified as an NPA opportunity, but after further investigation is determined to not be an appropriate NPA candidate.

Completed - indicates a case in which an NPA solution has been utilized to retire natural gas use and the related gas main has been retired.

Load Growth-Based Projects

PN Line - Overview

In an effort to understand location-specific gas distribution costs, Central Hudson employed a consultant, Demand Side Analytics, to perform the "2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods"[14] ("Avoided Gas Distribution Study"). The study includes the analysis of approximately 40 localized gas systems throughout Central Hudson's gas service territory. Probabilistic forecasting methods, including simulations of nonlinear growth trajectories, have been used to identify areas of demand growth. The study is based on a methodology consistent with the "Location Specific T&D Avoided Cost Study Report"[15] conducted for Central Hudson's electric system planning and included within the Company's 2020 DSIP[16] filing.

The avoided gas distribution study concluded that there are no imminent constraints on the gas distribution system that would warrant the development of a NPA at this time. All potential avoidable distribution cost or deferral value is concentrated in a single gas distribution system, referred to as the PN Line, which serves customers in the southern portion of the Town of Poughkeepsie. The PN Line is highly loaded but is experiencing near flat annual growth (-0.10%), with some uncertainty. There is a risk of exceeding the system's design parameters within the next four years, but the likelihood is less than 10%, with "the most likely outcome for loads to remain below pressure constraints over the next decade."[17] Relatively small amounts of demand management or local supply resources can further reduce this risk for the foreseeable future.

---

[14] Cases 17-E-0459, 17-G-0460, 18-M-0084 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service; In the Matter of a Comprehensive Energy Efficiency Initiative, 2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods. (filed June 18, 2020)
Using Probabilistic Forecasting and Planning Methods

[15] Case 15-E-0751 – in the Matter of the Value of Distributed Energy Resources, Central Hudson Gas & Electric Corporation's Avoided T&D Cost Study. June 30, 2020

[16] Case 16-M-0411 – In the Matter of Distributed System Implementation Plans and 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Central Hudson Distribution System Implementation Plan, filed June 30, 2020.

[17] 2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods, p.34.

PN Line – Energy Efficiency Initiative

Within the Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025[18], ("Energy Efficiency Order") the Commission encouraged utilities to utilize targeted energy efficiency to support constraints on the gas distribution system. As stated by the Commission, "…the kicker concept can apply equally to gas efficiency programs, where supply constraints create a value for gas peak reduction. Each utility should consider the potential for gas kickers to provide system value."

While the potential for future investment in the PN line is not certain enough to warrant the development of a NPA at this time, Central Hudson has considered this an opportunity to leverage existing initiatives to manage the potential for a future load constraint. With a focus on the PN Line, Central Hudson evaluated its existing portfolio of energy efficiency and electrification technologies in conjunction with "kickers" in a peak load management application. Kickers provide a flexible, low-cost solution that can be implemented on an as-needed basis. Six energy efficiency and electrification measures currently offered within Central Hudson's Demand Side Management program were considered. These measures are all currently deployed within Central Hudson's programs and have been determined to be broadly cost effective. To assess the use of kickers, Central Hudson conducted a simplified analysis to compare the incremental costs of higher incentives and benefits associated with more concentrated load reductions. The analysis, referred to as the Locational Benefit-Cost Analysis indicates that smart thermostats[19] are the most cost-effective measure to deliver targeted load reductions.

PN Line - Implementation

Central Hudson implemented a "kicker" incentive to promote ENERGY STAR certified smart thermostats to customers served by the Vassar Road portion of the PN Line with the goal of providing more concentrated load relief to that system.

In November of 2020, the Company initiated its "Double the Rebates" marketing campaign to approximately 750 residential and commercial customers in the targeted area. Customers were provided the opportunity to choose from a broad selection of eligible smart thermostats available at a variety of retailers. Customers were eligible to receive Central Hudson's standard smart thermostat

[18] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025. Issued and Effective January 16, 2020
[19] A smart (learning) thermostat controls HVAC equipment to regulate the temperature of the room or space in which it is installed, communicates with sources external to the HVAC system for remote adjustment and has the ability to reduce overall gas consumption by performing automatic adjustments in response to occupant behavior.

rebate plus an additional rebate of equal value. Combined, the rebates equaled $100 per thermostat with each eligible household able to purchase up to two smart thermostats.

This initiative was supported by energy efficiency budgets authorized by the Commission. Per the Energy Efficiency Order, "utilities employing kickers have the flexibility to adjust the portion of the budget spent on kickers as appropriate based on further experience."

Central Hudson's Double the Rebates offer was valid until May 1, 2021. Through the promotion, customers purchased a total of 21 thermostats. Central Hudson will implement this initiative on an as-needed basis and set incentive levels based on consideration of existing portfolio budgets.

The Company continues to monitor the PN line for operating within the system's design parameters.

Gas System Long-Term Plan - Overview

In 2024, as part of the Gas System Long-Term Plan ("GSLTP"), Central Hudson commissioned and completed an avoided gas distribution study to determine if there were imminent constraints on the gas distribution system that would warrant the development of such an NPA at the time. Two locations – the Kingston Saugerties and the Titusville-Pleasant Valley local gas systems- were identified as potential NPAs, and more detailed analysis was conducted for these locations to define strategies to avoid growth-related infrastructure upgrades. These Load Growth NPA proposals are identified within the GSLTP.

Decision No. C25-0091

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23A-0633G

IN THE MATTER OF THE VERIFIED APPLICATION OF BLACK HILLS COLORADO GAS, INC. FOR APPROVAL OF ITS 2024-2028 CLEAN HEAT PLAN.

COMMISSION DECISION ADDRESSING EXCEPTIONS TO DECISION NO. R24-0784

Issued Date: February 12, 2025
Adopted Date: January 8 & 22, 2025

TABLE OF CONTENTS

Colorado PUC E-Filings System

I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the exceptions filed to Recommended Decision No. R24-0784, issued October 29, 2024, by Administrative Law Judge ("ALJ") Alenka Han. The Recommended Decision approves the Settlement Agreement ("Settlement Agreement") filed August 16, 2024, and grants, with modifications, the Application for Approval of its 2024-2027 Clean Heat Plan ("Application") that Black Hills Colorado Gas, Inc. ("BHCG" or the "Company") filed December 29, 2023.

2. Through their exceptions, parties seek to reverse or modify portions of the Recommended Decision. After considering the filed exceptions, the responses thereto, and the evidentiary record in this Proceeding, we grant in part, and deny in part, the exceptions that the Southwest Energy Efficiency Project ("SWEEP") filed on November 18, 2024.

B. Background

3. BHCG filed its inaugural Clean Heat Plan application pursuant to § 40-3.2-108, C.R.S. (the "Clean Heat Statute") and Rules 4725 to 4733 of the Commission's Rules Regulating Gas Utilities, 4 *Colorado Code of Regulations* ("CCR") 723-4 on December 29, 2023. In its Application, BHCG requests that the Commission approve: 1.) BHCG's inaugural Clean Heat Plan for 2024-2028; 2.) BHCG's preferred Clean Heat Plan scenario; 3.) BHCG's proposed budgets within the preferred scenario and the proposed budget flexibility; 4.) BHCG's proposed cost recovery mechanisms including the creation of a new surcharge called the Clean Heat Plan Rider (CHPR); 5.) BHCG's proposal to track and defer costs incurred in association with preparing and litigating this proceeding into a non-interest bearing regulatory asset that will be recovered through

the CHPR; and 6.) any waivers or variances the Commission deems necessary for approval and implementation of its proposed clean heat plan.

4. On March 7, 2024, the Commission referred the Proceeding to the above-mentioned ALJ through Decision No. C24-0148-I, and the following entities became parties: the Colorado Public Utilities Commission Trial Staff ("Staff"), the Colorado Energy Office ("CEO"), SWEEP, and the Colorado Utility Advocate ("UCA").

5. On August 16, 2024, Black Hills filed a Motion to Approve the Settlement Agreement. Along with Black Hills, Staff, UCA, and CEO (collectively the "Settling Parties") joined the Settlement Agreement. SWEEP did not join the Settlement.

6. The ALJ held an evidentiary hearing on August 29, 2024. On September 20, 2024, each UCA, Staff, SWEEP, CEO, and Black Hills filed Statements of Position ("SOP").

7. On October 29, 2024, the ALJ issued Decision No. R24-0784 (the "Recommended Decision"). The Recommended Decision approves the Settlement Agreement in full.

8. On November 18, 2024, SWEEP filed exceptions to the Recommended Decision.

9. On November 26, 2024, the Commission granted a motion filed by CEO to extend the response deadline to SWEEP's exceptions in Decision No. C24-0873.

10. On December 5, 2024, Black Hills ("Black Hills Response") and CEO ("CEO Response") each filed a response to SWEEP's Exceptions.

11. At the January 8 and January 22, 2025 Commissioners' Weekly Meeting, the Commission conducted live deliberations on the Exceptions, resulting in this Decision granting SWEEP's exceptions in part and denying SWEEP's exceptions in part. Except as expressly modified by this Decision, the Commission upholds the Recommended Decision.

C. SWEEP Exceptions

1. CHP Budget and Budget Flexibility

12. The Recommended Decision approves the proposed Settlement Agreement budget of $18,374,321 for the three-year plan period, 2025-2027. It also bases the budget and cost cap calculations on a 5-year average of actual Company revenues for the years 2019-2023, with an assumed growth rate of 2 percent.[1]

13. The ALJ determined that SWEEP's proposed budget (nearly three times the Settlement budget) is not in the public interest and far exceeds what can reasonably be imposed on Black Hills' customers. She found that SWEEP's budget imposes too high a cost burden on Black Hills' customers and thus exceeds the benefits of greater GHG emission reductions.[2] The ALJ also interprets the Clean Heat Statute to prohibit the Commission from requiring a gas utility to exceed the cost cap related to the 2025 target. SWEEP understands § 40-3.2-108(6)(d)(IV), C.R.S. to allow the utility to make a voluntary request for exceeding the cost cap but prohibits the Commission from imposing a budget above the cost cap on a smaller gas utility unilaterally.[3]

a. SWEEP's Exception

14. SWEEP argues that the Commission should order a higher budget than that approved in the Recommended Decision because the Settlement Agreement would achieve minimal emission reductions, and would actually result in Black Hills increasing its greenhouse gas emissions compared to the 2015 baseline and throughout the course of the Clean Heat Plan. SWEEP requests that the Commission find it in the public interest for Black Hills' Clean Heat

[1] Recommended Decision, ¶ 43.
[2] Recommended Decision, ¶ ¶ 105-107.
[3] *Id*. at 108.

Plan to exceed the cost cap and approve the SWEEP portfolio and commensurate budget. SWEEP argues that exceeding the cost cap is in the public interest because doing so is necessary for this clean heat plan to "achieve significant and meaningful emissions reductions" and that the point of a clean heat plan is to reduce emissions compared to a 2015 baseline, which the Settlement Agreement fails to do. SWEEP argues that the Commission's decision in Public Service Company of Colorado's ("Public Service") Clean Heat Plan Proceeding (Proceeding No. 23A-0392EG) is instructive and that the policy reasons outlined by the Commission there also apply to Black Hills.

15. SWEEP also suggests that the Settlement Agreement assigns an impermissibly large amount of the Clean Heat budget to two recovered methane resources: renewable natural gas ("RNG") and advanced monitoring and leak detection ("AMLD"). SWEEP contends the Clean Heat statute limits how much recovered methane utilities can include in a Clean Heat Plan, and Black Hills' Plan, supported by the Settlement, exceeds these limits.[4] SWEEP argues these resources cost more per ton of emissions reductions than beneficial electrification and DSM. RNG also fails to provide several other benefits that beneficial electrification and DSM provide (discussed further below).

16. SWEEP also argues that the Recommended Decision incorrectly interprets the Clean Heat Statute relevant to the 2025 emissions target (§ 40-3.2-108(6)(d)(IV), C.R.S. as the instant proceeding is actually relevant to the 2030 emissions target which is referenced in a different section of the statute (§ 40-3.2-108(6)(a)(I), C.R.S). SWEEP argues that even if Section 6(d)(IV) applies, it would only limit the 2025 budget, not the remaining years covered under the Settlement.

[4] SWEEP Exceptions, p. 1.

17. Finally, SWEEP argues that the Commission should reverse the Recommended Decision because it mischaracterizes the Commission's decision in the Public Service clean heat plan. SWEEP states that the Recommended Decision tries to distinguish Black Hills' gas customers from Public Service because Public Service's gas customers would not pay for electrification, when in actuality, the Commission allocated 50 percent of electrification costs to Public Service gas customers.[5]

18. The Recommended Decision approves the Settlement term that provides Black Hills with 15 percent budget flexibility to shift budgets within and between clean heat resources.[6] SWEEP also requests the Commission order that the Company should not have discretion to shift funding away from lower-cost electrification and DSM resources towards higher cost-resources such as RNG.[7]

b. Responses

19. In response to SWEEP's exceptions, CEO argues that the Commission should reject SWEEP's proposal to exceed the statutory cost cap for this inaugural clean heat plan. CEO points out that the large growth in Black Hills' gas sales since 2015 makes meeting the clean heat target at a reasonable cost very difficult for Black Hills in particular, and states that it is "optimistic that by the next CHP filing in 2027, the Company will have developed more cost-effective paths towards meeting its 2030 clean heat targets based on the initial efforts undertaken as a result of this CHP."[8] CEO argues that the Public Service case is based on different facts and should not dictate the Commission's reasoning here as to whether exceeding the cost cap is in the public interest.

[5] SWEEP Exceptions, pp. 10-11.
[6] Recommended Decision, ¶ 44.
[7] SWEEP Exceptions, p. 31.
[8] CEO Response to SWEEP Exceptions, p. 9.

20. Similarly, Black Hills urges the Commission to reject SWEEP's proposed budget of nearly 52.8 million dollars. The Company notes SWEEP's proposed budget is nearly three times larger than the expenditure supported in the Settlement even though it would produce emission reductions only twice as high as the Settlement.[9] It argues that the Clean Heat Statute shows a clear intent to mitigate costs to customers for small gas utilities, that SWEEP's proposal would also not achieve the clean heat targets and, similar to the Settlement, would result in more greenhouse gases compared to the 2015 baseline. Black Hills suggests this is simply due to the substantial growth that has occurred in the Company's service territory since the 2015 base year. Further, Black Hills argues that there is no basis to exceed the cost cap because SWEEP has not presented evidence demonstrating that the factors found in § 40-3.2-108(6)(d)(III), C.R.S. are satisfied by its proposal.[10] Black Hills also argues that the budget flexibility is reasonable and is typical for similar plan-type proceedings. Black Hills argues that the Settlement term actually affords higher levels of protection beyond, for example, the Commission's DSM rules on budget flexibility.

c. Findings and Conclusions

21. We are not persuaded that exceeding the cost cap for this inaugural clean heat plan is in the public interest for Black Hills' customers. We therefore uphold the Recommended Decision to the extent that it approves the Settlement budget and Settlement methodology for calculating the cost cap and deny SWEEP's Exceptions on this point. Because we decline to exceed the cost cap or otherwise increase the budget from the Settlement budget, we do not see a need to address individually SWEEP's arguments as to why the Recommended Decision's reasoning is unsound. Regardless of whether § 40-3.2-108(6)(d)(IV), C.R.S., strictly applies to this clean heat

[9] Black Hills Response to SWEEP Exceptions, p. 4.
[10] Black Hills Response to SWEEP Exceptions, pp. 8-9.

plan, its inclusion signals that the Legislature intended for costs to remain on the lower end for the first round of clean heat plan filings by small utilities. Similarly, regardless of whether the Recommended Decision correctly characterizes the Public Service clean heat plan decision, we are persuaded by the arguments of CEO and Black Hills that, in this instance, the facts are sufficiently different to justify a different outcome for Black Hills in terms of adherence to the cost cap. We find that the Settlement's budget—supported by UCA, Staff, and the Company—is the best path forward for this inaugural clean heat plan. While we are troubled that the Settlement budget does not put the Company on a strong path to meeting the 2030 target, we decline to exceed the cost cap, which would impose far higher costs on customers. We agree with CEO that the Settlement budget presents a reasonable balance between "costs to customers, new funding approaches to emissions reductions, and employing various clean heat resources."[11]

22. Finally, we decline to modify the Settlement term regarding budget flexibility. We agree that some flexibility is appropriate for efficient plan administration, particularly for inaugural efforts like this clean heat plan.

2. Portfolio of Clean Heat Resources

23. The Recommended Decision approves the Settlement proposal of a 2024-2027 plan with clean heat resource spending of approximately $3.5 million for AMLD, $1 million for RNG (starting in 2027), $13.2 million in DSM, $100,000 for the Rocky Ford beneficial electrification pilot, $455,000 for a thermal pilot feasibility study, and an additional $100,000 for disproportionately impacted ("DI") community engagement and outreach.[12]

[11] CEO Response to SWEEP Exceptions, p. 10.
[12] Recommended Decision, ¶ 47.

24. The ALJ found that the Settlement Agreement was in the public interest because it promotes an array of statutorily designated clean heat resources and in doing so lowers risk because AMLD and RNG are not reliant on customer adoption of technology. The ALJ recognizes that AMLD and RNG are higher cost resources than DSM or BE, but that their inclusion is beneficial to the plan and reasonably justified because their success is completely independent from customer action. Further, the ALJ finds that the large amounts of BE in SWEEP's proposal could negatively impact Black Hills' existing customers.[13]

a. Inclusion of RNG and AMLD

(1) SWEEP's Exceptions

25. SWEEP requests the Commission reject the Settlement Agreement because of the inclusion of recovered methane and AMLD. SWEEP argues that the amount of recovered methane and AMLD included in the Settlement violates the Clean Heat Statute. SWEEP argues that the Settlement relies on an impermissibly large amount of RNG and AMLD to reduce emissions because § 40-3.2-108(3)(b)(II), C.R.S. limits the proportion of emission reductions attributable to recovered methane to meet the 2025 and 2030 clean heat targets. SWEEP calculates that the under the Settlement, recovered methane will account for almost 28 percent of the overall 2030 emission reductions, but asserts that the statute limits recovered methane to 22.7 percent of the 2030 emission reductions. SWEEP states that the Colorado Department of Public Health and Environment ("CDPHE") verification workbook that Black Hills filed in this Proceeding references a permissible amount of reductions coming from recovered methane but that because the Settlement's emission reductions fall far short of the target, the proportion attributable to recovered methane is actually impermissibly large. SWEEP argues that the percentage of

[13] Recommended Decision, ¶ ¶ 111-114.

recovered methane in a clean heat plan should be proportional to the plan's actual anticipated emission reduction, and not the statutory 2030 target.[14]

26. In addition to the legal argument above, SWEEP also argues that RNG and AMLD should not be included because both are comparatively expensive clean heat resources, and produce no additional benefits, compared to BE and DSM. SWEEP cites to the Commission's decision in Public Service clean heat plan, in which the Commission recognized other benefits of DSM and BE, including persistent emission reductions (compared to the need to buy recovered methane year over year), the potential need for reduced investment in gas infrastructure, and additional health benefits including lower indoor air pollution.[15]

(2) Responses

27. CEO supports the use of recovered methane resources in Black Hills' clean heat plan and believe that using RNG and AMLD will help Black Hills achieve its statutory goals. CEO highlights the guardrails that the Settlement imposes on RNG purchases, including compliance with CDPHE recovered methane protocols and the provision that reverts the funds to DSM if the Company does not enter into contracts for RNG by March 31, 2027.[16] CEO also points out that Black Hills commits to adhering to receiving approval from the Air Quality Control Commission of its proposed AMLD recovered methane protocol before it generates any recovered methane credits, which CEO found important in agreeing to the Settlement Agreement.[17]

28. CEO also argues that SWEEP misinterprets the Clean Heat Statute because it claims that recovered methane cannot account for more than 25 percent of emission reductions the utility expects to achieve by 2025 and no more than 22.7 percent of any emission reductions the

[14] SWEEP Exceptions, pp. 23-25.
[15] SWEEP Exceptions, p. 26.
[16] CEO Response to SWEEP Exceptions, p. 20.
[17] *Id*. at 21.

utility expects to achieve by 2030 in any given clean heat plan, whereas the statute actually applies to the total amount of emission reductions required by the clean heat target.[18]

29. Black Hills argues that AMLD should be included in its clean heat plan because it has (1) shown the resource is cost-effective, and (2) because there is "no question" that the Clean Heat Statute "intended for utilities to seriously consider leaks" in clean heat plans.[19] It also argues that the inclusion of recovered methane is appropriate because the Settlement contains appropriate guardrails, the Clean Heat Statute clearly contemplates the use of recovered methane as a clean heat resource, and as mentioned in the Recommended Decision, recovered methane does not require customer adoption.

(3) Findings and Conclusions

30. We decline to remove RNG and AMLD from the Company's clean heat plan. We therefore uphold the Recommended Decision to the extent that it approves the Settlement inclusion of RNG and AMLD, and deny SWEEP's Exceptions on this point.[20] We find that, for this inaugural plan, inclusion of a variety of resources is appropriate. We are also cognizant of the balance of interests represented in the Settlement Agreement, and strive to upset that balance as little as possible. For the policy reasons outlined by Black Hills and CEO in their respective responses, including that the Settlement contains appropriate guardrails and the assurance that AQCC protocols will be followed, we find that the limited spending here for RNG and AMLD is in the public interest. Further, we agree with CEO's interpretation of the Clean Heat Statute—by its plain language, the Statute contemplates a percentage of the clean heat target, not a percentage of the

[18] *Id*.

[19] Black Hills Response to Exceptions, pp. 21-22.

[20] Commissioner Plant dissents from the inclusion of AMLD in this clean heat plan citing his concerns that a limited budget as we have implemented here requires prioritizing the most cost-effective technologies with a focus on clean heat resources, he goes on to conclude that including AMLD as proposed fails on both counts.

actual projected emission reductions. Further, SWEEP's own calculations show that the maximum projected emissions that could be achieved through recovered methane is very close to the percentage envisioned by the Legislature. While requiring proportional to the actual emission reduction use of recovered methane may be a policy to consider in the future, we find that the Clean Heat Statute does not require that outcome. For these reasons, we decline to modify the inclusion of AMLD and recovered methane in Black Hills' clean heat plan and approve the commensurate budgets approved in the Recommended Decision.

31. However, we have two additional requirements to add to the guardrails on use of recovered methane and AMLD already found in the Settlement. With respect to the purchase of RNG, we note that the Settlement does not reference the potential duration or number of contracts for the commodity the Company may enter, or whether the expenditure approved may continue beyond the CHP period. Accordingly, we find it necessary to limit the expenditures so that the total procured RNG costs no more than $1 million on an NPV basis based on a return equal to the Company's weighted average cost of capital as established in its most recent rate case. With respect to AMLD, we recognize that the Legislature specifically attached requirements associated with the inclusion of methane reductions achieved by any leak repairs, including that "…the Commission must find that the leak reductions are cost-effective." and that "[t]he Commission may require the utility to evaluate nonpipelined alternatives." This record does not contain evidence needed to determine if certain leak repairs and their associated methane reductions are cost effective, so it is premature to determine that the use of AMLD will lead to methane reductions that are permitted to be considered as a clean heat resource. While we have some concern about the potential mismatch of spending monies collected through a rider intended to fund Clean Heat activities and resources on AMLD without the requisite cost-effectiveness determination set by the statute, we

also understand that deployment of AMLD may provide the measurements and information needed to determine, in the future, if certain leak repairs are cost-effective or not. Therefore, we find value in approving the AMLD inclusion in order to serve as a method to obtain this measurement and information. Accordingly, we find it necessary to require the Company to track and report on an annual basis the details and costs of improvements to infrastructure, by project, to mitigate leaks and the associated leak reduction measured by the AMLD equipment. The Company should make such information available upon its next clean heat plan application.

b. DSM

(1) SWEEP's Exceptions

32. In its exceptions, SWEEP argues that the Company's clean heat plan should include a larger DSM budget than approved in the Recommended Decision. SWEEP's proposal includes $21.9 million in DSM spending. SWEEP comes to this amount of incremental DSM resources by increasing the maximum "Tier II" resources identified in Black Hills' modeling, using Black Hills' availability and cost assumptions, but also assuming a 0.75 percent sales savings as a result of existing DSM programs and the incremental DSM programs in this clean heat plan.[21]

(2) Responses

33. CEO argues that the Commission should not increase the DSM budget because to do so would require exceeding the cost cap. Further, CEO agrees with the Recommended Decision that diversification of resource type for the inaugural clean heat plan is appropriate. CEO urges the Commission to approve the level of DSM in the Settlement Agreement as reasonable and in the public interest.[22]

[21] SWEEP Exceptions, pp. 28-29.
[22] CEO Response to Exceptions, p. 19.

34. Similarly, Black Hills urges the Commission to reject SWEEP's exceptions and maintain the DSM budget approved in the Recommended Decision. The Company highlights that DSM "is not a limitless resource that can be almost doubled in a short period of time" and that there is an upper bound for both DSM spendings and savings. Black Hills argues that doubling the funding as proposed by SWEEP would not yield the same level of savings for each incremental investment.

(3) Findings and Conclusions

35. We decline to adopt SWEEP's larger budget for DSM expenditures for the same reasons discussed above that we decline to exceed the cost cap for this inaugural clean heat plan. Because we find it important to remain within the cost cap for this clean heat plan, we deny SWEEP's exceptions to the extent it requests the Commission approve a larger DSM budget.

36. While we approve of the DSM budget contained in the Settlement Agreement and approved by the Recommended Decision, we have concerns with how the Company intends to spend these funds. According to the Settlement Agreement, the DSM funds will be used as an "over-flow" funding mechanism in the event budgets from traditional DSM programs are exceeded. These funds will supplement funding to implement traditional DSM program measures.[23] There will also be certain funding available for "incremental DSM" which represents energy-efficiency measures that were not included in the traditional DSM plan, but for which there may be market interest.

37. The Commission approved the Company's current DSM offerings in Proceeding No. 23A-0361G.[24] In reviewing the current DSM program offerings by the Company, we are

[23] Hr. Ex. 105, pp. 31-32.
[24] Hr. Ex. 105, p. 31.

uncertain if they will all result in quantifiable emission reductions that meet the intent of the Clean Heat Statute. In particular, the Company's current DSM programs provide rebates for high-efficiency furnaces, boilers and water heaters without any assurance that the new equipment is replacing less-efficient equipment. We struggle to see how it is appropriate to utilize clean heat plan-related funding for this purpose when replacing gas furnaces and other home equipment with new gas equipment without a demonstrated efficiency improvement may not actually result in emission reductions. Replacing "like for like" equipment results in negligible emission reductions, while simultaneously ensuring that the customer consumes natural gas, which produces associated emissions, for decades to come. Similarly, rebates for gas equipment in residential new construction will lock-in gas emissions for an extended period; the Commission finds this is incongruent with the purposes of the Clean Heat Statute. Further, the Company itself has repeatedly discussed how growth in its service territory makes meeting the clean heat target particularly difficult. By no means are we suggesting that further growth is prohibited or should be directly curtailed, only that using clean heat plan-related funding to encourage expanded gas usage in new construction is inconsistent with the purpose of the clean heat plan regime and unhelpful to Black Hills' future ability to reach its statutorily required targets.

38. To that end, we restrict the expanded DSM funding approved here in the clean heat plan to weatherization- and envelope-related initiatives. Weatherization and envelope offerings ensure reduced emissions while being fuel agnostic. We find that these DSM programs should be prioritized for clean heat funding because they are more consistent with the purpose of clean heat planning and provide a "no regrets" approach to incentivizing customer behavior. We acknowledge that restricting the available uses of the DSM budget will affect the Company's

ability to spend the entire DSM Settlement budget and discuss the priorities for that funding further below.

c. Beneficial Electrification

(1) SWEEP's Exceptions

39. SWEEP requests that the Commission approve its proposal which includes approximately $30.9 million in spending allocated to BE, compared to the Settlement Agreement which allocates only $100,000 to the Rocky Ford pilot. In addition to requesting that the Commission approve its proposed BE budget, SWEEP asks the Commission to reject the Recommended Decision's reasoning for excluding BE from Black Hills' clean heat plan.

40. According to SWEEP, the Rocky Ford Pilot that would apply to just 2,000 customers, or less than 1 percent of the Company's residential customers. SWEEP contends that the Clean Heat statute does not exempt gas-only utilities from beneficial electrification, and the record here shows that electrification, along with DSM, is the most cost effective and readily available resource to reduce Black Hills' greenhouse gas emissions.[25] SWEEP points to analysis conducted by Western Resource Advocates, using SWEEP data, and its own evaluation that indicates that BE is the lowest cost clean heat resource available to Black Hills.[26] SWEEP also notes that the Commission determined in Public Service's CHP (Proceeding No. 23A-0392EG) that BE, when combined with DSM, represents the best path forward for emission reductions aligned with SB 21-264.[27]

[25] SWEEP Exceptions, p. 1.

[26] Hr. Ex. 500, Brant Answer, pp. 41-42. *See* FN 100, citing Western Resource Advocates, *Costs of Building Decarbonization Pathways: Colorado*, https://westernresourceadvocates.org/wp-content/uploads/2023/11/Colorado-Synapse-Energy-Fact-Sheet-2023.pdf.

[27] Hr. Ex. 500, Brant Answer, p. 11.

41. SWEEP argues that the Clean Heat Statute includes beneficial electrification in the list of clean heat resources without making any distinction between gas-only and dual-fuel utilities. It urges the Commission to reject Black Hills' argument that electrification is not a tool available to gas only utilities and asserts that ordering Black Hills to offer BE rebates would not result in unjust or unreasonable rates. SWEEP disagrees that ordering Black Hills to offer BE rebates would result in Black Hills no longer rendering service in most instances. It argues that this argument mischaracterizes the BE in the SWEEP portfolio because most customers will remain on the system and assumes that 75 percent of market-rate customer incentives would be for hybrid systems that combine heat pumps with gas furnaces or boilers. These customers, like those who participate in gas DSM programs, will reduce gas usage, but still remain customers. SWEEP disputes Black Hills' claim that including electrification would require the Company to "turn away" customers who request gas service, which could risk its CPCN, and contends BE adoption would remain "voluntary." SWEEP argues that despite Black Hills' argument to the contrary, no risk of a takings claim will result from the offering of voluntary BE rebates.[28]

42. SWEEP also disputes the Recommended Decision's reasoning for rejecting BE, including that a portfolio of only DSM and BE presents compliance risks. SWEEP argues that the fact that customer adoption is necessary is not a basis for limiting the use of these clean heat resources. SWEEP also argues that the Recommended Decision is incorrect that a large amount of BE could negatively affect Black Hills' existing customers. SWEEP points out that most customers who receive a rebate will still be Black Hills customers and partial electrification is similar to gas DSM. It argues that the Recommended Decision incorrectly assumes that non-participating customers do not benefit from electrification when they actually do because of benefits to all

[28] SWEEP Exceptions, pp. 18-19.

customers, including health benefits, climate benefits, and reduced investments in gas infrastructure.[29]

(2) Responses

43. In its response to SWEEP's exceptions, Black Hills continues to vehemently oppose the inclusion of BE in its clean heat plan. Black Hills argues that forcing gas only utilities to electrify its customers is a violation of the takings clause and violates long-standing Commission principles regarding utility cost recovery. Accordingly, Black Hill contends, electrification is not an available tool for Black Hills. Further, it argues that "forced electrification" violates cost recovery principles because it leads to unjust cross-subsidization. Black Hills argues that SWEEP's analysis skews the results towards electrification because it used current electric rates and future projected emission rates. The Company notes that the rates for electricity offered by Colorado Springs Utilities, Public Service and Black Hills Electric are all expected to increase in the future.[30] The Company also contends its portfolio produces emission reductions at a lower cost than SWEEP's portfolio which is limited to DSM and electrification.[31] It also argues that the Commission's decision in the Public Service clean heat plan is not dispositive here.

44. CEO argues that the cost per amount of emission reductions is not the only metric that the Commission should consider when approving a clean heat plan. It also points out that the Settlement does include BE for a pilot in the Rocky Ford area and includes requirements for presentation of BE in the next clean heat plan. Overall, CEO argues that the level of BE in the Settlement Agreement is in the public interest and agrees with UCA's settlement testimony that increased levels of electrification could create a double economic burden on Black Hills' gas

[29] SWEEP Exceptions, pp. 19-21.
[30] Black Hills Response to SWEEP Exceptions, p. 17.
[31] Black Hills Response to SWEEP Exceptions, p. 21

customers.[32] CEO suggest that the Commission address these types of "seams issues" before ordering additional electrification for Black Hills.

(3) Findings and Conclusions

45. Overall, we agree with SWEEP that the Clean Heat Statute makes no distinction between gas-only and dual-fuel utilities as to which clean heat resources are available to each. Further, we agree that the Statute does distinguish between different types of utilities on other bases but makes no mention of a carveout for beneficial electrification for gas-only utilities. Thus, as a general matter, BE is a tool available to all utilities for compliance with the Clean Heat Statute.

46. At issue here is whether Black Hills is required to provide for the availability of *rebates* for electrification technologies for customers who choose to utilize them—a far cry from "forced electrification." The Commission disagrees with Black Hills that, by requiring the Company to offer electrification rebates across its entire service territory, we are mandating Black Hills cease service to its customers. Accordingly, we direct the Company to offer the electrification rebates as described in SWEEP's testimony to its entire customer base. The record here reflects that the vast majority of consumers who install electrification technology remain gas customers.[33] Black Hills' own modeling shows that a customer who receives a BE rebate for technology such as a heat pump is still likely to remain a Black Hills customer. Offering BE rebates is no different than other DSM offerings which similarly reduce a customer's total natural gas usage. In addition, the Company has repeatedly raised in this Proceeding that DSM is not a resource that can scale exponentially. The Company's own witnesses express doubts about the

[32] CEO Response to SWEEP Exceptions, p. 14, citing Hr. Ex. 301, Settlement Testimony of Leslie Henry-Sermos, at 12:3-8.

[33] REFERENCE Hr. Ex. 106, Harrington Suppl. Direct 17:16.

ability to dramatically scale DSM offerings, which is an indication that additional tools must be considered in order to move meaningfully toward the Clean Heat Targets. Offering BE rebates, in addition to existing DSM rebates, offers customers a choice to mitigate their overall gas usage, while still remaining on the gas system, and provides another viable pathway to compliance with the Clean Heat Statute.

47. The requirement for Black Hills to offer rebates on the scale approved here will not result in unjust or unreasonable rates. Making BE rebates available does not result in unjust or unreasonable rates for customers who choose not to receive a rebate because BE rebates are one of several costs the utility must pay to comply with statute. In Colorado, the Legislature has ordered gas utilities to reduce emissions. The Legislature was aware this would come at a cost to consumers, and costs to comply with statutory requirements generally are found to be just and reasonable. Costs to comply with the law are part of the costs of delivering service and we see no reason why those costs should not be shared amongst ratepayers.

48. Finally, we are unaware of any court that has found a regulatory taking where a utility was required to institute energy efficiency programs such as DSM. Utilities are often required to, whether by law or Commission directive, institute programs or offerings that overall reduce their sale of gas. At what point those programs diminish the value of the utility’s property to such an extent that a confiscatory taking has occurred is an open question so far unanswered by the courts. However, we are confident that the relatively meager amount of rebate spending authorized here is safely within the zone of reasonableness. For these reasons, we agree with SWEEP that BE is an option for Black Hills to comply with the statutory clean heat targets, although given Black Hill’s potentially conflicting financial incentives we remain concerned about

the Company's role in implementing this program effectively and, over time, may want to start exploring alternative marketing, education, and delivery options.

49. We also agree with SWEEP that BE is a viable solution to be included in this clean heat plan. We find SWEEP's analysis persuasive that BE, particularly when focused on existing residential customers, provides a path for reducing greenhouse gas emissions at a reasonable cost. We are unconvinced by Black Hills' analysis and find its limitation to considering the emission reductions only during the three-year life of the plan to be an unreasonable modeling constraint. As pointed out by SWEEP, heat pumps have emission reduction benefits for the life of the technology, long past 2027. Further, Black Hills' analysis, which used outdated assumptions and applied the full cost of upgrades (which is unlikely for most customers) results in an unreasonably high-cost estimate for BE.[34] We generally agree with SWEEP's findings that BE and DSM represent two lowest cost emission reduction opportunities available to Black Hills. Notably, the Recommended Decision does not dispute that BE and DSM are lower cost resources.[35] The Recommended Decision also does not contradict any of SWEEP's analysis.

50. Because we are mindful of exceeding the cost cap and agree that the Settlement budget sets a reasonable level of spending for the inaugural clean heat plan, we decline to approve SWEEP's BE budget. As discussed above, we have limited the availability of clean heat funds to supplement DSM programs. We cannot ascertain on this record what impact this limitation will have on the DSM budget in the Settlement. However, we are confident that limiting DSM as discussed above "frees up" some space under the cost cap for additional spending on BE. To that end, we require Black Hills to offer BE rebates with the remaining funds earmarked for DSM.

[34] Hr. Ex. 500, Brant Answer, at 36.
[35] Recommended Decision, ¶ 112.

Black Hills shall make BE rebates available to all customers in the manner suggested by SWEEP in its modeling.[36]

D. Other Changes and Additions to the Recommended Decision

51. **Corrections to Recommended Decision:** SWEEP requests that the Commission correct the Recommended Decision to reflect that SWEEP filed answer testimony and exhibits of Wael Kanj, who is a Senior Research Associate at Rewiring America, in addition to the answer testimony of Justin Brant. We agree that this was an omission in the Recommended Decision and correct the Commission's decision accordingly.

52. **Thermal Pilot Study**: The Recommended Decision approves the thermal pilot study proposed in the Settlement Agreement. This study would "investigate an application in its service territory to understand the potential costs and opportunities at a cost of $455,000."[37] The Settling Parties agree that the study would include a siting analysis and will include outreach to stakeholders for discussion on potential projects.[38] SWEEP does not address the thermal pilot study specifically in its Exceptions, but does not allocate any money to the study in its proposed portfolio. In its response, CEO reiterates its support for this study and highlights that thermal energy service presents an opportunity for Black Hills to begin to "bend the curve" on emissions and can help a gas utility retain its customers and reduce emissions. We find that certain parameters on the thermal energy study are necessary for the study to be an effective and prudent use of ratepayer funds. To that end, we require that Black Hills to coordinate with the stakeholders to this proceeding to develop reasonable assumptions, an appropriate scope of work and effective results

[36] *See* SWEEP Exceptions, pp. 21-22.
[37] Settlement Agreement, ¶ 23.
[38] Settlement Agreement, ¶ 24.

so that the study produces maximum insight into the opportunity of thermal networks. We also encourage Black Hills to prioritize studying the inclusion of a project located in a DI community.

53. **Third Party Administrator:** SWEEP requests that the Commission order Black Hills to use a third-party administrator to implement the BE programs. We do not have the record before us to institute this in a viable manner in this Proceeding. However, we find that, if Black Hills cannot effectively institute, promote and deliver BE rebates during this plan period, that a third-party administer will be reviewed as an option in the next clean heat plan.

54. **Compliance Filing:** The Commission requires Black Hills to file an updated version of its 2024-2028 clean heat plan to reflect all terms and conditions that are approved as a result of this Proceeding.[39] The updated version of the Company's clean heat plan must include a summary of the anticipated budgets for each clean heat resource (including BE) as modified by this Decision. This filing is due within 60 days after the effective date of this Decision, or, if any party files an Application for Rehearing, Reargument, or Reconsideration ("RRR") pursuant to § 40-6-114, C.R.S., the compliance filing will be due within 60 days after the effective date of the Commission's decision granting or denying the application for RRR.

55. If not specifically addressed here, we uphold the Recommended Decision and corresponding Settlement term.[40]

[39] *See* Hr. Ex. 104, AWC-1.

[40] For example, we approve without modification the rider recovery mechanism, the timeframe for filing the next clean heat plan, and the annual reporting and notice process provisions.

II. ORDER

A. The Commission Orders That:

1. The exceptions to Recommended Decision No. R24-0784, filed November 18, 2024, by the Southwest Energy Efficiency Project, are granted in part, consistent with the discussion above.

2. Black Hills Colorado Gas, Inc., shall file an updated version of its 2024-2028 clean heat plan to reflect all terms and conditions that are approved as a result of this Proceeding. This filing is due within 60 days after the effective date of this Decision, or, if any party files an Application for Rehearing, Reargument, or Reconsideration ("RRR") pursuant to § 40-6-114, C.R.S., within 60 days after the effective date of the Commission's decision granting or denying the RRR.

3. The 20-day time period provided by § 40-6-114, C.R.S., to file an Application for Rehearing, Reargument, or Reconsideration shall begin on the first day after the effective date of this Decision.

4. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING January 8 & 22, 2025.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

Service Date: December 22, 2022

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-220066 and UG-220067 (*consolidated*) FINAL ORDER 24
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility	DOCKET UG-210918 FINAL ORDER 10 REJECTING TARIFF SHEETS; APPROVING SETTLEMENTS, WITH CONDITIONS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis*: The Commission approves and adopts three partial multiparty settlements, subject to limited conditions, that, considered together, resolve all the issues in this consolidated proceeding for Puget Sound Energy (PSE).*

The Revenue Requirement Settlement provides for a two-year rate plan starting on January 1, 2023, approves a capital structure of 49 percent equity and 51 percent debt, sets cost of debt at 5.0 percent for the duration of the rate plan, maintains PSE's return on equity at 9.40 percent, provides for more timely recovery of power costs, provides for a pilot of time-varying rates (TVR), allows for provisional recovery of certain investments including Energize Eastside, creates a Demand Response (DR) Performance Incentive Mechanism (PIM), requires reporting on a number of metrics, and addresses a number of issues that are no longer disputed by the parties. The Settling Parties agree to, and the Commission approves with conditions in this Order, an increase to electric rates of $223 million in rate year one and $38 million in rate year two; and an increase to natural gas rates of $70.6 million in rate year one and $18.8 million in rate year two, for a total of $350.4 million, companywide, for both years combined.

As a result of the Revenue Requirement Settlement, a typical residential electric customer using 800 kWhs per month will pay $7.75 more per month in rate year one, for an average monthly bill of $96.65, and will pay $1.67 more per month in rate year two, for an average monthly bill of $98.32. A typical residential natural gas customer using 64 therms per month *will pay $4.87 more per month in rate year one, for an average monthly bill of $80.56; and will pay $1.34 more per month in rate year two, for an average monthly bill of $81.90.*

The Commission also approves and adopts the Green Direct Settlement, which provides a methodology for calculating the Energy Charge Credit. It is anticipated that this will provide current Green Direct customers with more predictable power costs.

Finally, the Commission approves and adopts the Tacoma Liquified Natural Gas (LNG) Settlement, which authorizes PSE to seek a prudency determination and recovery of the costs related to the Tacoma LNG Facility concurrent with its 2022 Purchase Gas Adjustment filing. The Tacoma LNG Facility costs will be tracked in a separate tariff schedule. The Commission accepts this Settlement subject to the condition that PSE recovers the costs of 4 miles of distribution pipe on a provisional basis and defers associated revenues as described in this Order.

TABLE OF CONTENTS

BACKGROUND

1 **PROCEDURAL HISTORY.** On January 31, 2022, PSE filed revisions to its currently effective tariff, WN U-60, for electric service and its currently effective tariff, WN U-2, for natural gas service. The Company's proposed revised tariff sheets provide an effective date of March 2, 2022. This is the Company's first general rate case, and first multi-year rate plan, filed pursuant to the recently enacted RCW 80.28.425.

2 In its initial filing, PSE proposed a three-year rate plan for the years 2023, 2024, and 2025. In rate year one, PSE sought to increase electric rates by approximately $310.5 million, or an average increase of approximately 13.59 percent across all customer classes. In rate year two, PSE sought to increase electric rates by approximately $63 million, or an average increase of 2.47 percent across all customer classes. In rate year three, PSE sought to increase base electric rates by approximately $31.8 million, or an average increase of 1.22 percent across all customer classes. The Company planned to update its projection of rate year power costs during this proceeding.

3 The Company proposed a similar, three-year rate plan for its base natural gas rates, with revised tariff sheets again providing an effective date of March 2, 2022. Specifically, in rate year one, PSE sought to increase natural gas rates by approximately $143 million, or an average increase of 12.98 percent across all customer classes. In rate year two, the Company proposed to increase natural gas rates by $28.5 million, or an average increase of 2.29 percent across all customer classes. In rate year three, PSE would increase base natural gas rates by $23.3 million, or an average increase of 1.83 percent across all customer classes.

4 On February 10, 2022, the Commission entered Order 01, Complaint and Order Suspending Tariff Revisions; Order of Consolidation. The Commission initiated an adjudication and consolidated PSE's electric and natural gas rate case filings in Dockets UE-220066 and UG-220067.

5 On February 28, 2022, the Commission convened a virtual prehearing conference. The Commission granted unopposed petitions to intervene filed by the Alliance of Western Energy Consumers (AWEC), The Energy Project (TEP), Nucor Steel, NW Energy Coalition (NWEC), Walmart, Inc. (Walmart), King County, Federal Executive Agencies (FEA), Sierra Club, and Microsoft Corporation (Microsoft). The Commission considered the opposed petitions to intervene filed by the Puyallup Tribe of Indians (Puyallup Tribe) and Coalition of Eastside Neighborhoods for Sensible Energy (CENSE), and ultimately granted the Puyallup Tribe and CENSE intervenor status subject to conditions.

6 On March 3, 2022, the Commission entered Order 03, Prehearing Conference Order; Notice of Hearing (Order 03). Among other points, Order 03 set a procedural schedule for these consolidated Dockets and resolved the parties' disputes as to the appropriate procedural schedule.

7 On March 1, 2022, Fred Meyer Stores Inc. and Qualify Food Centers, Divisions of The Kroger Co., (Kroger) filed a petition to intervene. Kroger amended its petition to intervene the following day. On March 16, 2022, the Commission entered Order 05, Granting Amended Petition to Intervene, finding no party objected to the petition and granting Kroger party status.

8 On March 11, 2022, The Energy Project (TEP) filed a Request for Case Certification and Notice of Intent to Request a Fund Grant. Later on March 14, 2022, AWEC, NWEC, CENSE, and the Puyallup Tribe filed a Request for Case Certification and Notice of Intent to Seek Fund Grant.[1]

9 On March 15, 2022, Front and Centered (the Joint Environmental Advocates) filed a Petition to Intervene along with a Request for Case Certification and Notice of Intent to Seek Fund Grant.

10 On March 22, 2022, the Commission entered Order 07, Granting Late-Filed Petition to Intervene, noting that no party objected to the petition and granting Front and Centered party status.

11 On March 30, 2022, PSE filed a Motion to Consolidate Proceedings and Motion for Exemption from WAC 480-100-645(2). PSE argued that the Commission should consolidate its general rate case (GRC) with the Company's Clean Energy Implementation Plan (CEIP), pending in Docket U-210795. Both Staff and Public Counsel filed responses objecting to PSE's motion, but Front and Centered and NWEC filed a joint response arguing in favor of consolidation.

12 On April 18, 2022, the Commission entered Order 10/01, Denying Motion for Consolidation; Denying Motion for Exemption from WAC 480-100-645(2) (Order 10/01), and denying PSE's motion to consolidate the GRC and CEIP proceedings.

13 On April 27, 2022, Staff filed a Motion to Consolidate. Staff argued that the Commission should consolidate the Company's GRC with Docket UG-210918, a Petition for an Order Authorizing Deferred Accounting Treatment for PSE's Share of Costs Associated with the Tacoma LNG Facility (Petition) filed on November 24, 2021. On May 12, 2022, the Commission entered Order 14/01, Granting Motion to Consolidate. The Commission granted

---

[1] As discussed more fully in Order 08 and Order 16/02 in these consolidated dockets, the Commission granted requests for case certification and approved proposed budgets for intervenor funding consistent with RCW 80.28.430.

Staff's motion to consolidate the two proceedings, noting that the proceedings presented related factual and legal issues and that no party objected.

14 On April 28, 2022, PSE petitioned for review of Order 10/01.

15 On May 23, 2022, the Commission entered Order 15/03, Denying Motion to Strike; Granting Review and Upholding Interlocutory Order Denying Motion for Consolidation, upholding the order declining to consolidate the Company's GRC with its pending CEIP.

16 On June 27, 2022, PSE filed a Motion for Leave to File Revised Testimony and Exhibits (Motion). PSE submitted revised testimony and exhibits for its witnesses Birud D. Jhaveri and Susan E. Free, correcting certain calculations regarding the Energy Charge Credit for PSE's Green Direct program.

17 On July 8, 2022, the Commission entered Order 17/03, Granting Motion for Leave to File Revised Testimony, granting PSE leave to file revisions to Jhaveri's and Free's testimony and exhibits.

18 On July 11, 2022, PSE filed a letter informing the Commission of a partial multiparty settlement in principle. PSE explained that it reached a settlement in principle with Staff, King County, and Walmart regarding the Company's Green Direct program.

19 On July 12, 2022, the Commission issued a Notice Requiring Filing of Settlement Documents, requiring the parties to file any settlement and supporting testimony regarding the Green Direct program by August 5, 2022.

20 On July 12, 2022, AWEC filed a Motion to Amend Procedural Schedule. To allow more time for settlement discussions, AWEC requested a continuance of the deadlines for response testimony and rebuttal/cross-answering testimony. No party opposed this motion.

21 On July 13, 2022, the Commission entered Order 18/04, Granting AWEC's Motion to Modify Procedural Schedule in Part; Denying Motion in Part (Order 18/04). The Commission adopted AWEC's proposed modifications to the procedural schedule with the exception of the deadline for rebuttal/cross-answering testimony, which was due by August 30, 2022.

22 On July 15, 2022, PSE petitioned for review of Order 18/04.

23 On July 19, 2022, the Commission entered Order 19/05, Granting Petition for Interlocutory Review of Order 18/04 and Modifying Procedural Schedule, moving the deadline for rebuttal/cross-answering testimony to September 7, 2022, as PSE requested.

24 On July 26, 2022, CENSE filed Response Testimony.

25 On July 28, 2022, Staff, Public Counsel, FEA, Kroger, Walmart, TEP, Nucor Steel, AWEC, the Puyallup Tribe, and Microsoft filed Response Testimony. That same day, NWEC, Front and Centered, and Sierra Club (the Joint Environmental Advocates) jointly filed Response Testimony.

26 On August 5, 2022, PSE filed a Settlement Stipulation and Agreement related to the Green Direct program (Green Direct Settlement) and Joint Testimony.

27 On August 12, 2022, counsel for PSE emailed the presiding administrative law judge to inform the Commission that PSE had reached settlement in principle with other parties on additional issues in the case. PSE requested that the Commission suspend and modify the procedural schedule. PSE indicated that no party objected to its proposed modified schedule.

28 On August 17, 2022, the Commission issued a Notice Suspending Procedural Schedule and Notice of Virtual Status Conference.

29 On August 18, 2022, the Commission held a virtual status conference. The Commission raised concerns that PSE's proposed modified schedule did not provide the Commission sufficient time to prepare for a hearing.

30 On August 22, 2022, the Commission entered Order 20/06, Granting Motion to Modify Procedural Schedule in Part; Denying in Part. The Commission adopted PSE's proposed modified schedule with the exception of the deadline for response testimony in opposition to the settlements, which was due by September 9, 2022.

31 On August 26, 2022, PSE filed a Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and PSE's Green Direct Program (Revenue Requirement Settlement) and a Settlement Stipulation and Agreement on Tacoma LNG (Tacoma LNG Settlement). PSE, Staff, AWEC, TEP, Microsoft, Walmart, Nucor Steel, FEA, and the Joint Environmental Advocates filed supporting testimony and exhibits relating to the settlements the same day.

32 On September 1, 2022, PSE filed joint testimony from its witnesses Birud D. Jhaveri and John D. Taylor, describing the proposed settlements' bill impacts.[2]

33 On September 9, 2022, Public Counsel and the Puyallup Tribe filed response testimony in opposition to the Tacoma LNG Settlement. CENSE filed response testimony in opposition to the terms of the Revenue Requirement Settlement concerned with the prudency of the Energize Eastside project. That same day, TEP filed a letter indicating that it opposed the

[2] The Revenue Requirement Settlement required PSE to file testimony describing the bill impacts of the proposed settlement by September 2, 2022.

Tacoma LNG Settlement, but TEP would provide argument in its post-hearing brief rather than submit testimony on the issue.

34 On September 20, 2022, the Commission issued Bench Request No. 01. The Commission observed that Sierra Club submitted testimony from its attorney representative, Gloria D. Smith, and required Sierra Club to explain whether Smith's testimony was consistent with the requirements of Washington Rule of Professional Conduct 3.7.[3]

35 On September 21, 2022, and again on September 23, 2022, CENSE filed proposed cross-examination exhibits.

36 On September 26, 2022, Public Counsel and the Puyallup Tribe filed proposed cross-examination exhibits. That same day, Microsoft filed objections to CENSE's proposed cross-examination of its witness, Irene Plenefisch.

37 On September 28, 2022, PSE filed Hearing and Exhibit Objections. PSE objected to any cross-examination conducted by CENSE witness Richard Lauckhart, and objected to the admissibility of certain cross-exhibits filed by CENSE.

38 On September 28, 2022, the Commission held a virtual public comment hearing in the consolidated proceedings. The Commission received comment from over 100 interested persons.[4]

39 On September 29, 2022, Staff filed a Motion in Limine, objecting to CENSE's proposed cross-examination of its witness Joel Nightingale.

40 The Commission conducted a virtual settlement hearing on October 3, 2022. By stipulation of the parties, the Commission entered into the record all pre-filed testimony and exhibits, as well as all cross-examination exhibits, with the exception of proposed CENSE cross-exhibits marked JBN-9X and DRK-29X through DRK-35X. During the hearing, the Commission admitted cross-exhibit JBN-9X and rejected cross-exhibits DRK-29X through DRK-35X.

41 On October 11, 2022, the Commission issued Bench Request No. 2 to PSE, requesting a complete set of workpapers supporting the Revenue Requirement Settlement and showing the treatment of Tacoma LNG Facility and Tacoma LNG Project costs. PSE subsequently responded to Bench Request No. 2 on October 18, 2022.

---

[3] Sierra Club responded to Bench Request No. 1 on September 27, 2022. Following a request by the presiding administrative law judge, Sierra Club filed a notice of withdrawal of representative for Gloria D. Smith on September 28, 2022.

[4] Public Counsel Brief ¶ 100, n.225 (citing Public Comment Hr'g Tr. vol. 3 (filed Oct. 7, 2022)).

42 On October 17, 2022, Public Counsel filed with the Commission Exhibit BR-3, public comments submitted in the proceeding. Public Counsel provided a total of 1,921 written comments, with two comments in favor of the proposed rate increase, eight comments described as undecided, and 1,911 comments opposed to the proposed rate increase.[5]

43 On October 31, 2022, the Commission received post-hearing briefs from PSE, Staff, Public Counsel, and each of the intervenors except for Microsoft.

44 **PARTY REPRESENTATIVES**. Sheree Strom Carson, Pamela J. Anderson, Donna L. Barnett, David Steele, Ryan C. Thomas, and Byron C. Starkey, of Perkins Coie LLP, Seattle, Washington, represent PSE. Jeff Roberson, Nash Callaghan, Harry Fukano, Joe Dallas, and Daniel Teimouri, Assistant Attorneys General, Tumwater, Washington, represent Commission staff (Staff).[6] Ann Paisner, Lisa W. Gafken, and Nina Suetake, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Brent Coleman and Summer Moser of Davison Van Cleve, P.C., Portland, Oregon, represent the Alliance of Western Energy Consumers (AWEC). Tyler Pepple and Corinne O. Milinovich of Davison Van Cleve, P.C., Portland, Oregon, represent Microsoft Corporation (Microsoft). Yochanan Zakai of Shute, Mihaly & Weinberger LLP and Simon J. ffitch, Attorney at Law, Bainbridge Island, Washington, represent The Energy Project. Damon Xenopoulos, Shaun C. Mohler, and Laura W. Baker, of Stone Mattheis Xenopoulos & Brew, PC, Washington, DC, represent Nucor Steel Seattle, Inc. (Nucor Steel). Jaimimi Parekh, Amanda Goodin, and Jan Hasselman, of Earthjustice, represent the NW Energy Coalition (NWEC), Front and Centered, and Sierra Club. Gloria D. Smith and Jim Dennison of the Sierra Club Environmental Law Program, also represent Sierra Club. Murial Thuraisingham, Clean Energy Policy Lead, also represents Front and Centered. Norm Hansen represents the Coalition of Eastside Neighborhoods for Sensible Energy (CENSE). Rita Liotta, of the United States Navy, represents the Federal Executive Agencies (FEA). Vicki M. Baldwin, of Parsons, Behle and Latimer, represents Walmart Inc. (Walmart). Verna Bromley and Raul Martinez, of the King County Prosecuting Attorney's Office, as well as Benjamin Mayer and Kari L. Vander Stoep, of K&L Gates LLP, represent King County. Lisa Anderson, Sam Stiltner, and Alec Wrolson, of the Law Office of the Puyallup Tribe, and Nicholas G. Thomas and Andrew S. Fuller, of Ogden Murphy Wallace, PLLC, represent the Puyallup Tribe of Indians.

---

[5] Response to BR-3 (Summary of Public Comments).

[6] 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.

45 **COMMISSION DETERMINATIONS**. As PSE notes in its post hearing brief, this may be the most complex general rate case in the Company's history.[7] The 15 parties to the case have grappled with dozens of complex issues with far-reaching implications. These include PSE's planned investments in clean energy, its proposals for a multi-year rate plan (MYRP) as required by recent legislation, and the Company's interest in addressing its financial health after implementing mitigation measures during the COVID-19 pandemic.

46 Our Order today approves three settlement agreements that resolve all the issues in this proceeding. We conclude that the three settlements, subject to certain conditions, reasonably balance the interests of PSE and its customers, while addressing several pressing issues regarding clean energy, power costs, and the inclusion of equity in capital planning. Considered together, these three settlements provide for a two-year MYRP for PSE that is lawful, supported by an appropriate record, and consistent with the expanded definition of the public interest.[8]

47 The overarching Revenue Requirement Settlement addresses numerous issues in the case and sets forth a two-year MYRP. We approve the Revenue Requirement's provisions for performance-based regulation (PBR), which include a modified demand response (DR) performance incentive mechanism (PIM), the continuation of established metrics with associated targets, and new metrics without any defined targets. We find that these tools, together, provide a basis for assessing PSE's performance. Overall, we approve the Revenue Requirement Settlement subject to the following conditions: (1) additional requirements for reporting the Settlement's proposed metrics to the Commission, (2) modifying the distributional equity analysis to reflect a Commission-led process for all investor-owned utilities in the state, (3) requiring PSE to demonstrate all offsetting benefits under the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act of 2021 (IIJA) when seeking review of capital investments, (4) similarly requiring PSE to demonstrate all offsetting benefits under the IRA and IIJA when seeking recovery of power costs, and (5) authorizing the Company's deferred accounting petition filed in Docket UG-210918 subject to certain modifications.

48 Public Counsel opposes certain terms, primarily the Revenue Requirement Settlement's proposed capital structure and return on equity (ROE). We reject these challenges as unpersuasive. The Revenue Requirement Settlement provides for the lowest weighted average

---

[7] *See* PSE Brief ¶ 19.

[8] *See* RCW 80.28.425(1) (providing that the Commission may consider factors such as "environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission.").

cost of capital for PSE in recent years. It reasonably maintains PSE's ROE at 9.40 percent in the face of increasing inflation.

49 We also observe that CENSE opposes the Revenue Requirement Settlement's terms related to the provisional recovery of the Energize Eastside investment. We find these challenges unpersuasive and contrary to the opinions of independent experts, who agree that there is a need for additional transmission capacity on the eastside of Lake Washington.

50 The Green Direct Settlement is narrower in scope and addresses PSE's Green Direct program, a voluntary renewable energy program for larger institutional customers. We agree that the Green Direct Settlement provides a reasonable method to calculate the Energy Charge Credit for current customers. This Settlement is not opposed by any party.

51 The Tacoma LNG Settlement is also narrow in scope, addressing the Company's recovery of its investment in the Tacoma LNG Facility located at the Port of Tacoma. This settlement, however, presents more difficult questions regarding prudency, equity, environmental health, specifically how the Commission should consider capital investments constructed before equity was recognized as an overriding public policy issue.

52 After carefully considering the challenges raised by Public Counsel and the Puyallup Tribe of Indians, we conclude that PSE acted prudently in developing and constructing the facility up through the Board of Director's decision to authorize construction on September 22, 2016. The parties may review and challenge subsequent construction and operation costs in a later proceeding. We also conclude that the prudency standard should remain focused on what the utility reasonably knew at the time it made its investment decisions. PSE's decisions should not be second-guessed based on facts or changes to the law that occurred after it initiated construction and after the facility was mechanically completed. We accept the Tacoma LNG Settlement subject to the condition that PSE include $30 million reflecting the cost of 4 miles of distribution pipe in rates on a provisional basis and defer associated revenue for later review.

MEMORANDUM

I. STANDARD OF REVIEW

A. Regulating in the public interest and determining equitable, fair, just, reasonable, and sufficient rates

53 The Legislature has entrusted the Commission with broad discretion to determine rates for regulated industries. Pursuant to RCW 80.28.020, whenever the Commission finds after a hearing that the rates charged by a utility are "unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order."

54 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company.[9] The burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[10]

55 More recently, in 2019, the Legislature expanded the traditional definition of the public interest standard. As Washington state transitions to a clean energy economy, the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[11] In achieving these policies, "there should not be an increase in environmental health impacts to highly impacted communities."[12]

56 In 2021, the Legislature again expanded upon the public interest standard in the context of reviewing multiyear rate plans. RCW 80.28.425 provides that "[t]he commission's consideration of a proposal for a multiyear rate plan is subject to the same standards applicable to other rate filings made under this title, including the public interest and fair, just, reasonable, and sufficient rates." The statute continues, "In determining the public interest, the commission may consider such factors including, but not limited to, environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission."[13]

57 Following the passage of RCW 80.28.425, the Commission indicated its commitment to considering equity while regulating in the public interest: "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."[14] The Commission also indicated that regulated companies should be prepared to address equity considerations in future cases:

---

[9] RCW 80.04.130(1).

[10] *WUTC v. Pacific Power and Light Company,* Cause No. U-76-18 (December 29, 1976) (internal citations omitted).

[11] RCW 19.405.010(6).

[12] *Id.*

[13] *Id.*

[14] *WUTC v. Cascade Natural Gas Corporation,* Docket UG-210755 Order 10 ¶ 58 (August 23, 2022).

"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."[15]

58 This evolving statutory framework is an overarching issue in this proceeding. We consider equity, environmental health, and other public interest factors in greater detail below. To the extent that recent legislation has added requirements to the Commission's consideration of MYRPs and PBR, these issues are also addressed below.

B. The Commission's process for considering settlements

59 Pursuant to WAC 480-07-750(2), the Commission will approve a settlement "if it is lawful, supported by an appropriate record, and consistent with the public interest in light of all the information available to the commission."

60 The Commission has emphasized that our purpose is "to determine whether the Settlement terms are lawful and in the public interest."[16] While the Commission "do[es] not consider the Settlement's terms and conditions to be a 'baseline' subject to further litigation,"[17] we may modify or reject a settlement that is not in the public interest.[18]

61 The Commission may therefore take one of the following actions after reviewing a settlement:

(1) Approve the proposed settlement without condition,

(2) Approve the proposed settlement subject to condition(s), or

(3) Reject the proposed settlement.[19]

62 If the Commission approves a proposed settlement without condition, a settlement is adopted as the Commission's resolution of the proceeding.[20] If the Commission approves a proposed settlement subject to any conditions, the Commission will provide the settling parties an

---

[15] *Id.*

[16] *WUTC v. Avista Corp.*, Dockets UE-080416 and UG-080417 (consolidated), Order 08, ¶ 20 (December 29, 2008).

[17] *Id.*

[18] *Id.*

[19] WAC 480-07-750(2).

[20] *See* WAC 480-07-750(2)(a).

opportunity to accept or reject the conditions.[21] When the settling parties accept the Commission's conditions, the Commission's order approving the settlement becomes final by operation of law.[22] However, when one or more of the settling parties rejects the Commission's conditions, the Commission deems the settlement rejected and the procedural schedule reverts to the point in time where the Commission suspended the procedural schedule to consider the settlement.[23]

II. REVENUE REQUIREMENT SETTLEMENT

C. Overview of the Revenue Requirement Settlement and Supporting Testimony

63 On August 26, 2022, the Settling Parties filed a multiparty settlement that resolves all issues in this proceeding except those related to the Tacoma LNG Facility and Green Direct. The Revenue Requirement Settlement proposes a two-year MYRP, rather than three years as initially proposed by PSE. Below, Table 1 provides a side-by-side comparison of the revenue requirement as requested and as settled.

Table 1: As filed and settlement revenue requirement comparison[24]
(in millions of dollars)

		Rate Year 1	*Rate Year 2*	*Rate Year 3*	Total MYRP
PSE Electric Service	*As filed*	310.60	63.10	31.80	405.50
	Settlement	223.00	38.00	N/A	261.00
PSE Natural Gas Service	*As filed*	143.00	28.50	23.30	194.80
	Settlement	70.60	18.80	N/A	89.40
PSE total	*As filed*	453.60	91.60	55.10	600.30
	Settlement	293.60	56.80	N/A	350.40

64 Notably, the Settling Parties propose to remove certain investments from base rates and to recover them in separate tariff schedules, known as trackers. PSE agrees to file two new

[21] WAC 480-07-750(2)(b). *Accord WUTC v. Avista Corp.*, Dockets UE-080416 and UG-080417 (consolidated), Order 08, ¶¶ 19-20 (December 29, 2008).

[22] WAC 480-07-750(2)(b)(i).

[23] WAC 480-07-750(2)(b)(ii). *See also* WAC 480-07-750(c).

[24] *See* Exhibit SEF-3-1-31-22 and Exhibit SEF-8-1-31-22, Exhibit A to the Settlement Stipulation Agreement Revenue Requirement, page 5, line 1

trackers to recover all rate base, depreciation, and operations and maintenance (O&M) expenses related to investments under the Company's Clean Energy Implementation Plan (CEIP) and Transportation Electrification Plan.[25] Tacoma LNG Facility costs are also excluded from the Revenue Requirement Settlement and will be recovered through a "future rate tracker,"[26] which is discussed in the Tacoma LNG Settlement.[27]

65 The Settling Parties agree to other adjustments and modifications to the Company's initial filing. At a high level, these terms include:

1. *Rate of return and capital structure:* The Revenue Requirement Settlement provides, "The authorized return on equity is set at 9.4 percent and the capital structure is set at 49 percent equity/51 percent debt with the cost of debt at 5.0 percent for the duration of the MYRP."[28]

2. *COVID deferral:* PSE agrees to a partial write-off of its deferred COVID costs filed in Dockets UE-200780 and UG-200871, but PSE may seek to recover "Additional Funding for Customer Programs" provided by PSE in compliance with Order 01 in Docket U-200281 and bad-debt accrued in excess of levels embedded in existing rates.[29]

3. *Provisional pro forma plant*: As noted above, PSE agrees to remove CEIP, Transportation Electrification Plan, and Tacoma LNG Facility costs from rate base and to recover these investments through trackers. PSE agrees to further reductions including:
    a. Excluding PSE's Colstrip dry ash facilities from recovery;[30]
    b. Excluding PSE's renewable natural gas costs from recovery;[31]

---

[25] *E.g.*, Revenue Requirement Settlement ¶¶ 23.f, k, l.

[26] The Settling Parties do not precisely define the term "future rate tracker." PSE witnesses use this term when describing the recovery of CEIP costs and other costs through rate trackers, *see* JAP-SEF-JJJ-1JT at 14:5-8, 17:4-8. But regardless, PSE witnesses make clear in supporting testimony that the Revenue Requirement Settlement's proposed tracker for CEIP costs allows for recovery of projected costs, subject to later review and possible refund. *Id.* at 15:4-6. We therefore interpret this term as describing the provisional recovery of investments subject to later review and possible refund.

[27] Joint Testimony Exh. JAP-SEF-JJJ-1JT at 17:4-7.

[28] Revenue Requirement Settlement ¶ 23.a.

[29] Revenue Requirement Settlement ¶ 23.n.

[30] Revenue Requirement Settlement ¶ 23.j.

[31] Revenue Requirement Settlement ¶ 23.c.

c. Reducing PSE's natural gas revenue requirement by $5 million in 2023 and $1 million in 2024;[32] and
d. Delaying $70 million in electric and natural gas reliability spending from 2023 to 2024.[33]

4. *Equity return on advanced metering infrastructure (AMI)*: The Settling Parties agree, among other points, that PSE may recover its AMI plant put into service through December 31, 2021, to the extent not already recovered, and that PSE may recover its debt component of return on AMI rate base over three years.[34] However, PSE will continue to defer recovery of its return on equity on AMI, and the Company will not receive a final prudency determination until AMI installation is complete and it files an AMI benefits progress report.[35] This is consistent with the Commission's findings in the Company's 2019 GRC.[36]

5. *Reductions to Electric Operations & Maintenance (O&M)*: The Settling Parties agree that PSE will reduce its as-filed electric O&M costs to reflect certain adjustments, including $34.7 million in reductions to 2023 and 2024 electric O&M costs to reflect the recovery of Energy Charge Credit under the Green Direct Program in Schedule 141A.[37]

6. *General reduction to Gas O&M*: The Settling Parties agree to a 20 percent or $15.5 million overall reduction to PSE's proposed increases for 2023 and 2024 gas O&M.[38]

7. *Delayed service dates for Energize Eastside*: The Settling Parties agree that delayed service dates for Energize Eastside are assumed to be incorporated into the agreed-upon revenue requirement.[39]

8. *Corporate Capital Planning*: By the end of the MYRP, PSE will submit a compliance filing that describes how its Board of Directors and senior management plan for equitable outcomes. This will include a "transparent and

[32] Revenue Requirement Settlement ¶ 23.g.

[33] Revenue Requirement Settlement ¶ 23.b.

[34] Revenue Requirement Settlement ¶ 23.e.

[35] *Id.*

[36] 2019 PSE GRC Order ¶¶ 155-56.

[37] Revenue Requirement Settlement ¶ 23.h (citing Revenue Requirement Settlement Exh. J).

[38] Revenue Requirement Settlement ¶ 23.i. (citing Revenue Requirement Settlement Exh. J).

[39] Revenue Requirement Settlement ¶ 23.m.

inclusive" methodology for applying an "equity lens" to the Corporate Capital Allocation framework.[40]

9. *Investment decision optimization tool (iDOT)*: The Settling Parties agree that PSE will consult with its Equity Advisory Group and take other steps to include new benefits and costs in iDOT, which include societal impacts, non-energy benefits and burdens, and the Social Cost of Greenhouse Gases.[41]

10. *Power Costs:* PSE agrees to a power cost-only rate case stay-out during the pendency of the MYRP.[42] The Settling Parties accept the prudency of all power supply resources included in the Company's initial filing,[43] and set forth a detailed process for annual updates to power costs.[44]

11. *Low-income issues:* By July 1, 2023, PSE will submit a compliance filing for approval of a Bill Discount Rate (BDR) and Arrearage Management Plan (AMP) developed in consultation with its Low-Income Advisory Committee.[45] PSE agrees to increase Home Energy Lifeline Program (HELP) funding consistent with RCW 80.28.425(2),[46] and agrees to make a good faith effort to increase weatherization measure incentive amounts in 2022.[47]

12. *Time Varying Rates (TVR) Pilot*: The Settling Parties agree that PSE will carry out its proposed TVR pilot with certain modifications, among other aspects, by providing enabling technology to half of low income-participants and providing bill protection to half of low-income participants.[48] PSE agrees to propose a full opt-in TVR program for residential customers in its next GRC.[49]

13. *Gas Line Extension Margin Allowances:* The Settling Parties agree that PSE will gradually reduce gas line extension margin allowances over the course of the

---

[40] Revenue Requirement Settlement ¶ 24.

[41] Revenue Requirement Settlement ¶ 26.

[42] Revenue Requirement Settlement ¶ 27.

[43] Revenue Requirement Settlement ¶ 31.

[44] Revenue Requirement Settlement ¶¶ 28-30.

[45] Revenue Requirement Settlement ¶ 37.

[46] Revenue Requirement Settlement ¶ 38.

[47] Revenue Requirement Settlement ¶ 39.

[48] Revenue Requirement Settlement ¶ 41.

[49] Revenue Requirement Settlement ¶ 42.

MYRP, and that by January 1, 2025, the gas line extension margin allowance will be reduced to zero.[50]

14. *Distributional Equity Analysis:* PSE agrees to conduct a pilot distributional equity analysis, which will be applied to the Company's proposed acquisition of 80 MW of distributed energy resources, and the Company agrees to participate in a Staff-led process to refine the methods for distributional equity analysis.[51]

15. *Northwest Pipeline:* A one-year amortization of $4.4 million from the Northwest Pipeline refund funds will reduce 2023 forecasted power costs.[52]

16. *Streamlining of Reports:* The Settling Parties agree to PSE's proposed streamlining of reporting to the Commission.[53]

17. *Performance Based Ratemaking:* As discussed below in sections II.E and II.F of this Order, the Settling Parties accept PSE's proposed Demand Response (DR) Performance Incentive Mechanism (PIM) with certain modifications. The Settling Parties agree that there will be no electric vehicle (EV) PIM.[54] PSE will, however, be required to report on a number of metrics addressing grid resiliency, environmental impacts, customer affordability, and equity, in addition to the metrics set forth in the Company's initial filing.[55] With the exception of the DR PIM, the Settlement proposes no targets for benchmarks in new metrics.[56]

18. *Decarbonization Study:* PSE will file an updated decarbonization study within 12 months of the issuance of this order, and the results of this study will be incorporated into PSE's 2025 Natural Gas Integrated Resource Plan (IRP).[57]

---

[50] Revenue Requirement Settlement ¶ 49.

[51] Revenue Requirement Settlement ¶¶ 50-51.

[52] Revenue Requirement Settlement ¶ 23.d.

[53] Revenue Requirement Settlement ¶ 56 (discussing Piliaris, Exh. JAP-1T at 62:14-79:8).

[54] Revenue Requirement Settlement ¶ 59.

[55] Revenue Requirement Settlement ¶¶ 60-64.

[56] Revenue Requirement Settlement ¶ 60.

[57] Revenue Requirement Settlement ¶ 66.

19. *Targeted Electrification Pilot:* PSE will conduct a Targeted Electrification Pilot, aimed at engaging 10,000 customers through rebates, incentives, electrification assessments, and education.[58]

20. *Targeted Electrification Strategy:* PSE will use the information gained from its decarbonization study and Targeted Electrification Pilot to develop a Targeted Electrification Strategy, which will be included in the Company's next Natural Gas IRP or Progress Report.[59] The Company is required, among other points, to consider fuel-switching rebates and to phase out promotional advertising for connecting new customers to the gas system by January 1, 2023.[60]

66 Each of the Settling Parties have provided testimony in support of this agreement. PSE witnesses Piliaris, Free, and Jacob describe the Revenue Requirement Settlement as a "fair, reasonable, and a delicately crafted resolution of significant number of issues in this very complex case."[61] They submit that "[t]he agreed-upon revenue requirement and provision for timely changes to rates for updates to PSE's power costs helps to ensure that the Company has the financial health required to provide safe and adequate service."[62] They also note that the Settlement incorporates equity into the Company's corporate planning processes, provides a greater level of support for low-income customers, and furthers the public interest in environmental health.[63]

67 Staff witness Erdahl likewise supports the Revenue Requirement Settlement as a reasonable outcome for the Company's revenue requirement and "a number of sizeable policy issues," including cost of capital, equity, AMI, Colstrip, and CEIP costs, among other issues.[64]

68 Considering the Revenue Requirement Settlement in light of RCW 80.28.425, TEP witness Cebulko observes that the Settlement will require PSE "to begin collecting a robust data set on the utility's performance from year to year that measures if the Company is providing energy service that meets the Commission's regulatory goals and outcomes."[65] Cebulko also supports

---

[58] Revenue Requirement Settlement ¶ 67.

[59] Revenue Requirement Settlement ¶ 68.

[60] *Id.*

[61] Joint Testimony, Exh. JAP-SEF-JJJ-1T at 5:8-9.

[62] Joint Testimony, Exh. JAP-SEF-JJJ-1T at 4:1-3.

[63] Joint Testimony, Exh. JAP-SEF-JJJ-1T at 4:10-21.

[64] Erdahl, Exh. BAE-1T at 2:20-3:4.

[65] Cebulko, Exh. BTC-7T at 3:4-6.

the Settlement's proposed DR PIM,[66] TVR pilot,[67] low-income customer programs,[68] decarbonization and electrification studies,[69] and capital planning processes.[70]

69 AWEC witness Mullins notes that the Revenue Requirement Settlement is supported by a "diverse group" of interested parties and that it addresses steps PSE will take to comply with CETA and the CCA.[71] Mullins supports the Settlement as providing for fair, just, reasonable, and sufficient rates.[72]

70 Nucor witness Higgins submits that the Revenue Requirement Settlement's allocation of class revenue reflects a reasonable compromise among the parties.[73] Higgins supports the removal of renewable natural gas costs from the Company's revenue requirement and the reasonable rate design for Schedules 87, 87T, 141R and 141N.[74]

71 The Joint Environmental Advocates also testify in support of the Settlement. Smith explains that "[o]verall, the Settlement advances clean energy and the public interest by limiting PSE's expenditures in gas system expansion, providing for improved future analysis and planning related to gas system decarbonization, and limiting investments in unproven alternative pipeline fuels."[75] McCloy similarly testifies that the Settlement is consistent with the public interest and a "clean, affordable, and equitable energy system in Washington."[76] McCloy discusses the Settlement's treatment of CETA issues, PBR, Colstrip, DR, distribution system planning, EV supply equipment payment methods, low-income issues, and CCA issues, among other points.[77]

72 Kronauer testifies that the Settlement addresses issued raised in Walmart's responsive testimony. These include the proposed 9.40 ROE; the recovery of 80 percent of Colstrip tracker costs through demand charges and 20 percent through energy charges; and the

---

[66] *E.g.*, *id.* at 4:5-8.

[67] *Id.* at 7:5-8:6.

[68] *E.g.*, *id.* at 8:16-9:12.

[69] *Id.* at 12:9-13:21.

[70] *Id.* at 14:1-7.

[71] Mullins, Exh. BGM-11T at 12:11-15.

[72] *Id.* at 12:22-13:1.

[73] Higgins, Exh. KCH-7T at 2:2-23.

[74] *Id.* at 2:22-3:1.

[75] Smith, Exh. GDS-1T at 4:17-20.

[76] McCloy, Exh. LCM-10T at 2:15-16.

[77] *E.g.*, *id.* at 2:18-20.

inclusion of demand and energy components for Schedule 141-R and 141-N customers, proportional with each rate schedule's rate design.[78]

73 Al-Jabir explains that FEA supports the Revenue Requirement Settlement because it provides for lower revenue requirement increases compared to the Company's initial filing.[79] Al-Jabir notes as well that the Settlement results in more cost-based rates for Schedule 49 customers; incorporates demand and energy charges into the design of the Colstrip rider and MYRP riders; and reasonably allocates the costs of the Targeted Electrification Pilot and Targeted Electrification Strategy.[80]

74 The scope of opposition to the Revenue Requirement Settlement is relatively narrow and limited. Out of the four parties that did not join the Revenue Requirement Settlement, two parties take an essentially neutral position. King County neither joins nor opposes the Settlement.[81] The Puyallup Tribe does not directly address the Revenue Requirement Settlement in its testimony, but instead focuses its opposition on the Tacoma LNG Settlement.[82]

75 Two parties oppose specific terms within the Revenue Requirement Settlement. CENSE opposes the prudency of the Energize Eastside transmission project.[83] Public Counsel supports many of the Settlement's terms as consistent with the public interest,[84] and it takes no position on several other terms.[85] Public Counsel, however, opposes the terms related to capital structure and ROE.[86] Our discussion of the Revenue Requirement Settlement will focus on these limited areas of disagreement raised by CENSE and Public Counsel.

---

[78] Kronauer, Exh. AJK-17T at 2:2-9.

[79] Al-Jabir, Exh. AZA-7T at 2:12-16.

[80] *Id.* at 2:17-3:9.

[81] Revenue Requirement Settlement ¶ 3.

[82] *See generally* Sahu, Exh. RXS-30T (Response Testimony of Ranajit Sahu in Opposition to the Settlement Stipulation and Agreement on Tacoma LNG).

[83] *E.g.*, Revenue Requirement Settlement ¶ 4 (noting CENSE's opposition).

[84] Bauman, Exh. SB-9T at 6:6-19 (noting that Public Counsel accepts the Settlements terms regarding PBR, PCORCs, CETA costs, decarbonization and electrification studies, gas line extension margin allowances, distributional equity analysis, the TVR pilot, low-income issues, Colstrip cost recovery, AMI, rate spread, and rate design).

[85] *Id.* at 7:1-6 (noting that Public Counsel takes no position on the overall revenue requirement, Energize Eastside, depreciation, earnings test, and power costs).

[86] Bauman, Exh. SB-9T at 1:21; 2:1-2.

76 We begin by considering whether the Revenue Requirement Settlement complies with the provisions in recently enacted RCW 80.28.425. Although no party argues that the settlement fails to satisfy the statute's requirements, we must consider whether the Settling Parties' proposed terms meet the requirements for a MYRP and whether it is consistent with the Commission's expectations for PBR.

D. The Revenue Requirement Settlement's proposed two-year MYRP.

77 The Settling Parties have agreed to a two-year MYRP.[87] PSE witnesses explain that the two-year MYRP in combination with other terms in the Settlement will "help PSE to restore its financial health."[88] While the Company initially requested a three-year rate plan, the Company cites economic uncertainty and regulatory changes as factors supporting a shorter term.[89]

78 *Commission Determination*. We accept the Settlement's proposed two-year MYRP. The Settling Parties' agreement on this issue is lawful, supported by an appropriate record, and consistent with the public interest.

79 On May 3, 2021, Washington Governor Jay Inslee signed into law Senate Bill 5295, titled "an Act to transform the regulation of gas and electric utilities toward multi-year rate plans and performance-based rate making."[90] Although the Commission already had authority to consider MYRPs and other performance-based ratemaking mechanisms,[91] the newly codified RCW 80.28.425 provided the Commission specific direction and new tools to address the limitations of traditional cost-of-service ratemaking and help achieve state policy goals.

80 Beginning January 1, 2022, gas and electric investor-owned utilities must include a MYRP between two and four years in length as part of any general rate case filing.[92] Following an adjudicative proceeding, the Commission may approve the utility's MYRP, approve it with

---

[87] Revenue Requirement Settlement ¶ 20.

[88] Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 8:12-14.

[89] *Id.* at 9:26-28.

[90] Laws of 2021, ch. 188.

[91] RCW 19.405.010(5) ("[T]he legislature recognizes and finds that the utilities and transportation commission's statutory grant of authority for rate making includes consideration and implementation of performance and incentive-based regulation, multiyear rate plans, and other flexible regulatory mechanisms where appropriate to achieve fair, just, reasonable, and sufficient rates and its public interest objectives.").

[92] RCW 80.28.425(1).

conditions, or reject it.[93] The Commission may also approve an alternative proposal from another party.[94]

81 When considering a proposed MYRP, the Commission considers whether the rate plan results in fair, just, reasonable, and sufficient rates, following the same standard that applies to other rate cases.[95] The Commission may also consider factors "including, but not limited to, environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices" of the utility.[96] The Commission "shall separately approve rates" for each year of the rate plan.[97]

82 The Commission also has discretion in structuring the terms of the MRYP. We may establish "terms, conditions, and procedures" for any such rate plan.[98] The utility is bound by the terms of the approved MYRP for the first and second rate years, but the utility may choose to file and propose a new MYRP for the third and fourth years of the rate plan.[99]

83 The statute also requires that "[t]he commission must, in approving a multiyear rate plan, determine a set of performance measures that will be used to assess a gas or electrical company operating under a multiyear rate plan."[100]

84 As required by RCW 80.28.425, PSE proposed an MYRP in its initial filing. PSE specifically proposed a three-year MYRP with performance measures.[101] PSE also proposed an earnings sharing mechanism, as required by statute.[102]

85 The evidence describes several likely benefits from the proposed MYRP. Company witness Piliaris testifies that a well-constructed MYRP allows for more timely recovery of costs, strengthens a utility's incentives to contain costs during the stay-out period, reduces

---

[93] *Id.*

[94] *Id.*

[95] *Id. See also* RCW 80.28.425(10) ("The provisions of this section may not be construed to limit the existing rate-making authority of the commission.").

[96] *Id.*

[97] RCW 80.28.425(3)(a).

[98] RCW 80.28.425(4).

[99] RCW 80.28.425(5).

[100] RCW 80.28.425(7).

[101] *E.g.*, Piliaris, Exh. JAP-1T at 3:11-12.

[102] *See* RCW 80.28.425(6) (requiring the implementation of an earnings sharing mechanism).

administrative costs, and allows more time and space to discuss other regulatory issues.[103] We find the Settlement's proposed two-year MYRP to be reasonable and supported by the evidence. We agree that it is warranted to limit the MYRP to a two-year term because this is the Company's first general rate case under the recently enacted RCW 80.28.425.[104]

86 We find further support for our decision given PSE's prior successes with MYRPs, which occurred under the previous statutory framework. In June 2013, the Commission entered Final Order 07, its Final Order in Dockets UE-130137, *et al*.[105] As relevant here, Final Order 07 approved a Rate Plan for the Company that allowed for modest increases in rates with a defined stay out period.[106] In 2016, the Commission extended this stay out period based on the parties' joint petition.[107] In 2017, the Rate Plan concluded, and the Commission observed that it "mitigated the effects of regulatory lag and attrition during the Rate Plan effective period," allowing the Company to earn slightly below its authorized rate of return.[108]

87 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).[109] The Commission authorizes replacing the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6) and, further, clarifies that the decoupling deferral must include accruing ROR on the balance of the deferral.

88 We therefore accept the Settlement's proposed two-year MYRP. As this MYRP comes to a close, however, we encourage PSE, and indeed all investor-owned electric companies, to consider ways they might avoid filing their next GRCs in close proximity to those of another investor-owned utility, thereby helping the Commission and others to manage their resources.

---

[103] Piliaris, Exh. JAP-1T at 3:14-4:3.

[104] *See* Public Counsel Brief ¶ 75 (noting that Public Counsel supports the "limited duration" of the MYRP and other modifications to the Company's proposed PIMS and metrics).

[105] *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (consolidated), Final Order 07 (June 25, 2013).

[106] *Id.* ¶¶ 147-50.

[107] *Notice of Commission Action Amending Order 07*, Dockets UE-130137 et al., (March 17, 2016).

[108] *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170334, Order 08 at ¶ 409 (Dec. 11, 2017).

[109] RCW 80.28.425(6).

E. The Revenue Requirement Settlement's Proposed Performance-based Metrics and Incentives

89 The Settling Parties agree that PSE will annually report metrics discussed in PSE's direct testimony and those provided in the Settlement.[110] The Settlement also provides for one PIM. The Settling Parties accept PSE's proposed DR PIM as part of the two-year rate plan subject to the following modifications:

- The initial reward threshold will activate at 105 percent of the DR target and will be a percent of DR program costs equal to PSE's approved weighted average cost of capital (WACC).
- The second reward threshold will activate if PSE exceeds 115 percent of the DR target and will be 15 percent of DR program costs.
- The PIM is based on the DR target of 40 MW by 2024.[111]
- The DR PIM incentive is capped at $1 million over the course of the MYRP.
- The DR PIM discontinues at the end of Rate Year 2 unless the Commission orders otherwise.[112]

90 An overview of the Settlement's proposed DR PIM is provided in Table 2 below:

---

[110] Revenue Requirement Settlement ¶ 60. The Settlement refers to metrics proposed in Lowery, Exh. MNL-1T in additional to the Settlement.

[111] Revenue Requirement Settlement ¶ 58. The Settling Parties state that the 40 MW by 2024 will "be calculated in the same way that PSE calculates its peak load reduction for compliance with the DR target in PSE's CEIP. This does not replace the requirement to adopt a DR target in the CEIP. The Settling Parties reserve the right to support a higher target in the CEIP docket."

[112] Revenue Requirement Settlement ¶ 58.

Table 2: Settlement DR PIM

Year	*Target*	*Achievement Targets, as a percentage*	*Corresponding Incremental MW*	*Incentive, as a percentage of estimated costs*
		< 105 percent	< 5.25 MW	0 percent
2023	40 MW	105 percent – 115 percent	5.25 MW – 5.75 MW	7.156 percent[113]
		>115 percent	< 5.75 MW	15 percent
		< 105 percent	< 42 MW	0 percent
2024	40 MW	105 percent – 115 percent	42 MW – 46 MW	7.156 percent
		>115 percent	< 46 MW	15 percent

- Payment cap:

* No additional incentives for achievement above 150 percent of the annual target.
* The total incentive shall not exceed $1 million over the entire MYRP.
* The DR PIM ends at the end of the MYPR Rate Year 2 unless the Commission orders otherwise.

91 The Settling Parties have not agreed to PSE's proposed electric vehicle PIM, and it is not included in the Revenue Requirement Settlement.[114]

92 As stated above, the Settlement adopts the metrics proposed by PSE in direct testimony and new measures proposed in the Settlement.[115] The Settlement provides no targets or

---

[113] Settlement Stipulation at 23(a) provides the components for weighted average cost of capital resulting in a rate of return of 7.156 percent. The components are as follows: 51 percent debt with a cost of debt of 5.0 percent, and 49 percent equity with a return on equity of 9.4 percent.

[114] Revenue Requirement Settlement ¶ 59.

[115] *See* Revenue Requirement Settlement at 60 (incorporating metrics discussed in Lowry, Exh. MNL-1T). The Settlement includes 69 metrics, as follows: 14 metrics proposed by PSE in direct testimony, 49 metrics proposed by the Settling Parties using the regulatory goals identified in Docket U-210590, and 5 modifications or additions to existing metrics related to the Company's Service Quality Index (SQI), implemented in the Commission's 14th Supplemental Order approving the merger between Puget Sound Power & Light Company and Washington Natural Gas Company in 1997. *See Puget Sound Power & Light Company and Washington Natural Gas Company*, Dockets UE-951270 and UE-960195, 14th Supp. Order (Feb. 5, 1997).

benchmarks except for the DR PIM.[116] The Settlement's proposed measures are summarized by category in Table 3 below:

Table 3: Categories of metrics proposed by the Settlement

Categories	**Number of Measures**
Demand-side Management[117]	5
Electric Vehicles[118]	4
Emission[119]	1
Advanced Metering Infrastructure Metrics[120]	3
Additional Equity Metrics[121]	2
Resilient, reliable, and customer-focused distribution grid[122]	21
Environmental Improvements[123]	5
Customer Affordability[124]	9
Advancing Equity in Utility Operations[125]	14
New Measures	**64**
SQI modified Metrics[126]	5
Total Settlement Measures	**69**

[116] Revenue Requirement Settlement at 60. The Revenue Requirement Settlement adopts the metrics in Lowry's testimony but fails to include sufficient detail outlining and describing the Company's initially proposed metrics. Instead, the Settlement refers only to other exhibits in the record. We expect that settling parties will provide more detailed descriptions of metrics and terms (including any associated benchmarks and targets) in future settlements. Any inaccuracy in our characterization of this portion of the Revenue Requirement Settlement is due to this lack of detail and the Settlement's reliance on cross-references to other exhibits.

[117] Lowry, Exh. MNL-4 at 5-9.

[118] Lowry, Exh. MNL-4 at 9-12.

[119] Lowry, Exh. MNL-1T at 44:1-17 and Lowry, Exh. MNL-4 at 12-13.

[120] Lowry, Exh. MNL-1T at 45:1-47:3 and Lowry, Exh. MNL-4 at 13-15.

[121] Lowry, Exh. MNL-1T at 47:4-17 and Lowry, Exh. MNL-4 at 15-18.

[122] Settlement Stipulation at 61. This is a Commission defined regulatory goal from U-210590 but the metrics themselves are proposed by the Settlement.

[123] Settlement Stipulation at 62. This is a Commission defined regulatory goal from U-210590 but the metrics themselves are proposed by the Settlement.

[124] Settlement Stipulation at 63. This is a Commission defined regulatory goal from U-210590 but the metrics themselves are proposed by the Settlement.

[125] Settlement Stipulation at 64. This is a Commission defined regulatory goal from U-210590 but the metrics themselves are proposed by the Settlement.

[126] Lowry, Exh. MNL-4 at 1-5. PSE's SQI metrics include targets and penalties and are pre-existing service quality indices. Joint testimony, Exh. JAP-SEF-JJJ-1JT at 38:17-20.

93 The Settlement requires PSE to report on the above metrics annually, both in its compliance filing in these consolidated dockets and in conjunction with PSE's annual review process.[127] PSE's proposed annual filings on March 31 of each calendar year are described in more detail in the testimony of Company witnesses Free and Piliaris.[128]

94 In its post-hearing Brief, PSE submits that the Settlement requires the Company to report on a "robust suite of performance measures that are consistent with the requirements of RCW 80.28.425(7)."[129] PSE argues that, while the statute requires the Commission to determine a set of performance measures that will be used "to assess" the utility's performance, the statute does not require the performance measures to contain incentives or penalty mechanisms.[130] PSE concludes that the MYRP agreed to by the Settling Parties includes the "full panoply of performance metrics, incentives, and penalty mechanisms" and that no party opposes these performance metrics.[131]

95 Staff supports the Settlement and its proposed performance measures. Staff notes that the modifications to the Company's proposed DR PIM create "customer safeguards" by capping the incentive payment and sunsetting the PIM at the end of the MYRP.[132] Staff argues that the Settlement's proposed metrics are an "evolutionary step forward" in the Commission's regulation of PSE and that they will help establish whether the Company's investments are "producing benefits for PSE's customers and whether those benefits are being distributed equitably."[133]

96 Public Counsel also argues in support of the Settlement's terms regarding performance-based regulation. Public Counsel argues that under RCW 80.28.425(7) the Commission may develop performance measures, incentives, and penalty mechanisms but is not required to do so.[134] Public Counsel concludes that the Settlement's proposed performance metrics, coupled with the reporting obligations, meet the requirements of the statute and provide a basis to

---

[127] Revenue Requirement Settlement ¶ 60.

[128] *See, e.g.*, Free, Exh. SEF-1Tr at 30:9-13; Piliaris, Exh. JAP-3 (Planned Filing Schedule During Multiyear Rate Plan).

[129] PSE Brief ¶ 79.

[130] *Id.*

[131] *Id.* ¶ 82.

[132] Staff Brief ¶ 63 (citing, *inter alia*, Cebulko, Exh. BTC-7T at 6:3-4; Erdahl, Exh. BAE-1T at 19:5-12).

[133] *Id.* ¶ 66 (citing Erdahl, Exh. BAE-1T at 19:17-19).

[134] Public Counsel Brief ¶ 73.

measure PSE's performance.[135] Public Counsel supports the Settling Parties' agreement to a single PIM, arguing that "[t]aking a conservative approach in this case is reasonable, especially since the Legislature directed the Commission to examine alternatives to traditional cost of service regulation."[136]

97 The Joint Environmental Advocates also support the Settlement's terms related to performance-based regulation as consistent with the statute.[137] Although the Joint Environmental Advocates advocated for more robust performance-based regulation tools in response testimony, they support the Settlement as a "reasonable first effort" given that the Commission is still evaluating how it may implement these tools.[138]

98 *Commission Determination.* We find that the Settlement's proposed performance metrics should be approved, subject to the condition of additional measures to assist the Commission in assessing the Company's performance under the MYRP. The Commission recognizes that the new proposed metrics will be informed by its ongoing proceeding to evaluate performance-based regulation in Docket U-210590, and that establishing appropriate 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.

99 The Settlement provides that these metrics will be reviewed and reported annually. The Settlement, however, does not state that these metrics should be used to assess the Company's operations under the MYRP. Further, the Settlement's agreed new 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.

100 We also approve the Settlement's proposed DR PIM for use over the term of the MYRP. Although the Commission is developing a policy statement to provide more clarity on performance-based regulation, this work will not be completed before the suspension date in this case.[139] The Settling Parties' proposal for a modified DR PIM and various metrics

---

[135] *Id.*

[136] *Id.* ¶ 75.

[137] Joint Environmental Advocates' Brief at 11.

[138] *Id.* at 12-13.

[139] *See* Update on Performance-Based Regulation Proceeding, Docket U-210590 (Jan. 27, 2022).

represents one of the first attempts to establish a performance incentive mechanism under the new statutory framework.

101 It is notable that no party opposes the Settlement's terms on this issue or argues that the Settlement fails to comply with the requirements of RCW 80.28.425(7). At hearing, the Settling Parties argue that the proposed DR PIM, the Company's proposed metrics, and the Settlement's proposed, additional metrics will provide essential information that will allow the Commission "to assess" the Company consistent with the requirements of RCW 80.28.425(7).[140]

102 We are concerned, however, that the Settlement lacks detailed information identifying or suggesting how the Commission might use these metrics to evaluate the Company's operations under the MYRP or the agreed calculations for all metrics. Due to the Settlement's terms and Settling Parties' relative lack of clarity as to how the agreed performance metrics should be used to evaluate PSE's operations under the MYRP in compliance with RCW 80.28.425(7), the Commission finds it necessary to meet its statutory obligation by adopting a limited number of performance measures, described later in Section II.F of this Order, that it will use to evaluate PSE's operations during the MYRP.

103 Our assessment of PSE's performance under the MYRP will necessarily require the Settling Parties to, in a future proceeding, review the data with respect to the functioning of the modified DR PIM, the data with respect to the new metrics proposed in the Settlement, and the metrics adopted from the Company's initial filing, and report these findings to the Commission. Much as Staff explains, the Settlement will create a "baseline" that will allow the Commission to craft a "wide spectrum of PIM and penalty mechanisms in future cases."[141] Washington's efforts towards performance-based regulation are still in an early stage, and it will take data, the passage of time, experience, and input from interested parties to fully carry out the legislature's intent in this area. We remind the parties that our approval of the Settlement should not impute precedential value to the continuation of any specific metrics, targets, or the DR PIM, should the Commission determine that other or additional metrics or measures are more appropriate in the future for the same or other purposes.

104 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 additional requirements for reporting the performance metrics to the Commission. Within three

---

[140] *See* Piliaris, TR 325:16-326:3 (discussing whether the Settlement complies with RCW 80.28.425); Celbulko, TR 326:6-327:7 (same).

[141] Staff Brief ¶ 66.

months of PSE's annual March 31 filing pursuant to the Revenue Requirement Settlement's MYRP, we require the non-Company parties to review reported performance metrics and provide feedback and recommendations for the Commission to consider. Subject to this condition, 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.

F. Performance Measures Pursuant to RCW 80.28.425(7)

105 As noted above in Section II.E, we find it reasonable and appropriate to require PSE to report on additional metrics than just those identified in the Settlement. These metrics are necessary for the Commission's future assessment of PSE's operations under the MYRP.

106 The Commission must, by law, "determine a set of <u>performance measures</u> <u>that will be used to assess</u> a gas or electrical company <u>operating under a multiyear rate plan</u>."[142] This burden of law is placed on the Commission, not any company or party to a GRC. Such 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 other party throughout the proceeding.[143] 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.

107 As recognized by the Settling Parties, the Commission has initiated a proceeding in Docket U-210590 to examine and establish performance metrics, performance incentives and penalties.[144] 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 after the Commission issued a Notice of Opportunity to File Written Comment in Docket U-210590 on August 5, 2022, the Settlement proposes 49 performance metrics categorized using the Commission's established regulatory goals. However, not all of the proposed Settlement metrics necessarily reflect the Commission's regulatory goals and desired outcomes or design principles provided in Docket U-210590,

---

[142] RCW 80.28.425(7) (emphasis added).

[143] RCW 80.28.425(7).

[144] 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."

which is the Commission's collaborative proceeding concerning performance-based ratemaking.

108 The Commission is required by law to determine a set of performance measures to assess a MYRP. Settlement proposes 64 new performance metrics in addition to existing metrics to be recorded and tracked, but the Settlement lacks detailed information related to how the Commission should use the metrics to evaluate PSE's MYRP. These metrics are not necessarily measures for evaluating PSE's operations under the MYRP.

109 We therefore determine that certain measures, independent and aside from the 69 metrics included in the Settlement, are necessary to meet the legal requirement for the Commission's future assessment of PSE's operations under the MYRP. We adopt the measures outlined in Table 4, below, related to operational efficiency, company earnings, affordability, and energy burden.

Table 4: MYRP Performance Measures and Outcomes

Topic	Measure/Calculation	Outcome[145]
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[146] 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[147]	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 the company's reinvesting and payout patterns.
Affordability[148]	Average Annual Bill Impacts (by Census Tract)	Assesses the average annual residential bill impacts to better understand over time, and by location, affordability of rates for residential customers using the same average energy usage from year to year for better comparison.[149]
	Average Annual Bill Impacts (by Zip code)	
Energy Burden[150]	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.[151]
	Average Annual Bill *divided by* Average Median Income (by Zip code)	

110 The measures we require PSE to track and report, outlined above, will provide essential and critically important financial and customer equity data for the Commission's evaluation of PSE's performance during this MYRP. We also observe that the measures we require will likely continue to be consequential even beyond the term of the 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. In the future, the data these measures will collect during the MYRP will be instructive and inure greater understanding of PSE's operations.

111 Likewise, we would find extraordinary benefit from all the historical data related to these measures. At this time, we will not require PSE 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 PSE's performance at the end of this MYRP. Thus, we require PSE to make a compliance filing within 45 days of this Order to provide the measures and calculations outlined in Table 4, 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 PSE to report the performance measures outlined in Table 4, above, for each year of the MYRP (beginning January 1 and ending December 31 of each year 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 PSE's next GRC and future MYRPs.

---

[145] Outcome descriptions are approximate. Baseline data is required prior to a full understanding of outcomes and results.

[146] Provide results for both calculations but include in reporting which the Commission authorized; the use of AMA or EOP.

[147] "Current" means all current assets that can be converted into cash within one year and all current liabilities with maturities within one year.

[148] These measures are similar to Settlement's first Customer Affordability metric (at 63). These measures track both by census tract and by zip code. PSE should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[149] Use 800 kWh and 64 therms for all required reporting in this Order.

[150] These measures are similar to Settlement's second Customer Affordability metric (at 63). These measures track both by census tract and by zip code. PSE should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[151] *See* WAC 480-100-605 (defining "Energy assistance need" as "the amount of assistance necessary to achieve an energy burden equal to six percent for utility customers.").

G. Capital Structure

112 We next turn to the Settling Parties' proposed cost of capital. A utility's cost of capital has three main components: capital structure, return on equity, and cost of debt. Taking all these factors into account, it is possible to describe the utility's WACC.

113 One of the contested issues in this case is the Revenue Requirement Settlement's proposed capital structure. The Revenue Requirement Settlement provides for a capital structure of 49 percent equity and 51 percent debt for the duration of its two-year MYRP.[152] Public Counsel opposes the Revenue Requirement Settlement's proposed capital structure and advocates for a lower equity ratio of 48.5 percent.[153]

114 In their joint testimony, PSE witnesses Jon A. Piliaris, Susan E. Free, and Joshua J. Jacobs explain that the Settlement's equity ratio of 49 percent will improve PSE's weighted cost of equity relative to its peers; enable PSE to finance its activities with less debt; partially replace lost cash flows resulting from the 2017 Tax Cuts and Jobs Act (TCJA), and improve PSE's credit metrics.[154] Compared to the Company's initial filing, the Revenue Requirement Settlement lowers the Company's WACC by 23 basis points in 2023 and 28 basis points in 2024.[155] This reduces the Company's revenue requirement by $26.5 million in 2023 and $34.3 million in 2024.[156]

115 Cara G. Peterman provides additional testimony for PSE. Disagreeing with the response testimony from Public Counsel witness J. Randall Woolridge, Peterman explains that the Company has managed its equity ratio based upon the 48.5 percent equity ratio approved by the Commission in its last two GRCs, but this does not, by itself, justify maintaining the Company's equity ratio at 48.5 percent.[157] Peterman argues that changing conditions, such as the passage of CETA, Senate Bill 5295, and inflationary pressures, militate against relying on previously-approved equity ratios.[158]

116 Peterman argues that PSE received downgrades in ratings outlooks from both S&P Global Ratings and Fitch Ratings, which improved only because of the prospect of a more credit-

---

[152] Revenue Requirement Settlement ¶ 23.a.

[153] Bauman, Exh. SB-9T at 1:21; 2:1-2: 7-16. *Accord* Woolridge, Exh. JRW-13T at 12:20-21.

[154] Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 49:14-20.

[155] *Id.* at 49:22-50:1.

[156] *Id.* at 50:2-4.

[157] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 46:19-47:4.

[158] *Id.* at 47:8-12.

supportive regulatory paradigm.[159] Peterman also disputes Woolridge's selection of proxy companies in support of its capital structure recommendation. Peterman observes that Woolridge selected parent companies of regulated utilities,[160] that Woolridge's proxy companies do not appear to calculate their equity ratio on an average-of-monthly-averages (AMA) basis,[161] and that Woolridge's proxy companies are not consistent with his recommended equity ratio of 48.5 percent.[162]

117 In response, Public Counsel witness Woolridge submits that the Settlement's proposed equity ratio is higher than the average common equity ratio of companies in his proxy group.[163] Woolridge notes, "As of December 31, 2021, the average common equity ratios for the Electric, Bulkley, and Gas Proxy Groups were 41.7 percent, 39.4 percent, and 38.6 percent respectively."[164]

118 Woolridge explains that he agrees with the 48.5 percent equity ratio originally recommended by Staff witness David C. Parcell.[165] Citing Parcell's earlier testimony, Woolridge observes that PSE had 46.9 percent common equity in its actual capital structure as of December 31, 2021, that the Company's equity ratio has not increased in recent years, and that an equity ratio of 48.5 percent is consistent with the level authorized by the Commission in past decisions.[166]

119 In its post-hearing brief, PSE argues that the Settlement's proposed equity ratio of 49.0 percent will help PSE improve its credit metrics performance and that it will allow the Company to begin rebalancing how much debt and equity is invested in its business to meet changing conditions.[167] PSE observes that the Settlement will result in the lowest WACC that PSE's customers have seen in recent memory, providing customers a significant cost savings.[168]

---

[159] *Id.* 47:15-22.

[160] *Id.* at 49:1-10.

[161] *Id.* at 49:17-20.

[162] *Id.* at 50:6-14.

[163] Woolridge, Exh. JRW-13T at 4:11-15 (citing Woolridge, Exh. JRW-1T at 28–29).

[164] Woolridge, Exh. JRW-1T at 28:18-20 (citing Woolridge, JRW-5).

[165] Woolridge, Exh. JRW-13T at 12:20-23.

[166] *See id.* at 12:1-10 (citing Parcell, Exh DCP-1T at 27:14–19 and 28:1–2).

[167] PSE Brief ¶ 37.

[168] *Id.*

120 Staff also supports the Settlement's proposed equity ratio in its brief. Staff observes that the Settlement will help PSE retain access to capital on reasonable terms and that this will benefit customers in the long term.[169]

121 In its brief, Public Counsel argues that PSE's equity ratio should be maintained at 48.5 percent.[170] Public Counsel notes that the average equity ratios in Woolridge's electric and gas proxy groups were well below the 49.0 percent as proposed in the Settlement.[171] Public Counsel notes that PSE and its parent company have maintained stable equity ratios over the last five years and have maintained positive credit ratings.[172]

122 *Commission Determination.* We accept the Revenue Requirement Settlement's proposed capital structure of 49 percent equity and 51 percent debt for the duration of the MYRP. We find Public Counsel's arguments for a lower equity ratio of 48.5 percent unpersuasive.

123 Establishing a capital structure for ratemaking purposes requires the Commission to strike an appropriate balance between debt and equity on the bases of economy and safety.[173] The economy of lower cost debt, on which the Company has a legal obligation to pay interest, must be balanced against the safety of higher cost common equity on which the Company has no legal obligation to pay a return at any particular time.[174]

124 The Commission has used actual or hypothetical capital structures to strike the right balance and determine overall rate of return on a case-by-case basis.[175] In past cases, we have used a hypothetical capital structure, which may be prospective or imputed, primarily as a means to address financial hardship or tight capital markets.[176]

125 In this case, we observe that the Revenue Requirement Settlement represents a compromise as compared to the Company's initial filing. PSE proposed a common equity ratio of 49.0 percent in 2023, 49.5 percent in 2024, and 50.0 percent in 2025.[177] By providing for a lower

---

[169] Staff Brief ¶ 34 (citing Shipman, Exh. TAS-1T at 2:1-3, 29:7-13).

[170] Public Counsel Brief ¶ 54.

[171] *Id.* ¶ 53.

[172] *Id.* ¶ 55.

[173] *WUTC v. Puget Sound Energy*, Dockets UG-040640, UE-040641 (consolidated) Order 06 ¶ 27 (February 18, 2005) (citation omitted). *See also* 2017 Avista GRC Order at 39, ¶ 109.

[174] *Id.*

[175] *Id.*

[176] *WUTC v. Avista Corporation d/b/a Avista Utilities*, UE-170485 and UG-170486 (consolidated) Order 07 ¶ 110 (April 26, 2018).

[177] Peterman, CGP-1CT at 5:8-12 (Table 2).

common equity ratio of 49.0 percent over the two-year rate plan, the Settlement lowers the Company's WACC by 23 basis points in 2023 and 28 basis points in 2024, resulting in cost savings and the lowest WACC for customers in recent memory.[178]

126 Although Public Counsel witness Woolridge argues that an equity ratio of 48.5 percent better represents the Company's historical capitalization, Peterman persuasively explains that the Company has managed its actual equity ratio at, or above, the equity ratios approved by the Commission in past cases.[179] Under these circumstances, the Company's historic capitalization does not represent a persuasive reason to adopt Public Counsel's proposal.

127 We are also persuaded by Peterman's testimony that recent statutory changes and downgraded credit ratings outlooks justify increasing the Company's equity ratio.[180] As Peterman explains, the Company did not receive a full credit downgrade, but it experienced downgrades in ratings outlooks from both S&P Global Ratings and Fitch Ratings from 2020 to 2021.[181] Credit ratings may impact the utility's borrowing costs, which ultimately impacts its revenue requirement. It is reasonable to provide for a 50-basis point increase to the Company's common equity ratio given these considerations.

128 All of these considerations weigh in favor of accepting the capital structure as proposed by the Settling Parties.

H. Return on Equity

129 The other contested cost of capital issue in this proceeding concerns the agreed upon ROE. The Revenue Requirement Settlement assumes and incorporates a 9.40 percent ROE for both years of PSE's MYRP.[182] Public Counsel argues that PSE's ROE should be set lower, at 8.80 percent.[183]

130 In the Company's initial filing, Ann E. Bulkley testified that that a range between 9.75 and 10.50 percent ROE is reasonable to address PSE's need to attract capital on reasonable terms and its ability to provide safe and reliable service.[184] Bulkley based this finding on the

---

[178] *Id.* at 49:22-50:4. *Accord* PSE Brief ¶ 37.

[179] Joint Testimony of Peterman, Bulkley, and Shipman, Exh. CGP-AEB-TAS-1JT at 46:19-20.

[180] *See* Joint Testimony of Peterman, Bulkley, and Shipman, Exh. CGP-AEB-TAS-1JT at 47:8-20.

[181] Joint Testimony of Peterman, Bulkley, and Shipman, Exh. CGP-AEB-TAS-1JT at 47:15-19.

[182] Revenue Requirement Settlement ¶ 23.a.

[183] *E.g.*, Public Counsel Brief ¶ 65.

[184] Bulkley, Exh. AEB-1T at 15:1-4. Bulkley notes that the range of results for the proxy group companies, the relative risk of PSE's electric and natural gas operations in Washington as compared to

median-high results of her Discounted Cash Flow (DCF) model, forward-looking Capital Asset Pricing Model (CAPM) and Empirical CAPM (ECAPM) analyses, a Bond Yield plus Risk Premium analysis, and an Expected Earnings analysis.[185] Bulkley also argues that recent inflationary pressures are another key component that will increase the long-term interest rates.[186] PSE requested an ROE of 9.90 percent for each of the three years of the proposed MYRP, and Bulkley supported this as a reasonable request.[187]

131 In response testimony, Staff, AWEC, Walmart, and Public Counsel witnesses argued in favor of a lower ROE for the Company.[188] Because Staff, AWEC, and Walmart later joined the Revenue Requirement Settlement and came to support its proposed ROE of 9.40 percent,[189] we focus only on Public Counsel's response testimony.

132 Specifically, Public Counsel witness Woolridge testifies in favor of an ROE of 8.80 percent.[190] Woolridge bases this recommendation primarily on the results of his DCF and CAPM analyses, which indicated a common equity cost range of 7.40 to 8.90 percent.[191] Woolridge also argues that interest rates and capital costs have remained at historically low levels,[192] and that PSE's risk profile is similar to other electric utility companies.[193]

---

the proxy group, and current capital market conditions were considered to arrive at that conclusion. By the time testimony was written, economic projections indicated a strong economic recovery in 2022. *See* Bulkley, Exh. AEB-1T at 15:9-17:2. However, accommodative monetary policies to counter the effects of the COVID-19 pandemic in 2020 were gradually dialed down in 2021. *See* Joint Testimony, Exh. CGP-AEB-TAS-1JT at 13:14-18. A number of analysts expect utilities to underperform in the broader market as interest rates increase. *Id.* at 18:3-4.

See also Peterman, Exh. CGP-1CT at 40:15-21. Peterman argues that PSE's ROE should be increased to 9.90 percent: (1) to allow PSE to earn a fair and competitive rate of return in line with its peers; (2) to adequately compensate PSE for risks it is currently facing to fund critical operational programs for the benefit of customers, including investments to enable PSE to provide safe and reliable service to its customers and make CETA-required investments; (3) to begin to replace losses of cash flow due to legislative changes (such as the TCJA); and (4) to help improve and stabilize PSE's credit profile.

[185] Bulkley, Exh. AEB-1T at 7:10-14.

[186] The Company's inability to reflect increasing costs between rate cases will affect credit metrics.

[187] Bulkley, Exh. AEB-1T at 4:4-5.

[188] *See generally* Parcel, Exh. DCP-1T. *See also* Mullins, Exh. BGM-1T at 10:17-12:13. Kronauer, Exh. AJK-1T at 8:1-8, 16:15-22.

[189] *E.g.*, Erdahl, Exh. BAE-1T at 5:14-22 (supporting the Settlement's ROE of 9.40 as reasonable, consistent with the public interest, and consistent with Parcell's earlier response testimony).

[190] Woolridge, Exh. JRW-1T at 92:4-6.

[191] *E.g.*, *id.* at 91:20-92:4.

[192] *Id.* at 6:15-18.

[193] *Id.* at 7:8-11.

133 Woolridge also takes issue with Bulkley's earlier testimony. Woolridge argues that Bulkley overstates the results of her DCF analysis by relying exclusively on forecasts from Wall Street analysts and *Value Line* and by claiming that DCF results underestimate the cost of equity due to high utility stock valuations and low dividend yields.[194] He also argues that Bulkley errs by relying on an ECAPM version of the CAPM, which is premised on a relatively high market risk premium of 11.00 percent.[195] Woolridge raises concerns as well with Bulkley's use of the Risk Premium model, her Expected Earnings model, and her consideration of regulatory risk and PSE's capital expenditures.[196]

134 PSE filed joint testimony from its cost of capital witnesses supporting the Revenue Requirement Settlement. With regard to the Settlement's proposed ROE, Bulkley explains that she updated the results of the ROE analysis from her initial testimony and that the results of her ROE estimation models were well above the Settlement's ROE of 9.40 percent.[197] Bulkley notes, for example, that her Constant Growth DCF model provided a median constant growth average of 9.35 percent and a mean constant growth average of 9.67 percent.[198] Her CAPM model provided long-term average betas between 10.07 and 10.25 percent, and her ECAPM model provided long-term average betas between 10.78 and 10.93 percent.[199]

135 Bulkley disagrees with Woolridge's earlier criticisms of her ROE estimation models. Bulkley notes, for instance, that Woolridge criticized her reliance on analyst and *Value Line* growth forecasts to support her DCF model.[200] Yet she observes that Woolridge also gave primary weight to analysts' projected EPS growth rates in his own DCF model and that the average growth rate in Bulkley's analysis was only six basis points higher than the median of projected EPS growth rates Woolridge considered.[201]

136 Bulkley notes as well that interest rates have increased since the Company's initial filing, that interest rates are expected to continue to rise over the course of the MYRP, and that inflation

---

[194] *Id.* at 7:12-21.

[195] *Id.* at 8:1-5.

[196] *Id.* at 9:4-10:10.

[197] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 5:14-16.

[198] *Id.* at 21:1 (Figure 6: Updated ROE Results).

[199] *Id.*

[200] *Id.* at 25:6-8 (citing Woolridge, Exh. JRW-1T at 7, 44-45, 68, 70-71).

[201] *Id.* at 25:8-14.

has reached levels not seen in four decades.[202] They explain that these market conditions have a "direct and significant" effect on the ROE required by investors.[203] Bulkley explains that recently authorized ROEs fail to reflect recent increases in interest rates and likely understate the investor-required return in the current market.[204]

137 Bulkley characterizes Woolridge's ROE recommendation as unreasonably low and below the low-end range of authorized ROEs for any electric or natural gas distribution company since 2018.[205] She explains that the range of authorized ROEs for vertically-integrated electric companies has been 8.75 to 10.60 percent, with an average of 9.66 percent.[206] The range of authorized ROEs for gas distribution companies has been 9.10 to 10.25 percent, with an average of 9.63 percent.[207] She concludes that Woolridge's recommended ROE of 8.80 percent is lower than 99 percent of all authorized ROEs since 2018.[208]

138 Although Woolridge presents evidence of authorized ROEs from 2000 to 2021, Bulkley explains that Woolridge includes ROEs associated with electric distribution utilities.[209] He does not limit his proxy group to vertically-integrated utilities, such as PSE.[210] Bulkley also critiques Woolridge for including ROEs authorized reflecting limited issue rider proceedings, alternative forms of regulation, and penalties imposed by regulatory commissions.[211]

139 In its testimony opposing the Revenue Requirement Settlement, Public Counsel maintains its earlier recommendation for an ROE of 8.80 percent.[212] Rather than focus on Bulkley's testimony supporting the Settlement, Woolridge focuses on the earlier response testimony from Staff witness David C. Parcell, who at the time recommended an ROE of 9.25 percent.[213] Woolridge explains that "[t]he errors and inconsistencies associated with Parcell's 9.25

---

[202] *Id.* at 5:17-21. *See also id.* at 14:5-15 (noting, among other points, that "the 30-day average of the 30-year Treasury yield is currently nearly 120 basis points higher as of July 31, 2022, than when I filed my Direct Testimony . . .").

[203] *Id.* at 5:21-22.

[204] *Id.* at 8:6-10.

[205] *Id.* at 6:1-8.

[206] *Id.* at 8:16-17.

[207] *Id.* at 8:18-19.

[208] *Id.* at 9:1-5.

[209] *Id.* at 12:6-8.

[210] *Id.*

[211] *Id.* at 12:9-17.

[212] Woolridge, Exh. JRW-13T at 3:10-14.

[213] *Id.* at 2:1-6.

percent ROE recommendation also highlight how unreasonable the Settlement's 9.40 percent ROE recommendation is."[214]

140 Woolridge argues that Staff witness Parcell relied on non-traditional approaches to estimating the cost of equity and distorted his DCF model results.[215] He argues that Parcell's DCF and CAPM results actually support an ROE in the range of 8.50 percent.[216] Woolridge submits that Parcell's Comparable Earnings approach is a "model of his own creation" and that his interpretation of the results is "totally subjective."[217] Woolridge argues that Parcell's Risk Premium approach is similarly "a model of his own making," which is merely a gauge of state commission behavior.[218]

141 Woolridge contends that PSE's investment risk is on par with the three proxy groups,[219] and that capital costs and authorized ROE remain at historically low levels.[220] Also, Public Counsel affirms that investors' long-term expectation of inflation is about 2.5 percent.[221]

142 Finally, Public Counsel asserts that while interest rates have increased in 2022, authorized ROEs never reflected the historically low rates associated with the COVID-19 pandemic.[222]

143 In its post-hearing brief, PSE observes, "Over the course of this proceeding, market conditions have only worsened: inflation persists while interest rates continue to climb, making investors require greater returns than anticipated at the outset of this case."[223] These market conditions support the Settlement's proposed ROE of 9.4 percent, which the Company argues is a reduction from its initial filing but still adequate when viewed as part of this complex Settlement.[224] PSE notes that the Commission approved an ROE of 9.5 percent for Avista in

---

[214] *Id.* at 23:7-9. *See also id.* at 5:18.

[215] *Id.* at 5:20-6:1. *See also id.* at 9:5-10:16 (arguing that Parcell improperly gave weight to the mid-point of the range of his DCF model and that he fails to group data to address the errors-in-variables problem).

[216] Woolridge, Exh. JRW-13T at 6:2-3.

[217] *Id.* at 16:5-7.

[218] *Id.* at 21:9-13.

[219] Woolridge, Exh. JRW-13T at 4:16-17. *See also* Woolridge, Exh. JRW-1T at 25:1.

[220] Woolridge, Exh. JRW-13T at 5:2.

[221] Woolridge, Exh. JRW-13T at 5:12.

[222] Woolridge, Exh. JRW-13T at 5:9.

[223] PSE Brief ¶ 41.

[224] *Id.*

2021, and contends that inflationary pressures and interest rate increases have only worsened since that time.[225]

144 PSE argues that Public Counsel is the only party to oppose the Settlement's proposed ROE and that Public Counsel's recommendation for a mere 8.8 percent is contrary to the principle of gradualism.[226]

145 Staff argues that the Revenue Requirement Settlement leaves the Company's authorized ROE in place.[227] Staff submits that this is a reasonable compromise considering the "risk-lowering" effects of the MYRP and the "risk-raising" effects of inflation and tightening monetary policy.[228] By comparison, Staff characterizes Public Counsel's lower recommendation as "facially unreasonable" and tantamount to "shock therapy."[229]

146 In its brief, Public Counsel argues that while authorized ROEs for utilities have declined since 2007, utility ROEs continue to be higher than the market-based cost of capital, and utility ROEs have not declined to the same extent as U.S. Treasury yields.[230] Public Counsel notes Woolridge's earlier objections to Parcell's DCF and CAPM models, and it argues that Parcell's ROE recommendation is only supported by his unorthodox and subjective Risk Premium and Comparable Earnings models.[231] Public Counsel maintains that Parcell's DCF and CAPM models support a lower ROE of 8.5 percent, well below the amount proposed in the Settlement.[232]

147 *Commission Determination.* After considering all of the testimony and evidence concerning PSE's cost of capital, we accept the Revenue Requirement Settlement's proposed ROE of 9.40 percent. We find that the Settling Parties' agreement on PSE's ROE is lawful, supported by an appropriate record, and consistent with the public interest.[233] We agree, in effect, with

---

[225] *Id.* ¶ 45 (citing *WUTC v. Avista Corporation d/b/a Avista Utilities*, Dockets UE-200900, et al., Final Order 08/05 ¶ 73 (September 27, 2021)).

[226] *Id.* ¶ 42.

[227] Staff Brief ¶ 40.

[228] *Id.*

[229] *Id.* ¶ 41.

[230] Public Counsel Brief ¶¶ 61-63.

[231] *Id.* ¶¶ 67-68.

[232] *Id.* ¶ 68.

[233] *See* WAC 480-07-750(2) (providing the Commission's standard for evaluating settlements).

the Settling Parties that PSE's ROE should be maintained at the same level as authorized in the Company's last general rate case.[234]

148 When evaluating a utility's ROE, the Commission follows the long-standing precedents set by the *Hope* and *Bluefield* decisions.[235] In *Hope* and *Bluefield*, the United States Supreme Court recognized that rates for regulated monopoly utilities must incorporate a fair rate of return on equity that is comparable to returns investors would expect to receive on other investments of similar risk, sufficient to assure confidence in the utility's financial integrity, and adequate to attract capital at reasonable costs.[236]

149 The Commission's long-standing practice is first to identify within the range of *possible* returns shown by expert analyses a range of *reasonable* returns on equity considering all cost of capital testimony in the record. Then, the Commission weighs the analysts' more detailed results and considers other evidence relevant to the selection of a specific point value within the range. The Commission's final determination of an acceptable ROE recognizes fully the guiding principles of regulatory ratemaking that require us to reach an end result that yields fair, just, reasonable, and sufficient rates. Public Counsel has not established that the Revenue Requirement Settlement's proposed ROE of 9.40 percent is inconsistent with the public interest or otherwise should be rejected.

150 The Commission benefits significantly from the different perspectives of the witnesses in making their recommendations. However, we must carefully balance their results to establish the end points of a zone of *reasonable* returns within which we can select a specific ROE point value, considering both the modeling and other factors in evidence. The witnesses do not dispute that determining an appropriate ROE presents challenges. As discussed above, they rely on familiar analytic tools such as the DCF, CAPM, Risk Premium, and Comparable Earnings methods. As is customary, they use a variety of data sources to populate their models to arrive at and support their respective ROE recommendations. Accordingly, as we have noted in previous proceedings, the results of the analytic models the expert witnesses use to estimate ROE can vary due to judgments they make when selecting specific approaches and data inputs for each model.[237]

---

[234] *See* 2019 PSE GRC Order ¶ 108 (approving an ROE of 9.40 percent).

[235] *See Fed. Power Comm'n v. Hope Nat. Gas*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Virginia*, 262 U.S. 679 (1923).

[236] *Hope Nat. Gas,* 320 U.S. at 603.

[237] *E.g., WUTC v. Puget Sound Energy*, Dockets UE-170033 and UG-170034 Order 08 ¶ 86 (December 5, 2017).

151 When considering changes to a regulated utility's authorized ROE, we endeavor to avoid material adjustments upward or downward in authorized levels to provide rate stability for customers and assurance to investors and others regarding the regulatory environment's support for the financial integrity of the utility. Based on the evidence produced by the various expert witnesses, we generally determine whether modest increases or decreases, if any, to currently authorized levels are appropriate given the evidence produced in the immediate proceeding.

152 Based on their individual analyses and modeling, the witnesses establish wide ranging ROE results. The parties' overall ROE recommendations span 110 basis points between the lowest recommendation of 8.8 percent and the highest recommendation of 9.9 percent.[238] This reflects the end points of the range of *possible* returns in the record.

153 We then turn to an evaluation of the various analytical methods broadly employed by each expert witness to establish a narrower *range of reasonableness*, and ultimately determine an appropriate ROE.

154 We begin with a review of the expert witnesses' application of the DCF method, "the method to which the Commission generally has afforded material weight in determining a company's authorized ROE."[239] PSE witness Bulkley describes a range of results for the constant growth DCF model. The mean low for Bulkley's proxy group ranges from 8.52 to 8.57 percent, and the mean high ranges from 10.07 to 10.15 percent.[240] In Settlement supporting testimony, Bulkley updates this analysis and arrives at a mean low of 8.97 to 9.07 percent and a mean high of 10.44 to 10.55 percent.[241] Staff witness Parcell notes a range of DCF results from a mean low of 7.00 percent to a mean high of 8.8 percent.[242] Parcell focuses on the highest of the DCF results, recognizing that these results are lower than historic DCF results.[243] Using a DCF model, Public Counsel witness Woolridge arrives at an equity cost rate of 8.80 percent

---

[238] *Compare* Woolridge, Exh. JRW-13T at 3:10-14 (recommending 8.8 percent) *with* Bulkley, Exh. AEB-1T at 4:4-5 (supporting the Company's request for 9.9 percent).

[239] *WUTC v. Avista Corporation d/b/a Avista Utilities*, Dockets UE-170485 and UG-170486 (consolidated) Order 07 ¶ 62 (April 26, 2018).

[240] Bulkley, Exh. AEB-1T at 45:1 (Figure 8).

[241] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 21:1 (Figure 6).

[242] Parcell, Exh. DCP-1T at 33:19-21.

[243] *Id.* at 34:12-14.

for the electric proxy group and 8.75 percent for the gas proxy group.[244] The expert testimony therefore describes a relatively wide, 355-basis point, range of DCF results.[245]

155 The CAPM method presents a slightly wider range of results. Bulkley's CAPM analysis produces a range of 9.56 percent to 11.72 percent.[246] Bulkley's ECAPM analysis produces a range between 10.41 percent and 12.03 percent.[247] In joint testimony supporting the Settlement, Bulkley updates the CAPM and ECAPM analyses to arrive at a range of results between 10.07 percent and 11.86 percent.[248] Staff witness Parcell's CAPM model provides a mean and a median result of 8.7 percent.[249] Public Counsel witness Woolridge arrives at a CAPM equity cost rate of 7.7 percent for the electric proxy group and 7.40 percent for the gas proxy group.[250] The expert witnesses' CAPM results therefore vary by 463 basis points.[251]

156 The two witnesses who provided Risk Premium analysis arrived at a narrower range of results. PSE witness Bulkley's Risk Premium analysis results in a range of recommended ROE's from 9.52 percent to 10.13 percent for electric utilities and 9.37 percent to 9.97 percent for gas utilities.[252] In testimony supporting the Settlement, Bulkley updates the Risk Premium analysis and arrives at a range between 9.90 and 10.10 percent for electric utilities and 9.86 to 10.13 percent for gas utilities.[253] Staff witness Parcell arrives at a range between 9.45 to 9.95 percent.[254] The Risk Premium method results therefore vary by 76 basis points.[255]

157 Applying the Expected Earnings or "Comparable Earnings" Method, Bulkley arrives at a mean of 11.19 percent and a median of 11.25 percent.[256] Bulkley updates these figures in joint

---

[244] Woolridge, Exh. JRW-1Tr at 50:17 (Table 7).

[245] 355 basis points describes the difference between Bulkley's highest result (10.55) and Parcell's lowest result (7.00).

[246] Bulkley, Exh. AEB-1T at 51:8-10.

[247] *Id.*

[248] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 21:1 (Figure 6).

[249] Parcell, Exh. DCP-1T at 41:12-14.

[250] Woolridge, Exh. JRW-1T at 62:12-15 (Table 8).

[251] Four hundred and sixty-three basis points describes the difference between Bulkley's highest result (12.03) and Woolridge's lowest result (7.40).

[252] Bulkley, Exh. AEB-1T at 55:3-14.

[253] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 21:1 (Figure 6).

[254] Parcell, Exh. DCP-1T at 4:4-5.

[255] Seventy-six basis points describes the difference between Bulkley's highest and lowest risk premium results (10.13 and 9.37 respectively).

[256] Bulkley, Exh. AEB-1T at 58:2-4.

testimony to a mean of 11.43 percent and a median of 11.55 percent.[257] Applying his own Comparable Earnings model, Parcell concludes that that an appropriate ROE for proxy utilities is between 9.0 percent and 10.0 percent, with a midpoint of 9.50 percent.[258] The Comparable Earnings method results therefore vary by 255 basis points.[259] We generally do not place material weight on the Comparable Earnings method, which is considered unreliable in other jurisdictions.[260] However, we have considered the results of the Comparable Earnings method when other cost of equity methods produce widely varying results.[261]

158 Based on our review of these four specific methods, we are presented with a range of returns between 7.0 percent and 12.03 percent. The record indicates significant disagreement among the expert witnesses as they attempt to account for investors' expectations during this period of changing market conditions.

159 We agree, however, with Parcell's opinion that the "range of reasonableness" falls between 9.0 percent and 9.5 percent.[262] This range of reasonableness is consistent with the most persuasive evidence in this case, which includes Parcell's DCF and CE model results.[263] We are persuaded by Parcell's decision to rely on the highest DCF results under the circumstances.[264] Parcell has explained that his DCF results are lower than historic results and that his recommendation based on this model should be considered "conservative." [265] The relatively lower DCF results are counterbalanced by Parcell's Risk Premium results, which support an ROE between 9.45 to 9.95 percent,[266] and by his Comparable Earnings results,

---

[257] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 21:1 (Figure 6).

[258] Parcell, Exh. DCP-1T at 47:15-16.

[259] Two hundred and fifty-five basis points describes the difference between Bulkley's highest CE result (11.55) and Parcell's lowest result (9.0).

[260] *See Assoc. of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator*, 169 F.E.R.C. ¶ 61,129, Opinion No. 569, ¶ 204 (2019) (finding that the CE method is "unable to effectively estimate the rate of return that investors require to invest in the market-priced common equity capital of a utility").

[261] *See WUTC v. Avista Corporation d/b/a Avista Utilities*, Dockets UE-170485 and UG-170486 (consolidated) Order 07 ¶ 65 (April 26, 2018) ("Although we generally do not apply material weight to the CE method, having stronger reliance on the DCF, CAPM and RP methods, we are inclined to include the CE method here given the anomalous CAPM results described previously.").

[262] *See* Parcell, Exh. DCP-1T at 54:9-11.

[263] *See id.* at 5:2-5 ("I further conclude that a reasonable range of ROE for PSE is 9.0 percent to 9.5 percent, which is more directly supported by the respective range of the results for the DCF model and CE method.").

[264] *See id.* at 34:12-14.

[265] *Id.* at 34:12-15.

[266] Parcell, Exh. DCP-1T at 4:4-5.

which support an ROE between 9.0 percent and 10.0 percent, with a midpoint of 9.50 percent.[267] Parcell places relatively greater reliance on the Comparable Earnings results compared to the Risk Premium results.[268] Given the widely-varying results from the witnesses' CAPM models, we agree that it is appropriate to consider and give weight to the results of both the Risk Premium and Comparable Earnings models in this case.

160 Although Bulkley's updated analysis suggests a higher cost of capital than Bulkley's direct testimony,[269] PSE has agreed to support the Revenue Requirement Settlement and no longer advocates for the higher ROE presented in its initial filing. The Settling Parties have reasonably arrived at an ROE of 9.40 percent, reflecting the give and take of negotiations.

161 After considering all of the testimony in the record, including the results of the DCF, RP, and CE models, we conclude that PSE's ROE should be maintained at 9.4 percent. An ROE of 9.4 percent is consistent with the results of Parcell's DCF model. It is below the range supported by Parcell's Risk Premium model and the mid-point of Parcell's CE analysis. The Settling Parties' agreement on this issue is lawful, supported by an appropriate record, and consistent with the public interest.

162 We also consider the broader context of our decision. As the U.S. Supreme Court held in *Bluefield*, a utility is generally entitled to a rate of return "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . ."[270] Our decision is consistent with the ROE currently authorized for other investor-owned utilities in the United States. An ROE of 9.40 percent is consistent with the 2021 average and median authorized ROEs for electric utilities and actually falls below the 2021 average and median authorized ROEs for natural gas utilities.[271]

163 Our decision is also consistent with currently authorized ROEs for investor-owned utilities in Washington. In 2020, the Commission authorized an ROE of 9.4 percent for Puget Sound

---

[267] Parcell, Exh. DCP-1T at 47:15-16.

[268] *See id.* at 5:2-5.

[269] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 20:2-4.

[270] *Bluefield*, 262 U.S. at 692.

[271] *See* Parcell, Exh. DCP-1T at 11:14-12:4 (providing an average of 9.39 percent and a median of 9.39 percent for electric utility ROEs in 2021 and an average of 9.56 and a median of 9.60 for natural gas utilities in the same year). *See also* Erdahl, Exh. BAE-1T at 5:16-18 (observing that the Settling Parties proposed ROE is consistent with the median authorized ROE for other utilities).

Energy, Avista, and Northwest Natural Gas Company.[272] The Commission approved a settlement authorizing a slightly higher ROE for PacifiCorp at 9.50 percent.[273] More recently in 2022, we approved a settlement authorizing an ROE of 9.40 percent for Cascade.[274]

164 The Settlement appears all the more reasonable given recent changes in the market. As Bulkley explains, interest rates have increased since the Company's initial filing, and are expected to continue to rise over the course of the MYRP, while inflation has reached levels not seen in four decades.[275] Bulkley notes that these market conditions have a "direct and significant" effect on the ROE required by investors.[276] We therefore agree with the PSE and Staff that the Settlement is reasonable in light of these changing market conditions. As Staff observes, the Settlement is a reasonable compromise considering the "risk-lowering" effects of the MYRP against the "risk-raising" effects of inflation and tightening monetary policy.[277]

165 We are not persuaded by Public Counsel's arguments in favor of a lower ROE of 8.8 percent. Although Woolridge argues that Staff witness Parcell relied on non-traditional approaches to estimating the cost of equity and distorted his DCF model results,[278] we are persuaded by Parcell's testimony that his DCF results are lower than historic results and that his recommendation based on this model should be considered "conservative." [279] Parcell's recommended "range of reasonableness" is also supported by his Risk Premium and Comparable Earnings models.

---

[272] *See WUTC v. Avista Corp*., Dockets UE-190334, UG-190335, and UE-190222 (Consol.), Final Order 09 (Mar. 25, 2020) (approving a settlement that set Avista's ROE at 9.4 percent); *WUTC v. NW Nat. Gas Co.*, Docket UG-181053, Final Order 06 (October 21, 2019) (approving settlement that set NW Natural's ROE at 9.4 percent); *WUTC v. Puget Sound Energy*, Dockets UE-190529 and UG-190530, Final Order 08, ¶ 108 (July 8, 2020) (deciding on a ROE of 9.40 percent) (2019 PSE GRC Order).

[273] *WUTC v. Pacificorp, d/b/a Pacific Power and Light Company*, Docket UE-191024 *inter alia* Order 09 ¶¶ 50-57 (December 14, 2020).

[274] *WUTC v. Cascade Natural Gas Corporation*, Docket UG-210755 Final Order 09 ¶ 95 (August 23, 2022) ("This determination, in combination with the uncontested cost of debt of 4.59 percent and uncontested return on equity of 9.4 percent, results in an authorized rate of return of 6.85 percent . . .")

[275] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 5:17-21. *See also id.* at 14:5-15 (noting, among other points, that "the 30-day average of the 30-year Treasury yield is currently nearly 120 basis points higher as of July 31, 2022, than when I filed my Direct Testimony . . .").

[276] *Id.* at 5:21-22.

[277] Staff Brief ¶ 40.

[278] Woolridge, Exh. JRW-13T at 5:20-6:1. *See also id.* at 9:5-10:16 (arguing that Parcell improperly gave weight to the mid-point of the range of his DCF model and that he fails to group data to address the errors-in-variables problem).

[279] *Id.* at 34:12-15.

166 PSE's witness Bulkley also provides persuasive critiques of Woolridge's cost of capital analysis. Although Woolridge presents evidence of authorized ROEs from 2000 to 2021, Bulkley explains that Woolridge includes ROEs associated with electric distribution utilities.[280] He does not limit his proxy group to vertically-integrated utilities, such as PSE.[281] Bulkley also critiques Woolridge for including ROEs authorized reflecting limited issue rider proceedings, alternative forms of regulation, and penalties imposed by regulatory commissions.[282] Bulkley's testimony on these issues was not refuted by any persuasive evidence or argument.

167 We are persuaded by Bulkley testimony in support of the Settlement, which characterizes Woolridge's ROE recommendation as unreasonably low and below the low-end range of authorized ROEs for any electric or natural gas distribution company since 2018.[283] Bulkley concludes that Woolridge's recommended ROE is lower than 99 percent of all authorized ROEs since 2018.[284] This testimony is not persuasively refuted by Public Counsel, and it weighs against any recommendation for a lower ROE of 8.8 percent. Ultimately, we agree with PSE and Staff that Public Counsel's recommendation for an 8.8 percent ROE is unreasonable.[285]

168 We therefore agree with the Settling Parties that the proposed ROE should be accepted as lawful, supported by an appropriate record, and consistent with the public interest.[286] It is within the range of reasonableness established by the credible testimony and evidence. The Settlement is consistent with the authorized ROEs for other investor-owned utilities, and it is reasonable given changing market conditions. Although Public Counsel argues for a lower ROE, we have concerns with Woolridge's selection of companies for his proxy group and the reasonableness of his recommendation in light of authorized ROEs for other utilities.

I. The Infrastructure Investment and Jobs Act of 2021 and Inflation Reduction Act

169 We next consider the Revenue Requirement Settlement in light of two significant federal laws.

---

[280] Joint Testimony, Exh. CGP-AEB-TAS-1JT at 12:6-8.

[281] *Id.*

[282] *Id.* at 12:9-17.

[283] *Id.* at 6:1-8.

[284] *Id.* at 9:1-5.

[285] PSE Brief ¶ 42. *Accord* Staff Brief ¶ 41.

[286] *See* WAC 480-07-750(2) (providing the Commission's standard for evaluating settlements).

170 On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act of 2021 (IIJA) PL 117–58, 135 Stat 429 , which seeks to upgrade the nation's energy infrastructure for a clean, resilient, and secure energy future.[287] The IIJA funds over 350 programs to be overseen through more than a dozen federal departments and agencies.[288] On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA) PL 117–169, 136 Stat 1818, into law. 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.[289]

171 The impacts of these laws on rates are not yet known, but it is apparent that both could greatly impact PSE's utility operations during the MYRP agreed to by the Settling Parties. Many aspects of PSE's operations, costs, funding, and financial health may be impacted by these new laws, including extending investment tax credits, creating new tax credits, accelerated depreciation of clean electricity facilities, and extending tax credits for investment in certain energy properties, among other aspects.[290] The Biden administration announced additional

---

[287] https://www.energy.gov/ceser/articles/investing-secure-resilient-and-clean-energy-future.

[288] 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 [hereinafter IIJA Guidebook].

[289] 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/.

[290] Among other things, the IRA:

- 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 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.

funding to provide increased 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.[291] 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.[292]

172 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.[293] The impacts of tax credits and other financial provisions will result in changes that impact utility revenue requirements and, ultimately, changes in customers' bills. The IRA could bring significant reductions to energy costs for customers, up to $500 in energy bills savings per year.[294] 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,

---

[291] 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/.

[292] 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/.

https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate.

[293] *See, e.g.*, *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.

[294] 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/.

savings to customers will be provided in a one-time refund of $25 million in the month of January 2023.[295]

173 The Revenue Requirement Settlement in this case was filed just 10 days after the IRA was signed into law. The Settlement does not refer to the IIJA and only refers to the IRA in passing,[296] suggesting that the parties did not have an opportunity to consider the impacts of the IRA. 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. As discussed below in section II.I, we expect PSE to participate in a collaborative with other investor-owned utilities regarding the potential benefits of the IRA and IIJA and to document its consideration of, and application for, benefits provided pursuant to the IRA and IIJA in future filings. In addition, for any other IRA and IIJA benefits not addressed in this Order, we expect PSE will file with the Commission an accounting petition requesting to defer other benefits or revenue, as appropriate.

J. Energize Eastside

174 The Energize Eastside project consists of a new 230 kV to 115 kV transformer that will be served by approximately 16 miles of new high-capacity transmission lines on the east side of Lake Washington, from Redmond to Renton (the Eastside).[297] The project is split into two phases, the south phase and north phase. The south phase includes the development of the 230 kV to 115 kV Richards Creek substation in Bellevue and upgrading the Talbot Hill to Lakeside portion of the transmission line from 115 kV to 230 kV.[298] The north phase includes upgrading the Sammamish to Lakeside portion of the transmission line from 115 kV to 230 kV.[299]

175 The Revenue Requirement Settlement would allow PSE to recover $238 million in plant associated with its Energize Eastside project on a provisional basis, subject to later review and possible refund.[300] The Settling Parties agree to the following:

---

[295] *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.

[296] Revenue Requirement Settlement ¶¶ 66.e, 67.d.iv.

[297] Koch, Exh. DRK-1T at 43:9-15.

[298] *Id.*at 46:7-9.

[299] *Id.* at 46:9-11.

[300] *See* Revenue Requirement Settlement ¶ 23.m (incorporating PSE's estimated costs in the initial filing as set forth in Koch, Exh. DRK-1T at 47:4-7).

> The Settling Parties agree that delayed service dates for Energize Eastside are assumed to be incorporated into the agreed-upon revenue requirement above (*i.e.*, South Phase in service by October 2023 and North Phase in service by October 2024). The Settling Parties agree that estimated costs associated with Energize Eastside (as described in PSE's initial filing) may enter rates provisionally (on the updated timeline, outlined above), subject to refund. Settling Parties accept and will not challenge that PSE has met its threshold prudence requirement to demonstrate that the investment should be provisionally included in rates. Settling Parties may challenge the costs of the project in the review of investments after the plant is placed in service.[301]

176 CENSE opposes the Settlement on this issue and argues that the Energize Eastside project is not a prudent investment.[302] We therefore consider the testimony in favor and in opposition to this project.

177 In the Company's initial filing, PSE witness Dan'l R. Koch contends that the Energize Eastside project is needed to address transmission capacity deficiencies on the Eastside during peak periods, and that it will improve reliability for the Eastside communities and allow sufficient capacity for growth and development.[303] Koch argues that this project is necessary to meet North American Electrical Reliability Corporation (NERC) transmission planning standards, compliance with which is required to comply with the Clean Energy Transformation Act (CETA).[304]

178 NERC is the regulatory authority certified by the Federal Energy Regulatory Commission (FERC) to develop and enforce reliability standards. The NERC standards mandate that certain forecasts and studies must be completed to determine whether the system has sufficient capacity to meet expected loads now and in the future.[305] Absent sufficient capacity to meet foreseeable demand, Koch explains that federal regulations require PSE to use corrective action plans (CAPs), such as intentional load shedding (*e.g.*, rolling blackouts), to meet demand.[306] Koch states that in recent years, the need for the project has become even

---

[301] Revenue Requirement Settlement ¶ 23.m.

[302] *E.g.*, Revenue Requirement Settlement ¶ 4 (noting CENSE's opposition).

[303] Koch, Exh. DRK-1T at 43:17-21.

[304] Koch, Exh. DRK-1T at 48:3-14.

[305] Koch, Exh. DRK-1T at 49:14-50:14.

[306] Koch, Exh. DRK-1T at 45:1-8.

more urgent, and that PSE has exceeded transmission capacity on the Eastside in four of the last five summers.[307]

179 Koch explains that PSE considered alternatives to the Energize Eastside project. These included "non-wires" alternatives such as additional conservation, additional generation, demand response, and energy storage expansion, as well as "wires" alternatives, including expansion of transmission substations and transmission line upgrades.[308] After considering all of these alternatives, PSE concluded that the Energize Eastside project, with its 230kV/115kV transformer and 230kV transmission lines, was the most effective solution that met all criteria and complied with federal requirements.[309]

180 In response testimony, CENSE witness Richard Lauckhart argues that the Energize Eastside project is not a prudent investment because PSE has failed to meet each of the four factors historically used in determining prudence.[310]

181 Lauckhart submits that PSE has failed to meet its legal burden to prove that the project is necessary.[311] Lauckhart points to the Lauckhart-Schiffman load flow study, provided by CENSE to the Commission in connection with PSE's IRP Docket UE-160918, and argues that this study shows no transmission reliability problem on the Eastside.[312]

182 Lauckhart argues that PSE avoided providing evidence through data requests in support of PSE's analysis in this proceeding and that PSE "inappropriately relies on Critical Energy Infrastructure Information (CEII) arguments and confidentiality arguments to refuse to provide the solid verifiable facts demonstrating project need."[313] Lauckhart points to the Commission's Acknowledgment Letter from PSE's 2016 IRP, in which the Commission identified a lack of narrative in the plan surrounding PSE's choice not to provide modeling data to interested parties with CEII clearance from FERC.[314] He affirms that without that information for inspection, there can be no finding of prudency for Energize Eastside.[315]

---

[307] Koch, Exh. DRK-1T at 43:17-44:6.

[308] Koch, Exh. DRK-1T at 56:2-11.

[309] *Id.* at 61:3-12.

[310] Lauckhart, Exh. RL-1T at 17:1-20.

[311] *Id.* at 6:16.

[312] Lauckhart, Exh. RL-1T at 25:23-39.

[313] Lauckhart, Exh. RL-1T at 17:4-7.

[314] Dockets UE-160918 & UG-160919, Puget Sound Energy 2017 IRP, WUTC Acknowledgment Letter Attachment p.10.

[315] Lauckhart, Exh. RL-1T at 9:16-17.

183 Additionally, Lauckhart argues that PSE has made no legitimate effort to study appropriate alternatives.[316] He identifies four alternatives that CENSE asserts "are much better than building Energize Eastside."[317] These include (1) using the existing Seattle City Light 230kV line located to the west of the proposed Energize Eastside transmission line; (2) looping the existing Bonneville Power Administration (BPA) 230kV line though the Lake Tradition switching station; (3) installing a small peaker power plant near the City of Bellevue; and (4) utilizing Demand Side Management (DSM) programs.[318]

184 Lauckhart also argues that there has not been adequate communication between PSE management and PSE's Board of Directors, based on PSE's answers to data requests.[319] Lauckhart further submits that decisions made by the Company have not been properly documented, arguing that PSE has refused to provide necessary information to allow for proper investigation as to why the project is needed and why the conclusions of the Lauckhart-Schiffman load flow study are not correct.[320] Finally, Lauckhart expresses safety concerns regarding Energize Eastside's shared right-of-way with the Olympic Pipeline, pointing to the Olympic Pipeline explosion in Bellingham in 1999.[321]

185 In testimony supporting the Revenue Requirement Settlement, Koch provides additional testimony regarding the studies performed by PSE and its examination of alternatives. Koch argues that its studies have identified the need for Energize Eastside since 2009.[322] Koch maintains that these studies were conducted in accordance with NERC Transmission Planning Standard (TPL) TPL-004-1, which requires utilities to evaluate its transmission system annually and to identify deficiencies where the system is unable to meet its performance requirements. [323] PSE also contracted with Quanta to perform studies specifically for the transmission system serving the Eastside area to confirm the results of PSE's annual TPLs.[324] This collaboration resulted in the 2013 and 2015 Energize Eastside Needs Assessment studies,

---

[316] Lauckhart, Exh. RL-1T at 17:8-10.

[317] Lauckhart, Exh. RL-1T at 27:7-9.

[318] *Id.* at 27:12-28:15.

[319] *Id.* at 17:11-16.

[320] Lauckhart, Exh. RL-1T at 17:17-20.

[321] Lauckhart, Exh. RL-1T at 20:2-15.

[322] Koch, Exh. DRK-26T at 7:7-10.

[323] *Id*.

[324] *Id.* at 7:10-12.

which PSE asserts has been reviewed by multiple third-party experts as part of the siting and permitting process with local municipalities.[325]

186 Koch also addresses the Lauckhart-Schiffman study, which CENSE uses as its primary evidence to support its arguments for the lack of need for Energize Eastside. Koch provides excerpts from the hearing examiners from Bellevue and Newcastle, who both found that the Lauckhart-Schiffman study was not credible.[326] Koch notes that the City of Newcastle hired and conducted its own independent third-party assessment of need with MaxETA Energy as part of the land use permitting process.[327] This assessment found that a need exists in the Energize Eastside area.[328]

187 Koch then addresses the four alternatives identified by Lauckhart, and argues that all these alternatives have been identified and studied as part of the above-mentioned studies.[329]After weighing these alternatives, PSE concluded that Energize Eastside is the best solution.[330]

188 Koch explains that all associated state and federal permits have been issued for the project and that four of the five Conditional Use Permits (CUPs) have been issued by local jurisdictions. Only the CUP for the north half of the Bellevue segment remains to be issued.[331]

189 In testimony opposing the Revenue Requirement Settlement, CENSE witnesses reiterate their objections to the Energize Eastside project. CENSE witness Norm Hansen argues, for example, that PSE could have requested a permit from the Energy Facility Site Evaluation Council (EFSEC) rather than “the long and arduous journey of time and substantial economic and labor expense” of seeking siting approval from the individual municipalities.[332] Hansen argues that PSE could have contained costs for the Energize Eastside project by seeking

---

[325] Koch, Exh. DRK-26T at 7:17-8:7.

[326] Koch, Exh. DRK-26T at 9:13-10:3.

[327] *E.g.*, Koch, Exh. DRK-26T at 5:20-6:2.

[328] Koch, Exh. DRK-26T at 5:20-6:5. *See also* Koch, Exh. DRK-12 (City of Newcastle by MaxETA Energy (June 2020)).

[329] Koch, Exh. DRK-26T at 13:6-14.

[330] Koch, Exh. DRK-26T at 11:24-12:9.

[331] Koch, Exh. DRK-26T at 14:11-17.

[332] Hansen, Exh. NH-1T at 5:1-14.

required permits through EFSEC,[333] and that Staff should have conducted its own technical need load flow study to confirm the need for this project.[334]

190 Lauckhart argues that the Revenue Requirement Settlement departs from longstanding Commission practice by allowing an investment into rates before the Company has provided the final system design and before the Company establishes the prudence of the investment.[335] Lauckhart argues that Staff has not identified errors with Lauckhart's earlier testimony,[336] and that Staff only has excerpts from PSE's Transmission Planning Assessments.[337] Lauckhart also takes issue with the Settling Parties' proposal to include the Energize Eastside project in rates on a provisional basis, arguing that a refund would not make customers whole.[338] He argues that the Settlement's reference to a "threshold prudence requirement" is not defined and departs from longstanding Commission policy.[339]

191 In its post-hearing Brief, PSE characterizes the provisional recovery, on a slightly delayed basis, for the Energize Eastside project as a "key component" of the Revenue Requirement Settlement.[340] PSE "requests a determination from the Commission that PSE's analysis of the need for the project and consideration of alternatives was reasonable . . . " indicating that this is consistent with the Settlement.[341] PSE submits that the project will promote the public interest by improving reliability for customers and by making reasonable adjustments to service dates to reflect the current construction schedule.[342]

192 Staff argues that the Commission should reject CENSE's arguments and allow PSE to recover Energize Eastside on a provisional basis.[343] Staff observes that CETA allows for the recovery of investments on a provisional basis and that the Settlement's treatment of Energize Eastside

---

[333] *Id.* at 5:10-11.

[334] *Id.* at 5:19-20.

[335] Lauckhart, Exh. RL-35T at 6:1-5.

[336] *Id.* at 7:7-8.

[337] *Id.* at 7:14-15.

[338] *See id.* at 9:3-15.

[339] Lauckhart, Exh. RL-35T at 10:5-11.

[340] PSE Brief ¶ 56.

[341] *Id.*

[342] *Id.* ¶ 71.

[343] Staff Brief ¶ 57.

"are fully consistent with CETA's changes to the law, the Commission's policy statement, and with the public interest . . ."[344]

193 Staff disputes CENSE's factual arguments as well. Staff observes that the legislature tasked the Commission with regulating electric companies to prevent events such as load shedding.[345] Staff notes that PSE considered both "wires" and "non-wires" alternatives and that none of these options were more cost-effective.[346]

194 In its Brief, CENSE maintains that PSE has not established that the Energize Eastside project meets the four factors relied on by the Commission for prudency review.[347] CENSE also argues that the "7 fatal flaws" identified in the Lauckhart-Schiffman study are "unrebutted" in this proceeding.[348]

195 *Commission Determination*. We accept the Settling Parties proposal for provisional recovery of the Energize Eastside on a slightly delayed basis. The Settling Parties present a proposal that is consistent with CETA and the Commission's Used and Useful Policy Statement to implement the statutory changes in CETA. CENSE's objections are contrary to the opinions of third-party experts, fail to account for contrary evidence, and fail to account for recent statutory changes.

196 Pursuant to CETA, specifically RCW 80.04.250, the Commission possesses the authority to determine the value of any utility property used and useful for service "by or during the rate effective period."[349] The Commission may approve changes to rates up to 48 months after the rate-effective date, while establishing a process to identify, review, and approve property that came into service after the rate effective date.[350]

---

[344] *Id.* ¶ 58.

[345] *Id.* ¶ 59.

[346] *Id.* ¶ 60.

[347] CENSE Brief ¶ 4.

[348] *Id.* ¶¶ 4-5 (noting that the "fatal flaws" include (1) the shutting down of 6 natural gas fired generators in the PSE/Quanta load flow studies, (2) assuming the proposed I-5 Corridor Reinforcement Project would be completed, (3) not allowing nearby 230/115 kV transformers to serve Eastside load in modelling, (4) a false assumption regarding the transmission of 1,500 MW of power to flow to Canada, (5) using the wrong rating of transformers and transmission line segments in load flow studies, (6) assuming Eastside demand will grow over the next 10 years, and (7) not simulating reasonable alternatives to Energize Eastside).

[349] RCW 80.04.250(2).

[350] RCW 80.04.250(3).

197 Senate Bill 5295 further modifies the Commission's authority to value utility property. Pursuant to RCW 80.28.425(3)(b), the Commission shall determine the fair value for rate-making purposes of the utility's property that will be used and useful in each year of the MYRP.[351] For the first year of any MYRP, the Commission shall "at a minimum" determine the fair value of any property that is used and useful as of the rate effective date.[352] The Commission may also order refunds if property is not used and useful by the rate effective date as expected.[353]

198 In the Used and Useful Policy Statement, the Commission has established a process to identify, review, and approve property coming into service after the rate effective date, as required by CETA. The Used and Useful Policy Statement is concerned with "the process the Commission will use to value property (investment or plant) that is, or will become, used and useful by or during the rate effective period," which may encompass a single year, a MYRP, or any single year within a MYRP.[354]

199 The Policy Statement affirms that the Commission intends to follow its longstanding practices by using a modified historical test-year, considering post-test year rate-adjustments using the known and measurable standard, employing the matching principle, and applying the used and useful standard.[355] It also provides a process for the provisional recovery in rates of property, subject to refund.[356] "Under this process, we make our final decision on rate recovery in a future period after sufficient information about the property in question has become available."[357]

200 As an overall matter, we find that the Revenue Requirement Settlement's terms regarding Energize Eastside are consistent with RCW 80.04.250, the MYRP statute RCW 80.28.425, and the Used and Useful Policy Statement. The Settlement merely provides that PSE may begin to recover the costs of this project on a provisional basis, subject to later review and possible refund, if warranted.[358] This provision is consistent with recent statutory changes and the Commission's guidance implementing these changes.

---

[351] *Id.* (citing RCW 80.04.250).

[352] *Id.*

[353] RCW 80.28.425(3)(b).

[354] Used and Useful Policy Statement ¶ 19.

[355] Used and Useful Policy Statement ¶ 21.

[356] Used and Useful Policy Statement ¶ 20.

[357] *Id.*

[358] Revenue Requirement Settlement ¶ 23.m.

201 We agree with the Settling Parties that PSE has brought forward sufficient evidence to establish that this investment may be included in rates. The Used and Useful Policy Statement explains that the "[t]he threshold for including provisional pro forma adjustments will be determined on a case-by-case basis according to the specifications of the rate-effective period investment."[359] Including rate-period effective investment in rates is an exercise of the Commission's discretion, and it involves careful judgments depending on the facts of each case. The evidence in this case shows that the Settling Parties have reasonably evaluated and agreed to the recovery of this investment on a provisional basis.

202 The Settling Parties, for example, have paid attention to the timing of PSE's recovery. Identifying when an investment will become used and useful is an important consideration, particularly in the context of an MYRP.[360] In this case, the Settling Parties have provided for slightly delayed recovery of Energize Eastside in light of the current construction schedule.[361] This is consistent with our earlier guidance and helps establish the reasonableness of the proposed provisional recovery in this MYRP.

203 We turn next to the issue of the prudency of Energize Eastside. Although this issue is discussed at length by both PSE and CENSE, the Used and Useful Policy Statement indicates that this issue is not fully ripe for determination. In the Policy Statement, the Commission explained that "in most cases the Commission will not confirm or verify such property as known and measurable, used and useful, or otherwise conforming to the Commission's ratemaking standards before the property is included in rates."[362] Allowing provisional recovery does not amount to "pre-approval of the prudency of the investment."[363] In accordance with this guidance, the Commission will decline to fully confirm the prudency of Energize Eastside until a later proceeding, after this project is included in rates.

204 Given the extensive efforts of the parties, however, we find it appropriate to discuss the evidence of prudency that has been presented. As the Commission has observed, "Overall, the Commission's prudence standard is a reasonableness standard."[364] The test "is what would a reasonable board of directors and company management have decided given what they knew

---

[359] *Id.* ¶ 35.

[360] *Id.* ¶ 36.

[361] *See* Revenue Requirement Settlement ¶ 23.m.

[362] Used and Useful Policy Statement ¶ 38.

[363] *Id.* ¶ 44.

[364] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-110148 & UG-111049 Order 08 ¶ 408 (May 7, 2012) (internal citation and quotation omitted).

or reasonably should have known to be true at the time they made a decision."[365] Although there is no "single set of factors," the Commission "typically focuses on four factors."[366] These are:

1) *The Need for the Resource:* The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.

2) *Evaluation of Alternatives:* The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.

3) *Communication With and Involvement of the Company's Board of Directors:* The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.

4) *Adequate Documentation:* The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[367]

205 In this proceeding, PSE "requests a determination from the Commission that PSE's analysis of the need for the project and consideration of alternatives was reasonable . . ." and PSE submits that this is consistent with the Settlement.[368] CENSE, however, argues that PSE has failed to establish the prudency of Energize Eastside according to each of the four factors.[369]

206 Regarding the first factor, we agree that PSE has demonstrated a need for Energize Eastside. As PSE witness Koch explains, in five of the past six summers, the demand has exceeded the

---

[365] *Id.*

[366] *Id.* ¶ 409.

[367] *Id.*

[368] PSE Brief ¶ 56.

[369] CENSE Brief ¶ 4.

reliability threshold for transmission capacity on the eastside.[370] It is expected that demand will continue to increase.[371] Koch explained at the settlement hearing, as well, that in the summer of 2020 PSE was "one event away from needing to load shed," *i.e.*, needing to intentionally shut off power to certain customers, due to the transmission deficiency on the Eastside.[372]

207 PSE's testimony on this issue is supported by credible evidence of record, which includes the 2009 NERC reliability assessment, a needs assessment report conducted in 2013 and updated in 2015 in consultation with Quanta Technology, [373] and reviews conducted by third-party experts.[374] FERC has also found that PSE complied with applicable transmission planning requirements.[375]

208 CENSE's arguments to the contrary are not persuasive. As Koch explains, the Lauckhart/Schiffman report fails to appropriately stress the system because it appears to have only studied one contingency, uses incorrect load growth for the Eastside area, does not perform a summer analysis, and erroneously interprets power flows to Canada.[376] The City of Newcastle and the City of Bellevue have both rejected CENSE's evidence as lacking in credibility.[377] We also find CENSE's arguments difficult to accept given the evidence of actual demand exceeding reliability thresholds.

209 CENSE continues to maintain that the "7 fatal flaws" identified in the Lauckhart-Schiffman study are "unrebutted" in this proceeding.[378] However, a party does not convince the Commission by simply ignoring contrary evidence and asserting that its position is unrebutted. As we have detailed in the preceding paragraphs, FERC, the City of Newcastle,

---

[370] Koch, Exh. DRK-26T at 9:1-4; Koch, Exh. DRK-1T at 44:1-6.

[371] Koch, Exh. DRK-1T at 44:7-45:11.

[372] Koch, TR 404:13-405:5.

[373] Koch, Exh. DRK-1T at 48:16-49:12.

[374] *See* Koch, Exh. DRK-10 (City of Bellevue Utility System Efficiencies (2015)); Koch, Exh. DRK-11 (Stantec Consulting Services, Inc. Review Memo (2015)); Koch, Exh. DRK-12 (City of Newcastle by MaxETA Energy (June 2020)).

[375] Coalition of Eastside Neighborhoods for Sensible Energy, et. al. v. Puget Sound Energy et. al., Dkt. EL15-74-000, 153 FERC ¶ 61,076 at ¶ 61 (Oct. 21, 2015) (finding PSE complied with applicable transmission planning requirements).

[376] Koch, Exh. DRK-26T at 9:11-10:17 (discussing concerns with the Lauckhart-Schiffman report).

[377] Koch, Exh. DRK-28 at 4 (City of Newcastle Hearing Examiner) (noting that "[n]o credible evidence was presented refuting the operational need for the Project"); Koch, Exh. DRK-27 at 4 (City of Bellevue Hearing Examiner finding CENSE reports defective and not credible).

[378] CENSE ¶¶ 4-5.

and the City of Bellevue rejected the Lauckhart-Schiffman study for lacking credibility. FERC specifically critiqued CENSE's "vague" allegations and found that PSE complied with applicable requirements.[379] Koch also identifies specific concerns with the Lauckhart-Schiffman study, which, somewhat ironically, CENSE fails to rebut.[380] CENSE instead focuses on certain distinctions and procedural arguments, which have little to do with the substance of the Lauckhart-Schiffman study, fail to rebut PSE's criticisms, and fail to demonstrate any prejudice to CENSE in this proceeding.[381] CENSE's position is a relative outlier, failing to account for contrary evidence and arguments, and contrary to the opinions of third-party experts. The evidence establishes a need for expanding PSE's transmission on the Eastside, and this issue does not appear to be in genuine dispute according to any of the credible evidence.

210 We also agree that PSE sufficiently considered alternatives to the Energize Eastside project. CENSE argues that PSE has not identified and studied four alternatives, referring to (1) Seattle City Light eastside lines, (2) Lake Tradition Transformer, (3) 50 MW peaker plant, and (4) demand side management.[382] Yet the Company evaluated each of these alternatives and found that they were either not viable or more expensive than the Energize Eastside project.[383] Although CENSE broadly claims that "any of these four alternatives would have been lower cost,"[384] CENSE again ignores the evidence that is contrary to its claims.

211 We defer any finding as to the third prudency factor, communication with the Board of Directors. PSE specifically requests a determination on the first and second prudency factors.[385] We find it reasonable to defer any final determination as to the third factor until a later proceeding, when the Commission reviews the prudency of Energize Eastside costs recovered on a provisional basis.

---

[379] Koch, Exh. DRK-26T at 10:1-8.

[380] *Compare* Koch, Exh. DRK-26T at 10:9-17 (identifying concerns with the Lauckhart-Schiffman study) *with* Lauckhart, Exh. At 4:20-6:3 (failing to respond directly to the concerns noted by Koch).

[381] *See id.* (asserting that the Lauckhart-Schiffman study "refutes all of Mr. Koch's criticism", that municipal permitting decisions did not address the prudency of Energize Eastside, and that PSE convinced hearing examiners that CENSE should not be given load flow files).

[382] *E.g.*, CENSE Brief ¶ 9.

[383] Koch, Exh. DRK-5r; Koch, Exh. DRK-6r; Koch, Exh. DRK-21.

[384] CENSE Brief ¶ 9.

[385] *E.g.*, Koch, Exh. DRK-1T at 46:17-20 ("PSE requests that the Commission determine that the Energize Eastside project is prudent—specifically that there is a need for the transmission capacity and the Energize Eastside project is a reasonable alternative to meet the need, when considering the alternatives."). *Accord* PSE Brief ¶ 56.

212 Nonetheless, we should make clear that we are not persuaded by any of CENSE's arguments regarding the third prudency factor, i.e., the involvement of PSE's Board of Directors in the decision-making process. In its Brief, PSE addresses this factor and argues that "[n]o party to this proceeding suggested that PSE failed to meet its burden of keeping contemporaneous documentation in the consideration and construction of Energize Eastside."[386] This is not an entirely accurate characterization given CENSE's position. Lauckhart argues, briefly, that there has not been adequate communication with PSE's Board of Directors, based on PSE's answers to data requests.[387] However, Lauckhart does not explain this assertion further or provide the data requests at issue.[388] Lauckhart also suggests that a prudent owner, purchasing a controlling share in PSE in 2018, would have negotiated to eliminate Energize Eastside from the purchase price.[389] This argument is unsupported by any persuasive detail and assumes that CENSE's other arguments are accepted as true. We are not persuaded by any of these cursory challenges regarding the third prudency factor.

213 We also defer any determination on the fourth prudency factor, documentation of the project. It is appropriate for the parties and the Commission to review this issue in a later proceeding.

214 For the present time, however, we make clear that CENSE does not establish any valid objection based on PSE's documentation of its decisions. Although Lauckhart suggests that PSE has refused to provide necessary information to allow for proper investigation as to why the project is needed and why the conclusions of the Lauckhart-Schiffman load flow study are not correct,[390] CENSE did not file any motion to compel or establish any violation of the formal rules of discovery in this proceeding. At the settlement hearing, PSE witness Koch explained that CENSE requested CEII approval six months after the case began and that the Company held meetings and worked with CENSE to narrow the request.[391] CENSE has not undermined Koch's testimony on this issue. Given the credible evidence of need for Energize Eastside, which is confirmed by third-party experts, we are not persuaded by procedural arguments or accusations regarding underlying load flow data.

215 While CENSE raises other challenges to Energize Eastside, we are not persuaded to reject or modify the Revenue Requirement Settlement on the basis of any of them. For example, CENSE takes issue with the Settlement's use of the term "threshold prudency determination"

---

[386] PSE Brief ¶ 70.

[387] Lauckhart, Exh. RL-1T. at 17:11-16.

[388] *See* Lauckhart, Exh. RL-10 (providing PSE's responses to CENSE's data requests that generally do not concern communications with the Board of Directors).

[389] *Id.* at 18:23-19:3.

[390] Lauckhart, Exh. RL-1T at 17:17-20.

[391] Koch, TR 405:9-406:1.

and suggests that it should be struck from the Settlement.[392] This is not persuasive. CENSE simply fails to account for recent statutory changes and the Commission's guidance implementing those changes. Pursuant to RCW 80.04.250, the Commission may determine the value of any utility property used and useful for service "by or during the rate effective period" and may provide for subsequent rate changes based on rate-effective period investments.[393] The Used and Useful Policy Statement provides guidance on the provisional recovery of rate-period effective investments.

216 Despite what CENSE suggests, the Revenue Requirement Settlement is consistent with these statutory changes and policy guidance. The Settling Parties "accept and will not challenge that PSE has met its threshold prudence requirement to demonstrate that the investment should be provisionally included in rates."[394] This term is consistent with the Used and Useful Policy Statement, which contemplates a "threshold" determination before an investment is included in rates on a provisional basis.[395] The threshold determination involves an exercise of discretion in each case, but it is only logical that the parties and the Commission would make some initial evaluation of the need for and prudency of a new resource before stipulating to its inclusion in rates on a provisional basis.[396] The Commission itself also has a duty to ensure that proposals for provisional recovery of investments are consistent with ratemaking principles and the public interest. If there was no "threshold" prudency evaluation, this would imply that prudency would be *irrelevant* in requests for provisional recovery or that the prudency evaluation would *end* with the approval of provisional recovery. Either outcome would be illogical, contrary to the Used and Useful Policy Statement, and contrary to the public interest.

217 CENSE also faults PSE for choosing to proceed with permitting through local municipalities, rather than the Energy Facility Site Evaluation Council (EFSEC). This is ultimately a Company management decision that we are not willing to second-guess.

218 CENSE also suggests that Energize Eastside raises safety and environmental concerns. This position is difficult to credit. Transmission lines are already running through this corridor, and

---

[392] CENSE Brief ¶¶ 11-14.

[393] RCW 80.04.250(2). *See also* RCW 80.28.425(3)(b) (providing for recovery of rate-period effective investments in MYRPs).

[394] Revenue Requirement Settlement ¶ 23.m.

[395] Used and Useful Policy Statement ¶ 35 ("The threshold for including provisional pro forma adjustments will be determined on a case-by-case basis according to the specifications of the rate-effective period investment.").

[396] *Cf.* Public Counsel Brief ¶ 18 (observing in the context of the Tacoma LNG Facility, "If an investment is not prudent, it should not be included in rates, even on a provisional basis).

safety and environmental considerations were considered in the Environmental Impact Statement (EIS).[397]

219 We therefore find it appropriate to approve the Revenue Requirement Settlement's terms regarding the Energize Eastside project. PSE has established that there is a need for the project and that it appropriately evaluated alternatives. As with any provisional recovery, however, the Commission will review the prudency of costs and make a final prudency determination in a future proceeding.

K. Significant Uncontested Issues

i. Corporate Capital Planning

220 The Revenue Requirement Settlement requires PSE to incorporate equity considerations at several different points in its capital planning process. It sets forth several concrete steps for the Company to incorporate equity in its planning processes. Those steps were not included in the initial filing.

221 PSE witness Catherine A. Koch describes the Company's Delivery System Planning as an engineering function that evaluates operating needs according to five basic steps, which include the use of the Investment Decision Optimization Tool (iDOT).[398] Koch also describes the Company's process for Corporate Spending Authorizations (CSAs).[399] At the time of the initial filing, the Company was still evaluating how to weight benefits associated with equity, named populations,[400] and carbon impacts.[401]

222 PSE witness Joshua A. Kensok provides further background on capital allocation and business planning processes.[402] He explains that the Company's five-year business plan forms the basis for its MYRP.[403] PSE witness Roque B. Bamba also describes the Project Lifecycle Model used for program management.[404]

---

[397] PSE Brief ¶ 73 (citing Koch, Exh. DRK-17 at 18).

[398] *E.g.*, Koch, Exh. CAK-1Tr2 at 11:15-12:2.

[399] Koch, Exh. CAK-1Tr2 at 13:14-14:2.

[400] *See* Jacobs, Exh. JJJ-3 at 67 (defining "highly impacted communities" and "vulnerable populations") (internal citations omitted).

[401] Koch, Exh. CAK-1Tr2 at 23:15-24:2.

[402] Kensok, Exh. JAK-1T at 5:15-15:14.

[403] Kensok, Exh. JAK-1T at 6:6-7.

[404] Bamba, Exh. RBB-1T at 5:1-2 (Figure 1).

223 The Revenue Requirement Settlement brings equity considerations into these capital planning processes. The Settlement provides that, by the end of the MYRP, PSE will submit a compliance filing demonstrating:

> (a) a process or procedure for how PSE's Board of Directors and senior management plan for equitable outcomes when making decisions on enterprise-wide capital portfolios, including a transparent and inclusive methodology for the use of the Enterprise Project Portfolio Management (EPPM) tool; [405]
>
> (b) the consideration of equity and a distributional equity analysis in Corporate Spending Authorizations; [406]
>
> (c) Distribution System Planning aimed at achieving an equitable distribution of benefits and burdens to named communities; [407] and
>
> (d) development of equity-related benefits and costs, including the social cost of greenhouse gas and societal impacts, for use in the optimization step of iDOT;[408]

224 *Commission Determination.* We accept the Revenue Requirement Settlement terms that incorporate equity considerations into PSE's capital planning processes. These terms are not opposed by any party. Because this is one of the first general rate cases filed pursuant to RCW 80.28.425, we find it appropriate to discuss our consideration of equity in approving the Settlement.

225 RCW 80.28.425(1) provides that the Commission, in determining the public interest, may consider such factors, *inter alia*, as environmental health and equity. CETA also recognizes and finds that the public interest includes but is not limited to the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[409]

226 In our final order in Cascade Natural Gas Corporation's 2021 GRC, the Commission adopted the principles of equity set forth in the statute and "commit[ed] to ensuring that systemic harm

---

[405] Revenue Requirement Settlement ¶ 24.

[406] Revenue Requirement Settlement ¶ 24.

[407] Revenue Requirement Settlement ¶ 25.

[408] Revenue Requirement Settlement ¶ 26.

[409] RCW 19.405.010(6).

is reduced rather than perpetuated by our processes, practices, and procedures."[410] In order to bring equity into the context of utility ratemaking, we found salient guidance in the four core tenets of energy justice. These 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.[411]

227 We concluded in that order that "no action is equity-neutral" and that the Commission must apply an "equity lens"[412] in all public interest considerations going forward.[413] Regulated companies must also take a proactive approach. We observed that "regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[414]

---

[410] *WUTC v. Cascade Nat. Gas Corp.*, Docket UG-210755 Final Order 09 ¶ 55 (August 23, 2022) (2021 Cascade GRC Order).

[411] 2021 Cascade GRC Order ¶ 56 (citing Jenkins, K., McCauley, D., Heffron, R., Stephan, H., & Rehner, R., Energy Justice: A Conceptual Review. *Energy Research & Social Science* 11, 174-82 (2016). *See also* McCauley, D., Heffron, R., Stephan, H. & Jenkins, K. Advancing Energy Justice: The Triumvirate of Tenets. *International Energy Law Review*, 32, 107-110 (2013); *and* Carley & Konisky, The Justice and Energy Implications of the Clean Energy Transition. *Nature Energy*, 5, 596-577 (2020)).

[412] "Equity lens" is defined as providing consideration to those characteristics for which groups of people have been historically, and are currently, marginalized to evaluate the equitable impacts of an agency's policy. *See* RCW 43.06D.010(4). *See also* RCW 49.60.030.

[413] *Id.* ¶ 58.

[414] *Id.*

228 Neither PSE, nor any other regulated company, should consider this Order to provide comprehensive guidance on this issue. We will continue to expand upon our discussion of equity in future proceedings. Moreover, we decline to provide specific programmatic guidance, as our discussion of equity in relation to the 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 final order in Cascade Natural Gas Company's most recent general rate case that PSE must integrate considerations of equity into every proposal through an energy justice lens.

229 In this case, we find that the Revenue Requirement Settlement takes appropriate first steps to incorporate equity into PSE's corporate capital planning. As Staff witness Erdahl explains, the Settling Parties included several terms in the Settlement, including the terms regarding corporate capital planning, specifically "to ensure the MYRP both meets statutory requirements and makes significant progress toward equitable outcomes."[415] Furthermore, the goal of the Settlement terms "is to give the Commission very specific first attempts that it can evaluate when providing guidance on equity in the future."[416] By incorporating equity into PSE's corporate capital planning, the Settling Parties respond to recent statutory changes and our recent guidance in the 2021 Cascade GRC Order.

230 We also consider Staff witness Deborah Reynolds's earlier recommendation that the Commission focus on issues of distributional equity in this proceeding, because "more data about equity is needed to consider procedural and structural equity elements."[417] The Revenue Requirement Settlement terms focused on equity in corporate capital allocation, contained in paragraphs 24 to 26 of the Settlement, tend to focus on an equitable distribution of benefits and burdens. We agree with Reynolds that it is appropriate to focus on distributional equity as the Commission gathers data to inform later decision-making.

231 We therefore accept the Revenue Requirement Settlement's terms regarding corporate capital planning. We next discuss the extent to which the Settlement addresses equity through its proposed distributional equity analysis.

---

[415] Erdahl, Exh. BAE-1T at 6:8-12.

[416] *Id.* at 8:5-6.

[417] Reynolds, Exh. DJR-1T at 9:7-9.

ii. Distributional Equity Analysis

232 The Settling Parties further agree that PSE will develop and participate in a pilot Distributional Equity Analysis.[418] PSE will apply certain methods to its proposed 80 MW of distributed energy resources.[419] Within 15 months of the approval of the MYRP, which we interpret to be the effective date of this Order, PSE will submit a compliance filing to the Commission documenting its methods and results.[420]

233 The Settlement specifically proposes that the Distributional Equity Analysis will be led by Staff, while remaining open to participation from other parties.[421] Staff will select a third-party facilitator that PSE must hire in consultation with Staff.[422]

234 *Commission Determination.* 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.

235 The issue of equity, broadly, and the more specific need to consider distributional equity in planning processes affects all utility companies regulated by the Commission. Developing a plan for distributional equity requires input, collaboration, and buy-in from persons and parties not included or represented in PSE'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. At the settlement hearing, both PSE and Staff indicated that they either would not object to or would support a Commission-led process.[423]

---

[418] Revenue Requirement Settlement ¶ 50.

[419] *Id.*

[420] *Id.*

[421] *Id.* ¶ 51.

[422] *Id.*

[423] Piliaris, TR 347:17-24; Erdahl, TR 348:6-9.

236 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 to (that Staff will direct this process and select a facilitator for PSE 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 PSE should be required to participate, as should 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.

iii. Review of plant investment

237 The Revenue Requirement Settlement also addresses PSE's recent plant investments and its plans for future plant investments over the course of the MYRP. The Settling Parties agree to the prudency of plant investment through 2021, and they do not object to the provisional recovery of plant projected to go into service in 2022 through 2024 subject to later review and possible refund, as proposed by PSE witness Susan Free.[424] Free specifically proposes an annual filing on March 31 of each year,[425] which, as modified by the Settlement, would include a four-month review process.[426]

238 This Settlement term is not opposed by any party. Public Counsel does not offer any argument opposing this Settlement term.[427]

239 *Commission Determination.* We accept the Settlement's terms related to both traditional and provisional recovery of plant investment for the purpose of resolving the issues presented in this GRC.[428]

---

[424] Revenue Requirement Settlement ¶ 23.p.

[425] Free, Exh. SEF-1Tr 30:9-31:2. *See also* Piliaris, Exh. JAP-3 (Planned Filing Schedule During Multiyear Rate Plan).

[426] Revenue Requirement Settlement ¶ 53.p.

[427] *See, e.g.*, Bauman, Exh. SB-9T at 6:6-7:6 (identifying areas of the Revenue Requirement Settlement that Public Counsel supports, opposes, or takes a neutral position on).

[428] We observe that the Settling Parties agree to the recovery of capital projects as proposed in the testimony of PSE witness Free. *See* Revenue Requirement Settlement ¶ 23.p. However, the Settlement is again unclear as to exactly which projects are proposed for provisional recovery, and we refer to the

240 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 IIJA and IRA will affect capital investment and could provide immediate customer savings, as we highlighted previously.[429]

241 The Commission intends to initiate a collaborative 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 PSE. Following the conclusion of that proceeding, the Commission expects utilities to incorporate the benefits of the IRA and IIJA into the retrospective review of any provisional investment.

242 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 PSE and its ratepayers related to its capital project planning, and more urgently in capturing any changes that will result in immediate customer savings. We find it imperative that PSE pursue those opportunities the IRA and IIJA might offer during the MYRP. For that purpose, we find it appropriate for PSE to record and share its efforts for identifying opportunities for rate mitigation, seeking benefits as well as what benefits it receives.

243 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 as per the following: We require that PSE demonstrate all offsetting benefits received or for which it has applied through the IRA and IIJA for all retrospective review of provisional plant (capital projects). Further, we require PSE's reporting to include all funding, tax benefits, or any other benefit for which it has and has not applied and, if it has not, the reasons justifying its decision to not pursue the IRA and IIJA funding options. Subject to these

---

supporting testimony of PSE witnesses for clarification. *See* Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 6:26-30. Any inaccuracy in our description of the Settlement is again attributable to a relative lack of clarity in the underlying submissions.

[429] *Supra* paragraphs 169-73.

conditions, we determine that the Settling Parties' agreement regarding capital projects review is in the public interest and should be approved.

iv. Power costs

244 The Revenue Requirement Settlement seeks to provide for more timely recovery of PSE's power costs. Although the Settlement's treatment of power costs is not directly opposed by any party, we consider Public Counsel's recommendation that the prudency of power costs should only be reviewed in the context of an adjudicative proceeding.

245 PSE witness Paul K. Wetherbee testifies that the Company's projected power costs for 2023 are $902.4 million, which is 18.1 percent higher than the amount currently in rates, and he describes the various contracts and inputs driving this increase.[430] Projected power costs for 2024 are $913.4 million.[431] PSE also requests a prudency determination on new Power Purchase Agreements (PPAs), as well as new and continuing transmission contracts.[432]

246 Company witness Janet K. Phelps recommends that Power Cost Only Rate Cases (PCORCs) continue but also proposes a system of annual updates for power costs.[433] Annual updates would result in changes to the variable portion of the baseline rate on January 1 of each year and annual changes to the deferral rate on October 1 of each year.[434] This would be similar to the Company's current Purchased Gas Adjustment (PGA) mechanism.[435]

247 PSE also requests to earn a return on clean energy PPAs.[436] PSE witness Kazi H. Hasan testifies that PPAs are "off-balance sheet financial obligations" and credit rating agencies view them as "debt-like obligations."[437] Hasan suggests that PPAs will weaken the Company's financial strength if it does not earn a rate of return.[438]

248 The Revenue Requirement Settlement generally accepts the power cost increases in PSE's initial filing and presumes a $125 million increase in power costs for 2023.[439] The Settling

---

[430] *E.g.*, Wetherbee, Exh. PKW-1CT at 9:10-10:15.

[431] Wetherbee, Exh. PKW-1CT at 10:20.

[432] *E.g.*, Wetherbee, Exh. PKW-1CT at 21:12-20.

[433] Phelps, Exh. JKP-1T at 49:13-16.

[434] Phelps, Exh. JKP-1T at 49:18-20.

[435] Phelps, Exh. JKP-1T at 12:2-3.

[436] Hasan, Exh. KKH-1CT at 16:13.

[437] Hasan, Exh. KKH-1CT at 16:14-19.

[438] *See id.*

[439] Revenue Requirement Settlement ¶ 23.d.

Parties agree to the prudence of all power supply resources for which PSE sought a prudency determination.[440]

249 PSE agrees, however, to amortize refunds from the Northwest Pipeline settlement over the 12 months of 2023 as a credit against forecasted power costs.[441] An estimated $4.4 million of the $28.7 million Northwest Pipeline settlement is attributed to the Company's electric customers and will be applied against forecasted 2023 power costs in this manner.[442]

250 PSE also agrees to a PCORC stay-out for the duration of the MYRP.[443] PSE will submit a compliance filing at the conclusion of the case for 2023 power costs, and it will submit a second compliance filing within 90 days of the conclusion of the case for 2024 power costs.[444]

251 The Settling Parties also clarify the process for updating and reviewing power costs, compared to the initial filing. Power cost updates will include several inputs such as updated natural gas prices, hedges, and costs for Mid-C contracts.[445] While PSE may include new contracts in power cost updates,[446] the Settling Parties require PSE to submit workpapers detailing any new transmission contracts or new resources;[447] and the Settling Parties reserve the right to challenge prudency in future proceedings.[448] The Settling Parties specifically agree to review prudency in connection with the Company's Power Cost Adjustment (PCA) filing in April each year.[449]

252 The Settling Parties also agree that any Distributed Energy Resources (DERs), battery resources, or demand response costs are "eligible" for potential earnings on PPAs pursuant to RCW 80.28.410.[450]

---

[440] Revenue Requirement Settlement ¶ 31.

[441] Revenue Requirement Settlement ¶¶ 23.d, 55. *See also* Mullins, Exh. BGM-1T at 41:10-19 (observing that PSE will receive a refund of $28.7 million from Northwest Pipeline reflecting deferred taxes).

[442] Revenue Requirement Settlement ¶ 55.

[443] Revenue Requirement Settlement ¶ 27.

[444] Revenue Requirement Settlement ¶ 28.

[445] Revenue Requirement Settlement ¶ 28.

[446] Revenue Requirement Settlement ¶ 28.

[447] Revenue Requirement Settlement ¶ 29.

[448] Revenue Requirement Settlement ¶ 28.

[449] Revenue Requirement Settlement ¶ 30.

[450] Revenue Requirement Settlement ¶ 32. *See also* RCW 80.28.410(2)(a) (providing that an electrical company may earn its authorized return on equity for any PPAs).

253 Public Counsel generally supports or takes a neutral position on the Settlement's treatment of power costs. Shay Bauman explains that Public Counsel supports the PCORC stay-out provision.[451] Bauman notes that "Public Counsel does not oppose any of the other power cost terms of the [Revenue Requirement] Settlement, but we do have particular concerns regarding the prudency provision."[452]

254 As Robert L. Earle testifies on behalf of Public Counsel, there are a long list of inputs to PSE's power costs, and Earle therefore recommends that the prudency of the Company's power costs be reviewed in a full adjudication, specifically the Company's next general rate case.[453] Earle suggests that it may be difficult for intervenors to quickly respond to and analyze power cost prudency in the context of a PCA filing.[454]

255 In its post-hearing Brief, PSE emphasizes that the power cost provisions of the Settlement are of "critical importance" and that the Company has repeatedly under-recovered its power costs in recent years.[455]

256 *Commission Determination.* We accept the Revenue Requirement Settlement's terms regarding power costs. The Settling Parties agree to the prudency of the resources described in PSE's initial filing.[456] No party challenges this Settlement term. We find that the record adequately supports the Settling Parties' agreement but emphasize that our approval of these terms is not precedential.

257 We also accept the Settling Parties' modifications to PSE's power cost filings. This includes the PCORC stay-out provision, the power cost compliance filings, and the Settling Parties' proposed process for reviewing the prudency of new resources.[457] PSE explains that it has under-recovered power costs in recent years and that these Settlement terms are, from the Company's perspective, one of the most important aspects of the Settlement.[458] The Company plans to continue adding new resources to its system over the next several years. This is driven by the Company's need to meet the capacity needs identified in its IRP, to meet resource planning standards, to reduce its exposure to spot market prices, and to comply with

---

[451] Bauman, Exh. SB-9T at 24:7-10.

[452] Bauman, Exh. SB-9T at 24:13-15.

[453] Earle, Exh. RLE-14CT at 21:18-22.

[454] Earle, Exh. RLE-14CT at 21:18-22.

[455] PSE Brief ¶ 48.

[456] Revenue Requirement Settlement ¶ 31.

[457] Revenue Requirement Settlement ¶¶ 27-28.

[458] *E.g.*, Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 13:5-10.

CETA.[459] In light of the Settling Parties' agreement, it is reasonable to modify our review of PSE's power costs to provide more timely review and recovery for the Company.

258 The Settling Parties also agree that any DERs, battery resources, or demand response costs are "eligible" for potential earnings on PPAs pursuant to RCW 80.28.410.[460] Although we emphasize that the Settlement is non-precedential, we find this agreement consistent with the statute and the public interest. To the extent that the DERs, battery resources, or demand response costs in question are "major projects in the electrical company's clean energy action plan pursuant to RCW 19.280.030(1)(l), or selected in the electrical company's solicitation of bids for delivering electric capacity, energy, capacity and energy, or conservation,"[461] whether they are PPAs or not, these projects are eligible for earnings under the statute. Yet whether return is appropriate on a particular resource, or the precise level of potential earnings, is not set forth in the Settlement and must be determined in a future proceeding, as the statute provides discretion for the Commission in determining the appropriate return on a PPA.

259 We do not agree with Public Counsel's proposed modification to the Revenue Requirement Settlement's treatment of power costs, which would require the Commission to review the prudency of new resources in the Company's next general rate case.[462] As Staff explains, this proposal could add to the Commission's administrative burden by turning power costs filings into adjudications by default.[463] It also appears to overlook the Settlement provision that allows interested persons to extend the review process by asking the Commission to defer a prudency finding for one year.[464] Because the Settlement already provides a process for interested parties to request additional time, we find that this addresses the concerns raised by Public Counsel related to public participation and prudency review of new resources.

260 Finally, we discussed above relating to review of plant investment, the precise impacts of the IIJA and IRA, and extent of those impacts is currently unknown. However, it is apparent that there are opportunities for benefits to PSE and its customers for the Company's resource planning, and more urgently in capturing any changes that will result in immediate customer savings. It is imperative that PSE pursue the opportunities the IRA and IIJA offer during the MYRP. To that end, we find it appropriate for PSE to record and share its efforts for

---

[459] Wetherbee, Exh. PKW-1CT at 16:4-10. *Accord* Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 13:10-13.

[460] Revenue Requirement Settlement ¶ 32. *See also* RCW 80.28.410(2)(a) (providing that an electrical company may earn its authorized return on equity for any PPAs).

[461] RCW 80.28.410(1).

[462] *E.g.*, Public Counsel Brief ¶ 96.

[463] Staff Brief ¶ 49.

[464] *Id. Accord* Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 12:17-19

identifying opportunities for rate mitigation, both seeking benefits as well as the benefits it receives.

261 Further, as we discussed above in Section II.I, the Commission intends to initiate a collaborative 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.

262 We therefore accept the Settlement's treatment of power costs subject to the following condition.

> **Condition:** We condition our approval of the Settlement on the following modifications of the Settlement's terms regarding power costs: We require that PSE demonstrate all offsetting benefits received or for which it has applied through the IRA and IIJA when demonstrating the prudency of power costs. Further, we require PSE's reporting with respect to the recovery of its power costs to include all funding, tax benefits, or any other benefit for which it has and has not applied and, if it has not, the reasons justifying its decision to not pursue the IRA and IIJA funding options. Subject to these conditions, we determine that the Settling Parties' agreement regarding capital projects review is in the public interest and should be approved.

v. Low-income issues

263 The Revenue Requirement Settlement requires PSE to further develop and enhance its programs for low-income customers. The Revenue Requirement Settlement requires PSE to consult with its Low-Income Advisory Committee (LIAC) to develop and design the Bill Discount Rate (BDR) and Arrearage Management Plan (AMP) the Company discusses in its initial testimony.[465] Although the BDR program will begin on October 1, 2023, PSE will make a subsequent filing with the Commission on July 1, 2023, seeking approval of the BDR and AMP program design developed through the LIAC process.[466] The Revenue Requirement Settlement sets forth several concrete steps for the Company to incorporate equity in its planning processes that were not present in the initial filing.

264 In a commitment to make a good faith effort to increase weatherization measure incentive amounts, PSE agrees to work with its Conservation Resources Advisory Group (CRAG) to survey actual installed measure costs and adjust rebate amounts per survey findings.[467] PSE agrees to continue to fund low-income weatherization programs that the community action

---

[465] Revenue Requirement Settlement ¶ 37.

[466] *Id.*

[467] Revenue Requirement Settlement ¶ 39.

agencies inform PSE they can feasibly achieve with an annual base funding level of no less than the amount in PSE's current Biennial Conservation Plan Low-Income Weatherization Programs through the next general rate case.[468]

265 The Revenue Requirement Settlement also states that PSE will increase HELP funding consistent with RCW 80.28.425(2), as amended.[469] PSE will additionally continue its existing credit and collection processes until the conclusion of the proceeding currently being conducted in Docket U-210800.[470]

266 In supporting testimony for the settlement, Bradley T. Cebulko, witness for The Energy Project, supports the low-income provisions outlined above.[471]

267 The Settlement's provisions for low-income customers are not opposed by any party. Although it did not join the Settlement, Public Counsel argues that "[e]ach of these terms provides critical assistance and protection to PSE's low-income customers and are in the public interest."[472]

268 *Commission Determination.* We accept the Settlement's terms regarding low-income customer programs. As the Commission determined in the 2021 Cascade GRC 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 the Company work with its LIAC to make significant changes to PSE's low-income programs that will increase access to, and enrollment in, those programs.

269 Specifically, the Settlement increases the LIAC's involvement in program design and implementation, demonstrates a deeper understanding of the flexibility necessary for certain budgeting structures, and enhances coordination of PSE's low-income related programs. Consistent with our decision on the retrospective review of provisional plant, we require that PSE provide evidence of its consideration of IRA and IIJA funding opportunities related to supporting and promoting low-income programs, projects, and interests.

---

[468] Revenue Requirement Settlement ¶ 39. *See also*, Docket U-210542, Order 01, Appendix A, Commitment 43.

[469] Revenue Requirement Settlement ¶ 38.

[470] Revenue Requirement Settlement ¶ 40.

[471] Cebulko, Exh. BTC-7T at 8:7-12:8.

[472] Public Counsel Brief ¶ 83.

270 As we discussed above in the context of corporate capital planning, neither PSE, nor any other regulated company, should consider this Order to provide comprehensive guidance on the issue of equity. We reiterate our expectation set out in the 2021 Cascade GRC Order that PSE and other regulated utilities must integrate considerations of equity into every proposal through an energy justice lens.

vi. Colstrip Tracker and Decommissioning and Remediation Costs

271 PSE proposes to place costs related to the coal-fired Colstrip Steam Electric Station (Colstrip) into a tracker, which would include both rate base and decommissioning and remediation (D&R) costs. The Revenue Requirement Settlement generally accepts PSE's proposed tracker. Although these Settlement terms are not opposed by any party, we discuss this issue given its significance to the public interest and the statutory prohibition on including costs related to coal-fired resources in rates after December 31, 2025.

272 In the Company's initial filing, witness Ronald J. Roberts provides background on PSE's ownership interest in Colstrip and PSE's obligations under contracts such as the Ownership and Operating Agreement.[473] Roberts describes historical capital expenditures at the facility;[474] planned capital expenditures for 2023, 2024, and 2025;[475] and forecasted decommissioning and remediation (D&R) expenses.[476] For example, Roberts explains the plans to install a "dry waste disposal system" at Units 3 and 4, which must be installed pursuant to a 2012 settlement agreement among the Colstrip owners and several environmental and public interest organizations.[477]

273 Susan E. Free describes PSE's proposal to recover Colstrip costs in a tracker, effective with the first year of the MRYP.[478] The revenue requirement for the first year of the tracker, in 2023, is \$53.9 million.[479] Free explains that use of a tracker will make it easier for PSE to take advantage of future chances to sell its ownership interest in Colstrip.[480] In terms of procedure, Free proposes that PSE submit an annual filing for its Colstrip tracker on October 31 of each

---

[473] *See generally* Roberts, Exh. RJR-1CT 70:8-108:7.

[474] Roberts, Exh. RJR-1CT at 84:2-91:4.

[475] Roberts, Exh. RJR-1CT at 91:6-100:2.

[476] Roberts, Exh. RJR-1CT at 100:5-108:7.

[477] Roberts, Exh. RJR-1CT at 94:5-100:2.

[478] *See generally* Free, Exh. SEF-18.

[479] Free, Exh. SEF-18 at 38:6-7. *See also* Free, Exh. SEF-19 line 36 (Revenue Requirement Summary).

[480] Free, Exh. SEF-18 at 3:10-15.

year and that there would be a 60-day review period, before rates take effect on January 1 of the following year.[481]

274 As instructed by the Commission in the Company's last general rate case, Free discusses how the Company plans to offset D&R costs with Production Tax Credits (PTCs), and estimates that $127.8 million in PTCs are available for this purpose.[482] Free explains that the Company met with Staff in November 2021 while developing its proposed tracker for Colstrip costs, and Staff was generally agreeable to the Company's proposal.[483]

275 Free explains, furthermore, that the proposed Colstrip tracker is compliant with CETA because "all plant related and operating expenses will be removed from the tracker as of December 2025, with the exception of D&R related costs."[484] The Company also proposes to discontinue the Annual Colstrip Report and to instead provide this information in its annual tracker tariff filing.[485]

276 Jon A. Piliaris explains how PSE proposes to allocate Colstrip D&R costs to Microsoft, which "wheels" electricity through PSE's transmission system and is served under a special contract.[486] PSE proposes to allocate these costs based on Microsoft's share of total retail sales from 2002 to 2025.[487] Because PSE has more than enough PTCs to offset remaining Colstrip net plant balances, PSE does not seek to allocate any further depreciation to Microsoft.[488]

277 The Revenue Requirement Settlement generally accepts the proposals set forth in PSE's initial filing. Specifically, the Settling Parties agree that PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed by PSE witness Free.[489] The tracker will therefore include all Colstrip rate base and operational costs, with the exception of variable power costs and transmission-related costs.[490] The Settling Parties also

---

[481] Free, Exh. SEF-18 at 43:18-44:2.

[482] Free, Exh. SEF-18 at 41:3-4.

[483] Free, Exh. SEF-18 at 41:7-10.

[484] Free, Exh. SEF-18 at 44:4-5.

[485] Free, Exh. SEF-18 at 44:7-45:11.

[486] *See generally* Piliaris, Exh. JAP-1T at 45:6-50:11.

[487] Piliaris, Exh. JAP-1T at 46:20-22.

[488] Piliaris, Exh. JAP-1T at 50:8-11.

[489] Revenue Requirement Settlement ¶¶ 23.j, 43 (citing Free, Exh. SEF-18).

[490] Free, Exh. SEF-18 at 2:4-3:3.

accept PSE's forecast of D&R costs.[491] Colstrip costs included in rates in 2023 and beyond are subject to later prudency review.[492]

278 The Settling Parties also agree that major maintenance costs will be amortized over a three-year period, regardless of the year incurred.[493] Costs amortized after 2025 will not be included in rates.[494]

279 PSE agrees, however, to exclude capital investments associated with its Colstrip "dry ash" facilities from recovery in base rates or the tracker.[495]

280 The Settling Parties also agree to PSE's proposed allocation factor for purposes of the Microsoft buyout,[496] and they accept Microsoft's proposal to pay its remaining obligations for D&R costs in a lump sum of approximately $0.4 million following the conclusion of this case.[497]

281 *Commission Determination.* We find that the Settling Parties' treatment of Colstrip costs is supported by an appropriate record, consistent with the public interest, and consistent with applicable law.

282 First, we turn to the issue of removing coal-fired resources from rates. Pursuant to RCW 19.405.030(1)(a), "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation of these facilities." As Company witness Free confirmed at the hearing, the Settlement removes these coal-fired resources from rates by 2025.[498] Any major maintenance amortized after 2025 will not be recovered.[499]

283 We next discuss the issue of D&R costs. RCW 19.405.030(1)(b) provides that "[t]he commission shall allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility for a coal-fired resource." In PSE's last general rate case, the Commission discussed this statutory requirement and gave notice that it would

---

[491] Revenue Requirement Settlement ¶ 44.

[492] Revenue Requirement Settlement ¶ 23.j.

[493] Revenue Requirement Settlement ¶ 23.j.

[494] Revenue Requirement Settlement ¶ 23.j.

[495] Revenue Requirement Settlement ¶ 23.j.

[496] Revenue Requirement Settlement ¶ 44.

[497] Revenue Requirement Settlement ¶ 45. *See also* Plenefisch, Exh. IP-1Tr at 4:22-23

[498] Free, TR 338:23-339:10.

[499] *Id.*

address the recovery of D&R costs and Microsoft's share thereof in the Company's next general rate case, with the caveat that prudency review of those D&R costs would occur after they are incurred.[500] The terms of the Revenue Requirement Settlement are consistent with these instructions. As Staff witness Erdahl explains, the Colstrip tracker provides for transparency and facilitates CETA compliance by allowing for a later review of the prudency of D&R costs.[501] Erdahl also explains that Microsoft's lump sum payment for its remaining obligation for D&R costs provides Microsoft certainty while protecting PSE's remaining ratepayers from having to pay more if the D&R costs exceed PSE's estimates.[502] We agree with Staff's testimony. The Settlement's treatment of Colstrip costs is consistent with the Commission's earlier order and CETA's requirements. We observe, as well, that Public Counsel supports the Settlement's treatment of Colstrip D&R costs, even though Public Counsel is not one of the Settling Parties.[503]

284 We also accept the Settling Parties' agreement to exclude capital investments associated with Colstrip "dry ash" facilities from recovery in base rates or the tracker.[504] These "dry ash" facilities are also described as a "dry waste disposal system" by Company witness Roberts.[505] In response testimony, Public Counsel witness Andrea C. Crane objected to PSE recovering the costs of the dry ash facility because this investment sought to extend Colstrip's operational life.[506] Although PSE maintains this was a prudent investment, the Company has compromised on this issue in the interest of supporting the broader Settlement.[507] We accept the Settling Parties' compromise on this issue and find it consistent with the public interest to exclude this investment from recovery.

---

[500] *WUTC v. Puget Sound Energy*, Dockets UE-190529 UG-190530 (Consolidated), Final Order 08 ¶ 430 (July 8, 2020).

[501] Erdahl, Exh. BAE-1T at 9:22-10:10:2.

[502] *Id.* at 10:15-17.

[503] Bauman, Exh. SB-9T at 15:6-18 ("[R]ecovering appropriate Colstrip maintenance costs over three years regardless of when costs are incurred will result in some costs extending beyond 2025, when CETA no longer allows those costs in rates.").

[504] Revenue Requirement Settlement ¶ 23.j.

[505] Free, TR 337:17-23.

[506] *See* Crane, Exh. ACC-1CT at 29:6-8.

[507] Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 18:18-22.

vii. Gas Line Extension Margin Allowances

285 Line extension allowances are ratepayer-funded subsidies that reduce the cost of extending new gas service lines to customers' homes.[508]

286 The Settling Parties agree that PSE will significantly reduce its gas line extension allowance in the first year of the MYRP by using a two-year timeframe rather than a seven-year timeframe for the net present value (NPV) methodology. The line extension allowance will decrease further in 2024 before it is eliminated entirely in 2025. This reflects a compromise between the Company's initial filing, which did not propose any further reductions, and the response testimony filed by the Joint Environmental Advocates, who advocated eliminating line extension allowances.[509]

287 The Revenue Requirement Settlement therefore requires PSE to submit tariff revisions reflecting the following:

a) effective by the time new building codes take effect in 2023, a gas line extension margin allowance, based on the NPV methodology using a two-year timeframe and updated inputs from this rate case;

b) by January 1, 2024, a gas line extension margin allowance based on the NPV methodology using a one-year timeframe and the same inputs used in 2023; and

c) by January 1, 2025, reducing the gas line extension margin allowance to zero.[510]

288 *Commission Determination*. We accept the Settling Parties' agreement to gradually reduce PSE's gas line extension allowances as consistent with public policy. This proceeding provides an appropriate opportunity to revisit this issue.

289 The Commission recently considered the issue of line extension allowances at its October 29, 2021, open meeting.[511] After considering various proposals, the Commission ordered the

---

[508] Burgess, Exh. EAB-1T at 36:4-5.

[509] *See* Burgess, Exh. EAB-1T at 46:17-47:9.

[510] Revenue Requirement Settlement ¶ 49.

[511] *See In the Matter of Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology*, Docket UG-210729, Order 01 (October 29, 2021).

investor-owned gas companies to adopt a NPV methodology using a seven-year timeline.[512] Noting the urgent issue of climate change, the Commission described its decision as an "interim measure" and planned to continue its dialog with regulated utilities and interested parties.[513] On November 17, 2021, PSE filed revised tariff sheets reducing its line extension allowance from $4,328 to $1,997, consistent with the Commission's order.

290 Although PSE did not directly address the issue of line extension allowances in its initial filing, this issue was raised by the Joint Environmental Advocates in response testimony.[514] The Revenue Requirement Settlement reflects the Settling Parties' subsequent agreement to gradually reduce PSE's line extension allowance to zero, much as recommended by the Joint Environmental Advocates.[515] We accept the Settling Parties' agreement as lawful, supported by an appropriate record, and consistent with the public interest.

viii. Time Varying Rates Pilot

291 Time Varying Rates (TVR) are designed to lower peak demand and lower system costs by providing pricing signals that encourage customers to reduce usage during periods of peak demand.[516] TVR rates are designed to be revenue neutral.[517] The Settling Parties agree that PSE will carry out the TVR pilot proposed in its initial filing, subject to certain modifications.

292 In PSE's initial filing, consultant Ahmad Faruqui explains how PSE developed its Time Varying Rates (TVR) pilot in order to test revenue-neutral Time of Use (TOU) rates, peak-time rebates (PTRs), and TOU rates focused on customers with electric vehicles.[518] PSE will offer the TVR pilot to customers who are selected randomly,[519] and the customers may then opt-in.[520] PSE plans to run the pilot for a two-year period,[521] and will evaluate the success of the pilot in light of certain metrics.[522] Faruqui explains that the Company is not planning to

---

[512] *Id.* ¶ 24.

[513] *Id.* ¶ 27.

[514] *See, e.g.*, Burgess, EAB-1T at 7:6-12:21.

[515] Revenue Requirement Settlement ¶ 49.

[516] Faruqui, Exh. AF-1T at 2:11-14.

[517] Faruqui, Exh. AF-1T at 16:19.

[518] *See generally* Faruqui, Exh. AF-1T.

[519] Faruqui, Exh. AF-1T at 25:3-4.

[520] Faruqui, Exh. AF-1T at 24:8.

[521] Faruqui, Exh. AF-1T at 27:18-28:4.

[522] *E.g.*, Faruqui, Exh. AF-1T at 30:11-22.

offer bill protection to participants,[523] but low-income customers will be eligible for other low-income discounts and programs.[524]

293 PSE witnesses William T. Einstein and Birud D. Jhaveri provide further background on the Company's TVR pilot.[525] Einstein explains that PSE will spend $7.5 million on this pilot through 2025.[526] He also notes that customers will be encouraged, but not required, to utilize enabling technologies.[527]

294 The Revenue Requirement Settlement provides that PSE will carry out its TVR pilot with certain modifications:

- including low-income customers up to 200 percent of the federal poverty level or 80 percent of the area median income;
- providing enabling equipment to half of the low-income participants at no cost to those participants;
- providing bill protection to half of the low-income participants;
- providing for review and comment on recruitment language by Consumer Protection Staff;
- including an exit survey for participants, asking if they understood their rates; and
- refreshing the TVR pilot rates to reflect the revenue increases as provided in the Settlement.[528]

295 The Settling Parties also agree that PSE will propose a full opt-in TVR program for residential customers in its next general rate case (as opposed to the two-year pilot program at issue in this case).[529]

296 *Commission Determination*. We accept the Revenue Requirement Settlement's terms, providing for a modified TVR pilot and requiring PSE to propose a full opt-in TVR program in its next general rate case. The Settlement provides greater protections and resources for

---

[523] Faruqui, Exh. AF-1T at 27:5.

[524] Faruqui, Exh. AF-1T at 27:14-15.

[525] *See generally* Einstein, Exh. WTE-1CT at 13:10-24:4; Jhaveri, Exh. BDJ-1Tr 92:2-108:20.

[526] Einstein, Exh. WTE-1CT at 21:18-19.

[527] Einstein, Exh. WTE-1CT at 17:15-19.

[528] Revenue Requirement Settlement ¶ 41.

[529] Revenue Requirement Settlement ¶ 42.

low-income customers, randomly selecting half of low-income TVR participants to receive bill protection and, again, randomly selecting half of low-income participants to receive enabling technology.[530]

297 Consistent with the Company's proposal, the Commission will evaluate the success of the TVR pilot in light of an "ex-post load impact" analysis and certain metrics, such as change in average peak period demand, change in average off-peak period demand, and change in average usage level, among others.[531] The Settlement provides for a customer exit survey,[532] and requires the Company to report on other relevant metrics, such as a count of participating customer complaints in each of PSE's TVR pilots and load reduction during called events for customers enrolled in the TOU+PTR pilot, a program combining time of use rates and peak-time rebates.[533] These metrics will inform the Commission's evaluation of the TVR pilot and the Company's future proposal for a full opt-in TVR program.

ix. Other, undisputed adjustments

298 PSE proposes 39 restating and pro forma adjustments to its electric revenue requirement and 34 restating and pro forma adjustments to its natural gas revenue requirement over the term of the MYRP that are uncontested by any party.. All of these adjustments are adequately supported by the record. Accordingly, we find that the remaining uncontested adjustments should be approved without condition.

III. GREEN DIRECT SETTLEMENT

299 On August 5, 2022, PSE filed the Green Direct Settlement and Joint Testimony. The Settlement was joined by PSE, Staff, Public Counsel, King County, and Walmart (Settling Parties). The following parties neither joined nor opposed the Green Direct Settlement: AWEC, TEP, NWEC, Front and Centered, Sierra Club, FEA, and Kroger.[534]

300 The Green Direct Settlement is a partial multiparty settlement as defined by WAC 480-07-730(3)(b).[535] There are four key provisions:

---

[530] Piliaris, TR 355:18-21.

[531] *See* Faruqui, Exh. AF-1T at 29:9-30:22.

[532] Revenue Requirement Settlement ¶ 41.e.

[533] Revenue Requirement Settlement ¶ 61.p, q.

[534] Green Direct Settlement ¶ 1.

[535] The parties participated in formal settlement conferences regarding PSE's Green Direct program on May 3, 2022, and again on June 13, 2022. No agreements were reached at that time, but the parties

1) The Resource Option Energy Charge for Green Direct customers shall remain unchanged from the rates approved by the Commission in Docket UE-200817;[536]

2) Effective January 1, 2023, the Energy Charge Credit shall be $47.826 per MWh (reflecting the adjusted value of the Resource Option Energy Charge, *see infra*, paragraph 317, n.571) and shall increase by two percent each year thereafter;[537]

3) PSE may recover the Energy Charge Credit amounts paid to Green Direct customers through base rates, subject to a review of the accuracy of PSE's calculation of the amount to be recovered; and

4) The methodology established in the Company's 2020 Power Cost Only Rate Case (PCORC) for tracking costs and benefits associated with generation surplus or deficiency of Green Direct resources remains unchanged.

301 Among these four settlement terms, the primary issue is the proposed change to the Energy Charge Credit. Specifically, the Settling Parties propose to set the Energy Charge Credit as equal to the Resource Option Energy Charge for the 20-year blended resource option,[538] adjusted to remove (a) costs that PSE incurs that are specific to administering the Green Direct program, and (b) the amortization of liquidated damages awarded to PSE due to delays in the commercial operation date of the Skookumchuck Wind Energy Project.[539] Effective January 1, 2023, the Energy Charge Credit shall be $47.826/MWh and shall increase by 2 percent each year thereafter.[540]

---

continued phone and email conversations. On July 11, 2022, PSE informed the Commission that the Company reached a settlement in principle with Staff, Public Counsel, King County, and Walmart (the Settling Parties).

[536] In Docket UE-200817, the Commission took "no action" at its October 15, 2020, open meeting and allowed PSE's tariff filing for the Green Direct Program to take effect. This set rates per kWh for different resource options, including the $0.04323 per kWh rate for the 20-year mixed resource option, which forms the basis for the Resource Option Energy Charge in this case.

[537] Green Direct Settlement ¶ 17.

[538] On October 15, 2020, the Commission took no action in Docket UE-200817, allowing PSE to file revisions to its Schedule 139 Resource Option Charge consistent with the Commission's final order in *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-190529 et. al, (consolidated) Final Order 08 (July 8, 2020). The current value for the 2023 Resource Option Energy Charge for 20-year blended resource option is set forth in Confidential Attachment A, to the Green Direct Settlement.

[539] Green Direct Settlement ¶ 17.B.

[540] Green Direct Settlement ¶ 17.B.

302 The Settling Parties submit that this is a durable method for calculating the Energy Charge Credit, providing greater certainty for customers.[541]

303 To support the Settlement, PSE witness Piliaris explains that "as much as some would like to believe there is a 'right' answer, the best that can realistically be accomplished is to determine a 'reasonable' resolution of this issue."[542] Piliaris submits that the Green Direct Settlement promotes harmony among interested parties and supports the Company's recovery of the Energy Charge Credit.[543]

304 Staff witness Chris McGuire agrees that there is no single, "correct" manner of calculating the Energy Charge Credit.[544] The Settling Parties therefore propose using the cost of the two Green Direct PPAs themselves (reflected in the Resource Option Charge) because the avoided cost calculation should reflect a variable cost resource with similar non-energy attributes similar to the Green Direct PPAs.[545] McGuire explains that the Green Direct Settlement excludes administrative costs and liquidated damages because these costs are not relevant to the avoided cost calculation and should not be borne by non-participants.[546]

305 McGuire testifies that the resulting Energy Charge Credit is a "reasonable split" between the two methods approved by the Commission in the past.[547] McGuire explains further that "[t]he agreed-upon rate of $47.8/MWh is $2.0/MWh higher than the variable portion of the PCA rate ($45.8/MWh) and $1.6/MWh lower than the energy portion of the PCA rate ($49.4/MWh)."[548] This is important because the agreed-upon rate indicates that Green Direct customers would be contributing to fixed costs while being given some compensation for the benefits Green Direct resources bring to PSE's system.[549]

306 McGuire submits that the Green Direct Settlement will provide customers with predictability and rate stability.[550] McGuire also argues that the Green Direct Settlement complies with

---

[541] Joint Testimony, Exh. JT-1T at 8:6-8.

[542] Joint Testimony, Exh. JT-1T at 10:9-11 (citing Piliaris, Exh. JAP-1T at 61:17-18).

[543] Joint Testimony, Exh. JT-1T at 11:1-6.

[544] Joint Testimony, Exh. JT-1T at 17:4-5.

[545] Joint Testimony, Exh. JT-1T at 17:16-19.

[546] Joint Testimony, Exh. JT-1T at 18:10-16.

[547] Joint Testimony, Exh. JT-1T at 19:11.

[548] Joint Testimony, Exh. JT-1T at 19:12-14.

[549] Joint Testimony, Exh. JT-1T at 19:4-7.

[550] Joint Testimony, Exh. JT-1T at 19:17-18.

applicable statutes, which prohibit cross-subsidization between participating and non-participating customers.[551]

307 Public Counsel also supports the proposed Energy Charge Credit as a "transparent and simple mechanism that is easily implemented."[552] Public Counsel witness Robert L. Earle notes that the cost of the Green Direct PPAs provides a reasonable proxy for PSE's avoided costs because the Green Direct PPAs' contract prices reflected market prices at the time the contracts were signed and PSE would likely have entered into similar agreements to serve Green Direct customers' load.[553] Earle recommends this simple *ex ante* approach over a more complicated *ex post* approach, which could require complex calculations and result in "volatile" changes to the Energy Charge Credit.[554]

308 King County submits that the Green Direct Settlement provides a durable resolution that seeks to eliminate the need for Green Direct customers to intervene in future proceedings.[555] With the predictable Energy Charge Credit, witness Rachel Brombaugh explains that King County will be able to budget accurately and avoid further litigation.[556]

309 Walmart witness Alex Kronauer similarly supports the Green Direct Settlement, noting that programs such as Green Direct are an important tool for achieving Walmart's renewable energy goals.[557]

310 As this proceeding continued, the parties incorporated the Green Direct Settlement's terms into the Revenue Requirement Settlement. All of the Settling Parties in the Green Direct Settlement joined the Revenue Requirement Settlement, with the exception of King County, which neither joined nor opposed the Revenue Requirement Settlement.[558] The Revenue Requirement Settlement avers that "[n]o party opposes the Green Direct settlement."[559]

---

[551] Joint Testimony, Exh. JT-1T at 20:6-11 (citing RCW 19.29A.090(5)).

[552] Joint Testimony, Exh. JT-1T at 20:17-19.

[553] Joint Testimony, Exh. JT-1T at 24:4-9.

[554] Joint Testimony, Exh. JT-1T at 24:11-14.

[555] Joint Testimony, Exh. JT-1T at 25:19-26:2.

[556] Joint Testimony, Exh. JT-1T at 26:6-8.

[557] Joint Testimony, Exh. JT-1T at 27:2-4.

[558] Revenue Requirement Settlement ¶ 3,

[559] Revenue Requirement Settlement ¶ 14.

311 *Commission Determination.* We agree with the Settling Parties that the Green Direct Settlements presents a reasonable, and relatively easy-to-administer, method of calculating the Energy Charge Credit. We accept this Settlement without condition.

312 Pursuant to RCW 19.29A.090(1), utilities are required to provide electric customers a voluntary option to purchase qualified alternative energy resources. By statute, the costs and benefits associated with such voluntary programs may not be shifted to non-participating customers.[560] In 2016, the Commission approved PSE's Green Direct program tariff, which offers long-term contracts to certain large commercial and local government customers.[561] While there was some concern that these costs – and the integration cost of the output from those contracted resources to serve the load of the Green Direct customers – would be appropriately allocated to only participating customers, the Commission observed that PSE committed to tracking separately the costs and benefits of the Green Direct program in its Power Cost Adjustment mechanism.[562] At that time, the Commission did not approve any specific method of calculating the Energy Credit for Green Direct customers.

313 Over the following years, the Commission considered different concerns and proposals for calculating the Energy Charge Credit. In PSE's 2019 GRC, the Commission emphasized that Green Direct customers should benefit exclusively from the sale of over-generation but should not be subsidized by non-participants.[563] The Commission directed PSE "to work collaboratively with Staff and other stakeholders to ensure that the costs and benefits of the Green Direct program are tracked and maintained separately pursuant to statute."[564]

314 Later in PSE's 2020 PCORC, the Commission approved a settlement agreement modifying the Company's Green Direct Program.[565] After the parties raised concerns that the "peak credit method" for calculating the Energy Charge Credit resulted in PSE paying Green Direct customers an Energy Credit in excess of the Company's actual avoided costs, the 2020 PCORC Settlement eliminated the use of the peak credit method and instead set the Green Direct Energy Credit at the Variable PCA Baseline Rate.[566] The 2020 PCORC Settlement also

---

[560] RCW 19.29A.090(5).

[561] *See In the Matter of the Tariff Revisions Filed by Puget Sound Energy*, Docket UE-160977 Order 01 (September 28, 2016).

[562] *Id.* ¶ 10.

[563] *WUTC v. Puget Sound Energy*, Dockets UE-190529 and UG-190530 (consolidated) Order 08 ¶ 296 (July 8, 2020) (2019 PSE GRC Order).

[564] *Id.*

[565] *See generally WUTC v. Puget Sound Energy*, Docket UE-200980 Final Order 05 (June 1, 2021) (2020 PSE PCORC Order).

[566] 2020 PSE PCORC Order, App. A ¶ 11.A.1.b (Settlement Stipulation and Agreement).

required the parties to work towards a "durable method" for calculating the Energy Charge Credit.[567] The Commission observed that the tracking of Green Direct costs and benefits was a "complex issue" and that the 2020 PCORC Settlement "recognize[d] the need for further discussions."[568] The Commission therefore approved the use of the Variable PCA Baseline Rate as a "closer approximation" of PSE's avoided costs but expected the Company to encourage Green Direct customers to participate in future discussions.[569]

315 We agree with the Settling Parties that the Green Direct Settlement in this proceeding presents several advantages.

316 PSE has followed through on the Commission's expectations for including Green Direct customers in discussions related to the Energy Charge Credit. PSE witness Einstein explains that the Company conducted a series of meetings with Green Direct customers from July 28, 2021, to January 11, 2022.[570] Although the parties were not able to reach agreement before the Company filed its initial case on January 31, 2022,[571] two Green Direct customers—King County and Walmart—intervened and later joined the Green Direct Settlement. The Green Direct Settlement reflects greater participation from affected customers, and it compares favorably to the 2020 PCORC Settlement in this respect.

317 We also observe that the Settling Parties' proposal for calculating the Energy Charge Credit reflects a reasonable compromise. By setting the Energy Charge Credit as equal to the adjusted Resource Option Energy Charge, the Settling Parties arrive at a reasonable mid-point between earlier approved methodologies.[572] There is no single, correct method to measuring the Company's avoided costs for this voluntary renewable energy program.[573] The Settling Parties reasonably compensate Green Direct customers for the value provided to PSE's system by Green Direct PPAs without leading to unlawful cross-subsidization. No party to this proceeding has opposed the Green Direct Settlement or offered any evidence to the contrary.

---

[567] *Id.* ¶ 11.C.

[568] 2020 PSE PCORC Order ¶ 18.

[569] *Id.*

[570] Einstein, Exh. WTE-1CT at 11:10-12:13.

[571] *Id.* at 12:17-18.

[572] *See* Joint Testimony, Exh. JT-1T at 19:12-14 ("The agreed-upon rate of $47.8/MWh is $2.0/MWh higher than the variable portion of the PCA rate ($45.8/MWh) and $1.6/MWh lower than the energy portion of the PCA rate ($49.4/MWh)."). *See also* McGuire, TR 281:14-282:21 (clarifying the comparison to the rate approved in the 2020 PCORC).

[573] *E.g.*, Joint Testimony, Exh. JT-1T at 10:9-11 (citing Piliaris, Exh. JAP-1T at 61:17-18).

318 Finally, we agree that the Green Direct Settlement provides a straightforward, *ex ante* method for calculating the Energy Charge Credit and providing a set escalation factor.[574] We share the Settling Parties' expectation that this agreement will prove durable for the foreseeable future and provide Green Direct customers needed certainty in their rates. For these reasons, we accept the Green Direct Settlement without condition.

319 We recognize, however, that the Green Direct Settlement is specifically concerned with the Energy Charge Credit for current Green Direct customers.[575] It is possible that customers who join the Green Direct program in the future could be subject to a different Energy Charge Credit.[576] If that is the case, we would encourage the Company either to present new Green Direct customers with a durable method for calculating the Energy Charge Credit upfront or to encourage participation from all Green Direct customers, new and existing, in any discussions around changing this credit.

IV. TACOMA LNG SETTLEMENT

A. Overview of the Tacoma LNG Settlement

320 On August 26, 2022, PSE filed an Amended Settlement Stipulation and Agreement on Tacoma LNG (Tacoma LNG Settlement or, for purposes of this section, Settlement). This is a partial multiparty settlement,[577] which would allow the Company to begin recovering the costs of the Tacoma Liquified Natural Gas (LNG) Facility (Tacoma LNG Facility), largely on a provisional basis through a separate tariff schedule. This settlement is entered into by PSE, Staff, AWEC, Walmart, Kroger, and Nucor Steel (Settling Parties for purposes of this section). The Tacoma LNG Settlement is opposed by Public Counsel, the Puyallup Tribe, and The Energy Project. In this section, we provide a brief summary of the Commission's past orders concerning the same facility and the Tacoma LNG Settlement at issue in this proceeding.

321 On November 1, 2016, the Commission issued its Final Order in Docket UG-151663, approving and adopting a settlement stipulation that provided the terms and conditions under which PSE could pursue developing its Tacoma LNG Facility, including the joint ownership

---

[574] *E.g.*, Joint Testimony, Exh. JT-1T at 24:11-14.

[575] *See* Green Direct Settlement ¶ 17.

[576] Piliaris, Earle, McGuire TR 279:9-22

[577] As defined by WAC 480-07-730(3)(b).

Because the Settling Parties have also joined the Revenue Requirement Settlement, PSE has at times described the Tacoma LNG Settlement as a full multiparty settlement. Applicable WAC 480-07-730(3)(a).

shares and cost allocators for each component of the facility.[578] The facility, located at the Port of Tacoma, is capable of (1) receiving nearly 21,000 Decatherms per day of natural gas from which it can produce approximately 250,000 gallons of LNG and (2) storing approximately 8 million gallons of LNG.[579] The Tacoma LNG Facility (1) supplies fuel to Totem Ocean Trailer Express, Inc., (TOTE), a marine shipper, under a special contract, (2) provides fuel for sales to other marine vessels or other purchasers, and (3) may potentially serve as a peaking resource for PSE's core natural gas customers.[580]

322 The settlement in Docket UG-151663 authorized PSE to decide whether and how to move forward with the Tacoma LNG project,[581] and addressed the business model for the facility. Consistent with the terms of the settlement stipulation, PSE's parent corporation, Puget Energy, formed a wholly owned subsidiary named Puget LNG, a special purpose limited liability company formed solely for the purposes of owning, developing, and financing the Tacoma LNG Facility as a tenant-in-common with PSE. Puget LNG is not subject to the Commission's jurisdiction under Title 80 RCW, and Puget LNG's sales of LNG as marine fuel to TOTE and other sales of LNG as transportation fuel is not regulated by the Commission.[582] Only PSE's use of the facility as a potential peaking resource for retail natural gas customers is regulated by the Commission.

323 The settlement stipulation contained multiple ring-fencing provisions that protect PSE's ratepayers from the unregulated activities of Puget Energy and Puget LNG. Each entity is individually responsible for the performance of its own obligations. All risk, loss, and damage arising out of the ownership, construction, operation, or maintenance of any portion of the Tacoma LNG Facility is borne by each entity in proportion to its capital cost allocation as set forth in an attachment to the settlement stipulation.[583]

324 The settlement stipulation expressly reserved questions of prudence and cost recovery in rates for future review and determination by the Commission, and the parties to the settlement

---

[578] *In the Matter of the Petition of Puget Sound Energy, Inc., for (i) Approval of a Special Contract for Liquefied Natural Gas Fuel Service with Totem Ocean Trailer Express, Inc., and (ii) a Declaratory Order Approving the Methodology for Allocating Costs Between Regulated and Non-Regulated Liquefied Natural Gas Services,* Docket UG-151663, Order 10 ¶ 14 (Nov. 1, 2016).

[579] Docket UG-151663, Order 10 ¶ 23.

[580] Docket UG-151663, Order 10 ¶ 23.

[581] Docket UG-151663, Order 10 ¶ 21.

[582] Docket UG-151663, Order 10 ¶ 46.

[583] *Washington Utilities and Transportation Commission v. Puget Sound Energy,* Dockets UE-190529, UG-190530, UE-190274, UG-190275, UE-171226, UG-171226, UE-190991, and UG-190992, Order 08/05/03 ¶ 172 (July 8, 2020).

expressly reserved their rights to take any position they elect to take concerning those matters when brought before the Commission.[584]

325 In PSE's 2020 GRC, the Commission approved Staff's proposal to defer the costs associated with two upgrades to the Tacoma LNG project (four miles of new 16-inch pipe placed in service in October 2017 and upgrades to the Frederickson Gate Station placed into service in September 2017) until the facility was operational.[585] The Commission also advised the Company that it must adhere to the capital cost allocators and all other terms of the settlement stipulation when it seeks recovery of these costs in a later proceeding, and, if the Company wishes to deviate from the terms of the settlement stipulation, that it must renegotiate the capital cost allocator terms with the other parties.[586]

326 In this proceeding, on August 12, 2022, PSE informed the Commission that the Company reached two settlements in principle in this proceeding: one that specifically addresses the Tacoma LNG Project and one that addresses the Company's revenue requirement.[587] PSE subsequently filed the Tacoma LNG Settlement on August 26, 2022.

327 The Amended Settlement Stipulation and Agreement on Tacoma LNG (Tacoma LNG Settlement) is a partial multiparty settlement.[588] The Settling Parties include PSE, Staff, AWEC, Walmart, Kroger, and Nucor Steel. The Tacoma LNG Settlement is opposed by Public Counsel, the Puyallup Tribe, and The Energy Project. Several parties, however, take no position on this settlement. Specifically, NWEC, Sierra Club, and Front and Centered (the Joint Environmental Advocates) take no position. Microsoft, Federal Executive Agencies, CENSE, and King County did not participate in the Tacoma LNG settlement discussions.

328 Fundamentally, the Tacoma LNG Settlement provides that PSE may begin to recover the regulated portion of costs for the Tacoma LNG Facility on a provisional basis, in a tracker,

---

[584] Docket UG-151663, Order 10 ¶ 47.

[585] Docket UE-190529 et. al, Order 10 ¶ 177.

[586] Docket UE-190529 et. al, Order 10 ¶ 183.

[587] In the instant proceeding, the parties participated in formal settlement conferences on June 13, 2022, June 14, 2022, August 10, 2022, and August 12, 2022, and continued settlement discussions over email.

[588] As defined by WAC 480-07-730(3)(b). Because the Settling Parties have also joined the Revenue Requirement Settlement, PSE has at times described the Tacoma LNG Settlement as a full multiparty settlement. Applicable WAC 480-07-730(3)(a).

and that distribution costs may be recovered in base rates.[589] This Settlement provides in relevant part that:

1) When PSE files its 2023 Purchased Gas Adjustment (PGA) filing, the Company will request recovery of the Tacoma LNG Facility costs through a separate tracker.[590]

2) The Settling Parties agree that PSE met its "threshold" prudence requirement and that Tacoma LNG Facility costs may be included in rates on a provisional basis.[591]

3) Tacoma LNG distribution costs will be recovered in base rates.[592]

329 The Settling Parties have incorporated Tacoma LNG distribution costs into the Revenue Requirement Settlement. All other Tacoma LNG recovery will be requested when PSE files its 2023 PGA. The revenue increases set forth in the Revenue Requirement Settlement assume that the Commission will approve the Tacoma LNG Settlement.

B. Summary of the parties' testimony in support of, and in opposition to, the Tacoma LNG Settlement

330 PSE witness Ronald J. Roberts explains that the Tacoma LNG Facility is a dual-use project located at the Port of Tacoma.[593] This facility sells LNG as a fuel to non-regulated customers, such as TOTE, and it is also capable of vaporizing and injecting enough gas into the distribution system to serve the design peak day gas requirements of approximately 85,000

---

[589] The Tacoma LNG Settlement provides that distribution costs are included in base rates, without providing for any allocation of distribution costs to non-regulated customers. *See* Tacoma LNG Settlement ¶ 18.A.4. Any lack of clarity in our description of the Settlement arises from the corresponding lack of clarity in the Settlement on this same issue.

[590] Tacoma LNG Settlement ¶ 18.D.

[591] *Id.* ¶ 18.B.

[592] *Id.* ¶ 18.A.4.

[593] Roberts, Exh. RJR-1CT at 10:4-5.

homes.[594] PSE seeks a determination in this proceeding that the decision to develop and construct the Tacoma LNG Facility was prudent.[595]

331 Roberts provides testimony regarding the purpose, siting, design, safety, and other aspects of the Tacoma LNG Facility.[596] Roberts explains, for instance, that PSE compared the LNG Facility to other alternatives in its natural gas 2013 Integrated Resource Plan (IRP), and the LNG Facility emerged as the least-cost option.[597] PSE contends that the Tacoma LNG Facility remained the least-cost option over the following years, as the Company updated its analysis.[598] Supporting exhibits include a 77-page narrative timeline of the Company's decision-making,[599] and 1,872 pages of communications provided to the Company's Board of Directors.[600] Roberts's testimony is discussed in greater detail below.

332 Roque B. Bamba provides testimony for the Company regarding the distribution upgrades related to the Tacoma LNG Project. Bamba discusses three specific projects: four miles of pipeline connecting the Tacoma LNG Facility to PSE's gas distribution system; the rebuilding of the Frederickson Gate Station; and one mile of high-pressure pipeline along Golden Given Road East.[601] With respect to the four miles of pipeline, Bamba explains that "the four miles of new piping and meter station are utilized to supply natural gas to the Tacoma LNG Facility for liquefaction and to transport vaporized natural gas from the Tacoma LNG Facility to the distribution system. These four miles of new piping and the meter station support *both* uses of the Tacoma LNG Facility, PSE's use for system peaking and Puget LNG's use of LNG as transportation fuel."[602] The final cost of these distribution upgrades was $46.4 million excluding accruals related to allowance for funds used during construction (AFDUC),

---

[594] Roberts, Exh. RJR-1CT at 10:9-13.

[595] Roberts, Exh. RJR-1CT at 11:21-23.

For clarity, Roberts distinguishes between the "Tacoma LNG Facility" (or LNG Facility) itself and the broader term, "Tacoma LNG Project," which includes development, construction, and distribution improvements, among other costs. Roberts, Exh. RJR-1CT at 11:1-18.

[596] *See generally* Roberts, Exh. RJR-1CT at 10:3-63:5.

[597] *See, e.g.*, Roberts, Exh. RJR-1CT at 63:9-64:3.

[598] Roberts, Exh. RJR-1CT at 64:4-65:6.

[599] *See* Roberts, Exh. RJR-3 (Timeline and Narrative of Development and Construction Activities for the Tacoma LNG Project).

[600] *See* Roberts, Exh. RJR-5C (Cumulative Communications with the Board of Directors Regarding the Tacoma LNG Project).

[601] Bamba, Exh. RBB-1T at 21:13-19.

[602] Bamba, Exh. RBB-1T at 23:10-15 (emphasis added).

including $30 million for the four miles of pipe and meter station, $4.1 million for the Fredrickson Gate Station, and $12.3 million for the one mile of high pressure piping.[603]

333 In response testimony, Robert L. Earle testifies for Public Counsel that, at two major decision points, a better-informed Board of Directors may have reasonably concluded that the need forecasting was problematic and should be re-examined.[604] Even if the forecasting was accurate, Earle submits that the LNG Facility would not satisfy the projected need for more than four or five years and that the analysis failed to consider sufficient alternatives.[605]

334 First, Earle testifies that PSE failed to establish the necessity of an LNG liquefaction and storage facility. Specifically, Earle submits that PSE has repeatedly forecast "immediate" needs to justify the Tacoma LNG Project to serve peaking needs that never materialized, citing five incorrectly forecasted shortfalls.[606] Earle argues that PSE's gas resources far exceeded its actual peak load for nine winters (2012-2021).[607] Earle further argues that the starting point for each forecast far exceeded recent actual peak loads.[608] According to Earle, it appears that PSE did not inform its Board of Directors of these facts;[609] that the Board has received no updates on the regulated portion of the LNG Project for nearly two years;[610] and that no information was provided to the Board about the curtailment to PSE's gas customers, the level of immediate need, or forecasts versus actuals.[611]

335 Next, Earle testifies that the Tacoma LNG Project was a stopgap measure that was only intended to forestall the need for other peaking resources for four or five years, which means PSE could have implemented other temporary measures until a better solution could be found.[612] Earle submits that PSE failed to consider that demand for gas could be curtailed during peak periods, that it could use fuel oil to generate electricity from dual-fuel combustion

---

603 Bamba, Exh. RBB-1T at 22:15-16. AFUDC is a regulatory method of accounting for the full cost of an asset under construction. The method compensates a utility for financing costs incurred during the construction of new facilities, which is a critical component of cost when considering that utilities are capital-intensive, the time it takes to complete large projects, and cash flow issues related to normal utility operations.

604 Earle, Exh. RLE-1CTr at 2:25-3:5.

605 *Id*.

606 Earle, Exh. RLE-1CTr at 16:5-7.

607 Earle, Exh. RLE-1CTr at 17:1-8.

608 Earle, Exh. RLE-1CTr at 18:15-18.

609 Earle, Exh. RLE-1CTr at 20:6-7.

610 Earle, Exh. RLE-1CTr at 23:12-13.

611 Earle, Exh. RLE-1CTr at 23:13-17.

612 Earle, Exh. RLE-1CTr at 26:4-5.

turbines, or that it could install compressed natural gas storage at generating stations for use during peak periods.[613] Earle submits that PSE failed to present these alternatives to its Board of Directors.[614]

336 Finally, Earle testifies that PSE failed to consider equity in its decisions on the Tacoma LNG Project. Although statutory requirements to incorporate environmental justice into utility planning processes were enacted in 2021, after the Company's decision to construct the facility, Earle contends that PSE has previously stated it considers anticipated or approved laws and regulations in its decision making and has long been aware of equity considerations.[615]

337 Earle concludes that the Tacoma LNG Project fails in all four factors the Commission uses to evaluate prudency: need, evaluation of alternatives, communication with and involvement of board of directors, and adequate documentation.[616] Earle recommends, on behalf of Public Counsel, that the Commission disallow the recovery of $239 million in total plant costs for the facility and $46.6 million for the distribution upgrades plus any AFUDC.[617]

338 In response testimony on behalf of the Puyallup Tribe, Dr. Ranajit Sahu testifies that the decision to build the Tacoma LNG Facility was not prudent and that PSE could have pursued other alternatives that did not present the same public health and safety risks.[618] Dr. Sahu testifies that the LNG Facility presents (1) disparate impacts related to siting a facility with a risk of catastrophic explosion near low-income communities and communities of color and (2) disparate impacts related to increased air pollution located near the facility, which includes the Tribe and other low-income and communities of color synonymous with "vulnerable populations" and "highly impacted communities" as those terms are defined in the Clean Energy Transformation Act (CETA).[619]

339 Specifically, Dr. Sahu argues that PSE's decision to construct the facility was imprudent considering the negative externalities it presents.[620] Dr. Sahu defines "externality" as an indirect cost to an uninvolved third party that emanates from another party's activities that

---

[613] Earle, Exh. RLE-1CTr at 27:2-7.

[614] Earle, Exh. RLE-1CTr at 30:3-5.

[615] Earle, Exh. RLE-1CTr at 31:11-18.

[616] Earle, Exh. RLE-1CTr at 35:2-5; Exh. RLE-14CT at 18:7-11.

[617] Earle, Exh. RLE-1CTr at 3:8-16.

[618] *E.g.*, Sahu, Exh. RXS-1T at 8:3-9.

[619] Sahu, Exh. RXS-1T at 8:8-15.

[620] Sahu, Exh. RXS-1T at 15:18-20.

often involve natural resources or public health.[621] Dr. Sahu contends that the facility's location was obviously selected because it is advantageous to TOTE, but it disadvantages ratepayers for peak shaving gas because of the length the LNG must travel to reach the injection point into PSE's distribution system.[622] A "prudent option in the interest of ratepayers, even if such a facility was needed at all, would have been to site it closer to the injection point, minimizing an expensive new pipeline, and instead building the pipeline to bring LNG to TOTE, whose costs should have been borne by the non-regulated entity."[623] Dr. Sahu contends that many of the costs PSE seeks to recover from ratepayers, such as pretreatment costs, after pretreatment costs, after liquefication costs, and after storage costs, should be allocated to TOTE and its other non-regulated customers.[624]

340 Dr. Sahu submits that it is undisputed that the facility will emit pollution to the ambient air surrounding the facility – located on the peninsula between the Blair and Hylebos waterways in Tacoma, adjacent to the Puyallup Indian Reservation – including criteria air pollutants, toxic air pollutants, volatile organic compounds, and greenhouse gases.[625] Dr. Sahu argues that the facility will emit a number of Toxic Air Pollutants and Hazardous Air Pollutants, noting that the population residing adjacent to the facility already experiences disproportionately higher environmental burdens.[626] Dr. Sahu next describes the risk of explosions and other catastrophic events, citing explosions at similar facilities in other states and arguing that PSE's testimony is silent on this issue.[627] Dr. Sahu's testimony regarding air quality issues and safety impacts is discussed in greater detail below.

341 Dr. Sahu also argues that the air permit for the LNG Facility limits the use of the facility's vaporizer, which is used to re-gasify LNG so it can be introduced to PSE's distribution network, to no more than 240 hours in a 12-month period.[628] This means that the LNG Facility can only operate as a peak shaving facility 10 days per year at most.[629]

342 Dr. Sahu further argues that PSE provided no basis for sizing the tank based on six consecutive days of vaporization, despite data that shows there were just two consecutive high

---

[621] Sahu, Exh. RXS-1T at 15:18-20.

[622] Sahu, Exh. RXS-1T at 16:15-18.

[623] Sahu, Exh. RXS-1T at 16:19-22.

[624] Sahu, Exh. RXS-1T at 26:13-28:18.

[625] Sahu, Exh. RXS-1T at 17:6-14.

[626] Sahu, Exh. RXS-1T at 18:1-14; 19:8-21:9.

[627] Sahu, Exh. RXS-1T at 21:13-22:19.

[628] Sahu, Exh. RXS-1T at 10:1-5.

[629] Sahu, Exh. RXS-1T at 10:1-5.

usage days in the years prior to PSE's decision to size the facility.[630] Even if the demand for six consecutive days of peak shaving existed, Dr. Sahu contends, PSE's additional storage capacity and withdrawal needs could have been met by its Jackson Prairie storage facility or by diverting gas from its electric generating facilities.[631]

343 Dr. Sahu also argues that PSE unnecessarily incurred several costs, including re-designing Tacoma LNG due to a change in the composition of its incoming feed gas, and the litigation costs that PSE is attempting to recoup.[632]

344 On August 26, 2022, PSE filed the Tacoma LNG Settlement along with testimony in support of the settlement. In their joint testimony, Company witnesses Piliaris, Free, and Jacobs briefly provide support for the Settlement's terms related to the Tacoma LNG Facility.[633]

345 PSE also provides more detailed testimony from Roberts, responding to arguments raised earlier by Public Counsel and the Tribe. Roberts testifies that PSE adhered to the Commission's prudence standard in developing and constructing the Tacoma LNG Facility.[634] With regard to the need for the resource, Roberts argues that PSE established a need for new peak-day resources.[635] The potential need for an LNG storage facility was first identified in the Company's 2009 Integrated Resource Plan (IRP) and the Company's 2011, 2013, and 2015 IRPs, which continued to show a need for peaking resources.[636]

346 Roberts defends the Company's reliance on its load forecasts and the assessment of need for this peak-shaving facility.[637] While Public Counsel argues that actual peak day sales were below the Company's forecasts, Roberts explains that "this comparison appears to misunderstand the basic reason PSE engages in forecasting and system planning."[638] Roberts argues that its design day standard is intended to assure that gas resources are available on a

---

[630] Sahu, Exh. RXS-1T at 11:10-19.

[631] Sahu, Exh. RXS-1T at 12:5-13.

[632] Sahu, Exh. RXS-1T at 28:21-30:17.

[633] *See* Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 45:14-48:2.

[634] Roberts, Exh. RJR-30T at 4:4-5.

[635] Roberts, Exh. RJR-30T at 5:3-5.

[636] Roberts, Exh. RJR-30T at 5:5-24.

[637] Roberts, Exh. RJR-30T at 6:19-20.

[638] Roberts, Exh. RJR-30T at 7:8-13.

13ºF peak day.[639] He submits that this design day standard was previously acknowledged by the Commission, citing a 2005 IRP acknowledgment letter.[640]

347 Roberts identifies other concerns with Public Counsel's arguments. Roberts notes that if Public Counsel used weather-normalized actual maximum day sales, it would demonstrate that PSE's design day forecast is not materially different from IRP forecasts, which demonstrate a need for the Tacoma LNG Facility.[641] Roberts also notes that design day forecasts are based on economic, demographic, and customer information, which may lead forecasts to vary from weather-normalized actual maximum day sales.[642]

348 Roberts also disagrees that the Tacoma LNG Facility is a mere "stop gap" measure.[643] PSE intends to use the Tacoma LNG Facility even though additional resources will be necessary to meet peak day load.[644] Roberts does not agree that the Company should have pursued other, temporary measures to meet gas load, and he maintains that the Tacoma LNG Facility was the least-cost resource available to PSE.[645]

349 While the Puyallup Tribe suggests that the Tacoma LNG Facility would only serve PSE's needs for five years, Roberts argues that the Puyallup Tribe relies on an erroneous statement in the facility's Supplemental Environmental Impact Statement (SEIS).[646] Roberts submits that PSE did not contest the erroneous statement because the SEIS already resulted in a favorable outcome for the Company.[647]

350 Roberts maintains that PSE sufficiently evaluated other alternatives to the Tacoma LNG Facility. They note that the Company's 2015 IRP recommended a resource plan that included an LNG facility.[648] While the Company considered other options, such as expanding the

---

[639] Roberts, Exh. RJR-30T at 6:5-8.

[640] Roberts, Exh. RJR-30T at 8:1-2 (citing *Puget Sound Energy 2005 Least Cost Plan for Electricity and Natural Gas Operations*, Docket No. UE-050664, Acknowledgment Letter at 4-5 (Aug. 25, 2005)).

[641] Roberts, Exh. RJR-30T at 11:16-19. *See also id.* at 9:4-6.

[642] Roberts, Exh. RJR-30T at 10:4-8.

[643] Roberts, Exh. RJR-30T at 13:11-12.

[644] *See* Roberts, Exh. RJR-30T at 13:8-13.

[645] Roberts, Exh. RJR-30T at 14:6-17.

[646] Roberts, Exh. RJR-30T at 15:7-12.

[647] *See* Roberts, Exh. RJR-30T at 15:15-16:5.

[648] Roberts, Exh. RJR-30T at 17:15-17.

regional pipeline grid,[649] Roberts explains that the Tacoma LNG Facility was chosen as a preferred resource in the 2015 IRP,[650] in a presentation to the Board of Directors in August 2016,[651] and again in a February 2018 Portfolio Benefit Analysis, after construction began.[652]

351 While Public Counsel and the Puyallup Tribe argue that PSE could curtail gas generation to meet peak demand from gas customers, Roberts argues that this would result in a cross-subsidization of natural gas customers by electric customers.[653] When the Commission approved the merger of Puget Sound Power and Light Company with Washington Natural Gas, it required transactions between PSE's power supply and gas supply portfolios to occur at arm's length, with no cost shifting between the electric and gas divisions.[654] Roberts submits that electric customers pay for firm pipeline capacity to mitigate various risks and that it would not be prudent to reallocate this pipeline capacity.[655]

352 While the Puyallup Tribe suggests PSE could have used its Jackson Prairie Storage Facility to meet peak-shaving needs, Roberts explains that it only owns one-third of the Jackson Prairie Storage Facility and that this facility is already factored into PSE's peak day resource stack.[656] Even if there was additional capacity at the Jackson Prairie Storage Facility, the Company claims it does not have firm pipeline capacity to move additional gas into its distribution system.[657]

353 Roberts raises similar objections to using the Gig Harbor Satellite LNG Facility. PSE argues that this facility provides gas supply "during peak weather events for a distribution system

---

[649] Roberts, Exh. RJR-30T at 18:10-12.

[650] Roberts, Exh. RJR-30T at 19:1-2.

[651] Roberts, Exh. RJR-30T at 20:16-20.

[652] Roberts, Exh. RJR-30T at 22:9-11.

[653] Roberts, Exh. RJR-30T at 23:7-19.

[654] Roberts, Exh. RJR-30T at 24:4-7 (citing *In the Matter of the Application of Puget Sound Power & Light Company and Washington Natural Gas Company for an Order Authorizing the Merger of Washington Energy Company and Washington Natural Gas Company with and into Puget Sound Power & Light Company, and Authorizing the Issuance of Securities, Assumption of Obligations, Adoption of Tariffs, and Authorizations in Connection Therewith,* Docket No. UE-960195, Fourteenth Supplemental Order Accepting Stipulation Approving Merger (Feb. 5, 1997)).

[655] Roberts, Exh. RJR-30T at 25:3-12.

[656] Roberts, Exh. RJR-30T at 29:3-14.

[657] Roberts, Exh. RJR-30T at 29:19-22.

that is geographically isolated" from the rest of PSE's distribution system,[658] and that the facility is already factored into PSE's peak day resource stack.[659]

354 Roberts testifies that the Tacoma LNG Facility is used and useful for Washington customers.[660] While he acknowledges the facility's vaporizer may only operate for 240 hours each year, under its permit with the Puget Sound Clean Air Agency, Robert submits that this limit does not compromise the ability to use the full 6.3 million gallons of LNG storage allocated to PSE.[661]

355 Roberts also disputes the claim that the Tacoma LNG Facility causes significant adverse air pollution.[662] Roberts contends that the Pollution Control Hearings Board (PCHB) agreed with PSE's conclusions that the Tacoma LNG Facility was "not a major source" of air pollution,[663] and it found there was no evidence that the Tacoma LNG Facility would violate Ambient Air Quality Standards.[664] Roberts observes that the PCHB found the testimony of the Puyallup Tribe on the issue of hazardous air pollutants to be "devoid of supporting evidence."[665] Roberts acknowledges that particulate matter ($PM_{2.5}$) concentrations exceeded a screening threshold, but contends that this merely required further analysis, and that the PCHB ultimately rejected the Puyallup Tribe's arguments on this issue.[666]

356 Roberts also disagrees with any claims that PSE incurred "unnecessary" costs when developing and constructing the Tacoma LNG Facility. While the Puyallup Tribe suggests that PSE developed the facility for its non-regulated shipping customer, TOTE, Roberts

---

658 Roberts, Exh. RJR-30T at 30:10-13. *See also* Roberts, Exh. RJR-1CT at 32:13-14 (noting that the Tacoma LNG Facility will transfer LNG to the Gig Harbor LNG Facility through tanker trucks).

659 Roberts, Exh. RJR-30T at 30:17-18.

660 Roberts, Exh. RJR-30T at 36:15.

661 Roberts, Exh. RJR-30T at35:15-19.

662 Roberts, Exh. RJR-30T at 37:17-18.

663 Roberts, Exh. RJR-30T at 39:1:7 (citing Roberts, Exh. RJR-32 at 59 ("In sum, the Board concludes that Appellants did not meet their burden of proving in Issue 4d that PSCAA erroneously concluded that TLNG is not a major source of one or more pollutants, VOCs")).

664 Roberts, Exh. RJR-30T at 44:2-5. *Accord* RJR-32 at 62:11-63:5.

665 Roberts, Exh. RJR-30T at 46:11-15. *Accord* RJR-32 at 41, n.18 ("Appellants' sole witness, Dr. Sahu, also makes passing assertions that TLNG is a significant source of hazardous air pollutants, but the Board rejects any argument on the issue of whether TLNG is a major source of hazardous air pollutants as it is devoid of supporting evidence."). *See also* Roberts, RJR-30T at 65:5-66:9 (summarizing the Pollution Control Hearings Board's findings rejecting Dr. Sahu's testimony).

666 *See* Roberts, Exh. RJR-30T at 51:7-12.

argues that the Company achieved "economies of scale" by constructing a dual-use facility,[667] and that these costs are incurred during the construction of any LNG facility.[668]

357 Roberts dismisses the Puyallup Tribe's suggestion that the Tacoma LNG Facility could have been constructed in a more remote location. Roberts submits that the Tribe's argument "ignores the fact that TOTE committed to take LNG for marine fuel, and this commitment was a necessary predicate for the development of the Tacoma LNG Facility due to the economies of scale . . ."[669]

358 Roberts explains that pretreatment is a necessary step prior to liquification,[670] and that the costs of pretreating gas are not unique to marine fuel.[671] Roberts also disputes that PSE failed to anticipate changes in the composition of natural gas. Roberts explains that PSE has been taking gas from British Columbia since 1957 and that the recent increase in British thermal units (BTUs) was unprecedented.[672]

359 Finally, Roberts asserts that PSE's litigation costs responded to the scale and scope of litigation initiated by the Puyallup Tribe and other parties.[673]

360 Testifying on behalf of Staff, Erdahl provides brief testimony contending that the Tacoma LNG Settlement is in the public interest because it preserves the parties' rights to challenge the prudency of Tacoma LNG Facility costs in the future.[674] Erdahl argues that it will be easier to review the project once all costs are known and measurable.[675]

---

[667] Roberts, Exh. RJR-30T at 57:21-22.

[668] Roberts, Exh. RJR-30T at 58:2-3.

[669] Roberts, Exh. RJR-30T at 58:13-16. *See also* RJR-3 at 11 ("Moreover, the Port of Tacoma is in the heart of PSE's gas distribution system and siting the LNG facility there would provide system benefits for PSE's core gas customers.").

[670] Roberts, Exh. RJR-30T at 59:10-11.

[671] *See* Roberts, Exh. RJR-30T at 59:7-60:7.

[672] *See* Roberts, Exh. RJR-30T at 60:16-61:8.

[673] Roberts, Exh. RJR-30T at 61:16-65:2.

[674] Erdahl, Exh. BAE-1T at 20:7-9.

[675] Erdahl, Exh. BAE-1T at 20:20-21:2.

361 AWEC supports the Tacoma LNG Settlement's terms.[676] AWEC witness Mullins argues that PSE's decision to develop and construct the Tacoma LNG Facility was prudent,[677] but does not explain how he reached this conclusion.

362 Nucor Steel witness Higgins supports the Tacoma LNG Settlement as properly allocating costs to core gas customers.[678] Higgins explains that Nucor Steel is a gas transportation customer.[679]

363 Walmart witness Kronauer also provides brief testimony supporting the Tacoma LNG Settlement.[680]

364 In testimony opposing the Tacoma LNG Settlement, Dr. Sahu testifies on behalf of the Puyallup Tribe that Roberts makes broad, conclusory, and inaccurate statements, including PSE's claims that the Tacoma LNG Facility will not cause or contribute to human health impacts or inequitably affect surrounding communities, and that PSE did not incur unnecessary costs in developing, constructing, and defending its decision to construct the facility.[681] Dr. Sahu further argues that Roberts is not qualified to testify regarding air pollution or the health impacts it causes, and that PSE makes numerous incorrect statements that reflect its misunderstanding of the proceedings related to the Tacoma LNG Project before the Pollution Control Hearings Board (PCHB).[682] Dr. Sahu also describes the Commission's enumeration of equity considerations in the 2021 Cascade GRC Order, arguing that the Commission's recently expanded public interest analysis described in that order applies here.[683]

365 Dr. Sahu is critical of PSE's failure to consider equity in its decision to move forward with its development of the Tacoma LNG Project, noting that information about the existing environmental burdens in the area adjacent to the facility was readily available to the Company in 2016 when it made its decision to move forward.[684] The Tribe goes on to provide detailed testimony and numerous supporting exhibits demonstrating that the communities

---

[676] Mullins, Exh. BGM-11T at 9:6-10:12.

[677] Mullins, Exh. BGM-11T at 11:14-18.

[678] Higgins, Exh. KCH-7T at 3:3-5.

[679] Higgins, Exh. KCH-7T at 2:8-9.

[680] *See* Kronauer, Exh. AJK-1 at 2:9-12.

[681] Sahu, Exh. RXS 30T at 6:3-10.

[682] Sahu, Exh. RXS 30T at 6:21-9:6.

[683] Sahu, Exh. RXS 30T at 11:9-13.

[684] Sahu, Exh. RXS 30T at 14:11-15:8.

neighboring the LNG Facility are already overburdened.[685] For example, the Tideflats area, where the Tacoma LNG Facility is located, "is ranked 10 out of 10 for Environmental Health Disparities and the ranks of the surrounding areas range between 5 and 10."[686]

366 Dr. Sahu encourages the Commission to reject PSE's "misleading" claim that the PCHB did not find that the facility presents disparate impacts to the Tribe, citing the order where PCHB declined to reach that issue on the basis that it lacked subject matter jurisdiction to consider environmental justice claims.[687] Dr. Sahu also notes that the PCHB found that PSE's Clean Air Act Permit was deficient as to the facility's emissions of volatile organic compounds and sulfur dioxide, that those deficiencies are not yet cured, and that PSE has not prepared a Health Impact Analysis for the surrounding areas near the facility.[688]

367 Dr. Sahu also disputes PSE's conclusion that safety concerns about the Tacoma LNG Facility have been put to rest because the Final Environmental Impact Statement specifically identified safety risks as an "impact" and the PCHB made no determination that the facility poses no risks to the public.[689] Dr. Sahu argues that PSE conflates code compliance with safety and fails to address the Tribe's concern of whether Tribal members and Tacoma residents are in danger if there is a catastrophic accident, citing incidents in 2014 and 2022 at code compliant facilities.[690] Dr. Sahu also disputes the adequacy of PSE's "design spill" analysis for assessing risks at the Tacoma LNG Facility because it does not account for all potential risks presented by methane liquefaction facilities.[691]

368 Dr. Sahu also makes the following arguments:

- PSE's plans to provide LNG to the rail industry poses additional negative externalities that will disproportionately impact the Tribe, including concentrated air pollution and derailment risks.[692]

---

[685] Sahu, Exh. RXS 30T at 15:12-17:20.

[686] Sahu, Exh. RXS 30T at 16:1-2.

[687] Sahu, Exh. RXS 30T at 18:4-14.

[688] Sahu, Exh. RXS 30T at 20:11-15.

[689] Sahu, Exh. RXS 30T at 23:1-8.

[690] Sahu, Exh. RXS 30T at 23:9-24:4.

[691] Sahu, Exh. RXS 30T at 25:5-20.

[692] Sahu, Exh. RXS 30T at 27:9-29:6.

- PSE agrees that the weather and gas delivery data show only peak demand periods of three to four consecutive days, demonstrating that the facility's capacity significantly exceeds the public's need.[693]

- PSE's assertion that the Tribe's testimony regarding the need for pretreatment at the facility is contrary to the evidence is incorrect because PSE conflates *some* required pretreatment with *all* pretreatments.[694]

- PSE's claim that there is no significant difference between the gas quality needed for TOTE's engines and the gas quality needed for PSE's retail customers is incorrect, as demonstrated by the need for additional design features specific to TOTE's needs.[695]

- The Commission should consider the significant savings to the unregulated side of the LNG Project associated with PSE not having to construct and operate a delivery system to meet TOTE's needs, and PSE should not be allowed to shift those costs to its ratepayers.[696]

369 Gary S. Saleba also provides testimony on behalf of the Tribe in opposition to the Tacoma LNG Settlement. Saleba testifies that PSE's peak demand forecast declined between 2013 and 2016, demonstrating PSE's acknowledgement that the demand for natural gas was declining as early as 2014/2015, which preceded its decision in 2016 to construct the plant.[697] Saleba argues that the long-term trend in natural gas usage will continue to decrease with the push to reduce carbon emissions nationwide, as demonstrated by natural gas moratoriums enacted in numerous west coast jurisdictions.[698]

370 Saleba further argues that the plant location has a disproportionately adverse impact on the Tribe, which has not been adequately recognized or accounted for. A significant event has the potential to have major impacts on the Tribe's reservation activity and population given its proximity to the plant, and the emissions of pollutants will directly impact the airshed over the Tribe's reservation.[699]

---

[693] Sahu, Exh. RXS 30T at 30:1-13.

[694] Sahu, Exh. RXS 30T at 31:8-32:12.

[695] Sahu, Exh. RXS 30T at 34:9-19.

[696] Sahu, Exh. RXS 30T at 35:1-13.

[697] Saleba, Exh. GSS-1T at 8:6-9.

[698] Saleba, Exh. GSS-1T at 8:11-10:3.

[699] Saleba, Exh. GSS-1T at 11:8-13.

371 Saleba agrees with Public Counsel that PSE has not adequately considered equity, which precludes a determination that the decision to build the facility on the border of the Tribe's reservation was prudent. Saleba contends that the Tribe is disproportionately impacted by the siting and operations of the facility, which PSE concedes it has not addressed.[700] Saleba further argues that the facility did not undergo EFSEC or FERC siting reviews, thus circumventing another opportunity to consider equity.[701]

372 Finally, Saleba argues that if PSE is authorized to recover the cost of plant, the percentage allocation of the Tacoma LNG plant to PSE's regulated business is too high. Because 43 percent of the LNG plant was allocated in the 2016 settlement to PSE's regulated business, the Tribe argues that 43 percent should be used for peaking under the principle of cost causation.[702] According to Saleba, PSE's Supplemental Environmental Impact Statement (SEIS) for the facility states that 1.1 to 2.2 percent of the LNG plant will be used for peaking purposes and for only 10 years out of the plant's projected useful life of 40 years.[703] Using these statistics, Saleba concludes that only $2 million of the total plant costs should be allocated to PSE's rate base.[704] Saleba notes that PSE contests the conclusion in the SEIS that the plant will only provide LNG to ratepayers for 10 years but did nothing to address the alleged error.[705]

373 Public Counsel also provides testimony in opposition to the Tacoma LNG Settlement. Continuing to challenge the need for the facility, Earle observes that PSE's peak day forecast has declined from 2012 except for a jump in 2013, and it was clear that the forecasts had been declining at the two major decision points in 2016 and 2018.[706] Earle maintains that, in fact, no need showed up at all.[707] Earle asserts that PSE ignored the declining forecasts and failed predictions, instead dismissing Public Counsel's comparisons of the Company's model predictions to actual outcomes.[708]

374 Earle also advances the following arguments:

---

[700] Saleba, Exh. GSS-1T at 12:11-15.

[701] Saleba, Exh. GSS-1T at 12:17-25.

[702] Saleba, Exh. GSS-1T at 13:16-19.

[703] Saleba, Exh. GSS-1T at 13:21-24.

[704] Saleba, Exh. GSS-1T at 14:3-5.

[705] Saleba, Exh. GSS-1T at 14:7-13.

[706] Earle, Exh. REL-14CT at 3:7-10.

[707] Earle, Exh. RLE-14CT at 4:6-7.

[708] Earle, Exh. REL-14CT at 5:16-22.

- PSE fails to address a central problem with its decisions to continue with the Tacoma LNG Project by dismissing the idea that other measures could have been put into place until a better solution was found or there was greater clarity regarding the need for the Project.[709]

- PSE did not respond to Public Counsel's arguments that compressed natural gas was a viable alternative to the Tacoma LNG Project, and PSE argues unpersuasively that any arrangement between regulated natural gas operations and regulated electric operations would result in cross-subsidization.[710]

- None of PSE's top 50 gas system demand days are coincident with any of the top 50 gas-for-generation demand days.[711]

- PSE's statement that the Company may have chosen to purchase power rather than run its generation because it would be more economical to purchase than generate power directly contradicts its statement that during a weather-related event or a transmission outage, electric prices would have been very high, and it would be more economical to generate power than purchase it.[712]

- It would have been prudent for PSE to analyze the alternative of using sales between its gas business unit and its electric business unit when it was making its decisions to proceed with the Tacoma LNG Project.[713]

- PSE's 1,800-plus pages of documentation provided to its Board of Directors largely consists of documentation that missed the mark on the consideration of need, alternatives, and adequate information, and the table PSE presents in Exhibit RJR-1CT is misleading because it implies the Board received forecast need information at decision points even though it did not.[714]

375 In its post-hearing Brief, PSE argues that the evidence establishes that the Tacoma LNG Facility is safe and will provide benefits to the communities surrounding the facility.[715] PSE

---

[709] Earle, Exh. RLE-14CT at 8:6-13.

[710] Earle, Exh. RLE-14CT at 9:22-10:16; 11:16-12:15.

[711] Earle, Exh. RLE-14CT at 13:17-19.

[712] Earle, Exh. RLE-14CT at 14:1-8.

[713] Earle, Exh. RLE-14CT at 14:18-21.

[714] Earle, Exh. RLE-14CT at 17:11-18:1.

[715] PSE Brief ¶ 85.

submits that it worked closely with interested parties and made concessions in the project to address the Tribe's concerns.[716]

376 PSE "respectfully requests that the Commission approve the Tacoma LNG Settlement and determine that PSE's decision to build the regulated portion of the Tacoma LNG Facility was prudent."[717] PSE submits that the Settlement's reference to a "threshold prudence requirement" is consistent with the Used and Useful Policy Statement.[718] Noting that only Public Counsel and the Tribe submitted testimony in opposition to the Tacoma LNG Settlement, PSE argues that TEP did not provide any testimony supporting its opposition and that TEP's position should accordingly be given little weight.[719]

377 PSE submits that the Tacoma LNG Facility is already used and useful for customers, noting that it has been liquefying natural gas to fill the facility's storage tank since February 2022.[720] PSE emphasizes that the Commission's longstanding standards for determining prudence consider the information available at the time the decision was made, in light of what PSE knew or reasonably should have known at the time.[721]

378 PSE argues that the Company acted prudently in developing and constructing the facility, indicating that it has provided a "massive" case to defend the prudency of this investment.[722] PSE addresses several arguments raised by Public Counsel and the Tribe. PSE also argues that it made significant efforts to engage with interested parties, such as the Tribe, when developing and constructing the facility.[723]

379 PSE concludes that the Commission should approve the Tacoma LNG Settlement's proposed tracker for LNG Facility costs.[724] PSE also asks that the Commission approve its petition for deferred accounting of Tacoma LNG Facility costs, subject to modifying the deferral period

---

[716] *Id.*

[717] *Id.* ¶ 86.

[718] *Id.*

[719] *Id.* ¶ 87.

[720] *Id.* ¶ 97.

[721] *Id.*

[722] *Id.* ¶ 133.

[723] *Id.* ¶¶ 130-32.

[724] *Id.* ¶¶ 134-35.

consistent with the Settlement's proposed tracker.[725] In its brief, PSE also agrees to drop its request for carrying charges associated with the deferral.[726]

380 Staff argues that the Tacoma LNG Settlement simplifies ratemaking and eases the parties' review by shifting costs into a tracker for later review.[727] Staff submits that the Settlement preserves the parties' abilities to challenge construction and operational costs that do not survive scrutiny.[728]

381 Public Counsel argues in its brief that AWEC, Walmart, Kroger, and Nucor Steel did not perform a prudence analysis of the Tacoma LNG Facility "but simply accept and do not oppose a determination of prudence for settlement purposes."[729] Public Counsel avers that Staff had not completed its prudence review either.[730] Public Counsel continues to oppose the facility on the grounds of prudency and on the basis that it perpetuates systemic inequities.[731]

382 In its Brief, the Tribe argues as an overall matter that PSE's decision to locate the facility where the Tribe and the surrounding community will bear all associated burdens is contrary to the public interest and principles of equity.[732] The Tribe also challenges the prudency of building the facility.[733]

383 The Tribe observes that every individual who commented on the Tacoma LNG Facility at the Commission's public comment hearing opposed the facility.[734] With respect to the positions of other parties, the Tribe observes that AWEC did not focus on equity when considering its position on the Tacoma LNG Settlement,[735] and that Staff did not complete its prudency review of the facility.[736]

---

[725] *Id.* ¶ 135.

[726] *Id.*

[727] Staff Brief ¶ 68.

[728] *Id.* ¶ 69.

[729] Public Counsel Brief ¶ 14.

[730] *Id.* ¶ 16.

[731] *Id.* ¶ 15.

[732] Tribe's Brief at 2:4-7.

[733] *Id.* at 2:8-10.

[734] *Id.* at 2:24-3:8.

[735] *Id.* at 3:3-6 (citing Mullins TR 432:5-7).

[736] *Id.* at 3:7-12 (citing Roberson TR 477:5–11).

384 Because PSE chose not to cross-examine Public Counsel's witness, Earle, or the Tribe's witness, Dr. Sahu, the Tribe argues that the Commission should infer that PSE could identify no basis to challenge their testimony.[737]

385 The Tribe argues that "[w]ith or without a statute" PSE was required to consider the prudency and public interest implications of building the facility in this location.[738] The Tribe also argues that PSE did not have any "vested right" to assume, in 2016, that the law would remain unchanged.[739]

386 The Tribe argues that it is undisputed that PSE did not consider the facility's impacts on vulnerable populations and highly impacted communities.[740] The Tribe submits that PSE was aware of equity issues since at least 2015, when the City of Tacoma issued its Final Environmental Impact Statement (FEIS).[741]

387 The Tribe also maintains that the facility will contribute to air pollution in an already burdened area and that it will exacerbate inequities.[742] The Tribe maintains that PSE's witness, Roberts, was not qualified to testify as to air quality issues.[743]

388 The Tribe reiterates that the facility presents a risk of catastrophic accident, arguing that it was not designed or permitted based on consideration of worst-case scenarios.[744] The Tribe also submits that PSE intends to sell LNG that will be transported by rail, which would increase risks to the Tribe.[745]

389 The Tribe also argues that the Commission should require the completion of a Health Impact Analysis before approving the facility to assess the cumulative effects of air pollutants, before finding the facility to be prudent.[746]

390 Citing the testimony from Public Counsel and the Tribe, TEP argues that the Settling Parties have not demonstrated that the decision to build the Tacoma LNG Facility was prudent or

---

[737] *Id.* at 4:22-5:2.

[738] Tribe's Brief at 11:6-8.

[739] *Id.* at 11:9-11:26.

[740] *Id.* at 12:9-21.

[741] *Id.* at 15:10-18.

[742] *See id.* at 13:3-15:4.

[743] *Id.* at 15:5-9 (citing Roberts, TR 416:20-417:23; 416:18-19).

[744] *E.g., id.* at 17:17-21.

[745] *Id.* at 17:24-18:9.

[746] *Id.* at 21:1-18.

consistent with the public interest.[747] TEP argues that the Commission must consider the equity and environmental health impacts of locating the facility adjacent to the Tribe's reservation and that it is inappropriate for PSE to recover litigation costs resulting from locating its facility in such a location.[748]

391 *Commission Determination.* The Tacoma LNG Settlement is likely the most controversial and litigated issue in this case. This Settlement presents difficult questions about how the Commission should review and consider capital investments, built over a period of years, in light of public policy and statutory standards that changed after the decision to authorize construction. It also raises difficult questions about environmental justice, equity, and to what extent the Commission should consider issues of environmental health when approving recovery of a utility's capital investments.

392 We first address the prudency of the decision to build the Tacoma LNG Facility, before turning to the parties' arguments about equity and environmental health.

i. Prudency

393 As an initial matter, we observe that the Tacoma LNG Settlement is not precise regarding the prudency determination the Settling Parties request from the Commission. The Settlement provides that the Settling Parties "accept a determination that the decision to build the regulated portion of the Tacoma LNG Facility was prudent, thus PSE has met its threshold prudence requirement to demonstrate that the investment can be provisionally included in rates in a tracker."[749] In the interest of precision, we construe the Settlement as requesting a determination that the decision of PSE's Board of Directors to build the Tacoma LNG Facility on September 22, 2016, was prudent.[750] In its post-hearing Brief, PSE requests a determination that the "*decision to build* the regulated portion of the Tacoma LNG Facility was prudent."[751] Staff also suggests that the Settlement preserves the parties' ability to review certain *construction* costs in the future.[752] Taken together, we read the Settlement and the Settling Parties' post-hearing briefs as indicating an agreement that the Settling Parties are stipulating to the prudency of the Company's actions up through the initial decision to build

---

[747] TEP Brief ¶¶ 44-46.

[748] *Id.* ¶ 48.

[749] Tacoma LNG Settlement ¶ 23.B.

[750] *See* Roberts, Exh. RJR-1CT at 33:6-10.

[751] PSE Brief ¶ 86 (emphasis added).

[752] *See* Staff Brief ¶ 69 (arguing that the Settlement "preserve[s] all parties' ability to challenge *construction* or operations costs that do not survive scrutiny under the Commission's ratemaking standards.").

the LNG Facility on September 22, 2016, but that the Settlement allows the parties to review the prudency and reasonableness of costs incurred after that point. We accordingly focus our prudency review on the initial decision to build the facility.

394 Bearing this framework in mind, we agree that PSE has demonstrated a need for the Tacoma LNG Facility at least through the initial decision to build the facility on September 22, 2016. As PSE explains, the Commission has reviewed and accepted the approach PSE uses for its gas planning and IRP processes since at least 2005.[753] IRP planning standards encourage a reliable, adequate gas service for core customers.[754] PSE reasonably relied on its forecasts for gas demand, which showed a need for an LNG peak-shaving facility. Although Public Counsel and the Tribe challenge PSE's forecasting methods,[755] we find these arguments unpersuasive. PSE observes that its forecasts for gas demand declined, and it reevaluated the need for an LNG facility in 2016 and 2018.[756]

395 We are not persuaded that actual maximum day sales, emphasized by Public Counsel, justify rejecting investments planned on the basis of PSE's forecasts.[757] In explaining the Company's reliance on forecasts based on the "design day" standard, Roberts explains that PSE is obligated to serve all of its customers and that planning to accept one or two curtailments in a year would be contrary to the Company's obligation to serve.[758] While Public Counsel argues that forecasts must be examined in light of actual sales,[759] this argument does not fully appreciate the purposes behind planning for resource acquisitions based on a design day standard and customers' interests in reliable gas distribution. This undermines Public Counsel's characterization of PSE's forecasts as merely being "false alarms."[760] The design day standard is intended to ensure a more robust natural gas system that will not run short of resources when they are needed most.

396 Furthermore, we observe that if Public Counsel compared weather-normalized actual maximum day sales volumes to PSE's forecasts, it would be apparent that weather-normalized

---

[753] PSE Brief ¶ 88.

[754] *See generally* WAC 480-90-238.

[755] *E.g.*, Tribe's Brief at 19:15-24 (citing Saleba, Exh. GSS-1T at 6-10).

[756] PSE Brief ¶ 90 (citing Roberts, Exh. RJR-1CT at 60:1-15).

[757] *See* Public Counsel Brief ¶¶ 26-27.

[758] Roberts, Exh. RJR-30T at 7:8-13.

[759] *E.g.*, Earle, Exh. RLE-14CT at 5:15-22.

[760] Public Counsel Brief ¶ 33.

actual maximum day sales have been both above and below PSE's forecasts.[761] This provides further evidence that PSE adjusted its forecasts to reflect changing conditions.

397 Public Counsel also argues that PSE's forecasts declined from 2013 onward.[762] We agree to some extent with Staff that this argument invites second-guessing of the Company's decision-making based on information obtained later or events that occurred after the fact, such as municipal bans on new gas connections.[763] We are persuaded that the Company adequately adjusted its forecasts for gas demand but continued to project a need for an LNG facility through, at the very least, the Company's decision to initiate construction on September 22, 2016.

398 We also reject the argument that the Tacoma LNG Facility was a mere stop gap measure.[764] Roberts adequately explains that PSE intended to use the facility as a long-term resource.[765] Against this testimony, we are not persuaded by any claims that PSE either intends to use the facility for only a short period of time or that it needs to add additional resources fairly soon, rendering PSE's decision to build the facility imprudent.[766] PSE has already presented extensive evidence that the Tacoma LNG Facility was evaluated and found to be a least-cost resource with portfolio benefits. And as PSE observes, "Public Counsel cannot credibly argue on one hand that there is no need for the Tacoma LNG Facility while on the other hand claim that it was not a sufficient resource to meet PSE's longer-term need."[767]

399 We are not persuaded, either, that recovery should be denied because the SEIS indicated that the facility only met PSE's needs for five years.[768] Roberts testified that PSE chose not to dispute the erroneous statement in the SEIS and that, if PSE had challenged this statement, the SEIS would have been even more favorable to the Company.[769] Ultimately, the Company provides a credible response, and we are not persuaded that the comment in the SEIS amounts to a damaging admission in any way.

---

[761] *E.g.*, Roberts, Exh. RJR-30T at 9:1-6 (Figure 1 and accompanying explanation).

[762] *E.g.*, Earle, Exh. RLE-14CT at 3:7-13 (Figure 1 and accompanying explanation).

[763] *See* Staff Brief ¶ 71.

[764] *E.g.*, Tribe's Brief at 20:13-17.

[765] Roberts, Exh. RJR-30T at 13:3-12.

[766] Earle, Exh. RLE-14CT at 8:6-8.

[767] PSE Brief ¶ 93.

[768] Sahu, Exh. RSX-1T, at 12:11-16.

[769] Roberts, Exh. RJR-30T at 15:15-16:8.

400 We are not persuaded, either, that the facility's storage tank is overbuilt.[770] Roberts explains that PSE based its decision for sizing the Tacoma LNG Facility, in part, on its expectation of cold spells lasting two or three days occurring more than once each winter.[771] Roberts further explained at the hearing that a two-to-three-day cold spell would deplete the storage tank, and it could take up to 120 days to refill it.[772] While we observe that the most persuasive explanations for the size of the storage tank came later in the proceeding, this is not necessarily troubling. PSE has provided a large volume of evidence in support of the prudency of the Tacoma LNG Facility, and it is reasonable that the Company would have to adjust its testimony over the course of the proceeding given specific arguments raised by the parties. In addition, we have not been presented with, or granted, any motions to compel that would suggest that PSE failed to comply with discovery requests related to this issue.

401 Even if we agreed with the Tribe and Public Counsel that the tank is overbuilt, it is not evident that building a smaller storage tank would result in any significant savings for customers. Roberts explains that PSE examined downsizing the facility but found that this would not substantially reduce its costs.[773] The Tribe does not provide any persuasive evidence to the contrary.

402 To the extent that the Tribe raises other challenges to PSE's design of the facility, we find these arguments unpersuasive. Dr. Sahu argues, for instance, that the vaporizer would not be necessary if PSE had not liquefied LNG for storage.[774] Yet Dr. Sahu's argument overlooks the extensive discussion and justifications PSE has provided for *LNG storage* as opposed to other alternatives.[775] Once PSE established that LNG storage was a least-cost alternative for peak-shaving, a vaporizer was a necessary expense to reinject gas into PSE's distribution system.[776]

403 We are not persuaded, either, that PSE incurred unreasonable costs in redesigning the facility due to changing composition of imported natural gas.[777] Roberts testified that high levels of ethane or propane in imported natural gas were a problem for core gas customers as well as

---

[770] *See, e.g.*, Tribe's Brief at 20:1-8 (citing Sahu, Exh. RXS-1T at 10-13).

[771] Roberts, Exh. RJR-30T 16:14-19.

[772] Roberts, TR 428:13-25.

[773] Roberts, Exh. RJR-3 at 20-21, *see also* Roberts, RJR-5C at 859.

[774] Sahu, Exh. RSX-1T at 28:9-15 ("[T]here would be no need for a vaporizer to begin with but-for the fact that PSE decided to make LNG for other end users in the first place. Peak shaving needs gas not LNG.").

[775] *E.g.*, Roberts, Exh. RJR-1CT at 13:8-11.

[776] *See id.* at 16:18-19.

[777] *Id*. at 28:25-29:4 (arguing that PSE had to redesign the facility at substantial cost); RXS-30T at 31:11-32:12.

non-regulated, Puget LNG customers.[778] Roberts also testified that the redesign represented only a fraction of the facility's overall cost.[779]

404 With limited exception, we do not accept the Tribe's challenge to the allocation of the facility's costs. The Tribe argues that making ratepayers pay 43 percent when the benefit to them is 2.2 percent (at best) does not comport with cost causation principles or generally accepted regulatory precedents.[780] After careful consideration of the evidence, we find no reason to revisit the earlier settlement agreement in Docket UG-151663 where we approved ring-fencing provisions, the creation of a non-regulated subsidiary Puget LNG, and the allocation of Facility costs between PSE's regulated business and Puget LNG's non-regulated business.[781] The settlement agreement in Docket UG-151663 was the result of extensive discovery, litigation, and negotiation between interested parties, including Public Counsel, with the assistance of independent consultants.[782] The evidence in this proceeding does not justify overturning that earlier agreement, which provided allocation factors for each category of plant equipment.

405 Furthermore, we observe that capacity itself provides a benefit for customers. PSE confirms that the Facility is fully commissioned and ready to serve customers.[783] Although PSE has not yet used the Facility for peak-shaving,[784] we recognize that *capacity* is, by itself, a used and useful resource for customers when it is supported by credible forecasts for customer demand. When we review the prudency of costs included in PSE's 2023 Tacoma LNG tariff filing, the Commission may also consider the extent to which the Facility was used as a peak-shaving resource. Additionally, we expect to suspend the filing to allow an adequate opportunity for those opposing the Tacoma LNG Settlement to review the filing. The Commission benefits from full participation and diverse perspectives.

406 We nevertheless find it necessary to place a condition on our acceptance of the Tacoma LNG Settlement regarding the allocation of certain costs to upgrade distribution facilities.[785] The Settlement allows PSE to recover the costs for these distribution upgrades in base rates,

---

[778] *See* Roberts, TR 421:9-422:2, 423:1-12, 423:13-23.

[779] Roberts, Exh. RJR-30T at 61:9 (testifying that the redesign cost approximately $5.4 million).

[780] Tribe's Brief at 20:9-13 (citing Saleba, Exh. GSS-1T at 14).

[781] *In the Matter of the Petition of Puget Sound Energy, Inc.*, Docket UG-151663 Order 10 (November 1, 2016).

[782] *E.g.*, *id.* ¶ 8.

[783] Roberts, TR 427:1-8.

[784] *Id.* at 427:10-17.

[785] *See* Bamba, Exh. RBB-1T at 21:13-16 (describing distribution upgrades for the Tacoma LNG Facility).

without allocating any portion of these to non-regulated customers.[786] These distribution upgrade costs are not included in the Tacoma LNG Settlement's proposed tracker for the remaining Facility costs, and the Settling Parties do not explicitly reserve their right to later challenge the prudence of distribution upgrade costs. The most significant distribution costs reflect the four miles of pipeline connecting the Tacoma LNG Facility to PSE's distribution system.[787] This pipeline accounts for the majority of LNG distribution costs ($30 million out of $46.4 million without including AFUDC), and was placed into service in 2017.[788]

407 As discussed above, PSE's witness Bamba confirms that the four miles of distribution pipe support both PSE's use of the LNG facility for system peaking and Puget LNG's use of LNG as a transportation fuel.[789] PSE witness Piliaris also confirms that the distribution pipe serves both uses, but states that 100 percent of the costs of the distribution facilities would be placed into regulated rate base, and that PSE would "recover an appropriate share of their costs from Puget LNG through the distribution rates."[790] The settlement agreement in Docket UG-151663 reflects that the allocation of the project costs for liquefaction includes facilities used to bring natural gas to the facility.[791] Further, the settlement, and the Commission's Order approving the settlement in Docket UG-151663, provided that the provisions governing the "treatment" of costs relating to the four miles of 16" distribution line are binding only on PSE, given that Staff, Public Counsel, and other parties did not agree to that provision.[792]

408 From the prior settlement and order, and the testimony and evidence in this record, it appears there was recognition and agreement that the full cost of the four miles of distribution line should *not* be borne solely by core customers. However, it is not clear from the record or the Settlement in this proceeding how PSE will recover the shared costs for the distribution plant from Puget LNG, how the costs will be allocated, or how the treatment of the capital costs in regulated rate base will be addressed by the recovery of costs from Puget LNG.

409 Given this information, we are concerned that the Tacoma LNG Settlement includes LNG distribution costs in base rates without any clear determination of what method would be used

---

[786] Tacoma LNG Settlement ¶ 18.A.4.

[787] *See* Bamba, Exh. RBB-1T at 22:16-18.

[788] Bamba, Exh. RBB-1T at 22:5-6.

[789] Bamba, Exh. RBB-1T at 23:10-15.

[790] Piliaris, Exh. JAP-1T at 52:7-9.

[791] See *Id.*, ¶ 56(a): "The liquefaction allocator allocates capital costs associated with liquefaction, *which include the costs of facilities used to receive natural gas*, treat the gas, cool the gas below its boiling point and deliver the gas to onsite storage."

[792] *In the Matter of the Petition of Puget Sound Energy, Inc.*, Docket UG-151663 Order 10 (November 1, 2016). ¶ 113.

to allocate "an appropriate share" of those costs to the non-regulated activities of Puget LNG. We agree with PSE that it is appropriate for a portion of these costs to be allocated to non-regulated business activities, such as the use of LNG by TOTE Maritime, LLC, but are unclear how and when that allocation will be made or reflected in core customers' rates.[793]

410 Thus, we reject the Settling Parties' proposal for recovering the costs for the four miles of distribution pipe in base rates without further consideration of the allocation of costs between core customers and Puget LNG, specifically a determination of the "appropriate share" of costs for which Puget LNG is responsible, how those costs will be recovered from Puget LNG, and how those costs will be reflected in regulated rate base. Thus, we reject the Settling Parties' proposal for recovering the costs for the four miles of distribution pipe in base rates without further consideration of the allocation of costs between core customers and Puget LNG, specifically a determination of the "appropriate share" of costs for which Puget LNG is responsible, how those costs will be recovered from Puget LNG, and how those costs will be reflected in regulated rate base. While these costs should be included in rates on a provisional basis, the issues regarding the appropriate allocation and method of recovery should be addressed when the Company requests recovery of the Tacoma LNG Facility costs when submitting its 2023 PGA filing. We therefore accept the Tacoma LNG Settlement subject to the following condition:

> **CONDITION**: In PSE's compliance filings for rates under the MYRP authorized by this Order, PSE must include the $30 million for the four miles of distribution pipe in rates on a provisional basis, subject to consideration of the appropriate allocation of costs to Puget LNG and the method of recovery of these costs when the Company requests recovery of the Tacoma LNG Facility costs when submitting its 2023 PGA filing. PSE must defer the revenues associated with the provisional recovery of the $30 million for the four miles of distribution pipe for supporting proper allocation in the 2023 PGA filing.

411 Finally, we are not persuaded by the Tribe's argument that the Tacoma LNG Facility is "not really for ratepayers at all."[794] While Roberts admitted at the hearing that PSE would not have built the Facility if it could not produce LNG meeting TOTE's requirements,[795] as Roberts explained, PSE achieved economies of scale by constructing a dual-use facility.[796]

---

[793] *E.g.*, Sahu, Exh. RXS-1T at 23:18-24.

[794] Tribe's Brief at 7:3-6, 19:3-7.

[795] Roberts, TR 425:16-426:6

[796] Roberts, Exh. RJR-30T at 57:20-22.

412 We also agree that PSE has adequately considered alternatives to the Tacoma LNG Facility. For example, in its 2011 IRP, PSE evaluated five alternatives and an LNG storage facility was identified as one resource in a three-resource lowest reasonable cost plan for meeting gas demand in 2017 and beyond.[797] In its 2013 and 2015 IRPs, PSE again identified an LNG facility as part of its least-cost resource solution compared to several other options.[798] In 2016, PSE management presented the Board of Directors with an analysis showing a $54 million net present value benefit to customers with the Tacoma LNG Facility compared to other resources over a 20-year period.[799] In 2018, PSE management reevaluated the Tacoma LNG Facility and again recommended it to the Board of Directors as a least-cost resource, with a $112.5 million benefit to the existing gas portfolio.[800]

413 While Public Counsel and the Tribe suggest alternatives to the Tacoma LNG Facility,[801] we find that these proposals are not fully supported by the evidence. Public Counsel witness Earle suggests that the Company should have considered compressed natural gas storage at generating facilities.[802] Roberts explains, however, that Public Counsel fails to consider the physical footprint that would be required to store the necessary volume of compressed natural gas.[803] Public Counsel appears to overlook this response to its own proposed alternative.[804]

414 We have considered Public Counsel's argument that PSE should have considered curtailing gas for generation to meet gas peak-shaving needs. Public Counsel is correct, as a general matter, that PSE's electric and gas units may trade with each other when these trades are mutually beneficial.[805] However, we are persuaded that PSE's electric and gas units are both *winter peaking* and that it is possible that times of peak gas demand may coincide with peak electricity demand.[806] Furthermore, the Company separately allocates costs to its electric and

---

[797] Roberts, Exh. RJR-1CT at 57:10-16; see also Roberts, Exh. RJR-3 at 3-4.

[798] Roberts, Exh. RJR-1CT at 63:9-19; Roberts, Exh. RJR-3 at 25-26.

[799] Roberts, Exh. RJR-30T at 20:8-21:6; see also Roberts, Exh. RJR-3 at 45-52.

[800] Roberts, Exh. RJR-30T at 22:10-22:14; see also Roberts, Exh. RJR-3 at 63.

[801] *See* Public Counsel Brief ¶¶ 29-30 (arguing that PSE failed to consider curtailing gas for generation, using fuel oil to generate electricity, and installing compressed natural gas storage).

[802] Earle, Exh. RLE-14CT at 9:12-20.

[803] Roberts, Exh. RJR-1CT at 13:18-14:8.

[804] *See* Earle, Exh. RLE-14CT at 9:22 (asserting that Roberts did not respond to the proposed alternative of using compressed natural gas).

[805] Public Counsel Brief ¶ 30. *Accord* Earle, Exh. RLE-14CT at 10:17-11:13.

[806] See Earle, Exh. RLE-8 (PSE Response to Public Counsel Data Request No. 378(c) ("Both PSE's gas system and electric system provide service to highly temperature sensitive demand territory"); Earle, Exh. RLE-10 (PSE Response to Public Counsel Data Request No. 312(d) ("It was presumed that

gas customers.[807] A significant number of PSE's customers only take electric or gas service, which raises concerns regarding cross-subsidization between the electric and gas customers.[808] PSE has also raised credible concerns that there is a lack of firm pipeline capacity on the Northwest Pipeline System.[809] Curtailing gas for generation could also create reliability concerns for PSE's electric customers.[810] Public Counsel has not presented evidence, testimony, or cross-examination that effectively rebuts PSE's testimony on this issue.

415 Public Counsel witness Earle observes that PSE answered a question posed by the Puget Sound Clean Air Agency indicating that curtailing gas for generation and using fuel oil for dual-fuel combustion turbines could meet initial customer demand in a scenario where the Tacoma LNG Facility was not available.[811] However, this was merely a hypothetical scenario in which the Company did not have access to a needed resource. PSE also indicated that curtailing gas for generation would only meet "initial" customer demand and that the Company would "immediately" begin contracting for additional pipeline capacity.[812] This does not demonstrate that curtailing gas for generation would be a reasonable, lowest-cost option for serving gas demand. Roberts testified that there is no additional firm pipeline capacity on the Northwest Pipeline System. We are persuaded that, under these circumstances, curtailing gas for generation and relying on non-firm (*i.e.*, interruptible) pipeline capacity would be likely more expensive and present a risk of curtailments.

416 We also reject Public Counsel's arguments that PSE could have used capacity at the Jackson Prairie Storage Facility or the Gig Harbor Satellite LNG Facility to meet its peaking needs. As

---

if a peak event occurs, both PSE gas system needs and gas generation needs may very likely be coincident, thus putting extreme pressure on the entire gas and electric grid"); and Earle, Exh. RLE-10 (PSE Response to Public Counsel Data Request No. 312(e) ("PSE analyzed the Tacoma LNG project for purposes of meeting its natural gas distribution peak system needs. If PSE's electric system load peaked in the summer, like many parts of the country, such gas supply/transportation sharing arrangements might be feasible. However, hoping to divert gas supplies from electric generation when it is most needed to meet peak electric needs in winter is not a reasonable plan."); Earle, Exh. RLE-14CT at 11:3-7 (indicating that there may be a "rare occurrence" where the Company's electric business unit planned to burn all its available gas for generation at a time of peaking gas demand).

[807] Roberts, Exh. RJR-30T at 23:13-16.

[808] *See id.* at 23:7-13.

[809] Roberts, Exh. RJR-30T at 29:22-30:2.

[810] *Id.* at 25:20-23.

[811] Earle, Exh. RLE-10 at 20-21.

[812] *See id.*

PSE explains, these facilities are already factored into PSE's resource stack, and there is no firm pipeline capacity to move gas from these facilities during times of peak demand.[813]

417 With regard to the third prudency factor, we agree that PSE's Board of Directors was sufficiently informed and involved at least through its decision to authorize construction of the facility on September 22, 2016. In May 2012, the Company's Board of Directors approved the continued investigation of the potential ownership of an LNG facility.[814] PSE management continued to inform the PSE Board of Directors regarding its evaluation of owning an LNG facility, and in September 2016, the Company's Board of Directors authorized construction of the Tacoma LNG Facility.[815]

418 We also find that PSE provided adequate documentation of its decision-making as it developed and constructed the Tacoma LNG Facility. In Roberts's Exhibit RJR-3, PSE provided a thorough narrative timeline of the development and construction of the Tacoma LNG Facility, which describes dozens of reports and presentations provided to the Board of Directors. In Roberts's Exhibit RJR-5C, PSE provided its presentations to the Board of Directors regarding the Company's evaluation of an LNG facility and its later development and construction of the Tacoma LNG Facility.

419 Public Counsel and the Tribe argue that PSE failed to sufficiently inform its Board of Directors and failed to provide adequate documentation of its decision-making.[816] These arguments appear to be premised on earlier challenges to the Company's load forecasts and proposed alternatives such as curtailing gas for generation. Because we agree with PSE that it appropriately based planning decisions on its design day standard and that proposed alternatives, such as curtailing gas for generation, are problematic, we do not accept Public Counsel's or the Tribe's challenges to the third and fourth prudency factors.[817] PSE management provided the Board of Directors updated forecasts of gas demand over the course of the development and construction of the facility, keeping the Board of Directors sufficiently informed at least through September 22, 2016.[818] Because the Tacoma LNG

---

[813] PSE Brief ¶ 105 (citing Roberts, Exh. RJR-30T at 29:11-30:21).

[814] Roberts, Exh. RJR-1CT at 57:16-20; Roberts, Exh. RJR-3 at 4-8; Roberts, Exh. RJR-5C at 3-61; Roberts, Exh. RJR-30T at 31:5-6.

[815] Roberts, Exh. RJR-1CT at 58:1-60:8; Roberts, Exh. RJR-3 at 8-25, 29-43, 45-52; Roberts, Exh. RJR-30T at 31:6-12; Exh. RJR-5C at 62-1693.

[816] *E.g.*, Public Counsel Brief ¶¶ 34-38.

[817] *See* PSE Brief ¶¶ 108, 110.

[818] *E.g.*, Roberts, Exh. RJR-5C at 1794.

Settlement only indicates an agreement among the Settling Parties regarding the decision to build the facility, we do not proceed further.

420 Finally, we accept the Tacoma LNG Settlement's terms regarding PSE's litigation costs. Based on the evidence presented in this case, we agree that PSE incurred litigation costs responding to arguments from the Tribe and other parties related to a number of issues.[819] As we discuss in greater detail below, the PCHB found a number of Dr. Sahu's claims to be vague, unsupported, or lacking in credibility.[820] It is not credible for the Tribe to challenge PSE's recovery of litigation costs in this proceeding when PSE has so far prevailed on the vast majority of issues raised by the Tribe in other forums.

ii. Equity and environmental health

421 There is significant disagreement in this case as to how the Commission should review the Tacoma LNG Facility in terms of equity and environmental health. We are committed to "apply[ing] an equity lens in all public interest considerations going forward."[821] The Tacoma LNG Facility, however, presents difficult questions about how we might apply an equity lens while also applying long-standing principles of ratemaking. We recognize that long-standing principles of ratemaking have not required regulators to apply an equity lens in decision making. We also recognize that an equity lens is not additive, but rather foundational, to our review of all requests, proposals, and recommendations.

422 As we have observed, PSE's Board of Directors authorized construction of the Tacoma LNG Facility on September 22, 2016, and the facility was mechanically completed before RCW 80.28.425 was enacted. PSE argues that it acted prudently based on the standards that existed at the time and that its decisions should not be second-guessed based on hindsight. We also recognize that the Puyallup Tribe has been challenging the Tacoma LNG Facility on the basis of equity and environmental health outcomes since before the RCW 80.28.425 was enacted.

423 Public Counsel and the Tribe argue, however, that PSE failed to consider the impacts to Vulnerable Populations and Highly Impacted Communities and that approving recovery of this project would contribute to systemic injustice.[822] The Tribe presents a number of arguments as to why the Commission should consider equity and environmental health issues even though the facility was constructed before changes in public policy occurred.

---

[819] Roberts, Exh. RJR-30T at 63:15-64:2.

[820] See Roberts, Exh. RJR-32 ¶¶ 75, 77, 100.

[821] *WUTC v. Cascade Natural Gas Corporation*, Docket UG-210755 Order 09 ¶ 58 (August 23, 2022).

[822] *E.g.*, Tribe's Brief at 12:15-26 (citing Sahu, Exh. RXS-16; Saleba, Exh. GSS-1T at 12).

424 We begin our discussion by noting the statutes at issue. CETA envisions the equitable distribution of both the benefits and burdens of the transition to clean energy. Pursuant to RCW 19.405.010(6), the legislature recognizes and finds that the public interest includes but is not limited to the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency." More recent legislation specifically allows the Commission to consider equity and environmental health. Pursuant to RCW 80.28.425(1), the Commission may consider factors such as environmental health, greenhouse gas reductions, and equity considerations into the Commission's "consideration of a proposal for a multiyear rate plan."

425 Because we are focused on PSE's request for recovery of the Tacoma LNG Facility, we must consider the broader public interest standard from RCW 80.28.425 in a manner that is consistent with other applicable statutes and policies regarding the valuation of utility company property. Pursuant to RCW 80.04.250, the Commission has the authority to ascertain and determine the fair value for rate-making purposes of utility property. The Commission may provide for changes to rates "using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates."[823] The Commission must also establish an appropriate process to identify, review, and approve rate-period effective investments.[824] The Commission later established this process in the Used and Useful Policy Statement, which emphasizes that requests for rate-period effective investments must conform to long-standing rate-making principles.[825] The Company must show, for instance, that the property will be used and useful, based on known and measurable events, and that costs were prudently incurred.[826] In addition to a threshold prudency showing, the Company must also demonstrate prudency over the life of the investment.[827] Because the question of prudency requires us to consider the Company's actions both in light of what it knew at the time,[828] as well as over the life of the investment, there is a natural tension in this proceeding between the absence of equity and environmental health considerations in ratemaking as it relates to the threshold prudency of PSE's decision to construct the facility and the continuous demonstration of prudency over the life of the

---

[823] RCW 80.04.250(3).

[824] *Id.*

[825] Used and Useful Policy Statement ¶ 20.

[826] *Id.*

[827] *Id* ¶ 35, n.39.

[828] *E.g.*, *id.* ¶ 26 n.34 ("The Commission's prudency analysis examines many factors, including whether the costs asserted are reasonable compared to other alternatives a company considered at the time the decision to build or acquire was made.").

investment now that equity and environmental health considerations have been incorporated into ratemaking.

426 The Commission is committed and currently working to implement both performance-based regulation and equity considerations into its ratemaking framework. However, we find that it would be unreasonable and inappropriate to reject the Settlement's threshold prudency determination to construct the facility in light of later statutes that did not exist at the time that expand the Commission's authority to consider equity and environmental health.

427 We emphasize that the Commission serves primarily as an *economic* regulator. While RCW 80.28.425 expands the public interest standard to include issues such as equity and environmental health, we recognize that this law must be applied to prudency going forward but should not be applied retroactively. We further conclude that the law does not allow the Commission to retrospectively second-guess the determinations of other, more specialized environmental health agencies, such as the Pollution Control Hearings Board, which is responsible for reviewing agencies' actions in siting and permitting the plant.

428 As Staff observes, recent statutory changes pose difficult questions regarding the Commission's application of the public interest standard.[829] Staff asks, "But where does that leave this facility, which was planned and mostly built under the old legal regime?"[830] Staff concludes, and we agree for purposes of reviewing this non-precedential Settlement, that the applicable definition of the public interest was the one in effect at the time PSE decided to build the facility."[831] We find it would be unjust and unreasonable to incorporate information available only through hindsight into the prudency determination related to construction that occurred in 2016.[832]

429 We are not persuaded by the Tribe's arguments to the contrary. The Tribe argues, for example, that PSE did not have any vested right to assume, in 2016, that the law would remain unchanged.[833] Yet as we have observed, RCW 80.28.425 provides for a list of factors

---

[829] *See* Staff Brief ¶ 73.

[830] Staff Brief ¶ 73.

[831] *Id.* ¶ 74.

[832] *Cf.* Tribe's Brief at 8:9-10 (arguing that "PSE's investment in Tacoma LNG should not be found prudent because it does not serve the public interest.").

[833] Tribe's Brief at 11:9-22.

We agree though, that investor-owned utilities like PSE should have been and should be responsive to the needs of those they serve or those who are impacted by their operations. We recognize that this is not a requirement of law.

that the Commission may consider when reviewing MYRPs. It does not require the Commission to upend its longstanding principles of prudency review.

430 Thus, insofar as we apply the expanded public interest standard set forth in RCW 80.28.425(1) to our review of the Tacoma LNG Settlement, we consider it as one of three settlements setting forth a proposed MYRP for PSE. We consider the facility's implications for equity and environmental health in the context of the other two partial, multiparty settlements resolving this general rate case.

431 When considered in this light, we find that the Tacoma LNG Settlement is consistent with the public interest as one of three partial multiparty settlements resolving this general rate case and providing for a two-year MYRP. The parties opposing the Tacoma LNG Settlement fail to establish that the Settlement should be rejected as contrary to the public interest.

432 Turning to the specific factual arguments, we observe that the parties disagree widely on whether the Tacoma LNG Facility provides environmental benefits or whether it presents a significant risk of harm. On the one hand, it must be admitted that the facility is located on an existing "brownfield" site, in an existing industrial area, zoned for industrial activities.[834] PSE argues that—to the extent the Commission considers environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity in reviewing the Tacoma LNG Settlement—the Commission should consider various benefits the facility provides to the Tribe and others living and working near the Port of Tacoma.[835] PSE argues, for instance, that the facility was built on a brownfield site and that the Company performed a significant amount of cleanup and mitigation.[836] PSE describes revegetation efforts and other measures that benefit juvenile salmon in the area.[837] PSE witness Roberts also explains that environmental agencies have approved permits for the facility and found that it provides various benefits.[838]

433 On the other hand, the Tribe argues that "there can be no legitimate dispute" that the Tacoma LNG Facility will contribute to and exacerbate high levels of air pollution near the Facility.[839] The Tribe's witness, Dr. Sahu, testifies that the facility will emit a number of pollutants,

---

[834] Sahu, Exh. RXS-36 at 8.

[835] PSE Brief ¶ 115.

[836] PSE Brief ¶¶ 116-17 (citing, *inter alia*, Roberts, Exh. RJR-30T at 42:1-7).

[837] Roberts, Exh. RJR-30T at 42:4-20; Roberts, Exh. RJR-33 at 17:8-18:6, 33:11-13.

[838] Roberts, TR at 434:1-16.

[839] Tribe's Brief at 13:15.

including carcinogens and persistent, bio-accumulative chemicals.[840] Dr. Sahu contends that the facility will emit pollutants and pose a disparate impact on the Tribe even though PSE obtained a Clean Air Act permit to operate the facility.[841] Public Counsel also cites Dr. Sahu's testimony,[842] and argues that the facility will perpetuate systemic harm for the Tribe and the surrounding area.[843]

434 We have carefully considered all of the testimony and evidence on this issue. As a general matter, we agree that investor-owned utilities should generally be on notice that public policy envisions an equitable distribution of the benefits and burdens of the clean energy transition.[844] In order to address systemic inequity, companies must carefully evaluate future investments to ensure that they do not further burden vulnerable populations and highly impacted communities that have already borne a disproportionate share of pollution and environmental health impacts. However, in this proceeding we are reviewing a non-precedential Settlement for a facility that was built before changes in law and public policy were made.

435 With this understanding in mind, we consider the parties' arguments regarding the health and environmental impacts of the facility as one of several considerations when considering PSE's proposed MYRP. We ultimately find that many of the Tribe's arguments deserve little weight.

436 We observe, for example, that the PCHB repeatedly found PSE's air quality witness, Dr. Libicki, more credible than the Tribe's witness, Dr. Sahu.[845] The PCHB went so far as to characterize Dr. Sahu as providing "scant" evidence for certain claims and "no evidence" that the facility's NO2 emissions violated NAAQS.[846] To the extent the Tribe seeks to relitigate air quality issues in this proceeding, the PCHB's findings as to the credibility of Dr. Sahu's testimony undermine many of the Tribe's arguments regarding air quality impacts and its emphasis on Dr. Sahu's opinions.[847]

437 We place relatively little weight on the fact that PSE was required to install a CEMS at the facility. As PSE credibly explains, the PCHB did not adopt the Tribe's extensive proposed

---

[840] Tribe's Brief at 13:15-14:2 (citing Sahu, Exh. RXS-1T at 16; Sahu, Exh. RXS-30T at 15-16, 19).

[841] *Id.* at 14:3-12. *See also id.* at 14:13-15:4 (citing Saleba, Exh. GSS-1T at 11-12 for a similar proposition).

[842] Public Counsel Brief ¶ 40.

[843] *Id.* ¶¶ 41-43.

[844] *See* RCW 19.405.010(6).

[845] *See* Roberts, Exh. RJR-32 ¶¶ 75, 77, 100.

[846] *Id.* ¶¶ 127-28, 133.

[847] *See, e.g.*, Tribe's Brief at 5:7-19 (arguing that Dr. Sahu was well-qualified).

changes to the facility's permit.[848] PSE has already installed the CEMS,[849] which merely ensures that the facility does not violate air quality standards. Indeed, one witness testifying before the PCHB said that if a CEMS was installed, the facility would be the most heavily monitored minor source in the Puget Sound Clean Air Agency's jurisdiction.[850]

438 We have therefore considered the Tribe's arguments regarding air quality impacts and the PCHB's decisions and found them unpersuasive in several respects. The PCHB, as a specialized agency having jurisdiction over air quality issues, considered and rejected the majority of the Tribe's arguments. To the extent that the Tribe prevailed by requiring the installation of a CEMS, we are not persuaded that this warrants rejecting economic recovery of the cost to build the facility.

439 We also decline to require a Health Impact Assessment of the facility, as advocated by the Tribe.[851] The Commission primarily acts as an economic regulator. We do not have regulations or experience in administering Health Impact Assessments, and the legislature has not required any such assessment for this facility.[852] This request may be better directed to other agencies.[853]

440 We have also carefully considered the Tribe's arguments that the facility presents a risk of a catastrophic accident. The Tribe submits that even a code-compliant facility could cause a fire or explosion, citing a 2014 incident at Plymouth LNG in Kennewick, Washington, and a June 2022 incident at Freeport LNG in Texas.[854] The Tribe also argues that an internal Commission memo, which comments that "the existing regulatory process has a few fundamental flaws regardless of one's position on the project" and that the FEIS did not consider a "worst case discharge of oil" that assumes all of the contents of the largest tank are lost.[855] The Tribe argues that the facility therefore presents "unknown" and "unmitigated" risks to the public.[856]

---

[848] Roberts, Exh. RJR-32 at 77:6-11.

[849] Roberts, Exh. RJR-32 at 76:17-77:2.

[850] *Id.* ¶ 88.

[851] Tribe's Brief at 21:1-18.

[852] *Cf*. Laws of 2007, ch. 517 § 3(3) (requiring a Health Impact Assessment conducted by the Puget Sound Clean Air Agency and the King County Department of Health for certain modifications to SR-520).

[853] *See* WAC 173-460-090(3) (setting forth the Department of Ecology's Health Impact Assessment protocol).

[854] Tribe's Brief at 16:3-20 (citing, *inter alia*, Sahu, Exh. RXS-1T at 22-23).

[855] Sahu, Exh. RXS-36 at 7-8. *See also* Tribe's Brief at 16:21-17-6.

[856] Tribe's Brief at 17:17-18.

441 We must consider these arguments against the credible evidence of record. Notably, the City of Tacoma's FEIS appears to undermine many of the Tribe's assertions. The City of Tacoma sought independent peer review of the Company's design before approving it through the FEIS process.[857] The FEIS also explains that the Tacoma LNG Facility is subject to regulation and review by a number of governmental agencies, including the Pipeline Hazardous Materials Safety Administration (PHMSA), the Commission, the United States Coast Guard, the United States Department of Transportation, and the City of Tacoma, through its adoption of the Washington State Fire Code.[858] The FEIS observes that "[i]n the 70+ year operating history of United States LNG facilities, only two LNG safety-related incidents have occurred that resulted in adverse effects to the public or environment," citing a fire in Cleveland, Ohio in 1944 and an ignition of enclosed vapors in Lusby, Maryland in 1979.[859] The FEIS concludes that "[w]ith more than 110 functioning LNG facilities in the United States today, and an operational history beginning in the 1940s, the industry has a good safety record."[860] Although the Tribe has raised other, more recent incidents near Kennewick, Washington, and in Freeport, Texas, the FEIS presents credible evidence regarding the regulatory framework and safety measures taken with regard to the facility and to the LNG industry in general.

442 Although the Tribe suggests that the FEIS did not consider a "worst-case" spill scenario,[861] this argument invites second-guessing of PHMSA regulations. Federal regulations establish the "potential credible events (*i.e.*, 'accident scenarios') to be modeled for thermal and vapor events."[862] We will not reject the Settlement based on spill scenarios that are considered outside the scope of PMHSA regulations.

443 We also observe that the Commission's Pipeline Safety Division has already conducted its review of the facility and presented its recommendations to the Commission. In Docket PG-151949, the Commission granted PSE's request for an exemption from 49 C.F.R. § 193.2167, as recommended by the Pipeline Safety Division, to construct a Buried Liquefied Natural Gas Transfer System.[863] Staff observed that PSE included various mitigation measures in its

---

[857] *See* Roberts, RJR-30T at 54:16-55:11; Roberts, Exh. RJR-35 (Braemar Technical Services Engineering & Naval Architecture Group, Engineering, Tacoma LNG Fire and Safety Review (July 2, 2018)).

[858] Sahu, Exh. RXS-33 at 3-4.

[859] *Id.* at 9.

[860] *Id.*

[861] Tribe's Brief at 17:17-18.

[862] Sahu, Exh. RXS-33 at 9.

[863] Sahu, Exh. RXS-36 at 5-6.

design of the facility.[864] The Commission then granted this exemption subject to a number of conditions, which included securing the opinion of an independent geotechnical consultant to ensure that the pipeline meets federal requirements for withstanding seismic events.[865] Because the Commission's Pipeline Safety Division has been delegated authority to inspect pipelines and other facilities to ensure their compliance with PMHSA regulations, the review and recommendations from the Pipeline Safety Division weigh against any claims that the facility presents unknown or catastrophic risks.

444 Next, we place relatively little weight on the Tribe's citation to a comment from an internal Commission memo, which suggested that PSE did not consider a "worse case" spill scenario.[866] The Tribe does not establish that the individual author of this memo was qualified to speak to the evaluation of LNG facility risks. This comment is outweighed by other credible evidence, such as the FEIS, which shows that the facility was evaluated by experts.

445 We place relatively little weight on claims that PSE may transport LNG by rail.[867] In July 2020, PHMSA promulgated a rule that allowed for the bulk transportation of LNG by rail.[868] This was a rulemaking by a specialized federal agency, and we decline to second-guess PHMSA regulations in this proceeding. This is particularly true because such activities would appear to fall outside of the Commission's jurisdiction. The Washington Supreme Court has held that the Commission should confine its consideration of the public interest to regulated business activities.[869]

446 Furthermore, the evidence does not establish that PSE has any defined plans to carry out LNG transportation by rail. The marketing team for Puget LNG suggested that LNG may be transported by rail, but the Company's Rule 30(b)(6) designee indicated that there were no concrete plans to carry this out and that there may not be a market for LNG rail transport.[870] Because the Tribe does not present any further evidence indicating that the Company actually plans to carry out LNG rail transport, this argument carries relatively little weight.

---

[864] Sahu, Exh. RXS-36 at 8-9.

[865] *Id.*

[866] *See* Sahu, Exh. RXS-36 at 7-8. *See also* Tribe's Brief at 16:21-17-6.

[867] *See* Tribe's Brief at 17:24-18:9.

[868] 85 Fed. Reg. at 44995. *But see* 86 Fed. Reg. at 61731 (proposing to amend the Hazardous Materials Regulations to suspend authorization of LNG transportation by rail).

[869] *Cole v. WUTC,* 79 Wn.2d 302, 485 P.2d 71 (1971).

[870] Sahu, Exh. RXS-38 (Excerpt (non-confidential) from J. Hogan 30(b)(6) testimony on behalf of PSE, 1/7/2021).

447 In making our determination in this Order, we do not rely on any reduction in greenhouse gas emissions from the non-regulated activities of Puget LNG.[871] As Public Counsel observes, the Washington Supreme Court held that the Commission does not have the authority to consider the effect of a regulated utility's practices upon a nonregulated business.[872]

448 Thus, we find that the Tacoma LNG Settlement is consistent with the public interest when considered as one of three partial, multiparty settlements resolving this general rate case. The Commission should not reject the Settlement or disallow recovery of the facility on the basis of later changes to law or public policy.

449 We approve the Tacoma LNG Settlement subject to the condition that the costs of the four mile distribution line be included in rates provisionally, to allow for consideration when PSE files for LNG recovery of the appropriate allocation of costs of the distribution line to Puget LNG, as well as the method for PSE recovering the "appropriate share" of costs from Puget LNG, and how it will modify regulated rate base. We agree that PSE acted prudently in developing and constructing the Tacoma LNG Facility up through the initial decision to authorize construction of the facility on September 22, 2016. Consistent with the Tacoma LNG Settlement, the parties may review and challenge the prudency of later construction and operation costs in a future proceeding, including when PSE files for LNG recovery at the same time it files its 2023 PGA.

450 We therefore approve the Settlement's proposed LNG tracker, and we grant PSE's petition for deferred accounting filed in Docket UG-210918. Consistent with PSE's position in its post-hearing brief, we modify PSE's request for deferred accounting, extending the deferral period until recovery commences in the LNG tracker.[873] In authorizing PSE's deferred accounting agreement we accept PSE's request to withdraw its request to defer carrying charges associated with the deferral.[874]

> **Condition:** We authorize PSE's petition for deferred accounting filed in Docket UG-210918, subject to the modifications of (1) extending the deferral period until recovery commences in the LNG tracker and (2) accepting PSE's request to withdraw its request to defer carrying charges associated with the deferral.

---

[871] *Cf.* PSE Brief ¶ 118 (arguing that the Commission should consider the benefits of reduced emissions from TOTE Maritime, LLC's ships using LNG fuel).

[872] Public Counsel Brief ¶ 44 (citing Cole v. WUTC, 79 Wn.2d 302, 305-306 (1971)).

[873] PSE Brief ¶ 135.

[874] *Id.*

FINDINGS OF FACT

451 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 therefor, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

452 (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.

453 (2) PSE 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. PSE provides electric and natural gas utility service to customers in Washington.

454 (3) PSE's currently effective rates were determined on the basis of the Commission's Final Order in consolidated Dockets UE-190529, UG-190530, UE-190274, UG-190275, UE-171225, UG-171226, UE-190991, and UG-190992.

455 (4) The rates established by the 2020 PCORC in Docket UE-200980 updated PSE's rates previously established in the Company's 2019 GRC.

456 (5) On January 31, 2022, PSE filed this GRC with the Commission proposing revisions to its currently effective Tariffs WN U-60, Electric Service, and Tariff WN U-2, Natural Gas Service.

457 (6) In its initial filing, PSE proposed a three-year rate plan for the years 2023, 2024, and 2025. In rate year one, PSE sought to increase base electric rates by approximately $310.5 million, or an average increase of approximately 13.59 percent across all customer classes. In rate year two, PSE sought to increase base electric rates by approximately $63 million, or an average increase of 2.47 percent across all customer classes. In rate year three, PSE sought to increase base electric rates by approximately $31.8 million, or an average increase of 1.22 percent across all customer classes.

458 (7) With respect to natural gas service, PSE sought to increase base rates by approximately $143 million in rate year one, or an average increase of 12.98 percent across all customer classes. In rate year two, the Company proposed to increase base natural gas rates by $28.5 million, or an average increase of 2.29 percent across all customer classes. In rate year three, PSE would increase base natural gas rates by $23.3 million, or an average increase of 1.83 percent across all customer classes.

459 (8) The evidence demonstrates that a MYRP will provide for more timely recovery of costs and strengthen PSE's incentives to contain costs.

460 (9) The Revenue Requirement Settlement's provisions for a modified DR PIM, targets, and metrics are reasonable and supported by an appropriate record.

461 (10) The evidence supports the Revenue Requirement Settlement's proposed capital structure of 49 percent equity and 51 percent debt as reasonable and striking an appropriate balance between considerations of economy and safety.

462 (11) The evidence supports the Revenue Requirement Settlement's proposed ROE of 9.40 percent as reasonable, comparable to the rate of return investors expect for similar investments, sufficient to assure confidence in the utility's financial integrity, and adequate to attract capital at reasonable costs.

463 (12) Public Counsel's proposed ROE of 8.80 percent is unreasonably low, falling below 99 percent of all authorized ROEs since 2018.

464 (13) Although the Commission will not make a final determination with respect to the prudency of Energy Eastside until a later proceeding, the evidence shows that PSE has demonstrated a need for Energize Eastside and that it adequately evaluated alternatives.

465 (14) The Revenue Requirement Settlement reasonably and appropriately incorporates equity considerations into PSE's capital planning processes.

466 (15) The Revenue Requirement Settlement proposes reasonable modifications to PSE's filing requirements to allow for more timely recovery of power costs and to prevent under-recoveries.

467 (16) The evidence supports the Settling Parties' reasonable agreement to include Colstrip costs in a tracker mechanism.

468 (17) The evidence supports the Settling Parties' reasonable agreement regarding the allocation and payment of Microsoft's remaining obligations for Colstrip D&R costs.

469 (18) The evidence supports the Settling Parties' agreement to disallow recovery of Colstrip "dry ash" facilities.

470 (19) The evidence supports the Revenue Requirement Settlement's terms providing for the gradual reduction of PSE's gas line extension allowance to zero.

471 (20) The Settling Parties have proposed reasonable modifications to PSE's proposed TVR pilot, largely aimed at providing greater resources and protections for low-income customers.

472 (21) The Green Direct Settlement presents a reasonable means of calculating the Energy Charge Credit.

473 (22) The evidence shows that PSE acted prudently in developing and constructing the Tacoma LNG Facility up through the Board of Director's decision to authorize construction on September 22, 2016.

474 (23) The evidence supports conditioning our acceptance of the Tacoma LNG Settlement on including the costs of the four mile distribution line provisionally in rates, subject to a review of the appropriate allocation of costs between PSE core customers and Puget LNG.

475 (24) The Tacoma LNG Settlement is consistent with the public interest when considered as one of three partial multiparty settlements resolving all issues in this proceeding and providing for a two-year MYRP for PSE.

476 (25) PSE presents credible evidence that the PCHB rejected many of the Tribe's arguments as unsupported and that the Tacoma LNG Facility was designed and constructed in accordance with applicable safety regulations.

477 (26) PSE proposes 39 uncontested restating and pro forma adjustments to its electric revenue requirement and 34 uncontested restating and pro forma adjustments to its natural gas revenue requirement. These uncontested adjustments are supported by substantial competent evidence in the record of this proceeding.

478 (27) PSE's currently effective electric and natural gas rates do not provide sufficient revenue to recover the costs of its operations and provide a rate of return adequate to compensate investors at a level commensurate to what they might expect to earn on other investments bearing similar risks.

CONCLUSIONS OF LAW

479 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

480 (1) The Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

481 (2) PSE is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction.

482 (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 on the basis of the full evidentiary record.

483 (4) PSE's existing rates for electric service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

484 (5) PSE's existing rates for natural gas service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

485 (6) PSE proposed a MYRP as required by RCW 80.28.425.

486 (7) The Commission should authorize and require PSE 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).

487 (8) By providing for Performance Incentive Mechanisms (PIMs), targets, and incentives, the Revenue Requirement Settlement provides the Commission a set of performance measures that will be used to assess PSE's performance as required by RCW 80.28.425(7).

488 (9) In order to properly assess PSE's performance over the course of the MYRP, the Commission should adopt additional performance metrics as set forth in Table 4 of this Order, and the Commission should require PSE to report data on these metrics from 2019 onwards.

489 (10) The Revenue Requirement Settlement's proposed capital structure of 49 percent equity and 51 percent debt is lawful and consistent with past Commission precedent.

490 (11) The Revenue Requirement Settlement's proposed ROE of 9.40 percent is consistent with the longstanding principles set forth in *Hope* and *Bluefield*.

491 (12) The Revenue Requirement Settlement provisions for the provisional recovery of the Energize Eastside project are consistent with CETA, RCW 80.28.425, and the Used and Useful Policy Statement.

492 (13) The Revenue Requirement Settlement lawfully provides that PSE's investments in DERs, battery resources, and demand response costs are eligible for earnings on PPAs as provided by RCW 80.28.410.

493 (14) The Infrastructure Investment and Jobs Act and Inflation Reduction Act will likely have a significant effect on PSE's power costs, and the Company should document its consideration of the benefits of these federal laws in future proceedings.

494 (15) The Revenue Requirement Settlement properly removes coal-fired resources from rates by 2025 as required by RCW 19.405.030(1)(a).

495 (16) PSE should be allowed to recover prudently incurred Colstrip D&R costs.

496 (17) The Green Direct Settlement appropriately avoids unlawful cross-subsidization between participating and non-participating customers.

497 (18) The Tacoma LNG Settlement appropriately requests a prudency determination up through the initial decision to authorize construction of the facility on September 22, 2016.

498 (19) The Commission's longstanding prudency standard requires an assessment of what the utility knew at the time, and it should not be amended in this proceeding to incorporate facts or changes in the law that occurred only later, after the decisions at issue.

499 (20) In approving the Tacoma LNG Settlement, we do not place any consideration on potential reductions of greenhouse gas emissions in industries that are not regulated by the Commission.

500 (21) PSE should be required to defer the revenues resulting from its provisional recovery of the $30 million for four miles of LNG distribution pipeline, subject to later review in the Company's 2023 PGA filing.

501 (22) The Commission should approve PSE's accounting petition filed in Docket UG-210918, subject to the modifications that the deferral period should be extended until recovery commences in the LNG tracker and that interest should not accrue for the deferred amounts. PSE accepts these modifications.

502 (23) PSE should be required to document its consideration of, and application for, loans and other benefits provided pursuant to the federal Infrastructure Investment and Jobs Act and Inflation Reduction Act in future proceedings seeking recovery of the Company's power costs.

503 (24) The Commission should accept each of the uncontested restating and pro forma adjustments and issues resolved on rebuttal.

504 (25) The Commission should authorize and require PSE to make a compliance filing in these consolidated dockets to recover in prospective rates its revenue deficiency of $223 million for electric operations in year one and $38 million for electric operations in year two. The Commission should similarly authorize and require PSE to make a compliance filing in these consolidated dockets to recover in prospective rates its revenue deficiency of $70.6 million for rate year one and $18.8 million for rate year two, for the Company's natural gas operations.

505 (26) The Commission should authorize the Commission Secretary to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

506 (27) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

507 (1) The Commission rejects the proposed tariff revisions Puget Sound Energy filed in these dockets on January 31, 2022.

508 (2) The Revenue Requirement Settlement filed by PSE on behalf of Staff, AWEC, FEA, Walmart, TEP, Kroger, NWEC, Sierra Club, Front and Centered, Microsoft, and Nucor Steel, and attached to this Order as Appendix A, is approved and adopted; that PSE demonstrate all offsetting benefits received or for which it has applied through the IRA and IIJA when demonstrating the prudency of power costs; that PSE includes all funding, tax benefits, or any other benefits for which it has applied when seeking the recovery of power costs; that within 3 months of PSE's annual March 31 filing non-company parties review and provide recommendations to the Commission on PSE's reported metrics; that PSE report additional metrics as set forth in Table 4 of this

Order; and that PSE submits a compliance filing within 45 days of this Order providing historical data on the metrics set forth in Table 4 from 2019 to 2022.[875]

509 (3) The Green Direct Settlement filed by PSE on behalf of Staff, King County, Public Counsel, and Walmart, and attached to this Order as Appendix B, is approved and adopted without condition.[876]

510 (4) The Tacoma LNG Settlement filed by PSE on behalf of Staff, AWEC, Walmart, Kroger, and Nucor Steel, and attached to this Order as Appendix C, is approved and adopted subject to the condition that the costs of the four mile distribution line be included provisionally in rates, subject to a review of the appropriate allocation of costs between PSE core customers and Puget LNG. These costs should be included in a tracker for later review, and should not be included in base rates at this time.

511 (5) The Commission authorizes and requires Puget Sound Energy to make a compliance filing in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Final Order. The stated effective date included in the compliance filing tariff sheets must allow five business days after the date of filing for Commission Staff's review.

512 (6) Within three business days of the entry of this Order, all parties to the Revenue Requirement Settlement and the Tacoma LNG Settlement, respectively, must notify the Commission whether they accept or reject the conditions imposed by the Commission.

513 (7) The Commission authorizes the Commission Secretary to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

---

[875] Exhibits to the Revenue Requirement Settlement can be found with the originally filed settlement in this Docket.

[876] The exhibit to the Green Direct Settlement can be found with the originally filed settlement in this Docket.

514 (8) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective December 22, 2022.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chair

ANN E. RENDAHL, Commissioner

MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

By this Order, the Commission has approved a settlement subject to condition. The Parties have three business days to accept or reject the Commission's conditions. If all parties to the settlement notify the Commission that they accept the conditions, the Order will become final by operation of law with respect to those issues without further action from the Commission.

If any party to the settlement rejects the Commission's condition or does not unequivocally and unconditionally accept the Condition, the Commission will notify the parties that it deems the settlement to be rejected, and the adjudication will return to its status at the time the Commission suspended the procedural schedule to consider the settlement. In either case, a Party may seek clarification or reconsideration of a Commission order approving a settlement agreement with conditions pursuant to WAC 480-07-835, 480-07-840, or 480-07-850.

APPENDIX A

REVENUE REQUIREMENT SETTLEMENT

APPENDIX B

GREEN DIRECT SETTLEMENT

APPENDIX C

TACOMA LNG SETTLEMENT

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-220066/UG-220067 and UG-210918 (Consolidated) SETTLEMENT STIPULATION AND AGREEMENT ON REVENUE REQUIREMENT AND ALL OTHER ISSUES EXCEPT TACOMA LNG AND PSE'S GREEN DIRECT PROGRAM
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility	

**AUGUST 26, 2022
SETTLEMENT STIPULATION AND AGREEMENT ON
REVENUE REQUIREMENT AND ALL OTHER ISSUES EXCEPT
TACOMA LNG AND PSE'S GREEN DIRECT PROGRAM**

CONTENTS

I. INTRODUCTION

1. This Settlement Stipulation and Agreement addresses all issues in Puget Sound Energy's ("PSE" or "the Company") above-captioned general rate case except those issues relating to the Tacoma Liquified Natural Gas ("LNG") Facility and those related to the Settlement Stipulation and Agreement (Green Direct) [1] ("Settlement"). The Settlement is entered into by and between the following parties in this case: (i) PSE, (ii) the regulatory staff of the Washington Utilities and Transportation Commission ("Commission Staff"),[2] (iii) Alliance of Western Energy Consumers ("AWEC"), (iv) Federal Executive Agencies ("FEA"), (v) Walmart, Inc. ("Walmart"), (vi) The Energy Project, (vii) Kroger, Co. ("Kroger"), (viii) NW Energy Coalition, (ix) Sierra Club, (x) Front and Centered, (xi) Microsoft and (xii) Nucor Steel Seattle, Inc. ("Nucor"), as of August 26, 2022. These parties are hereinafter collectively referred to as "Settling Parties" and individually as a "Settling Party."

2. This Settlement is a partial multiparty settlement as that term is defined in WAC 480-07-730(3)(b).

3. King County neither joins nor opposes the Settlement.

4. The Coalition of Eastside Neighborhoods for Sensible Energy ("CENSE") opposes the Settlement.

[1] Issues relating to the Tacoma LNG facility and PSE's Green Direct Program are addressed in separate settlement stipulations. This stipulation incorporates the Green Direct settlement stipulation's Green Direct credit term into its agreed revenue requirement increase. *See* Section III.A, *infra*.

[2] 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.

5. The Public Counsel Unit of the Washington Office of the Attorney General ("Public Counsel") will respond to the Settlement on September 9, 2022, and may support or remain neutral regarding most terms, except cost of capital and capital structure.

6. To the extent appropriate given the limitations placed on its involvement in this case, the Puyallup Tribe of Indians may respond to this Settlement on September 9, 2022, indicating its support, opposition and/or neutrality regarding Settlement terms.

7. This Settlement is subject to review and disposition by the Washington Utilities and Transportation Commission ("Commission"). Section III of the Settlement is effective on the date of the Commission order approving it (unless the Commission establishes a different effective date). The remainder of the Settlement is effective as of August 26, 2022.

II. BACKGROUND AND NATURE OF THE DOCKET

8. On January 31, 2022, PSE filed with the Commission, in Dockets UE-220066 and UG-220067, a general rate case ("2022 GRC"), which proposed a three-year multiyear rate plan ("MYRP").

9. On February 10, 2022, the Commission suspended operation of the as-filed tariff schedules, commenced discovery, and set the matter for hearing in Order 01.

10. On February 28, 2022, the Commission convened a virtual prehearing conference. The Commission granted party interventions and set a procedural schedule in the Prehearing Conference Order, served on March 3, 2022.

11. On April 27, 2022, Commission Staff filed a motion to consolidate an accounting petition PSE filed in Docket UG-210918, seeking an order authorizing deferred accounting

treatment for PSE's share of costs associated with the Tacoma LNG Facility, with the 2022 GRC. On May 12, 2022, the Commission consolidated the proceedings.

12. On July 28, 2022, Commission Staff, Public Counsel, and Intervenors filed response testimony.

13. The parties to PSE's general rate case participated in several virtual settlement conferences, including on June 13, 14, and August 10 and 12, 2022. In addition, settlement discussions continued by email during this time period.

14. On August 5, 2022, a partial multiparty settlement on the Green Direct program was filed with the Commission, along with supporting testimony. The parties to that settlement are PSE, Commission Staff, Public Counsel, King County, and Walmart. No party opposes the Green Direct settlement.

15. On August 12, 2022, the parties notified the Commission that two settlements in principle had been reached: one that specifically addressed Tacoma LNG issues and a second settlement that addressed all other remaining issues in the case (this Settlement).

16. On August 18, 2022, Nucor agreed to join the settlements in principle reached on August 12, 2022.

17. On August 18, 2022, the Commission convened a Status Conference to discuss a schedule for filing settlement documents and testimony supporting and opposing the settlements.

18. On August 22, 2022, the Commission issued a revised procedural schedule for the Settlement hearing.

III. AGREEMENT

19. The Settling Parties agree to the following terms as a multiparty settlement in this filing that fully settles all issues in this proceeding except those relating to Tacoma LNG and

Green Direct. Supporting Schedules are presented as exhibits to this Settlement Stipulation and Agreement.[3]

A. Revenue Requirement and Prudence

20. Two Year MYRP. The Settling Parties agree to a two-year MYRP.

21. Electric Revenue Requirement. The Settling Parties agree to an overall electric revenue increase of $223 million in the first year of the rate plan and an overall electric revenue increase of $38 million in the second year of the rate plan.

22. Gas Revenue Requirement. The Settling Parties agree to an overall natural gas revenue increase of $70.6 million in the first year of the rate plan and an overall natural gas revenue increase of $18.8 million in the second year of the rate plan.

23. The Settling Parties agree the revenue requirement increases assume and reflect the following assumptions:

a. Return on Equity/Capital Structure/Cost of Debt. The authorized return on equity is set at 9.4 percent and the capital structure is set at 49 percent equity/51 percent debt with the cost of debt at 5.0 percent for the duration of the MYRP.

b. Reliability Spending. $70 million of electric and natural gas reliability spending that PSE projected to spend in 2023 is shifted to 2024.

c. Renewable Natural Gas. Renewable natural gas costs are not included.

d. Power Costs. Power cost increases embedded in the revenue requirement are assumed to equal PSE's filed case ($125.5 million in 2023) reduced for the

[3] Exhibits A-N are attached. Workpapers will be provided to the Settling Parties.

electric portion of the Northwest Pipeline settlement ($4.6 million, after grossing up for revenue sensitive items). The power cost update that will occur at the compliance filing in this case[4] will use these power costs as the reference point for projected 2023 power costs.

e. Advanced Metering Infrastructure ("AMI"). The Settling Parties accept a determination that:

   i. PSE has adequately demonstrated utility system benefits of AMI.

   ii. PSE will continue deferring recovery of its return on equity on AMI but will recover its debt component of return on rate base.

      1. On AMI plant in service as of December 31, 2019, PSE will defer through 2022 its return on rate base (equity and debt) per Order 08 in Dockets UE-190529 and UG-190530. Beginning in 2023, PSE will amortize over three years the debt component of return on rate base that has been deferred through 2022 on investments made as of 2019.

      2. As of January 1, 2023, the deferral of the return on equity on AMI plant will include plant as of December 31, 2021, and PSE will amortize the debt component of return on rate base deferred through 2021 over three years beginning in 2023.

      3. The deferral of the return on equity component of AMI will continue until rates are changed in PSE's next MYRP, and the

[4] *See* Section III.D. *infra.*

amortization of deferred return on equity on AMI investments may not occur sooner than 2025.

iii. PSE is entitled to recovery of its AMI plant put into service through December 31, 2021, to the extent not already recovered.

iv. Parties do not object to the Commission making a determination that costs (depreciation and the debt component of return on investment) for AMI after December 31, 2021, are reasonable, subject to refund, pending future review processes.

v. PSE will not receive a final determination of prudency on the AMI project until the AMI installation is complete and PSE provides an AMI benefits progress report. PSE will file a final AMI benefits progress report as a compliance filing in these dockets no later than the filing of its next MYRP. The report will provide an update describing how PSE has continued efforts to maximize Company and customer benefits realized under the program and PSE's plans to continue such maximization efforts, as well as any new Company or customer benefit use cases identified.

vi. In the AMI benefits progress report, PSE will update its AMI reporting metrics, including equity considerations.

f. <u>Electric Capital Investments.</u> The Settling Parties agree that PSE's proposed electric capital investments will be included in its proposed MYRP rates with reductions noted elsewhere in this Settlement. As discussed below, PSE will propose to recover certain capital expenses related to its Clean Energy

Implementation Plan ("CEIP") and Transportation Electrification Program ("TEP") through separate trackers.[5]

g. Gas Capital Investments. The Settling Parties agree that PSE's proposed gas capital investments will be included in its proposed MYRP rates with revenue requirement reductions of $5 million in 2023 and $1 million in 2024 to reflect lower gas rate base in part to be attributable to lower new gas customer construction costs.

h. Electric Operations and Maintenance ("O&M"). The Settling Parties agree to PSE's proposed increases to electric O&M with reductions embedded in Exhibit J to this Settlement. As discussed below, PSE will recover certain O&M expenses related to its CEIP and TEP through separate trackers.[6]

i. Gas O&M. The Settling Parties agree to PSE's proposed increases to gas O&M with a 20 percent reduction in the gas O&M increases in 2023 and 2024.

j. Colstrip. PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed in the testimony of Susan E. Free (Exh. SEF-18). PSE agrees to exclude capital investments associated with the construction of PSE's Colstrip dry ash facilities from recovery in base rates in this case and PSE's proposed Schedule 141-C tracker. The Settling Parties agree that Colstrip costs included in rates in 2023 and beyond (including major maintenance expense and new plant additions) are subject to review,

---

[5] *See* Section III.A, *infra* (the section detailing revenue requirement assumptions, subsections k and l).
[6] *See id.*

including but not limited to an examination of prudence, in PSE's annual Schedule 141-C tariff filing. Major maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates. The Settling Parties retain all rights to challenge Colstrip costs when PSE files tariff revisions for the tracker.

k. <u>Clean Energy Implementation Plan.</u> PSE agrees to develop a separate tracking mechanism and tariff ("Schedule XX, Clean Energy Implementation Tracker") for costs included in its approved CEIP in Docket UE-210795 that are not included in Power Costs and are appropriate for recovery during the MYRP. Such costs may include but are not necessarily limited to distributed energy resource ("DER") program costs, O&M expense, and capital expense for projects that enable CEIP implementation. The Settling Parties agree to work collaboratively with PSE in developing this tracker by April 1, 2023. All CEIP investments recovered through this separate tracking mechanism are subject to review, including but not limited to an examination of prudence. This tracker will expire upon the implementation of new rates in PSE's next general rate case, or other date agreed to by the Settling Parties. This proposal is non-precedential, and inclusion of costs in the tracker does not qualify them as incremental costs for the purpose of WAC 480-100-660(4). PSE agrees to include costs associated with its 2025 CEIP as part of base rates or the associated tariff schedules implementing PSE's MYRP (i.e., Schedules 141-N and 141-R) in its next general rate case.

l. Transportation Electrification. The Settling Parties agree to move recovery of Transportation Electrification Program ("TEP") costs to a new rate tracker. Such costs will include capital, depreciation, and O&M expenses to enable the TEP. The Settling Parties have no position as to whether this approach to recovery of TEP costs would be permanent or not. The Settling Parties retain all rights to challenge program costs when PSE files tariff revisions for the tracker.

m. Energize Eastside. The Settling Parties agree that delayed service dates for Energize Eastside are assumed to be incorporated into the agreed upon revenue requirement above (i.e., South Phase in service by October 2023 and North Phase in service by October 2024). The Settling Parties agree that estimated costs associated with Energize Eastside (as described in PSE's initial filing) may enter rates provisionally (on the updated timeline, outlined above), subject to refund. Settling Parties accept and will not challenge that PSE has met its threshold prudence requirement to demonstrate that the investment should be provisionally included in rates. Settling Parties may challenge the costs of the project in the review of investments after the plant is placed in service.

n. COVID Deferral. PSE agrees to a partial write-off of the COVID deferral. Deferred costs, savings, and fee revenues associated with PSE's COVID deferred accounting petition filed in Dockets UE-200780 and UG-200781 will be written-off, but PSE can seek to recover its "Additional Funding for Customer Programs" provided by PSE in compliance with Order 01 in Docket

U-200281 and bad-debt accrued in excess of levels embedded in existing rates through PSE's electric and gas Schedule 129.

o. Load Forecast. PSE agrees to change the load forecast for certain rate schedules. [7]

p. Plant Investment. The Settling Parties do not object to determination of prudence for all other plant investment through 2021 as proposed in PSE's direct case. The Settling Parties do not object to allowing to go into rates all other plant investment included in PSE's MYRP that went, or is projected to go, into service in 2022 through 2024 subject to refund and the annual review process for prudence proposed in the testimony of Susan E. Free (Exh. SEF-1Tr).

q. Depreciation Rates and Expenses. The Settling Parties accept PSE's proposed depreciation rates and expenses as proposed by Ned W. Allis (Gas and Common from Exh. NWA-3 and Electric from Exh. NWA-4) and Susan E. Free (Exh. SEF-1Tr).

r. Regulatory Assets

   i. Automated Meter Reading. The Settling Parties do not object to PSE's recovery of its AMR investment.

   ii. Water Heater Business. The Settling Parties do not object to PSE's recovery of its loss associated with its water heater business sale.

[7] *See* Section III.F, *infra*.

iii. Other Regulatory Assets and Liabilities. The Settling Parties do not object to PSE's proposals related to all other regulatory assets and liabilities, as identified in Exhibit N to the Settlement Agreement.

s. Green Direct. The recovery of the Green Direct Energy Credit is included in the proposed electric revenue requirement in this Settlement.

t. Other Revenue: PSE will remove from the Gas revenue requirement model the "Other Adjustments" in column I, line 28, on p. 1, of Exh. JDT-3. PSE will remove from the Electric revenue requirement model the "Other Adjustment" in column (b), line 24, on p. 2, of Exh. BDJ-3.

u. Estimated Residential Bill Impacts: The estimated bill impacts resulting from this Settlement for residential electric and gas customers is shown below. PSE will make a subsequent filing by September 2, 2022 with updated bill impacts for electric and gas customers.[8] Final electric impacts will not be known until the power cost update is completed in the compliance filing.

Electric		
Settlement Average Bill Increase		
Rate Class	**2023**	**2024**
Residential Sch 7	$ 10.83	$ 1.71

Gas		
Settlement Average Bill Increase		
Rate Class	**2023**	**2024**
Residential (16,23,53)	$ 4.93	$ 1.27

[8] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas.

v. Estimated Percent of Revenue Increase by Rate Class: The below is an estimate of the percent of total revenue increase by rate class, resulting from the Settlement, for electric and gas customers. PSE will make a subsequent filing by September 2, 2022 with updated percent of revenue increase by rate class for electric and gas customers.[9] Final electric revenue increase will not be known until the power cost update is completed in the compliance filing.

Electric		
Settlement % of Total Revenue Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential Sch 7	11.4%	1.6%
Sec Volt Sch 24 (kW< 50)	7.8%	1.3%
Sec Volt Sch 25 & 29 (kW > 50 & < 350)	8.7%	1.4%
Sec Volt Sch 26 (kW > 350)	7.2%	1.3%
Pri Volt Sch 31 (General Service)	7.7%	1.4%
Pri Volt Sch 35 (Irrigation)	21.8%	2.4%
Pri Volt Sch 43 (Interruptible)	5.5%	1.1%
Special Contract	-1.9%	1.6%

[9] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas

High Volt Sch 46 & 49 (Interruptible & Gen Svc)	2.0%	1.1%
Choice/Retail Wheeling Sch 449 & 459	1.2%	0.2%
Street & Area Lighting	15.4%	2.1%
Total	**9.7%**	**1.5%**

Gas		
Settlement % of Total Revenue Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential (16,23,53)	6.5%	1.6%
Comm. & Indus. (31,31T)	6.2%	1.6%
Large Volume (41,41T)	5.8%	1.5%
Interruptible (85, 85T)	10.7%	2.6%
Limited Interruptible (86, 86T)	2.1%	0.7%
Non-Exclusive Interruptible (87, 87T)	4.4%	1.4%
Contracts	-0.5%	0.0%
Total	**6.4%**	**1.6%**

w. <u>Estimated Percent of Margin Increase by Rate Class</u>: The below is an estimate of the percent of total margin increase by rate class, resulting from the Settlement, for gas customers. PSE will make a subsequent filing by

September 2, 2022 with updated margin increase by rate class for gas customers.[10]

Gas		
Settlement % of Margin Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential (16,23,53)	12.8%	3.3%
Comm. & Indus. (31,31T)	13.6%	3.7%
Large Volume (41,41T)	14.3%	3.8%
Interruptible (85, 85T)	19.1%	5.2%
Limited Interruptible (86, 86T)	6.4%	2.2%
Non-Exclusive Interruptible (87, 87T)	11.6%	3.7%
Contracts	-0.6%	0.0%
Total	**13.1%**	**3.5%**

B. Corporate Capital Planning

24. By the end of the MYRP, the Settling Parties agree PSE shall make a compliance filing in these dockets demonstrating:

a. Plan for Equitable Outcomes. A process or procedure for how PSE's Board of Directors and senior management plan for equitable outcomes when making decisions on enterprise-wide capital portfolios within the three-tier planning process. This will include a transparent and inclusive methodology for how the Enterprise Project Portfolio Management ("EPPM") tool will be used to

[10] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas.

apply an equity lens to the Corporate Capital Allocation framework that integrates feedback from persons affected by PSE's decisions.

b. Corporate Spending Authorizations ("CSAs"). PSE's use of CSAs that require sponsors to consider the equitable distribution of benefits and reduction of burdens of the project or program. This can be demonstrated either qualitatively or quantitatively, or both. Once the Company has completed its pilot distributional equity analysis, participated in the Commission Staff-led process,[11] and has received approval from the Commission for its methods (and updated its analysis as necessary to conform to any changes to methods potentially required by the Commission), PSE will include in its CSAs results of distributional equity analysis.

C. Delivery and Distribution System Planning

25. Distribution System Planning. PSE will conduct Distribution System Planning in coordination with its CEIP process, as part of an integrated system planning approach for distribution system investments. A goal of the Distribution System Plan is identifying ways that connected customer-side resources can provide system value for all customers and achieve an equitable distribution of benefits and burdens to vulnerable populations and highly impacted communities. During the MYRP, PSE will solicit stakeholder input to help identify options and priorities for community-based resources and provide equitable treatment of measures that can enhance distribution carrying capacity, including those not owned or controlled by PSE.

[11] *See* section III.L. *infra*.

26. Investment decision optimization tool ("iDOT"). PSE will develop new benefits and costs (with associated weights) related to equity for use in the optimization step in its replacement software for iDOT.

a. PSE must, at minimum, collaborate with its Equity Advisory Group, Integrated Resource Plan ("IRP") Advisory Group, and its customers, particularly in Named Communities. Engagement with these groups will occur at least at the "Collaboration" level on the International Association for Public Participation Spectrum.[12]
b. New benefits and costs in the iDOT should include, but are not limited to, societal impacts, non-energy benefits and burdens, and the Social Cost of Greenhouse Gases, as well as any other benefits and costs deemed appropriate after engagement with PSE's advisory groups.
c. PSE will establish a process for including new iDOT benefits and costs within the Solutions Assessment of projects.
d. Once PSE has completed its pilot distributional equity analysis, participated in the Commission Staff-led process,[13] and has received approval from the Commission for its methods (and updated its analysis as necessary to reflect the approved methods), PSE will incorporate such analyses as a decision-making tool alongside the Benefit/Cost Analysis ("BCA"), which is currently performed in the Optimization step and the Alternatives and Solutions Analysis step.

[12] International Association for Public Participation Spectrum USA, IAP2 Public Participation Spectrum, available at https://iap2usa.org/cvs.
[13] *See* section III.L. *infra*.

D. Power Costs

27. Power Cost Only Rate Case ("PCORC"). PSE agrees to a PCORC stay-out throughout the pendency of the MYRP. The Settling Parties reserve the right to challenge whether PSE's ability to file PCORCs as allowed under its Power Cost Adjustment ("PCA") Mechanism should continue in future proceedings.

28. Power Cost Updates. The Settling Parties agree that:

a. PSE will update power costs for recovery in 2023 as part of its compliance filing at the conclusion of this case and include the bulleted items listed in subpart b, below, as part of the power cost update.

b. PSE is required to file a 90-day compliance filing in this proceeding to change rates effective January 1, 2024, for power costs to be recovered in 2024. In this compliance filing, PSE will update the rate recovering the PCA baseline by updating the power cost model from this filing with the cost and inputs listed below:

- Costs associated with Mid-C hydro contracts;
- Costs associated with upstream pipeline capacity;
- Outage schedules;
- BPA rates;
- Load forecast (for the 2024 update);
- Variable O&M costs;
- Impacts to dispatch logic related to Climate Commitment Act ("CCA") compliance;
- Hedges and physical supply contracts;
- Natural gas prices;
- Changes to terms of current resources;
- Any new and updated resources (including transmission contracts);
- Nothing in this agreement limits the Settling Parties' ability to review and contest prudence in future proceedings.

29. <u>Timing.</u> By August 1, 2023, PSE must provide details regarding any complex changes to the PCA baseline rate including work papers demonstrating the method and effect of the changes. If there are no complex changes, PSE must provide a letter stating so. Complex changes include, but are not limited to:

- Any new power resources;
- Any new contracts (e.g., transmission);
- Modification in any existing contract structure or form;
- Any methodological changes to PSE's power cost calculations.

a. The Settling Parties agree that by October 1, 2023, PSE must provide all other changes to the forecast.

b. The compliance filing containing proposed rates to recover the new PCA baseline rate would be made by PSE with sufficient time for Commission Staff to review in order to become effective on January 1, 2024.

30. <u>Prudence.</u> Any new resources included in the January 1, 2023 or January 1, 2024 baseline update will undergo a prudency review in the annual PCA Compliance Filing. To reduce the amount of time that costs spend in deferral, the prudence of any new resources effective in 2023 will be determined in the April 2023 PCA filing. Prudence of any new resources effective in 2024 will be determined in the April 2024 PCA Compliance Filing.

a. The Settling Parties reserve the right to recommend to the Commission that a prudence determination of a particular resource occur in the following year.

b. The Settling Parties reserve the right to challenge actual deferrals in the following year's PCA Compliance Filing.

31. Power Supply Resources. The Settling Parties accept that all power supply resources (including transmission contracts) for which PSE sought a prudence determination in its initial 2022 GRC filing are deemed prudent.

32. DER Power Purchase Agreements ("PPA"). The cost of any DER PPA for distributed generation, battery resources and demand response costs are eligible for recovery through PSE's PCORC, PCA Mechanism and/or annual power cost update and are eligible for potential earning on PPAs pursuant to RCW 80.28.410.

E. Rate Spread

33. Electric. The Settling Parties accept PSE's filed rate spread methodology in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

34. Gas. The Settling Parties agree to a gas base rate spread that is midway between PSE's proposed relative percentage-based increases in the testimony of John D. Taylor (Exh. JDT-1T) and an equal percent of margin. The Settling Parties agree to spread Schedules 141-R and 141-N proportionately to the base increase.

F. Rate Design

35. Electric. The Settling Parties agree to:

a. No increase to residential basic monthly charge.

b. Increase the account limit for the conjunctive demand service option from 5 to 15 accounts per customer and increase the customer's participating load limit to 6 MW of winter demand. To accommodate increased load in this program, PSE agrees to increase the cap on the program size from 20 aMW to 30 aMW.

c. For all rate schedules with demand-based charges, the rate design of the MYRP riders (Schedules 141-R and 141-N) should include both a demand

and an energy component for each rate schedule that includes both a demand and an energy charge in its base rates. The amount of rider costs collected through the demand and energy charge components for each rate schedule should be proportional to the demand and energy charge revenues that are collected through base rates for each rate schedule. The Settling Parties agree that the proportion of costs to be recovered through the demand and energy charges would be tied to the projected proportion of base revenue in 2023, as actual results are unlikely to vary greatly and this would avoid the need to track/true-up for small differences between the projected proportionality and actual results.

d. For all rate schedules with demand-based charges, the rate design of the Colstrip rider (Schedule 141-C) is as follows: 80 percent of the revenue will be recovered through demand charges and 20 percent of the revenue will be recovered through energy charges.

e. The Settling Parties agree to split the difference (meet halfway) between PSE's electric forecasted billing determinants and Public Counsel's forecasted billing determinants for three specific rate schedules (Residential – Rate 7, Secondary Pumping/Irrigation – Rate 29, and High Voltage Interruptible – Rate 46). PSE will incorporate changes in loads associated with these changes to billing determinants into its updates to power costs during the rate plan.

36. <u>Gas.</u> The Settling Parties agree to:

a. The basic charge as proposed by PSE witness John D. Taylor (Exh. JDT-1T), with the exception that the residential customer basic charge be $12.5 per month.

b. The Schedule 87/87T charges as proposed by PSE witness John D. Taylor (Exh. JDT-1T), except as modified below:

    i. Demand charge remains unchanged at $1.45 per therm.

    ii. First through fifth base rate volumetric block rates receive an equal percentage increase. Sixth volumetric block rate will receive 33 percent of the average rate increase across base rates.

    iii. Schedules 141-R and 141-N rates are proportional to volumetric base rate increase.

    iv. Calculate rates using test year weather normalized actual volumes and blocking in both rate years plus PSE's filed Puget LNG forecast in corresponding years.

G. Low Income Issues

37. <u>Bill Discount Rate ("BDR") and Arrearage Management Plan ("AMP").</u> The Settling Parties agree that:

a. PSE will consult with the Low-Income Advisory Committee ("LIAC") to develop and design the BDR and AMP. By July 1, 2023, PSE will make a subsequent filing with the Commission for approval of the BDR and AMP program design developed through the LIAC process.

b. The BDR program will begin on October 1, 2023, will include at least five income-based discount tiers, and at a minimum offer to serve all low-income customers up to 200 percent of the Federal Poverty Level ("FPL") or 50 percent Area Median Income, whichever is higher. PSE, the LIAC, and Community Action Agencies will evaluate ways to provide bill discounts to customers with incomes between 50 and 80 percent of Area Median Income. PSE's subsequent July 1, 2023 filing will describe this evaluation, including the input of other parties and any proposals presented to the LIAC for providing bill discounts to customers with incomes between 50 and 80 percent of Area Median Income.

c. In consultation with the LIAC, PSE agrees to develop and adopt an AMP as part of an integrated program with BDR and Home Energy Lifeline Program ("HELP") with an effective date of October 1, 2024.

d. The program year for the HELP, BDR, and AMP will be October 1 to September 30.

e. PSE will consult with the LIAC concerning:

    i. eligibility criteria;

    ii. enrollment procedures, including the verification of income using self-attestations;

    iii. how to manage the overlap between the Low-Income Home Energy Assistance Program, HELP, and BDR; and

    iv. how to integrate the BDR with HELP and AMP.

f. PSE will not recover new types of costs in its Schedule 129 tariff riders without first consulting the LIAC and making a subsequent filing for Commission approval.

g. PSE will continue to include Community Action Agencies and other agencies delivering low-income bill assistance programs in LIAC meetings.

h. The Settling Parties agree that there will be joint administration of enrollment by PSE and the Community Action Agencies for BDR and AMP programs.

i. Current agency administrative allowances for bill assistance programs will be maintained, with the level to be revisited after the new BDR program is developed and the costs are better known.

j. BDR and HELP funding will be maintained as separate and independent (except unspent HELP funds, which shall be available to fund the BDR program).

k. The Settling Parties agree to preserve the grant function of HELP and its availability for arrearage assistance.

38. HELP Funding Increase. PSE will increase HELP funding consistent with RCW 80.28.425(2), as amended.

39. Low-Income Conservation and Weatherization.

a. PSE agrees to make a good faith effort to increase weatherization measure incentive amounts in 2022. PSE agrees to work with its Conservation Resources Advisory Group ("CRAG") to survey actual installed measure costs and adjust rebate amounts per survey findings, if warranted, and fully fund all low-income conservation measures shown to be cost-effective with a Total Resource Cost test result of at least 0.667 based on survey results.

b. PSE agrees to extend its current commitment[14] to maintain an annual base funding level for weatherization through the end of PSE's next GRC as follows:

> PSE agrees to continue to fund low-income weatherization programs that the low-income agencies inform PSE they can feasibly achieve with an annual base funding level of no less than the amount in PSE's current Biennial Conservation Plan Low-Income Weatherization Programs through the next General Rate Case.

c. Nothing in this Settlement is intended to modify any of PSE's existing obligations to make shareholder contributions for weatherization funding.

40. Credit/Collection. PSE agrees to continue its existing credit and collection processes until the conclusion of the proceeding currently being conducted in Docket U-210800.

H. Time Varying Rates Pilot

41. Time Varying Rates ("TVR") Pilot. The Settling Parties agree to the TVR pilot subject to the following modifications:

a. Include low-income customers up to 200 percent FPL/80 percent Area Median Income.

b. Provide enabling technology to half of the low-income program participants at no cost to the low-income participant, and funded through Schedule 120, and examine the results in the evaluation, measurement, and verification ("EM&V") plan.

c. Provide bill protection to half of the low-income program participants and examine the results in the EM&V plan.

[14] Docket U-210542, Order 01, Appendix A, Commitment 43.

d. Provide for review and comment on recruitment language by the Commission (Consumer Protection Division).

e. Include in the EM&V plan an exit survey that asks customers if they understood their rate.

f. Refresh the rates proposed for the pilot to reflect the electric revenue requirement resulting from this Settlement and the electric cost of service methodology presented in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

42. Proposal for Full Opt in Program. PSE agrees to make a proposal for a full opt-in TVR program for residential customers in its next general rate case.

I. Colstrip Tracker and Decommissioning and Remediation Costs

43. Colstrip Tracker. The Settling Parties agree to the Schedule 141-C Colstrip tracker as described above. The Settling Parties also agree to the proposed time period for the Colstrip Schedule 141-C tracker, as proposed by Susan E. Free (Exh. SEF-18), but the Settling Parties may request up to 90 days for review.

44. Forecasted Decommissioning and Remediation ("D&R"). The Settling Parties accept PSE's calculation of forecasted Colstrip D&R costs, net of monetized Production Tax Credits ("PTCs"), and PSE's proposed allocation factor for purposes of the Microsoft buyout.

45. Microsoft Lump Sum Payment. The Settling Parties accept Microsoft's proposal to pay its obligation in a lump sum following the conclusion of this case, as presented in the testimony of Irene Plenefisch (Exh. IP-1T). This results in an up-front payment from Microsoft to PSE's customers of $407,922.43. Microsoft will satisfy its obligation within 90 days of receipt of a bill from PSE following a final, non-appealable, order in these dockets. PSE retains the risk of an inaccurate forecast and will not allocate any under-recovered amounts from Microsoft to

any other customer class. PSE agrees that in the event that D&R costs exceed the estimates presented in this case, it will not seek recovery from Microsoft or other ratepayers of amounts that would otherwise be allocated to Microsoft. Microsoft agrees that in the event D&R costs are less than the estimates presented in this case, it will not seek reimbursement from PSE or other ratepayers for the amount of its overpayment.

46. Order of Priority for PTCs. The Settling Parties agree to the change in the order of priority for the application of PTCs to the recovery of Colstrip costs, as described in the testimony of Susan E. Free (Exh. SEF-18).

47. Colstrip Annual Report. The Settling Parties agree to move the Colstrip annual report to the annual Colstrip tracker filing, as proposed by Susan E. Free (Exh. SEF-18).

J. Clean Energy Transformation Act-Related Costs

48. The Settling Parties agree that there will be no determination regarding which costs may be included in the projected incremental cost of compliance with the Clean Energy Transformation Act in this docket. The Settling Parties agree that any questions surrounding the projected incremental cost of compliance will be addressed in the ongoing CEIP proceeding in Docket UE-210795, per WAC 480-100-660(4).

K. Gas Line Extension Margin Allowances

49. PSE shall provide the following tariff revisions for natural gas line extension margin allowances in its compliance filing immediately following the issuance of the final order in this case, with effective dates no later than when new state building codes take effect in 2023, January 1, 2024, and January 1, 2025:

a. No later than when new state building codes take effect in 2023, such tariff revisions shall reflect a natural gas line extension margin allowance based on the net present value ("NPV") methodology using a two-year timeframe and updated inputs from this rate case.

b. No later than January 1, 2024, such tariff revisions shall reflect a natural gas line extension margin allowance based on the NPV methodology using a one-year timeframe and the same inputs used in 2023.

c. No later than January 1, 2025, such tariff revisions shall reduce the natural gas line extension margin allowance to zero.

L. Distributional Equity Analysis

50. Pilot Distributional Equity Analysis. PSE agrees to develop methods and process for a pilot distributional equity analysis, by means that could include, but are not limited to, the Company hiring a technical expert, consulting literature, and collaborating with the Settling Parties. The Company will apply the methods developed to its proposed 80 MW of distributed energy resources, as proposed in its 2021 IRP and CEIP, as a pilot, updating the application of these methods to this program as needed upon possible updates to the program. Within 15 months of the approval of this MYRP, PSE will file with the Commission a compliance item documenting the methods and results of the pilot distributional equity analysis. If the proposed 80 MW of distributed energy resources is ultimately not included in the 2021 CEIP's preferred portfolio approved by the Commission, PSE will confer with other interested parties and decide on an alternative program to use for this pilot.

51. Distributional Equity Analysis Process. Following the pilot distributional equity analysis, PSE agrees to participate in a Commission Staff-led process, which will be open to participation from other parties, to refine the methods for a distributional equity analysis. Commission Staff will select a third-party facilitator to support this effort that PSE must hire in

consultation with Commission Staff. At the end of this process, PSE will request Commission approval of its methods for a distributional equity analysis going forward and, when approved, apply these methods as detailed in the Corporate Capital Planning and Delivery System Planning sections of this stipulation.

M. Other Issues

52. Decoupling. The Settling Parties agree to PSE's proposal for electric and gas decoupling discussed in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

53. Annual Review and Earnings Sharing. The Settling Parties agree to PSE's annual review process and earnings sharing proposals discussed in the testimony of Susan E. Free (Exh. SEF-1Tr), except that the review period will be four months.

54. Allocation of CEIP/TEP Costs. PSE agrees not to allocate CEIP or TEP costs, proposed to be recovered through a tracker, to customers served under Schedules 448/449.

55. Northwest Pipeline Refund. PSE agrees to amortize the estimated $24.3 million refund from Northwest Pipeline that are attributable to its gas customers over a 12-month period through its 2023 PGA filing. PSE also agrees to amortize the estimated $4.4 million refund from Northwest Pipeline attributable to its electric customers over the 12 months of 2023 as a credit against the forecasted power costs in this case.

56. Streamlining of Reports. The Settling Parties accept PSE's proposed streamlining of reporting as discussed in the testimony of Jon A. Piliaris (Exh. JAP-1T). Further, PSE agrees to update and file its matrix of filings in Docket U-210151 within 30 calendar days of the date of the Commission's final order in this case, and by January 1 each year thereafter.

57. Electric Vehicle Supply Equipment ("EVSE") Payment Methods. PSE shall make minimum payment methods available at all publicly available electric vehicle supply equipment,

owned or supported by the utility, to increase access to all customers. Minimum payment methods should be consistent with California's EVSE Standards, § 2360.2, titled "Payment Method Requirements for Electric Vehicle Supply Equipment." It is the Settling Parties' understanding that this standard does not include the use of "swipe" cards.

N. Performance Based Ratemaking

58. Demand Response ("DR") Performance Incentive Mechanism ("PIM"). The Settling Parties accept PSE's proposed DR PIM as described in the testimony of Dr. Mark Newton Lowry (Exh. MNL-1T), with the following modifications:

a. The initial reward threshold will activate at 105 percent of the DR target. The initial reward from the DR PIM will be a percent of DR program costs equal to PSE's approved weighted average cost of capital ("WACC").

b. The second reward threshold will activate if PSE exceeds 115 percent of the DR target. The reward for this threshold increases to 15 percent of DR program costs.

c. As explained in Exh. MNL-1T at 30:4-5, no additional reward is provided for achievement levels in excess of 150 percent of the target.

d. The PIM is based on the DR target of 40 MW by 2024, to be calculated in the same way that PSE calculates its peak load reduction for compliance with the DR target in PSE's CEIP. This does not replace the requirement to adopt a DR target in the CEIP. The Settling Parties reserve the right to support a higher target in the CEIP docket.

e. The incentive provided by this DR PIM shall not exceed $1 million over the course of this MYRP.

f. Unless otherwise ordered by the Commission, the DR PIM ends at the end of Rate Year 2.

59. Electric Vehicle ("EV") PIM. The Settling Parties agree that there will be no approved EV PIM as part of this rate case.

60. In addition to the metrics discussed by Dr. Mark Newton Lowry (Exh. MNL-1T), PSE agrees to report on the following metrics annually as a compliance filing in this docket and in conjunction with PSE's annual review process, as described in the testimony of Susan E. Free (Exh. SEF-1Tr), and as outlined in the timeline in Exh. JAP-3. Except for the DR PIM, there will be no targets or benchmarks at this time.

61. <u>Resilient, reliable, and customer-focused distribution grid.</u> The Settling Parties agree PSE will report on the following metrics relating to PSE's delivery of a resilient, reliable, and customer-focused distribution grid:

a. Number of EVSE stations and charging ports installed through PSE's TEP programs, broken out by program.

b. Energy served through PSE's TEP programs, per program.

c. Energy and capacity of load reduced or shifted, and percent of load reduced or shifted, through load management activities conducted through PSE's EV tariffs.

d. To the extent readily available, load profiles of energy consumption through PSE's TEP Programs by rate schedule.

e. Percentage of known EV energy sales under managed charging.

f. Percentage of known EVSE in DR programs.

g. Percentage of known EVSE using time-of-use rates.

h. Number of customers served by each of PSE's DER programs.

i. The energy and capacity provided through each of PSE's DER programs.

j. Percentage of utility spending on DR, DER, and renewable energy programs that benefits highly impacted communities or vulnerable populations.

k. Percentage of low-income customers that participate in DR, DER, or renewable energy utility programs

l. Average customer AMI electric bill read success rate.

m. Average customer AMI gas bill read success rate.

n. Average customer remote switch success rate.

o. Average customer reduced energy consumption from voltage regulation.

p. Count of participating customer complaints in each of PSE's TVR pilots.

q. Load reduction during called events for customers enrolled in the Time of Use ("TOU") + Peak Time Rebate ("PTR") pilot.

r. Count of customer impressions with AMI program marketing efforts.

s. High usage alert open rate.

t. Download count of energy data, in both CSV and green button format.

u. Count of customers enrolled in smart thermostat programs for space heating.

62. Environmental Improvements. The Settling Parties agree PSE will report on the following metrics relating to PSE's environmental improvements:

a. Total greenhouse gas ("GHG") emissions from energy delivery systems, reported separately for gas and electric service. The Settling Parties also agree to use this metric in place of "CO2 Emissions from Company-Owned Electric Operations" on PSE's proposed scorecard.

b. Carbon intensity: CO2e/MWh and CO2e/MW.

c. Annual SO2 emissions from utility-owned electric generation resources, by census tract.

d. Annual NOx emissions from utility-owned electric generation resources, by census tract.

e. Annual PM2.5 emissions from utility-owned electric generation resources, by census tract.

63. <u>Customer Affordability.</u> The Settling Parties agree PSE will report on the following metrics relating to customer affordability:

a. Average annual bill for residential customers, separately for electric and gas, by census tract.

b. Average annual bill as a percentage of the average income of all energy-burdened customers, separately for electric and gas.

c. Total revenue recovered from customers outside of rates approved within its MYRP. For this rate case, this would exclude base rates and Schedules 141-C, 141-N and 141-R.

d. Number and percentage of (1) disconnect notices, (2) residential disconnections for nonpayment, and (3) reconnection, each broken out by month and zip code, separately for electric and gas.

e. Total residential arrearages and average age of arrears by month and zip code, separately for electric and gas.

f. Average annual residential bill as a percentage of average residential income, by census tract, separately for electric and gas.

g. Average annual net plant in service per customer, separately for electric and gas.

h. Average annual O&M per customer, separately for electric and gas.

i. Average excess energy burden per household, separately for gas and electric.

64. Advancing Equity in Utility Operations. The Settling Parties agree PSE will report on the following metrics relating to equity in utility operations.

a. To the extent readily available, the number of customers in highly impacted communities and vulnerable populations taking service through PSE's EV tariffs.

b. Percentage of utility transportation electrification spending that is intended to benefit highly impacted communities and vulnerable populations through PSE's programs.

c. Percentage of utility-owned and supported EVSE by use case located within or intended to provide direct benefits and services to highly impacted communities and vulnerable populations.

d. Estimated percentage of PSE suppliers that are minority-owned, women-owned, or veteran-owned.

e. AMI electric bill read success rate for highly impacted communities and vulnerable populations.

f. AMI gas bill read success rate for highly impacted communities and vulnerable populations.

g. Remote switch success rate for highly impacted communities and vulnerable populations.

h. Reduced energy consumption from voltage regulation for highly impacted communities and vulnerable populations.

i. For each DER program: number and percentage of residential customers, known low-income customers, known customers in highly impacted communities and vulnerable populations taking part in each of PSE's DER programs; and average energy savings per home for each of these customer groups. The term "DER programs" is defined to include energy efficiency.

j. Count of customers in highly impacted communities and vulnerable populations taking part in each of PSE's DER programs.

k. The amount of PSE DER program capacity sited in areas of highly impacted communities and vulnerable populations.

l. Total residential arrearages and average age of arrears by month for known low-income households, highly impacted communities, and vulnerable populations.

m. Number and percentage of residential (1) disconnect notices, (2) electric disconnections for nonpayment, and (3) reconnection by month and zip code for known low-income households, highly impacted communities, and vulnerable populations.

n. Percentage of households with a high-energy burden (>6%), separately identifying known low income and highly impacted communities and vulnerable populations, separately for gas and electric by census tract.

O. Comprehensive Decarbonization Study, Targeted Electrification Pilot, and Targeted Electrification Strategy

65. Overview. The Settling Parties agree that PSE will (1) conduct an updated decarbonization study aimed at maximizing carbon reductions with more up-to-date assumptions on targeted electrification, (2) concurrently develop an electrification pilot that will evaluate a range of impacts to gas and electric delivery systems and PSE customers by deploying heat pump technologies, including high-efficiency electric-only solutions, and (3) incorporate a Targeted Electrification Strategy, based on the findings of the updated decarbonization study and electrification pilot, into its next Natural Gas IRP and Biennial Conservation Plan following the conclusion of the study and pilot, as provided below. PSE's final updated decarbonization study and the results of its electrification pilot will be made available to the public with no designations of confidentiality. PSE commits to an investment of up to $15 million in Company funds for these efforts through the end of 2024, which will be deferred for consideration of recovery in PSE's next general rate case. Costs will be allocated as described below. PSE will prioritize low-income customers, highly-impacted and vulnerable populations, and customers experiencing a high energy burden in its pilot programs and incentives developed pursuant to this condition.

66. Decarbonization Study. PSE's updated decarbonization study will build off the gas decarbonization study prepared for PSE by E3 with more up-to-date assumptions regarding efficient Cold Climate Heat Pumps ("CCHPs") for targeted electrification. Measures and scenarios evaluated in the study must include but are not limited to comparisons of cost to ratepayers and GHG emissions associated with installing all electric vs. dual fuel systems for new customers and for existing gas customers, DERs, and decarbonized fuels. This decarbonization study will also include an evaluation of the impacts of all electric heat pumps,

hybrid systems, and reducing and decarbonizing gas throughput. The study will be provided within 12 months of the Commission's final order in this case, and should include but not be limited to the following elements:

a. A more up-to-date electrification scenario that takes into account recent performance trends of CCHPs.

b. An accounting of both near-term (3-5 years) and long-term costs and benefits of electrification, including carbon reductions and avoided gas system infrastructure costs due to fewer new customer connections.

c. A segmentation of new and existing customers to separately evaluate the costs and benefits of electrifying new and existing customers and a scenario whereby PSE seeks to electrify all new customers and projected corresponding carbon emission reductions.

d. A review of the time to build out and the cost of incremental electric system costs based on recent cost trends in power and capacity, as well as sensitivity analysis around electric system assumptions to understand how these assumptions impact the viability of high electrification scenarios.

e. Updated unit costs, including the incentives provided by the Inflation Reduction Act.

f. Study the impacts and benefits of electric heat pump technologies on PSE's gas constrained delivery systems.

g. Collaborate with adjacent consumer-owned utility electric service providers to conduct coordinated electric delivery system and gas delivery system studies or pilots.

h. Evaluate how to use the biennial conservation planning process to advance least-cost decarbonization strategies in PSE's gas utility service area, including by promoting fuel switching to electric utility service.

i. Include regional forecasted load and market price sensitivities that reflect regional electrification.

j. An evaluation of the impact of electrification with and without hybrid heat pumps on gas and electric rates, to provide an update to the existing analysis in the E3 study referenced above.

k. The results of the updated study will be incorporated into PSE's 2025 Natural Gas Integrated Resource Plan and a compliance filing in this docket by January 2025.

67. Targeted Electrification Pilot. PSE will conduct an 18-month Targeted Electrification Pilot.[15] The pilot will deploy strategies to maximize effective carbon reduction measures associated with the deployment of electric-only heat pumps in homes and buildings with wood, oil, propane, electric resistance and gas heating. This pilot is targeted toward residential and small commercial customers.

a. The pilot will have a target of engaging 10,000 customers through at least two of the following measures:

    i. rebates and incentives for fuel switching to high-efficiency electric-only appliances that includes consideration of carbon emission reduction potential,

[15] The measures supported through the Targeted Electrification Pilot will be in addition to and separate from PSE's existing hybrid heat pump pilot program.

ii. remote and in-home electrification assessments, and

iii. education related to available electrification incentives and programs as described in item (d)(iv) below.

b. PSE agrees to file a report summarizing the results of the Targeted Electrification Pilot, including the number of residential and commercial customers engaged through each of the measures identified above, as a compliance requirement in this docket, no later than January 2025.

c. Funding for the Targeted Electrification Pilot program will only be used to support promotion or installation of high-efficiency electric-only appliances. However, to assist existing gas customers in transitioning to electric solutions, the pilot may rely upon existing gas appliances for back-up fuel supply (e.g., installing new electric-only heat pumps while maintaining existing gas furnaces as backup fuel supply).

d. The Targeted Electrification Pilot will also integrate the following elements to advance electrification efforts:

i. Identify opportunities for incremental DER investment as a mechanism to offset electric system reliability risk during peak load events and begin deploying these investments.

ii. Identify barriers to heat pump adoption and develop recommendations for improving the penetration of heat pump technologies in PSE's service territory.

iii. Identify barriers to low-income customers, highly-impacted populations, vulnerable populations, and customers experiencing high energy burdens accessing heat pump technology, and develop policies and programs to support adoption of heat pump technologies by those customers and populations.

iv. Provide education and outreach to customers on qualified installers, and available utility incentives offered through the pilot, or from state and federal sources (e.g., Inflation Reduction Act).

v. Evaluate whether providing a financial incentive to existing gas customers for fuel switching to electric-only appliances, would incentivize and promote increased adoption of high-efficiency electric-only appliances.

e. In consultation with the CRAG, findings from the Targeted Electrification Pilot should be considered in the 2025 Biennial Conservation Plan (for the 2026-2027 biennium).

f. PSE will consult with the LIAC and the CRAG to ensure the Targeted Electrification Pilot program and Targeted Electrification Strategy provide demonstrated material benefits to low-income participants, enrolls eligible participants in bill assistance programs, and includes appropriate low-income customer protections. As part of this consultation, PSE will consider the following:

i. Any guidance from the Department of Commerce concerning low-income electrification programs.

ii. What defines a material benefit to low-income customers; e.g., decreased energy burden, and/or back up heat sources or energy storage systems in areas with frequent outages if necessary to protect health and safety.

iii. Notification if participation will increase energy burden.

g. Costs will be spread to each electric rate schedule based on the schedule's share of total Targeted Electrification Pilot program funding expended for that schedule. For clarity, costs will not be allocated to Schedule 449 customers.

68. Targeted Electrification Strategy. PSE will use the information and analysis from the Targeted Electrification Pilot together with the updated decarbonization study to develop a Targeted Electrification Strategy for its electric service territory in its next Natural Gas Integrated Resource Plan or Progress Report following the completion of the Decarbonization Study and Targeted Electrification Pilot, and as a compliance filing in this docket by January 2025, and its 2025 Gas IRP. The Targeted Electrification Strategy will be based on findings from the Decarbonization Study, and the Targeted Electrification Pilot.

a. The Targeted Electrification Strategy will focus on maximizing carbon emission reductions consistent with legal requirements at the lowest reasonable cost, which includes consideration of adverse rate impacts to remaining gas customers and avoidance of inter-rate class cost shifting.

b. The Targeted Electrification Strategy shall consider a comprehensive set of strategies to minimize inter-class cost shifting, including the potential use of regulatory assets to shift rate base if the proposed strategy would create stranded assets.

c. The Targeted Electrification Strategy shall consider a comprehensive set of strategies, programs, incentives, promotional materials, and other measures to encourage electrification for new and existing customers.

d. The Targeted Electrification Strategy shall provide for a fuel-switching rebate that incentivizes gas customers to install electric-only appliances, to the extent that fuel switching to high-efficiency electric appliances is determined to be a cost-effective method to decarbonize gas utility service. This fuel switching rebate will provide an additional financial incentive to existing energy efficiency appliance rebates to promote rapid fuel switching to high-efficiency electric only appliances.

e. In consultation with the CRAG, PSE will integrate fuel switching concepts from gas to electric into its conservation planning for the next Biennial Conservation plan following the completion of the Targeted Electrification Strategy. In developing these concepts, PSE's approach will be informed by the steps outlined in the Equitable Building Electrification Framework. [16]

f. The Targeted Electrification Strategy shall include a proposed budget, and plan for implementing the measures and strategies that were studied in the electrification pilot and described in item b. above, a proposal to limit or phase out incentives for new gas appliances, based on an evaluation of their continued cost-effectiveness and risk to ratepayers. This strategy will also set

[16] https://greenlining.org/publications/reports/2019/equitable-building-electrification-a-framework-for-powering-resilient-communities/

annual targets to continue reducing new gas customer additions in future years.

g. PSE agrees to work with the CRAG on developing educational and communications materials encouraging customers to fuel switch to electric-only appliances in line with PSE's conservations targets, if the Targeted Electrification Strategy provides a fuel-switching rebate to customers, per sub-item (d).

h. The funds for the Targeted Electrification Strategy will be recovered from the class benefiting from the program.

i. PSE agrees to phase out promotional advertising specific to connecting new customers to the gas system or encouraging customers to switch to gas utility service away from other forms of energy service, as described in WAC 480-90-223 (including mailers to customers, promotions on PSE's website and social media, print, digital, television, and radio advertisements, etc.) by January 1, 2023.

IV. GENERAL PROVISIONS

69. Entire Agreement. This Settlement is the product of negotiations and compromise amongst the Settling Parties and constitutes the entire agreement of the Settling Parties. Accordingly, the Settling Parties recommend that the Commission adopt and approve the Settlement in its entirety as a full resolution of contested issues identified in this Settlement. This Settlement will not be construed against any Settling Party on the basis that it was the drafter of any or all portions of this Settlement. This Settlement supersedes any and all prior oral and written understandings and agreements on such matters that previously existed or occurred in

this proceeding, and no such prior understanding or agreement or related representations will be relied upon by the Settling Parties to interpret this Settlement or for any other reason.

70. Confidentiality of Negotiations. The Settling Parties agree that this Settlement represents a compromise in the Settling Parties' positions. As such, conduct, statements, and documents disclosed during the negotiation of this Settlement are not admissible in this or any other proceeding and will remain confidential. Notwithstanding the foregoing, the Settlement itself and its terms do not fall within the scope of this confidentiality provision, and each Settling Party is free to publicly disclose the basis for its own support of the Settlement.

71. Precedential Effect of Settlement. The Settling Parties enter into this Settlement to avoid further expense, uncertainty, inconvenience, and delay. This Settlement does not serve to bind the Commission when it considers any other matter not specifically resolved by this Settlement in future proceedings. Nothing in this Settlement compels any Settling Party to affirmatively intervene or participate in a future proceeding.

72. Positions Not Conceded. In reaching this Settlement, the Settling Parties agree that no Settling Party concedes any particular argument advanced by that Settling Party or accedes to any particular argument made by any other Settling Party. Nothing in this Settlement (or any testimony, presentation, or briefing supporting this Settlement) shall be asserted or deemed to mean that a Settling Party agreed with or adopted another Settling Party's legal or factual assertions in this proceeding.

73. Manner of Execution. This Settlement will be deemed fully executed when all Settling Parties have signed it. A designated and authorized representative may sign the Settlement on a Settling Party's behalf. The Settling Parties may execute this Settlement in counterparts. If the Settlement is executed in counterparts, all counterparts shall constitute one

agreement. A Settlement signed in counterpart and sent by facsimile or emailed as a pdf is as effective as an original document. A faxed or emailed signature page containing the signature of a Settling Party is acceptable as an original signature page signed by that Settling Party. Each Settling Party shall indicate the date of its signature on the signature page. The date of execution of the Settlement will be the latest date indicated on the signature page(s).

74. Approval Process and Support of Settlement. Each Settling Party agrees to support the terms and conditions of this Settlement in this proceeding. Each Settling Party agrees to support the Settlement during the course of whatever proceedings and procedures the Commission determines are appropriate for approval of the Settlement. Each Settling Party agrees to make available one or more witnesses to testify in support of the Settlement.

75. Commission Approval with Conditions. In the event the Commission approves this Settlement, but with conditions not proposed in this Settlement, the provisions of WAC 480-07-750(2)(b) will apply.

76. Commission Rejection. In the event the Commission rejects this Settlement, the provisions of WAC 480-07-750(2)(c) will apply. In that event, the Settling Parties agree to jointly and promptly request that the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ____________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ____________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and Transportation Commission Staff

KROGER

By: ____________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ____________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By: ____________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ____________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western Energy Consumers

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ______________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ______________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and Transportation Commission Staff

KROGER

By: ______________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ______________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By: ______________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western Energy Consumers

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ____________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ____________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and Transportation Commission Staff

KROGER

By: ____________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ____________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By: ____________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ____________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western Energy Consumers

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ___________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ___________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and Transportation Commission Staff

KROGER

By: ___________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ___________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By: ___________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ___________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western Energy Consumers

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ____________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ____________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and
Transportation Commission Staff

KROGER

By: ____________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ____________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By ____________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ____________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western
Energy Consumers

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

By: ___________________________
JON A. PILIARIS
Director, Regulatory Affairs

ROBERT W. FERGUSON
Attorney General

By: ___________________________
JEFF ROBERSON
Assistant Attorney General
Attorneys for Washington Utilities and Transportation Commission Staff

KROGER

By: ___________________________
KURT BOEHM
Attorneys for Kroger

WALMART, INC.

By: ___________________________
VICKI M. BALDWIN
Parsons Behle & Latimer
Attorneys for Walmart

NUCOR STEEL SEATTLE, INC.

By: ___________________________
DAMON XENOPOULOS
Stone Mattheis Xenopoulos & Brew, PC
Attorneys for Nucor Steel Seattle, Inc.

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ___________________________
SOMMER MOSER
Davison Van Cleve PC
Attorneys for the Alliance of Western Energy Consumers

THE ENERGY PROJECT

By: ______________________________
YOCHANAN ZAKAI
Shute, Mihaly & Weinberger LLP
Attorneys for The Energy Project

FEDERAL EXECUTIVE AGENCIES

By: ______________________________
RITA M. LIOTTA
Attorney for the Federal Executive Agencies

FRONT AND CENTERED

By: ______________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice
Attorneys for Front & Centered

SIERRA CLUB

By: ______________________________
GLORIA SMITH
JIM DENNISON
Attorneys for Sierra Club

MICROSOFT

By: ______________________________
TYLER PEPPLE
Davison Van Cleve PC
Attorneys for Microsoft

NW ENERGY COALITION

By: ______________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice

1552154.4

THE ENERGY PROJECT

By: ______________________________
YOCHANAN ZAKAI
Shute, Mihaly & Weinberger LLP
Attorneys for The Energy Project

FEDERAL EXECUTIVE AGENCIES

By: Rita M. Liotta
RITA M. LIOTTA
Attorney for the Federal Executive Agencies

FRONT AND CENTERED

By: ______________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice
Attorneys for Front & Centered

SIERRA CLUB

By: ______________________________
GLORIA SMITH
JIM DENNISON
Attorneys for Sierra Club

MICROSOFT

By: ______________________________
TYLER PEPPLE
Davison Van Cleve PC
Attorneys for Microsoft

NW ENERGY COALITION

By: ______________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice

1552154.4

THE ENERGY PROJECT

By: ____________________________
YOCHANAN ZAKAI
Shute, Mihaly & Weinberger LLP
Attorneys for The Energy Project

FEDERAL EXECUTIVE AGENCIES

By: ____________________________
RITA M. LIOTTA
Attorney for the Federal Executive Agencies

FRONT AND CENTERED

By: Jaimini Parekh
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice
Attorneys for Front & Centered

SIERRA CLUB

By: ____________________________
GLORIA SMITH
JIM DENNISON
Attorneys for Sierra Club

MICROSOFT

By: ____________________________
TYLER PEPPLE
Davison Van Cleve PC
Attorneys for Microsoft

NW ENERGY COALITION

By: Jaimini Parekh
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice

1552154.4

By: ____________________________
YOCHANAN ZAKAI
Shute, Mihaly & Weinberger LLP
Attorneys for The Energy Project

By: ____________________________
RITA M. LIOTTA
Attorney for the Federal Executive Agencies

FRONT AND CENTERED

By: ____________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice
Attorneys for Front & Centered

SIERRA CLUB

By: ____________________________
GLORIA SMITH
JIM DENNISON
Attorneys for Sierra Club

MICROSOFT

By: ____________________________
TYLER PEPPLE
Davison Van Cleve PC
Attorneys for Microsoft

NW ENERGY COALITION

By: ____________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice

1552154.4

THE ENERGY PROJECT

By: ____________________________
YOCHANAN ZAKAI
Shute, Mihaly & Weinberger LLP
Attorneys for The Energy Project

FEDERAL EXECUTIVE AGENCIES

By: ____________________________
RITA M. LIOTTA
Attorney for the Federal Executive Agencies

FRONT AND CENTERED

By: ____________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice
Attorneys for Front & Centered

SIERRA CLUB

By: ____________________________
GLORIA SMITH
JIM DENNISON
Attorneys for Sierra Club

MICROSOFT

By: Tyler Pepple
TYLER PEPPLE
Davison Van Cleve PC
Attorneys for Microsoft

NW ENERGY COALITION

By: ____________________________
JAIMINI PAREKH
AMANDA GOODIN
Earthjustice

1552154.4

EXH. JM-1CT
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: JOHN MANNETTI

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

JOHN MANNETTI

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

FEBRUARY 15, 2024

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
JOHN MANNETTI**

CONTENTS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF JOHN MANNETTI

LIST OF EXHIBITS

Exh. JM-2	Professional Qualifications of John Mannetti
Exh. JM-3	Projected Budgets Associated with Elements of Targeted Electrification Activities
Exh. JM-4	List of Public Funding Opportunities that PSE is Actively Tracking and Evaluating
Exh. JM-5C	Presentation to the Energy Management Committee on January 4, 2024, regarding PSE's Proposed Long-Duration Energy Storage Pilot
Exh. JM-6C	Memorandum of Understanding between PSE and Form Energy
Exh. JM-7C	Corporate Spending Authorization for Long Duration Energy Storage Pilot
Exh. JM-8	Comparison of Levelized Costs of Energy of Capacity Technologies Considered by PSE

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF JOHN MANNETTI

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is John Mannetti, and my business address is 355 110th Avenue NE, Bellevue, Washington 98004. I am the Director of Strategic Energy Initiatives for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes. Please see the First Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-2.

Q. What are your duties as Director of Strategic Energy Initiatives for PSE?

A. As Director of Strategic Energy Initiatives, I am responsible for PSE's emerging technology evaluation and development activities in pursuit of the company's clean energy objectives. I also lead PSE's efforts to secure public funds through federal and state programs.

Q. What topics are you covering in this prefiled direct testimony?

A. The purpose of this prefiled direct testimony is:

(i) to provide an update on PSE's targeted electrification pilot that began with Stipulation O of the settlement agreement in PSE's last general multiyear rate plan proceeding in Dockets UE-220066 & UG-220067[1] (the "Targeted Electrification Pilot");

(ii) to address PSE's proposal for a second phase of the Targeted Electrification Pilot and associated cost recovery mechanism (the "Targeted Electrification Pilot Phase 2");

(iii) to provide an overview of PSE's efforts to pursue public funding, such as under the Infrastructure Investment and Jobs Act ("IIJA")[2] and the Inflation Reduction Act ("IRA")[3];

(iv) to discuss PSE's consideration of emerging technologies, such as hydrogen, long-duration battery storage and small modular reactors; and

(v) to present PSE's proposal for a long-duration battery storage pilot.

II. TARGETED ELECTRIFICATION ACTIVITIES

A. Overview of the Targeted Electrification Activities

Q. Please describe PSE's activities under Stipulation O of the UE-220066 Settlement.

A. As part of Stipulation O in the UE-220066 Settlement, PSE committed to three general areas of work related to targeted electrification on the PSE system:

[1] *WUTC v. Puget Sound Energy*, Dockets UE-220066, *et al*. Final Order 24/10, Appx. A, Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and PSE's Green Direct Program (Dec. 22, 2022) (the "UE-220066 Settlement").

[2] Infrastructure Investment and Jobs Act of 2021, Pub. L. No. 117-58 (2021).

[3] Inflation Reduction Act of 2022, Pub. L. No. 117-169 (2022).

- Updated Targeted Electrification Study. PSE would conduct an updated decarbonization study aimed at maximizing carbon reductions with more up-to-date assumptions on targeted electrification.

- Targeted Electrification Pilot. PSE would develop a targeted electrification pilot that would evaluate a range of impacts to gas and electric delivery systems and PSE customers by deploying heat pump technologies, including high-efficiency electric-only solutions.

- Targeted Electrification Strategy. PSE would incorporate a targeted electrification strategy, based on the findings of the updated decarbonization study and electrification pilot, into its next natural gas Integrated Resource Plan and Biennial Conservation Plan following the conclusion of the study and pilot.[4]

(Collectively, these three areas are referred to in my testimony as "Targeted Electrification Activities").

In the past year, PSE has made progress in implementing the Targeted Electrification Activities. On December 21, 2023, PSE filed the updated targeted electrification study ("Targeted Electrification Study") with the Commission in Dockets UE-220066, et al. Section II.B below addresses the progress made with respect to the Targeted Electrification Pilot mentioned in the second bullet above. The targeted electrification strategy mentioned in the third bullet will follow the conclusion of both the Targeted Electrification Study and the Targeted Electrification Pilot.

[4] UE-220066 Settlement at ¶ 65.

B. The Targeted Electrification Pilot

Q. Please describe the Targeted Electrification Pilot.

A. In June of 2023, PSE launched the Targeted Electrification Pilot designed to deploy heat pumps, identify opportunities to offset electric system reliability risk, and identify barriers and provide recommendations to improve the market penetration of heat pumps, particularly in named communities.[5] The Targeted Electrification Pilot generally consists of the following elements:

- Home Electrification Assessments;
- Low-Income Heat Pump Direct Installations;
- Fuel-Switching Heat Pump Rebates;
- Multi-Family Residential Building Electrification Project in Named Communities;
- Small Business Heat Pump Direct Installations in Named Communities; and
- Targeted Electrification Pilot Evaluation.

1. Home Electrification Assessments

Q. What does the Home Electrification Assessment element of the Targeted Electrification Pilot entail?

A. Pursuant to the Home Electric Assessment element of the Targeted Electrification Pilot, PSE will complete 10,000 free, in-home electrification assessments conducted by Franklin Energy Services for PSE natural-gas customers. These

[5] The term "named communities" is a commonly-used shorthand phrase for highly impacted communities and vulnerable populations, as defined by RCW 19.405.020(23) and (40), respectively.

assessment reports provide participating customers with (i) actionable energy efficiency tips, (ii) a list of next steps to pursue electrification, and (iii) known and available financial incentives available from utilities, local, state, and federal programs, including the Inflation Reduction Act. PSE will also provide targeted marketing for fuel-switching heat pump rebates (dual-fuel customers) and the free Home Electrification Assessment (all PSE gas customers) in named communities. PSE plans to have a minimum of 30 percent of all Home Electrification Assessments conducted in named communities.

2. <u>Low-Income Heat Pump Direct Installations</u>

Q. What does the Low-Income Heat Pump Direct Installation element of the Targeted Electrification Pilot entail?

A. Pursuant to the Low-Income Heat Pump Direct Installation element of the Targeted Electrification Pilot, up to fifty low-income-qualified customers in PSE's dual-fuel service territory or part of the joint pilot with Seattle City Light (discussed in Section II.E) will receive whole-home weatherization and heat pump space/water heating upgrades at no cost. PSE will cover the full cost associated with the electrification projects, including the heat pumps and electrical panel upgrades, and weatherization assistance agencies will fund the whole-home weatherization.

3. Fuel-Switching Heat Pump Rebates

Q. What does the Fuel-Switching Heat Pump Rebate element of the Targeted Electrification Pilot entail?

A. Under the Fuel-Switching Heat Pump Rebate element of the Targeted Electrification Pilot, PSE will provide fuel switching rebates of between $2,400 and $4,000 to dual-fuel (active natural gas and electricity accounts) residential single-family customers of PSE that replace natural gas space heating with high-efficiency heat pumps. PSE aligned equipment requirements with tax credit requirements of the Inflation Reduction Act to assist customers in identifying and obtaining available funding. PSE cannot provide fuel-switching rebates through standard energy efficiency programs, so the fuel-switching heat pump rebate provides an additional incentive for customers pursuing electrification.

4. Multi-Family Residential Building Electrification Projects in Named Communities

Q. What does the Multi-Family Residential Building Electrification Projects in Named Communities element of the Targeted Electrification Pilot entail?

A. Under the Multi-Family Residential Building Electrification Projects in Named Communities element of the Targeted Electrification Pilot, PSE will provide heat pump direct installations for space and water heating to one or two multi-family residential buildings in named communities in PSE's dual-fuel service territory.

5. Small Business Direct Heat Pump Installations in Named Communities

Q. What does the Small Business Direct Heat Pump Installations in Named Communities element of the Targeted Electrification Pilot entail?

A. Under the Small Business Direct Heat Pump Installations in Named Communities element of the Targeted Electrification Pilot, PSE will provide heat pump direct installations for space and water heating to one or two small businesses in named communities in PSE's dual-fuel service territory.

6. Targeted Electrification Pilot Evaluation

Q. What does the Targeted Electrification Pilot Evaluation element of the Targeted Electrification Pilot entail?

A. Under the Targeted Electrification Pilot Evaluation element of the Targeted Electrification Pilot, PSE will contract with The Cadmus Group[6] to evaluate the Targeted Electrification Pilot over the 2024-2025 period. Starting in 2024, The Cadmus Group will identify barriers to heat pump adoption methods to increase market penetration of heat pumps for low-income customers, highly-impacted populations, vulnerable populations, and customers experiencing high energy burdens. The Targeted Electrification Pilot Evaluation will also aim to understand impacts of new heat pump systems on peak electricity needs during peak heating hours in areas with homes that switch from natural gas heating to heat pumps.

[6] The Cadmus Group, Inc. is an environmental consulting services firm that provides sustainability consulting, program management, scientific and risk analysis, strategic communications, regulatory support, evaluation, and technical assistance for the transportation, healthcare, and energy sectors.

C. Program Management for the Targeted Electrification Activities

Q. How long does PSE anticipate implementing the elements of the Targeted Electrification Pilot?

A. PSE anticipates implementing all elements of the Targeted Electrification Pilot, with the sole exception of the Targeted Electrification Pilot evaluation, by December 31, 2024. The Cadmus Group will begin the Targeted Electrification Pilot evaluation element in early 2024, and this evaluation will provide regular updates and insights to aid in the development of the targeted electrification strategy. As per the terms of the UE-220066 Settlement, PSE will publish a report summarizing the results of the Targeted Electrification Pilot, no later than January 2025, and PSE will consider findings from the Targeted Electrification Pilot in PSE's key planning processes.

Q. Does PSE plan to share the results of its Targeted Electrification Activities with the public?

A. Yes. PSE filed the Updated Electrification Study with the Commission on December 21, 2023, in Dockets UE-220066, et al.

Pursuant to the terms of Stipulation O of the UE-220066 Settlement, PSE will file a report summarizing the results of the Targeted Electrification Pilot, including the number of residential and commercial customers engaged through each of the measures identified above, as a compliance requirement in Dockets UE-220066, et al., no later than January 2025.[7]

Pursuant to the terms of Stipulation O of the UE-220066 Settlement, PSE will file the Targeted Electrification Strategy for its electric service territory as a compliance filing in Dockets UE-220066, et al. by January 2025.[8]

Q. Does PSE plan to consult with the Conservation Resources Advisory Group regarding incorporating the findings from the Targeted Electrification Pilot in the 2025 Biennial Conservation Plan for the 2026-2027 biennium?

A. Yes. PSE will consult with the Conservation Resources Advisory Group ("CRAG") regarding incorporating the findings from the Targeted Electrification Pilot in the 2025 Biennial Conservation Plan for the 2026-2027 biennium. Costs, customer uptake, and other learnings from the Targeted Electrification Pilot should provide insights to the CRAG with respect to conservation programs. PSE anticipates collaborating with CRAG participants to build and refine recommendations.

---

[7] *See* UE-220066 Settlement at ¶ 67.b.
[8] *See id*. at ¶ 68.

Q. Does PSE plan to consult with the Low-Income Advisory Committee and the CRAG to ensure that the Targeted Electrification Pilot benefits low-income participants?

A. Yes. PSE will continue to consult with the Low-Income Advisory Committee ("LIAC") and the CRAG to ensure that the Targeted Electrification Pilot benefits low-income participants. PSE typically provides updates to the LIAC at monthly meetings, which include time for questions and feedback. The CRAG meeting cadence for 2024 is already determined and will include at least four meetings with opportunities to share progress on the low-income elements of the Targeted Electrification Pilot.

Q. How will the Updated Targeted Electrification Study and the Targeted Electrification Pilot inform the Targeted Electrification Strategy?

A. The Updated Targeted Electrification Study and the Targeted Electrification Pilot will form the base of the Targeted Electrification Strategy, consistent with paragraph 68 of Stipulation O of the UE-220066 Settlement.[9] Data and analysis from the Targeted Electrification Study and Targeted Electrification Pilot will inform program costs, benefits, and recommendations within the Targeted Electrification Strategy.

[9] *See id*. at ¶ 68.

<u>D. Cost Recovery for Targeted Electrification Activities</u>

Q. What is PSE's projected budget for the Targeted Electrification Activities?

A. In Stipulation O of the UE-220066 Settlement, PSE "commit[ted] to an investment of up to $15 million in Company funds for the [Targeted Electrification Activities] through the end of 2024, which will be deferred for consideration of recovery in PSE's next general rate case." [10] As provided in Table 1 below and consistent with Stipulation O, PSE projects a budget of about $15 million through 2024 for the Targeted Electrification Activities.

Table 1. Projected Budget for Targeted Electrification Activities

Targeted Electrification Activity		Projected Budget
Updated Targeted Electrification Study		$573,798.10
Targeted Electrification Pilot		$12,451,201.90
Targeted Electrification Strategy		$1,975,000.00
	Total	**$15,000,000.00**

As of November 2023, PSE spent $2,864,567 on the Targeted Electrification Activities. Please see the Second Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-3, for projected budgets associated with elements of Targeted Electrification Activities.

[10] *See id*. at ¶ 65.

Q. What is the projected budget for the Targeted Electrification Pilot?

A. As indicated in Table 1 above, the projected budget for the Targeted Electrification Pilot is $12,451,201.

Table 2 below provides the projected budgets for the individual elements that comprise the Targeted Electrification Pilot.

Table 2. Projected Budget for Targeted Electrification Pilot

Targeted Electrification Pilot Element	Projected Budget
Home Electrification Assessments	$4,505,830.00
Low-Income Direct Heat Pump Installations	$4,938,132.90
Fuel-Switching Heat Pump Rebates	$2,000,000.00
Multi-Family Residential Building Electrification Projects in Named Communities	$200,000.00
Small Business Direct Heat Pump Installations in Named Communities	$200,000.00
Targeted Electrification Pilot Evaluation	$154,000.00
Development, Overhead, Administration, and Marketing	$453,239.00
Total	**12,451,201.90**

Q. What is PSE's request regarding costs associated with the Targeted Electrification Activities?

A. Consistent with Stipulation O of the UE-220066 Settlement, PSE requests recovery of its investment in the Targeted Electrification Activities in the amount of $15 million in base rates.

Q. How does PSE propose to allocate the costs of the Targeted Electrification Activities?

A. As discussed in the Prefiled Direct Testimony of Chris Mickelson, Exh. CTM-1T, PSE proposes to allocate the $15 million of costs of the Targeted Electrification Activities consistent with paragraph 67.g. of the UE-220066 Settlement:

> Costs will be spread to each electric rate schedule based on the schedule's share of total Targeted Electrification Pilot program funding expended for that schedule. For clarity, costs will not be allocated to Schedule 449 customers.[11]

E. Other Targeted Electrification Activities of PSE

Q. Is PSE engaged in other targeted electrification programs unrelated to the Targeted Electrification Pilot?

A. Yes. PSE and Seattle City Light are conducting a joint pilot aimed at installing heat pumps in twenty homes in a Seattle neighborhood through the Low-Income Weatherization Program. To demonstrate the effects of targeted electrification efforts on energy burden, customers participating in this joint pilot will receive a

[11] *Id*. at ¶ 67.g.

custom usage analysis to inform them of their (i) annual space heating cost prior to the installation of heat pumps, (ii) estimated annual space heating cost with an installed heat pump and weatherization, and (iii) estimated annual space heating cost with an installed heat pump, weatherization, and PSE Bill Discount Rate enrollment.

Q. How did PSE become involved in the joint pilot with Seattle City Light?

A. The joint pilot with Seattle City Light originated out of PSE's initial design of the Targeted Electrification Pilot, which was a full-home electrification program for a limited number of low-income qualified customers living in a neighborhood in Seattle. Throughout 2023, PSE met with parties to the UE-220066 Settlement regarding the Targeted Electrification Pilot to solicit feedback on pilot design. Parties to the UE-220066 Settlement expressed concern that a full-home electrification pilot for a limited number of low-income qualified customers was not of sufficient scope for the Targeted Electrification Pilot. After receiving this feedback, PSE changed the scope of the Targeted Electrification Pilot to be the broader offering discussed above, with rebates for heat pumps to a broader range of customers and the direct installation of heat pumps in homes of low-income customers and in a few multifamily buildings and small businesses in named communities. PSE's initial design for the Targeted Electrification Pilot, however, evolved into the joint pilot with Seattle City Light. Costs for the joint pilot with Seattle City Light will be recovered as part of the Low-Income Direct Heat Pump Installation budget item in the Targeted Electrification Pilot.

III. TARGETED ELECTRIFICATION PILOT PHASE 2

A. Overview

Q. Does PSE anticipate developing and implementing a second phase of the Targeted Electrification Pilot?

A. Yes. Building on the Targeted Electrification Pilot, PSE proposes the development and implementation of a second phase of the Targeted Electrification Pilot ("Targeted Electrification Pilot Phase 2") in its dual fuel service territory. PSE intends that its Targeted Electrification Pilot Phase 2 will provide heat pump incentives to sustain current customer offerings, assess whether targeted electrification can alleviate the need to expand the natural gas delivery system in a capacity constrained area, and broaden the customer reach of the first phase of the Targeted Electrification Pilot.

Q. What are the key components of PSE's proposed Targeted Electrification Pilot Phase 2?

A. The key components of PSE's proposed Targeted Electrification Pilot Phase 2 are as follows:

- three proposed low-income and equity-based pilots programs:
  - a low-income heat pump direct installation pilot;
  - a small businesses heat pump pilot in named communities;

- o a multi-family heat pump rebate in named communities pilot;

- a proposed targeted electrification of natural gas-constrained geographic area pilot; and

- two proposed targeted electrification pilots for additional customer classes:

    - o an income-qualified heat pump rebates pilot; and

    - o a commercial and industrial targeted electrification grant pilot.

1. <u>Low-Income Heat Pump Direct Installation Pilot</u>

Q. Please describe the Low-Income Heat Pump Direct Installation Pilot element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. If approved and implemented, the Low-Income Heat Pump Direct Installation Pilot for PSE's proposed Targeted Electrification Pilot Phase 2 would support residential, single-family, combined electric and gas customers of PSE with natural gas heating and incomes that fall at or below 80% of the Area Median Income ("AMI"). Participants in this pilot would receive a comprehensive, no-cost offering, which includes coverage of home weatherization expenses through the existing PSE Low-Income Weatherization program. Additionally, PSE would use funding from the proposed Targeted Electrification Pilot Phase 2 to cover the installation costs of heat pump systems for space and/or water heating, along with any related work needed for installation (e.g., electric panel upgrades/replacements, rerouting exhausts, etc.).

PSE anticipates that the Low-Income Heat Pump Direct Installation Pilot for PSE's proposed Targeted Electrification Pilot Phase 2 would utilize low-income agencies to manage eligibility verification and facilitate the installation of all measures. By collaborating with low-income agencies, PSE would work to alleviate the impact of underlying disparities and systemic inequalities to provide low-income customers with access to and benefits from affordable and energy-efficient homes. Over calendar years 2025 and 2026, PSE anticipates that the Low-Income Heat Pump Direct Installation Pilot for PSE's proposed Targeted Electrification Pilot Phase 2 would enroll up to 115 eligible customers at a projected total cost of $4,600,000.

2. <u>Small Businesses Heat Pump Pilot in Named Communities</u>

Q. Please describe the Small Businesses Heat Pump Pilot in Named Communities element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. The Small Businesses in Named Communities Pilot is targeted at small businesses in named communities in PSE's dual fuel territory, specifically those using natural gas for space and/or water heating. The focus of this pilot is to enhance existing energy efficiency offerings with the addition of heat pumps for space and/or water heating. Over calendar years 2025 and 2026, PSE anticipates that the Small Businesses in Named Communities Pilot would engage up to twenty small businesses in named communities at a total projected cost of $1,000,000.

3. <u>Multi-Family Heat Pump Rebate in Named Communities Pilot</u>

Q. Please describe the Multi-Family Fuel-Switching Heat Pump Rebates in Named Communities Pilot element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. The Multi-Family Fuel-Switching Heat Pump Rebates in Named Communities Pilot provides incentives to customers in residential multi-family buildings with natural gas space heating in named communities in PSE's dual fuel territory. Participants in this initiative would be eligible for a $2,000 rebate to install heat pump systems that replace natural gas heating systems. Over calendar years 2025 and 2026, PSE anticipates that the Multi-Family Fuel-Switching Heat Pump Rebates in Named Communities Pilot will engage customers in up to 1,000 dwelling units at a total projected cost of $2,000,000.

4. <u>Targeted Electrification of Natural Gas-Constrained Geographic Area Pilot</u>

Q. Please describe the Targeted Electrification of Natural Gas-Constrained Geographic Area Pilot element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. The Targeted Electrification of Natural Gas-Constrained Geographic Area Pilot would target fuel switching for space and water heating and complement PSE's existing Demand Side Management Programs to reduce gas volume demand to avoid capacity expansions of the gas delivery system. This pilot specifically targets dual fuel customers with natural-gas heated residential single-family homes in gas-constrained areas, with the initial phase set to commence in Duvall, Washington. Recognizing the challenges posed by constrained natural gas areas, this pilot aims to provide increased support to identified customers through tailored efforts, which may involve heightened outreach and incentives. Over calendar years 2025 and 2026, PSE anticipates that the Targeted Electrification of Natural Gas-Constrained Geographic Area Pilot will engage up to 500 customers at a total projected cost of $4,000,000.

5. <u>Income-Qualified Heat Pump Rebate Pilot</u>

Q. Please describe the Income-Qualified Heat Pump Rebate Pilot element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. The Income-Qualified Heat Pump Rebate Pilot would support income-qualified dual fuel customers of natural gas-heated residential single-family homes to transition their home's main heating source from gas to electric. Participants would be eligible for a $2,400 Efficiency Boost Rebate, with Efficiency Boost being an existing conservation program that provides higher rebates for income-qualified customers falling below or equal to 90 percent of the AMI. This pilot would encourage fuel switching and energy efficiency, thereby making sustainable heating options more financially viable for income-qualified households. Over calendar years 2025 and 2026, PSE anticipates that the Income-Qualified Heat Pump Rebate Pilot will engage up to 300 customers at a total projected cost of $1,200,000.

6. <u>Commercial and Industrial Targeted Electrification Grant Pilot</u>

Q. Please describe the Commercial and Industrial Targeted Electrification Grant Pilot element of PSE's proposed Targeted Electrification Pilot Phase 2.

A. The Commercial and Industrial Targeted Electrification Grant Pilot would leverage existing energy efficiency processes to facilitate electrification of commercial and industrial customers in PSE's dual fuel territories. This pilot would incorporate (i) expected gas savings, (ii) upgrade or incremental costs for electrification, and (iii) current gas energy efficiency incentive levels ($/therm). By offering custom grants, this pilot would strive to make electrification economically viable for commercial and industrial customers and inform future commercial and industrial fuel switching program design. With an existing program incentive cap set at 70 percent of the project cost, PSE anticipates that the Commercial and Industrial Targeted Electrification Grant Pilot would encourage up to twenty locations to electrify over calendar years 2025 and 2026, at a total projected cost of $6,000,000.

<u>B. Program Management for the Targeted Electrification Pilot Phase 2</u>

Q. Why is PSE proposing a Targeted Electrification Pilot Phase 2 in this proceeding?

A. PSE's proposed Targeted Electrification Pilot Phase 2 utilizes the momentum generated by the first phase of the Targeted Electrification Pilot, aligns with

PSE's 2030 clean energy goals, and presents an opportunity for PSE and the region to continue exploring the effectiveness of targeted electrification efforts. If the Commission were to approve PSE's proposed Targeted Electrification Pilot Phase 2, PSE anticipates that these additional offerings would further the understanding of costs, customer demand, and obstacles related to implementing electrification initiatives for participating customers. These offerings, if implemented, could provide a foundation for program design, customer education, contractor training requirements, and grid integration challenges. Additionally, the projects and programs proposed in the Targeted Electrification Pilot Phase 2 help reduce Climate Commitment Act compliance obligations of gas customers.

Q. What is PSE's proposed timeline for implementing the Targeted Electrification Pilot Phase 2?

A. If approved, PSE would implement the Targeted Electrification Pilot Phase 2 during the multiyear rate plan period (i.e., approximately January 2025 to December 2026).

Q. Did PSE consider equity when developing the Targeted Electrification Pilot Phase 2?

A. Yes. The program offerings of the Targeted Electrification Pilot Phase 2 described above focus primarily, although not exclusively, on low-income customers and customers in named communities. In particular, the pilot aims to provide insight on ways to mitigate, if not eliminate, the barriers to electrification for low-income customers and customers in named communities in order to provide more equitable access to electrification.

C. Cost Recovery for Targeted Electrification Pilot Phase 2

Q. What is the projected budget to implement the Targeted Electrification Pilot Phase 2 through the end of 2026?

A. The projected budget to implement the Targeted Electrification Pilot Phase 2 through the end of 2026 is $22,300,000. Please see Table 3 below for the projected budget for the Targeted Electrification Pilot Phase 2 by program and calendar year.

Table 3. Projected Budget for the Targeted Electrification Pilot Phase 2 Through the End of Calendar Year 2026

Effort	Year	Amount	Est. QTY	Est. Spend
Low-Income Heat Pump Direct Installs	2025	$40,000	50	$2,000,000
	2026	$40,000	65	$2,600,000
Constrained NG Areas Focus (Duvall)	2025	$8,000	250	$2,000,000
	2026	$8,000	250	$2,000,000
Income Qualified Fuel Switching HP Rebates	2025	$4,000	100	$400,000
	2026	$4,000	200	$800,000
Small Business Direct Installs	2025	$50,000	10	$500,000
	2026	$50,000	10	$500,000
Multi-Family Rebates	2025	$2,000	500	$1,000,000
	2026	$2,000	500	$1,000,000
Commercial & Industrial	2025	$300,000	10	$3,000,000

Table 3. Projected Budget for the Targeted Electrification Pilot Phase 2 Through the End of Calendar Year 2026

Effort	Year	Amount	Est. QTY	Est. Spend
Custom Grant Pilot	2026	$300,000	10	$3,000,000
Marketing	2025/2026	$1,000,000	1	$1,000,000
Overhead and Evaluation	2025/2026	$2,500,000	1	$2,500,000
			Total	$22,300,000
			Direct Customer Benefit	84%
			Operating Costs	16%

Q. How does PSE propose to recover the costs of the Targeted Electrification Pilot Phase 2?

A. PSE proposes to recover the costs of the Targeted Electrification Pilot Phase 2 through Electric and Gas Schedules 141DCARB Decarbonization Rate Adjustment.

Please see the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, for details about Electric and Gas Schedules 141DCARB and the recovery of costs for the Targeted Electrification Pilot Phase 2 thereunder.

D. Benefits of the Targeted Electrification Pilot Phase 2

Q. How will the Targeted Electrification Pilot Phase 2 and associated cost recovery mechanism benefit customers?

A. Customers will be benefited by PSE proactively pursuing targeted electrification programs and applying those lessons learned into future programs. Through the

Targeted Electrification Pilot Phase 2, PSE aims to maintain fuel conversion support in the existing Low Income Weatherization Program and the Small Business Direct Install Program, both of which cannot deliver those benefits today except through the active Targeted Electrification Pilot. PSE also hopes to learn if an income qualified rebate and a multi-family rebate program can gain traction in the marketplace to inform refinements to these offerings in the future. This will be PSE’s first program focused on the commercial and industrial market and aims to validate if the custom grant program offering combines well with the existing energy efficiency programs, and meets the needs for commercial customers to initiate fuel switching opportunities. Finally, PSE needs to validate if focusing fuel switching efforts in constrained areas can gain sufficient traction to mitigate capacity constraints. These offerings also provide opportunities for PSE to engage with customers and the contractors that perform the various upgrades to learn more about their reasons for moving ahead, barriers they overcame, benefits they secured, and areas to improve the process.

Q. Will PSE conduct an evaluation of the Targeted Electrification Pilot Phase 2?

A. Yes. PSE will engage with The Cadmus Group to evaluate each program offering of the Targeted Electrification Pilot Phase 2. The Cadmus Group is the organization conducting the evaluation of the initial Targeted Electrification Pilot.

IV. PSE IS ACTIVELY PURSUING PUBLIC FUNDING OPPORTUNITIES

A. PSE's Public Funding Approach and Strategy

Q. Please describe PSE's understanding of the Commission's Final Order 24/10[12] ("Order 24/10") as it relates to the pursuit of public funding opportunities.

A. The Commission's Order 24/10 approved the UE-220066 Settlement on several conditions. One of these conditions included the requirement for PSE to demonstrate all offsetting benefits received or for which it has applied through the Infrastructure Investment and Jobs Act and the Inflation Reduction Act of 2022, when seeking review and recovery of capital investments and power costs. At the time, Order 24/10 recognized that the impact of these laws on rates were not yet known, but that it was apparent that they could affect PSE's operations during the multiyear rate plan. Further, Order 24/10 requires PSE's reporting with respect to the recovery of its capital investments and power costs to include all funding, tax benefits, or any other benefit for which PSE has and has not applied and, if it has not, the reasons justifying its decision to not pursue the IRA and IIJA funding options.

[12] *See WUTC v. Puget Sound Energy*, Dockets UE-220066, et al., Final Order 24/10 (Dec. 22, 2022).

Q. What is PSE's strategy and longer-term plan for pursuing and managing public funding opportunities?

A. PSE is committed to leveraging funding opportunities that are available through state and federal programs that can accelerate efforts to reduce carbon emissions, as well as reduce the costs associated with the transition to clean energy and improve affordability for customers. Upon passage of the IIJA in November 2021, PSE hired external consultants to assist PSE in the evaluation of a wide range of funding opportunities and to develop an application strategy. These efforts resulted in some successes and some learnings that PSE will apply to future rounds of funding. PSE is also actively tracking, evaluating, and applying for newly emerging funding opportunities tied to the IIJA and IRA.

In early 2023, PSE implemented an internal process to track, evaluate, and report on public funding opportunities (grants, tax credits, loans) as they become available. The process involves subject matter experts embedded within the business that work as a team to seek out and respond to new funding opportunities. These opportunities fall into three main categories:

- **Direct Funding Opportunities** – Direct funding opportunities are opportunities that directly enable PSE's clean energy strategy and goals and where PSE would be the main recipient of the funds.
- **Strategic Partnership Opportunities** – Strategic partnership opportunities are opportunities where PSE is not the main recipient but can help drive funding to strategic partners (tribes, municipalities, industry, academia, etc.) that complement or accelerate PSE's clean energy strategy and goals.

- **Customer Education and Engagement Opportunities** – Customer education and engagement opportunities are opportunities for funding made available through state and federal programs that can help PSE customers to decarbonize or lower their energy costs.

Through this process, PSE hopes to create a transparent and efficient system for managing public funding opportunities within the organization. Please see the Third Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-4, for a list of opportunities that PSE is currently tracking, updated as of January 2024.

Q. How is PSE aligning projects with the potential for future public funds?

A. Currently, PSE is maintaining an active inventory of projects that align with potential opportunities to secure future public funds and working with internal subject matter experts to evaluate. When public funds become available, the subject matter experts are engaged to compare projects to the fund type and eligibility to determine if one or more project is a good candidate for the funding opportunity. The list of opportunities selected to pursue or to not pursue is reviewed and approved by management on a recurring basis.

<u>B. Funding Opportunities/Offsetting Benefits that PSE Has Pursued from the IIJA and IRA in 2022 and 2023</u>

Q. What was the criteria/process for evaluating funding opportunities/offsetting benefits from the IIJA?

A. As mentioned earlier, PSE hired external consultants after the passage of the IIJA in November 2021, to support PSE in the evaluation of funding opportunities that would provide benefits to PSE customers and align with PSE's strategic needs. The consultant also provided insight on best practices for successfully applying for federal grants, which they drew, in part, from successful grant awards of their past clients that arose from the American Recovery and Reinvestment Act.[13]

The consultants began working with a cross-section of PSE employees in December 2021 to build an approach for the IIJA application process. From December 2021 to February 2022, PSE evaluated grant opportunities for which a utility could receive direct funding as well as grant opportunities for which a utility could be a strategic partner or a sub-grantee. PSE identified the following grant opportunities under the IIJA as having the highest alignment with PSE's operations and needs:

1. Grid Resilience and Innovative Partnerships ("GRIP") through the Department of Energy
    a. Section 40101(c) or Topic Area 1: Grid Resilience Grants
    b. Section 40107 or Topic Area 2: Smart Grid Grants (Grid Flexibility)
2. IIJA provision 40333 and Energy Policy Act of 2005 Secs. 242, 243 and 247: Hydroelectric Incentives Funding in the Bipartisan Infrastructure Law
3. Sec. 60401: Middle Mile Broadband
4. Sections 11401, 30018, 71101: Electric Vehicles
5. Sections 40541, 40554, 40552: Energy Efficiency
6. Section 40314: Hydrogen Hubs

[13] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 (2009).

Q. What direct funding opportunities did PSE pursue from the IIJA and why?

A. Early in 2022 when the consultant work was being finalized, a Funding Opportunity Announcement had not yet been made available for most grants, and specific requirements were unknown. Therefore, PSE projects and programs were assessed for readiness and impact against the general grant descriptions and some scoring criteria that had been released by the U.S. Department of Energy at the time. Based on this scoring process, PSE decided to move forward with grant applications in four areas: Grid Flexibility, Grid Resilience, Hydroelectric Incentives Funding, and Hydrogen Hub.

Q. Can you describe the funding opportunities that PSE pursued relating to grid flexibility and grid resilience?

A. The U.S. Department of Energy combined Grid Flexibility and Grid Resilience into a single Funding Opportunity Announcement called Grid Resilience and Innovation Partnerships Program ("GRIP").[14] In July 2022, PSE contracted with different external consultants to provide support in the development of applications for Smart Grid Grant (BIL section 40107) and Grid Resilience Grant (BIL section 40101(c)) under the GRIP funding opportunity. PSE selected the external consultant primarily based on project approach, success of the consultant with prior grant opportunities, pricing, and flexibility to be responsive to timing milestones established by the U.S. Department of Energy.

[14] *See generally* Grid Deployment Office, *Grid Resilience and Innovation Partnerships (GRIP) Program*, U.S. Department of Energy https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program.

On December 16, 2022, PSE submitted concept papers for both a Smart Grid and Grid Resilience Grant. The U.S. Department of Energy responded on February 2, 2023 with letters of encouragement for PSE to submit full applications for both grants.

On March 16, 2023, PSE submitted a Smart Grid grant application for the maximum possible award of $50 million. The portfolio of projects included in the proposal would have helped PSE implement smart grid technologies to modernize PSE's transmission and distribution grid by adding flexibility, intelligence, and responsive system attributes. The projects would have helped enhance automation and control of distribution and transmission assets to improve PSE's ability to prevent outages and recover from them more quickly. PSE had planned to channel over 50 percent of Smart Grid project investments into disadvantaged communities, highly impacted communities, and vulnerable populations.

On April 6, 2023, PSE submitted a Grid Resilience grant application for the maximum possible award of $100 million. The portfolio of projects included in this proposal would have helped improve reliability of distribution circuits that have experienced higher frequency (or duration) of service disruption than the threshold Customer Minutes Interrupted metric. The projects would have also (i) replaced aging conductors that may cause reliability concerns in the near future and (ii) engaged in the proactive underground conversion of overhead lines to mitigate reliability concerns and improve resilience of our assets in high wildfire risk areas. PSE had planned to channel about 44 percent of Grid Resilience project investments into disadvantaged communities, highly impacted communities, and vulnerable populations.

The competition for these grants was substantial, with over 700 applications received. On October 18, 2023, the U.S. Department of Energy released the list of 58 winning applications for the first round of Grid Flexibility and Grid Resilience grants.[15] Unfortunately, neither of PSE's proposals was among those selected.

There are two additional rounds of funding expected for similar grants, and PSE intends to pursue these opportunities. The U.S. Department of Energy issued the latest Funding Opportunity Announcement for Grid Flexibility and Grid Resilience grants on November 13, 2023,[16] with concept papers due on January 12, 2024 and full applications due on April 17, 2024. PSE submitted one concept paper as a primary applicant and is part of regional partnerships in four additional concept papers for the second round of GRIP funding.

Q. Can you describe the funding opportunities that PSE has pursued relating to hydroelectric efficiency?

A. Since 2014, PSE has applied for, and been awarded, incentive payments under the hydroelectric incentive program under Section 242 of the Energy Policy Act

[15] *See* Grid Deployment Office, Grid Resilience and Innovation Partnerships (GRIP) Program Projects, U.S. Department of Energy (Oct. 18 2023), https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects; *see also* U.S. Department of Energy, *Biden-Harris Administration Announces $3.5 Billion for Largest Ever Investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs* (Oct. 18 2023), https://www.energy.gov/articles/biden-harris-administration-announces-35-billion-largest-ever-investment-americas-electric.

[16] *See* Grid Deployment Office, *Biden-Harris Administration Announces Up to $3.9 Billion to Modernize and Expand America's Power Grid*, U.S. Department of Energy (Nov. 14, 2023), https://www.energy.gov/gdo/articles/biden-harris-administration-announces-39-billion-modernize-and-expand-americas-power.

of 2005[17] for new generation sources developed on existing dams (the "242 Program"). The 242 Program is among the suite of hydroelectric incentives that received new or increased funding under the IIJA. The increase in funding for this program has greatly helped PSE, which received two incentive payments (for calendar years 2021 and 2022) for hydropower generated from the Lower Baker Unit 4. Specifically, the U.S. Department of Energy determined that PSE was eligible for payment on 38,211,401 kilowatt-hours (kWh) generated by Lower Baker Unit 4 in each of calendar years 2021 and 2022. At the rate of \$0.02617/kWh, the U.S. Department of Energy determined that PSE's final incentive payment for power generated during calendar years 2021 and 2022 was \$1,000,000 and \$1,000,000, respectively. This amount represented an increase from incentive payments received by PSE in prior years. These benefits offset the operating budgets of the plant. Note that the availability of this incentive payment has varied by year and depends on approved funding and other factors, such as generation at the plant and how many other entities apply. Given this uncertainty, PSE currently conservatively forecasts receiving \$250,000 in 2024 and 2025, respectively.

Q. Can you describe the opportunities that PSE has pursued related to funding a regional hydrogen hub?

A. PSE is a member of the Pacific Northwest Hydrogen Association ("PNWH2"), a consortium of public and private entities spanning Washington, Oregon, and

[17] Section 242 of the Energy Policy Act, Pub. L. No. 109-58, codified at 42 U.S.C. § 15881.

Montana working together to bring clean hydrogen power solutions that leverage the region's vast renewable energy resources to market.

On April 7, 2023, PNWH2 submitted a grant application to secure funding for a regional clean hydrogen hub. PSE is one of 17 companies that has projects proposed as part of the PNWH2 Hub. On October 13, 2023, the U.S. Department of Energy selected the PNWH2 Hub for award negotiations following a competitive nationwide process.[18] The PNWH2 Hub is eligible to receive up to $1 billion in federal funding over four development phases defined by the U.S. Department of Energy that span nine years.

The projects proposed in the PNWH2 Hub would drive economic opportunity across all demographics, creating or supporting more than 10,000 good-paying jobs and stronger energy security to improve the lives and futures of people throughout the region. The PNWH2 Hub's vision and projects were developed with leadership from tribes, unions, industry, and many others and will help deliver a shared vision of clean and equitable energy systems in the Pacific Northwest.

Specifically, PSE is pursuing capital funding for a hydrogen-fueled peaker plant through the PNWH2 application for a hydrogen hub. If a hub were awarded to the region, PSE would be in a position to build, own, and operate a zero-carbon dispatchable electric generating facility that helps provide a stable source of clean

[18] *See* Office of Clean Energy Demonstrations, Regional Clean Hydrogen Hubs Selections for Award Negotiations, U.S. Department of Energy (Oct. 13, 2023), https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.

energy for PSE customers. PSE chose to pursue this opportunity to help address resource adequacy challenges and future CETA requirements noted in the Prefiled Direct Testimony of Josh Jacobs, Exh. JJJ-1T and to benefit from the overall strength of the public-private team that was assembled to pursue a hub.

Q. How has PSE incorporated energy equity into the IIJA project selection process?

A. Each application that PSE has pursued has required the development of detailed community benefit plans. In selecting projects to include in these applications, PSE considered location of projects and how to benefit disadvantaged communities, as defined by the Justice40 Initiative.[19] Projects selected were, in many cases, part of PSE's five-year plans. However, PSE sought to select projects where IIJA funding would provide increased benefit, such as accelerations to project timelines in order to improve service or enable new benefits, such as DER expansion, in disadvantaged communities.

PSE shared the project proposals submitted for funding under the IIJA with PSE's Equity Advisory Group to receive feedback on the approach. PSE incorporated suggestions of the Equity Advisory Group into the final applications. The Equity Advisory Group also submitted letters of support for PSE's grant applications.

[19] *See*, *e.g.*, Office of Energy Justice and Equity, Justice40 Initiative, U.S. Department of Energy, https://www.energy.gov/justice/justice40-initiative.

Q. What funding opportunities from the IIJA did PSE not pursue and why?

A. PSE did not pursue grant opportunities for middle mile broadband, energy efficiency, electric vehicles, and certain sections of the hydroelectric fleet incentives:

- **Middle Mile Broadband**. Upon evaluation, the middle mile broadband grant opportunity was not well-aligned with PSE's regulated business model or strategic focus.
- **Energy Efficiency**. PSE was not eligible to be a direct recipient of energy efficiency grants.
- **Electric Vehicles**. PSE was not eligible to be a direct recipient of electric vehicle grants; however, PSE is working to support community partners, such as school districts in PSE's service area, pursuing electric vehicle grants under the IIJA by providing letters of support and technical assistance
- **Hydroelectric Efficiency**. PSE evaluated hydroelectric efficiency grants under section 243 for Upper Baker Unit 2 but decided not to pursue them because PSE was too far along in the redesign of the unit to qualify for the incentives.

PSE also evaluated the hydroelectric fleet funding opportunity under the dam safety category (section 247) for the Upper Baker Spillway project. PSE filed a letter of intent with the U.S. Department of Energy in June 2023. However, due to heavy competition for these funds, the U.S. Department of Energy indicated that it would prioritize the applications based on the following three criteria:

- Dam safety condition classification;
- Hazard potential classification; and

- Potential to increase resiliency to future hydrologic conditions.

After consideration of the scoring criteria, PSE concluded that the Upper Baker Spillway project would rank relatively low, particularly due to the large number of facilities that have a lower Dam Safety Condition Classification than the Upper Baker facility. Thus, PSE decided not to pursue the grant further.

Q. What offsetting/rate mitigation opportunities is PSE pursuing from the IRA?

A. The IRA contains approximately $370 billion in renewable energy investment tax credits and advanced energy economy support. These renewable energy investment tax credits will make the development and acquisition of renewable and nonemitting electric generation resources more affordable for PSE and its customers. Among other things, the IRA helps create a level playing field for the development of renewable energy resources. When PSE develops and builds its own renewable energy resources, it is PSE's customers who own and derive the long-term benefit of those resources. Accordingly, PSE's customers receive the full benefit of the investment tax credits, receive the credit for generating and using the renewable energy resource, and receive the benefit of lower rates when excess renewable energy can be marketed to other areas. Please see the Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T, for details on how PSE plans to leverage the investment tax credits available under the IRA and how these benefits will flow back to PSE customers.

Q. How is PSE planning to leverage Home Efficiency and Electrification Rebates available through the IRA to help customers?

A. In July 2023, the U.S. Department of Energy released guidance (program requirements and the application instructions) on the Home Efficiency and Electrification Rebates grant program, a year after approval of the IRA. PSE has closely monitored this development and is in the process of assessing how program activities align with the requirements outlined by the U.S. Department of Energy. For example, home efficiency audit requirements outlined by the agency are extensive, and PSE will be working with the state to assess the most effective deployment of the audits in order to seek efficiency rebates. PSE will also seek clarity on how to qualify its electrification assessments. PSE is currently running home electrification assessments as part of its Targeted Electrification Pilot and is exploring how this program may qualify within IRA electrification rebates program requirements.

In addition to IRA-based home rebate grants, the State of Washington is expected to allocate CCA funds in the amount of $80 million for home electrification and appliance rebate programs. Washington State Department of Commerce issued a Request for Information that highlighted intentions to utilize these funds, and PSE's response included advice on program deployment specific to these home electrification rebate programs.

To leverage federal and state funding for home efficiency and electrification rebates, PSE will align its efficiency and electrification projects with its residential conservation programs, which include:

- Efficiency Boost (which offers higher rebates on energy-efficient upgrades to income-qualified customers);
- Home Weatherization Assistance (which connects income-qualified customers to local agencies for a free whole-home efficiency upgrade);
- Increased incentives for Multifamily New Construction and Retrofit (which provides rebates to offset the cost of in-unit and common area upgrades that improve energy efficiency);
- Electric space heat rebates;
- Water heating system rebates;
- Weatherization rebates; and
- Rebates and programs associated with PSE's Targeted Electrification Pilot.

Q. What support has PSE provided to its community partners to help them pursue funding opportunities from the IIJA and the IRA for which they may be eligible?

A. PSE has provided letters of support to various community partners that have sought funding from the IIJA, including the following:

1. La Conner School District – U.S. Environmental Protection Agency Clean School Bus grant;
2. Highline School District – U.S. Environmental Protection Agency Clean School Bus grant;

3. North Kitsap School District – U.S. Environmental Protection Agency Clean School Bus grant;

4. Issaquah School District – U.S. Environmental Protection Agency Clean School Bus grant;

5. Port Gamble S'Klallam Tribes – Energy Transitions Initiatives Partnership Project (ETIPP);

6. Northwest Seaport Alliance (NWSA) – U.S. Department of Transportation's Charging and Fueling Infrastructure Discretionary Grant Opportunity FY2022 and FY2023, for a project titled "Catalyzing Zero-Emission Drayage Trucking Infrastructure & Opportunities in the Seattle-Tacoma Region";

7. Sandia National Laboratories – U.S. Department of Energy, Office of Clean Energy Demonstrations' "Collaborative Alignment for Critical Technology Industries" funding for a project titled "National Consortium for the Advancement of LDES Technologies";

8. King County Metro electrification;

9. University of Washington-Bothell charging stations;

10. Sound Transit's Federal Transit Administration request;

11. Washington Department of Commerce "Solar for All" application to the U.S. Environmental Protection Agency;

12. The Nisqually Indian Tribe's "Solar for All" application to the U.S. Environmental Protection Agency; and

13. PSE signed a letter of support as a member company of the Electric Utilities of the West Coast Transit Corridor Initiative (WCCTCI) to support the application of the states of California, Oregon, and Washington to the U.S. Department of Transportation's Charging and Fueling Infrastructure Discretionary Grant Opportunity FY 2022 and FY 2023 for the West Coast Truck Charging and Fueling Corridor Project.

Q. How is PSE working with state agencies, like the Washington State Department of Commerce, on IIJA and IRA funds that are distributed through the state agencies?

A. The Washington State Department of Commerce ("Commerce") issued a Request for Information ("RFI") in September of 2023 to officially gather recommendations and insights from market participants and stakeholders (e.g., utilities, building owners, public agencies, advocacy organizations, equipment distributors, contractors, etc.) regarding twenty-four energy programs that use IIJA/IRA and other funds. PSE responded to this RFI to provide Commerce with advice on co-deployment with PSE programs and program priorities, where appropriate.

Other actions PSE has taken include active participation in Commerce-established roundtable and public listening sessions as well as targeted comment opportunities that Commerce has provided to the public on home efficiency and electrification rebate programs. PSE will continue to work with Commerce to provide market and program insights and expertise and expects funds to begin flowing in mid-to-late 2024, according to Commerce-communicated timelines. PSE expects Commerce programs will ultimately deploy both federal funds as well as state budget funds (from revenues from the CCA auctions, for example).

C. Other Federal and State Funding Opportunities

Q. Which other federal and state funding opportunities has PSE pursued?

A. PSE has applied for grants through the state's Clean Energy Fund for the following projects:

- **Grid Modernization Projects**. PSE applied for, and was awarded, a $200,000 grid modernization grant through the Clean Energy Fund. PSE will use the funding to perform a feasibility study evaluating the use of storage and other technologies to increase distribution system hosting capacity in the Kittitas County region so that PSE can provide an opportunity for more customer solar adoption. The phase 1 application was approved, and PSE submitted phase 2 of the application on September 21, 2023. PSE was selected for a funding award on December 20, 2023.

- **Clean Energy Research, Development and Demonstration**. PSE has applied for a $1,000,000 grant to pursue a metal hydride hydrogen storage pilot project that would enable PSE to test a hydrogen storage option that can be deployed safely.

In addition, PSE has also applied for funding through the Washington State EV Charging Program, which is offering, in the first round of funding, $64 million in incentives to install Level 2 and DC fast chargers throughout the state, with a goal of directing 40 percent of funding into overburdened and vulnerable communities. PSE was the lead applicant for two multifamily projects within this program and a partner applicant on over 100 other proposed projects. For a full list of public funding opportunities that PSE is actively tracking and evaluating, please see the Third Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-4.

Q. Is PSE pursuing any loans through the U.S. Department of Energy Loan Programs Office?

A. PSE is assessing the applicability of the U.S. Department of Energy Loan Programs Office's ("LPO") Title 17 Clean Energy Financing Program for funding planned projects. Under the Title 17 Clean Energy Financing Program, the LPO can provide federal financing for projects located in the United States that support clean energy deployment and energy infrastructure reinvestment to reduce greenhouse gas emissions and air pollution.

Q. How is PSE assessing the applicability of the Title 17 Clean Energy Financing Program for funding planned projects?

A. PSE is reviewing the Title 17 Clean Energy Financing Program requirements and project eligibility requirements to determine if one or more projects are a good candidate for this funding opportunity. As part of this evaluation, PSE is in conversations with the LPO regarding project funding applicability.

Q. When will PSE be applying for a Title 17 Clean Energy Financing Program loan and how long does the application process take?

A. Due to the complexity of the Title 17 Clean Energy Financing Program requirements, it will take some time to understand if this is a viable solution for low-cost funding for the company and our customers. If PSE has eligible projects, according to the LPO, the application process through conditional commitment commonly takes up to a year.

V. PSE IS ACTIVELY CONSIDERING EMERGING TECHNOLOGIES IN THE CLEAN ENERGY SPACE

Q. What are PSE's clean energy capacity needs for 2030 and 2045?

A. PSE projects that demand for electricity will increase over the next two decades. Moreover, the transition to clean energy means that reliable, dispatchable sources of energy that have traditionally provided baseload power, such as coal and natural gas, will no longer be available. Replacement of these resources with intermittent renewable resources requires substantial additional capacity to balance the intermittent nature of these renewable resources.

PSE's 2023 Electric Progress Report identified the need to acquire almost 7,000 MW of nameplate renewable resources by 2030 and 15,000 MW of nameplate renewable resources by 2045.[20] To put this into perspective, PSE's current generating capacity including owned and contracted resources is around 6,500 MW of nameplate capacity. In other words, PSE will likely need to more than double its existing nameplate capacity to meet the 2030 goal of CETA and more than triple its existing nameplate capacity to meet the 2045 goal of CETA.

Q. What is PSE's vision/strategy for meeting these capacity needs?

A. In the 2023 Electric Progress Report, PSE laid out its vision for meeting its clean energy capacity needs in 2030 and 2045. The plan illustrated that significant investment in intermittent renewable resources, combined with energy storage,

[20] For a copy of the 2023 Electric Progress Report, please see the Second Exhibit to the Prefiled Direct Testimony of Josh Jacobs, Exh. JJJ-3.

and demand response, will shape the foundation of PSE's future energy system. PSE also assumes that other technologies will emerge over the coming fifteen years that will help PSE maintain a reliable system while meeting the state's policy goals. Having a diverse set of resources is especially critical for meeting customer needs at times of peak demand, such as a cold winter day or a summer heat wave.

PSE believes that no single technology solution will be the sole solution for a clean energy future, which is why PSE is taking an "all of the above" approach, including pragmatic and diversified engagement with others in the region to take concrete steps to move multiple technologies forward. PSE works to identify future resources to maintain the reliability and affordability that customers expect as PSE works with others in the region to create a cleaner and more equitable energy system.

Q. What emerging technologies is PSE exploring to meet future capacity needs?

A. As stated above, given PSE's significant capacity needs and the lack of existing carbon-free dispatchable and baseload capacity resources, PSE has cast a wide net to explore emerging technologies that can help fill this capacity gap. This prefiled direct testimony discusses PSE's exploration of three emerging technologies: (i) clean hydrogen technologies, (ii) small modular nuclear reactors, and (iii) long-duration energy storage technologies.

A. Clean Hydrogen Technologies

Q. Is PSE exploring clean hydrogen technologies?

A. Yes. PSE is currently exploring clean hydrogen technologies and how such technologies can help decarbonize PSE's energy operations and meet decarbonization goals of PSE customers. Specifically, PSE is considering the use of clean hydrogen as a fuel for combustion turbine peaking plants. When used as a fuel for power generation, the combustion of clean hydrogen in a turbine does not produce carbon dioxide emissions.

Q. How has PSE been involved in the effort of the Pacific Northwest Hydrogen Association to develop a hydrogen hub?

A. As discussed above in Section IV.B of this prefiled direct testimony, PSE is a member of the Pacific Northwest Hydrogen Association ("PNWH2"). PSE is pursuing capital funding for a hydrogen-fueled peaker plant through the PNWH2 Hub application. If successful, PSE will be in position to build, own, and operate a zero-carbon electric generating facility to balance and firm intermittent renewable resources. The peaker that PSE is developing also includes a storage tank for renewable diesel, a backup fuel, in the event that the plant must operate during periods in which clean hydrogen is unavailable. This project would serve as a catalyst not only for the regional hydrogen economy, but also for the transition of PSE's existing natural gas-fueled thermal fleet to zero carbon fuels, including clean hydrogen, by 2045.

Q. Is PSE participating in other efforts to consider the use of clean hydrogen as an energy source?

A. Yes. In addition to the PNWH2 Hub, PSE is also participating in trade organizations and regional alliances, including the Renewable Hydrogen Alliance, HyReady through Pacific Northwest National Laboratory, and the Green Hydrogen Coalition.

Q. What are some barriers to commercializing and deploying hydrogen?

A. There are currently several barriers to commercialization and deployment of clean hydrogen as fuel for power generation, including initial costs and scaling of solutions, availability of renewable power to produce clean hydrogen at competitive rates, and electrical transmission capacity. Additionally, there is no large-scale geologic storage or pipeline capacity in Washington to facilitate the movement of hydrogen between suppliers and offtakers. Production tax credits and investment tax credits made available in the Inflation Reduction Act improve the economics of clean hydrogen as a fuel source for power generation, however recent guidance issued by the U.S. Department of the Treasury and Internal Revenue Service on the application of IRA tax credits for hydrogen production in section 45V of the Internal Revenue Code may make those tax credits difficult to obtain. There also continue to be challenges around the public perceptions of hydrogen, including safety concerns and arguments about hydrogen's proper role in decarbonizing the economy.

B. <u>Small Modular Nuclear Reactors</u>

Q. Is PSE exploring small modular nuclear reactor technologies?

A. Yes. PSE is exploring small modular nuclear ("SMR") reactor technologies. Nuclear energy already generates a large percentage of electricity in the U.S. and has accounted for between 19 percent and 20 percent of the total annual U.S. electricity generation from calendar years 1990 through 2021.[21] In Washington, the Columbia Generating Station in Richland, Washington, provides nearly ten percent of the state's energy.[22]

In recent years, there have been significant improvements in advanced reactors that seek to address some of the concerns associated with cost, size, and safety of existing commercial reactors, such as the Columbia Generating Station:

> Advanced reactors are often referred to as "Generation IV" nuclear technologies, with existing commercial reactors constituting "Generation III" or, for the most recently constructed reactors, "Generation III+." Major categories of advanced reactors include advanced water-cooled reactors, which would make safety, efficiency, and other improvements over existing commercial reactors; gas-cooled reactors, which could use graphite as a neutron moderator or have no moderator; liquid metal-cooled reactors, which would be cooled by liquid sodium or other metals and have no moderator; molten salt reactors, which would use liquid fuel; and fusion reactors, which would release energy through the combination of light atomic nuclei rather than the splitting (fission) of heavy nuclei such as uranium. Most of these concepts have been studied, but relatively few have advanced to

---

[21] U.S. Energy Information Administration, *U.S. Nuclear Industry* (Aug. 24, 2023), https://ww.eia.gov/energyexplained/nuclear/us-nuclear-industry.php.

[22] Energy Northwest, *Nuclear Energy*, https://www.energy-northwest.com/energy101/energysources/Pages/Nuclear.aspx.

> commercial-scale demonstration, and such demonstrations in the United States took place decades ago.[23]

In light of PSE's significant capacity needs and the need for a CETA-compliant baseload resource to replace coal in our portfolio, PSE has engaged in regional discussions around small modular reactors. Small modular reactors are advanced nuclear reactors that have a power capacity of up to 300 MW per unit, which is about one-third of the generating capacity of traditional nuclear power reactors, and can produce carbon-free electricity.[24] Many of the benefits of SMRs are inherently linked to the nature of their design:

> Many of the benefits of SMRs are inherently linked to the nature of their design – small and modular. Given their smaller footprint, SMRs can be sited on locations not suitable for larger nuclear power plants. Prefabricated units of SMRs can be manufactured and then shipped and installed on site, making them more affordable to build than large power reactors, which are often custom designed for a particular location, sometimes leading to construction delays. SMRs offer savings in cost and construction time, and they can be deployed incrementally to match increasing energy demand.[25]

If small modular reactors could advance beyond commercial-scale demonstration and become available for commercial use in the U.S., they could play a critical role in integrating intermittent renewable resources, like wind and solar, and provide a critical reliability benefit to the grid.

[23] Congressional Research Service, *Advanced Nuclear Reactors: Technology Overview and Current Issues*, Summary (Feb. 17, 2023), https://crsreports.congress.gov/product/pdf/R/R45706.

[24] *See* International Atomic Energy Agency, *What Are Small Modular Reactors (SMRs)?* (Sept. 13, 2023), www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs.

[25] *Id*.

Q. Is PSE evaluating any specific small modular nuclear reactor projects?

A. Yes. As part of an "all of the above" approach to meeting clean energy and capacity needs, PSE is investing $10 million with Energy Northwest to support early project development activities for the first phase of a small modular nuclear reactor facility in exchange for future energy and capacity generated as part of these projects.

Q. Is PSE seeking cost recovery of this $10 million investment?

A. No. PSE is not seeking cost recovery of this $10 million investment in Energy Northwest to support early project development activities for the first phase of a small modular nuclear reactor facility.

C. Grid-Scale Long Duration Energy Storage Technologies

Q. Is PSE considering grid-scale long duration energy storage technologies?

A. Yes. PSE is currently considering a number of grid-scale long duration energy storage technologies. PSE is working with both internal and external parties, such as the Electric Power Research Institute, to understand the chemistries behind the technologies and how PSE could operationalize the storage capabilities of such technologies.

PSE is a member of the National Consortium for the Advancement of LDES Technologies, which Sandia National Laboratories formed in partnership with Argonne National Laboratory, Idaho National Laboratory, the National

Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory. PSE is one of 87 entities to join the consortium, which seeks to "enable, facilitate, and coalesce collaborative efforts between public and private entities to address the core issues facing long duration energy storage commercialization, including investor confidence, market planning, interconnection, standardization, safety, economic evaluation, and more."[26]

Q. How will long duration energy storage help mitigate PSE's clean energy capacity needs?

A. LDES technologies can help maintain a continuous and reliable supply of clean energy in the absence of baseload resources like coal and natural gas. An LDES battery can store energy produced by intermittent renewable resources, like wind and solar, for use when the sun is not shining and the wind is not blowing.

As discussed further in Section VI below, Form Energy's iron-air technology can dispatch at full nameplate capacity for up to 100 hours.[27] For reference, PSE typically maintains about 56 hours of distillate back-up at existing peaker plants, and more common grid-scale battery energy storage systems generally have durations of four hours or less:

> By the end of 2022 about 9 GW of energy storage had been added to the U.S. grid since 2010, adding to the roughly 23 GW of pumped storage hydropower (PSH) installed before that. Of the

[26] U.S. Department of Energy Office of Technology Transitions, *DOE Announces over $15 Million towards Two Projects to Support Industry Engagement and Alignment for Clean Energy Solutions* (Sept. 7, 2023), https://www.energy.gov/technologytransitions/articles/doe-announces-over-15-million-towards-two-projects-support-industry.

[27] *See id*.

> new storage capacity, more than 90% has a duration of 4 hours or less, and in the last few years, Li-ion batteries have provided about 99% of new capacity.[28]

Therefore, Form Energy's iron-air technology offers the potential for a much longer firm energy duration than that of lithium-ion batteries. A longer duration would enable PSE to maintain reliability over a much longer duration or during times of limited generation from intermittent renewable resources during peak events.

Q. What are some barriers to the commercialization of LDES technologies?

A. LDES technologies are only just starting to be developed and deployed, and there are many types (over 100) of LDES technologies under development. The lack of operational history is the most significant current barrier to commercialization of LDES technologies. Without historical operational data from comparable utilities or companies, it is difficult for utilities, such as PSE, to anticipate, plan, and prepare to operate LDES technologies. The significant leap from current grid-scale lithium-ion battery energy storage systems to LDES technologies will take time, and utilities must develop a technological understanding of how best to deploy LDES technologies as grid-scale devices.

[28] Paul Denholm, et al., *Moving Beyond 4-Hour Li-Ion Batteries: Challenges and Opportunities for Long(er)-Duration Energy Storage*, National Renewable Energy Laboratory, at v (Sept. 2023), https://www.nrel.gov/docs/fy23osti/85878.pdf.

VI. PSE'S PROPOSED LONG-DURATION ENERGY STORAGE PILOT

A. Overview

Q. What is PSE proposing for a long-duration energy storage pilot?

A. PSE is proposing to install a 10 MW iron-air battery technology developed by Form Energy (the "LDES Pilot"). Form Energy's iron-air battery technology can discharge for a duration of 100 hours.[29] PSE projects that the proposed LDES Pilot would go into service by the end of calendar year 2026.

Q. Please describe PSE's proposed LDES Pilot.

A. PSE is proposing installation of a 10 MW/1000 MWh iron-air battery from Form Energy. The battery features a 100-hour duration discharge, which far exceeds other battery storage technologies, including grid-scale lithium-ion batteries. PSE is currently analyzing siting options that will maximize project benefits under the clean energy investment tax credits ("ITC"), thereby providing positive customer benefits while allowing PSE to evaluate the capacity benefits of this new resource type.

This 100-hour duration would allow PSE to discharge the LDES battery during winter peaking and summer peaking events when intermittent resources, such as wind and solar renewable resources, may not be generating. Form Energy has developed the operating characteristics of this iron-air battery to resemble those of a combustion turbine peaking plant. If this LDES Pilot proves successful, PSE

[29] *See* Form Energy, *Battery Technology*, https://formenergy.com/technology/battery-technology/.

could consider deploying similar LDES systems in 100 MW increments, fulfilling PSE's need for CETA-compliant dispatchable capacity.

Q. Please describe the technology PSE selected for the LDES Pilot.

A. Form Energy's LDES system is based on iron-air technology. The chemistry of this technology utilizes a reverse rusting process that allows for a much longer duration than that of lithium ion or flow battery technologies. Form Energy's LDES technology can charge continuously for days and discharge for upwards of 100 hours. The abundance of iron worldwide, as opposed to lithium, helps decrease material and cost risk, thereby allowing for a much smoother supply chain process. Form Energy further reduces supply chain risk by using off-the-shelf components in its battery equipment. The iron-air chemistry is also composed of a non-flammable aqueous electrolyte meaning that there is no risk of thermal runaway and no heavy metals required with this technology.

Q. Why is PSE introducing the proposed LDES Pilot as part of this proceeding?

A. Both the region and PSE have a growing need for carbon-free dispatchable capacity resources to provide balancing and ancillary services for intermittent renewable resources, such as solar and wind, to comply with CETA and similar requirements of other states. PSE has a need to learn about LDES technologies through first-hand deployment of these systems on PSE's grid. The experience and learning gained by PSE from the proposed LDES Pilot will help prove out

LDES use cases and costs, which will inform future resource planning and acquisition decisions.

PSE and Form Energy can build and deploy the LDES Pilot assets by 2026, which is sooner than other types of carbon-free dispatchable capacity evaluated by PSE. Additionally, the primary battery material—iron—is an affordable and abundantly available commodity that, if successful, could demonstrate the promise of the Form Energy LDES technology as a cost-effective carbon-free dispatchable capacity resource.

Q. How would PSE's proposed LDES Pilot benefit customers?

A. PSE intends to use the proposed LDES Pilot for several use cases.

On the generation side, PSE will leverage the long duration capacity of the proposed LDES Pilot to supplement system peak management. Optimizing market conditions, PSE will test capacity in two scenarios: (1) the use of capacity a few hours per day over many days, and (2) the use of capacity for three to four consecutive days. PSE will learn from and assess the 100-hour duration of the technology in each use case to understand the value in each use case.

Additionally, PSE will test capacity planning and qualifying capacity of the proposed LDES Pilot. In both trading and capacity planning, PSE's load office will be able to use the LDES system for ancillary services as a contingency reserve obligation.

Q. What research did PSE conduct to understand the Form Energy LDES technology?

A. PSE partnered with Electric Power Research Institute to understand LDES technologies in general and the Form Energy iron-air LDES technology in particular. PSE also contracted with Black and Veatch, an outside consultant, to perform technology evaluation in the development of the 2025 Integrated Resource Plan. PSE's internal subject matter experts worked with these organizations to understand the potential value of LDES technologies and evaluated numerous battery technologies, including LDES technologies.

Q. Does Form Energy have other pilot projects in progress?

A. Yes. Form Energy has a number of publicly announced pilot projects under development. Form Energy has contracted with each of Georgia Power, Great River Energy, Dominion Energy, Xcel Energy, and the California Energy Commission on LDES projects ranging from five to fifteen MWs.

Q. Will the iron-air LDES technology selected by PSE align with existing technologies and control systems?

A. Yes. The Form Energy LDES technology will complement a number of batteries and microgrids currently under deployment by PSE. Leveraging existing information and operational technology requirements, asset management practices, and internal operational standards for distributed as well, as front-of-the-meter batteries, PSE has a process and framework for how to operationalize the LDES Pilot. Further learning will enhance PSE's understanding of battery interaction on the market as well as ancillary services with the load office. Through this pilot, PSE hopes to further develop its knowledge of how this technology can support existing technologies on the system.

Q. How does PSE plan to engage the community and consider equity while developing the LDES Pilot?

A. PSE is in the process of site selection for the LDES Pilot. Through this process, PSE is committed to a robust community engagement process that involves 1) providing an opportunity to participate in the project planning and development and 2) listening to ideas and feedback to ensure the project benefits our customers, including PSE's vulnerable populations and highly impacted communities. PSE will work with its public engagement and policy teams to approach interested parties and communities in a methodical, equitable, and inclusive process.

Q. Did PSE engage with its management/executive team on the proposed LDES Pilot?

A. Yes. The Energy Management Committee approved the proposed LDES Pilot on January 4, 2024. Please see the Fourth Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-5C, for the presentation to the Energy Management Committee on January 4, 2024. PSE entered into a memorandum of understanding ("MOU") with Form Energy to further develop the LDES Pilot on

January 4, 2024. Please see the Fifth Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-6C for the MOU between PSE and Form Energy. Additionally, PSE management approved a Corporate Spending Authorization ("CSA") form for the LDES Pilot in PSE's capital plan. Please see the Sixth Exhibit to the Prefiled Direct Testimony of John Mannetti Exh. JM-7C for the Corporate Spending Authorization for the Long Duration Energy Storage Pilot.

Q. Did PSE consider alternative technologies?

A. Yes. PSE has considered and continues to research a number of other emerging technologies. In the space of LDES specifically, PSE is unaware of any alternatives in the battery space that have a duration of longer than twelve hours. This puts the technology developed by Form Energy in a unique position to address longer peak events.

B. Implementation Strategy for the Proposed LDES Pilot

Q. Please explain PSE's implementation strategy for the proposed LDES Pilot.

A. In calendar year 2024, PSE and Form Energy will work together on technical due diligence, site identification, and selection of system size and configuration. PSE and Form Energy will also finalize necessary contracts for the proposed LDES Pilot.

In calendar year 2025, PSE and Form Energy will engage in (i) project design, (ii) permitting, (iii) community engagement to assess the equity implications of specific locations, and (iv) engineering, procurement, and construction activities.

In calendar year 2026, construction will begin, factory acceptance tests will be performed, and the LDES system will be delivered to the selected site.

Q. Will PSE manage the engineering, procurement, and construction activities for the proposed LDES Pilot?

A. No. Form Energy brings experience and expertise in LDES projects to the proposed LDES pilot. This experience and expertise includes the ability to contract with Form Energy's engineering, procurement, and construction team. PSE anticipates learning from Form Energy through implementation of the proposed LDES Pilot rather than managing the engineering, procurement, and construction work. In other words, PSE will be relying on the experience and expertise of Form Energy, while also gaining a better understanding of the technicalities of LDES systems.

Q. Please describe what PSE anticipates may be included in the Evaluation, Measurement, and Verification process.

A. PSE will use the proposed LDES Pilot to evaluate the technological readiness for full-scale utilization and deployment of LDES systems. PSE aims to learn and optimize how and when to dispatch LDES systems. For example, PSE will seek to understand how to utilize the technology for system peak reduction and ancillary services, such as voltage support and frequency response. Learning how and when PSE can most effectively dispatch LDES systems will help determine the value of future deployments of LDES systems at scale.

C. Cost Recovery for the Proposed LDES Pilot

Q. What is PSE's projected capital budget for the LDES Pilot?

A. PSE's projected capital budget for the LDES Pilot is [redacted], with the LDES Pilot achieving operations in calendar year 2026.

Table 4. Projected Capital Budget for the LDES Pilot

Calendar Year	Projected Capital Expense
Calendar Year 2024	[redacted]
Calendar Year 2025	[redacted]
Calendar Year 2026	[redacted]
[redacted]	[redacted]

Table 4 above reflects only the capital expenditures and does not reflect financing costs, in the form of allowance for funds used during construction ("AFUDC") and construction work in progress ("CWIP"). Table 5 below reflects the projected amounts associated with the LDES Pilot that would be placed in rate base.

SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160

REDACTED VERSION

Table 5. Projected Amounts to be Added to Rate Base for the LDES Pilot

Year	Beginnning CWIP	Capital Expenditures	AFUDC	Closing	Ending CWIP
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. What is the projected operations and maintenance budget for the LDES Pilot after it becomes operational in 2026?

A. PSE projects an annual operations and maintenance budget for the LDES Pilot of approximately $200,000 (not including the cost of electricity to charge) or about $2,845,000 total over a 15-year period.

Q. How does PSE expect to recover the costs of the proposed LDES Pilot?

A. PSE proposes to recover the [redacted] reflected in Table 5 above in base rates during the multiyear rate plan period. PSE has included these costs in the filed rate plan as part of this proceeding.

PSE will also apply for clean energy investment tax credits under Section 48E of the tax code, 26 U.S.C. § 48E, for the proposed LDES pilot. The LDES Pilot should qualify for ITCs of 40 or 50 percent of the qualified investment, depending on siting of the pilot. The LDES Pilot would be eligible for the ITC of 50 percent of the qualified investment if sited in an energy community and 40 percent of the qualified investment if not sited in an energy community.

Please see the Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T, for a discussion of how PSE is evaluating and applying investment tax credits.

Q. Is LDES technology currently a cost-effective solution? If not, what would it take for LDES technology to be cost-effective?

A. No. Currently, LDES technology is not a cost-effective solution. PSE is testing the Form Energy LDES technology in the pilot to understand how and when to operationalize LDES technology once it becomes more cost-effective. PSE is optimistic that once scaled, LDES technology may be a cost-effective capacity resource.

The levelized cost of capacity for PSE's LDES pilot is estimated to be $[redacted] per kilowatt-year. However, PSE projects that the levelized cost of capacity of the Form Energy LDES technology at scale could be as low as $129 per kilowatt-year, which would compare favorably with the projected levelized cost of capacity of a biodiesel peaker at $176/KW-year. By contrast, the cost of multiple lithium-ion batteries to equal the duration of one Form Energy LDES battery would be significantly higher.

Please see the Fifth Exhibit to the Prefiled Direct Testimony of John Mannetti, Exh. JM-8, for a comparison of levelized costs of energy of capacity technologies considered by PSE.

SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160

REDACTED VERSION

VII. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-80-B December 6, 2023

Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals.

ORDER ON REGULATORY PRINCIPLES AND FRAMEWORK

TABLE OF CONTENTS

SUMMARY

The Department of Public Utilities ("Department") announces a regulatory framework intended to set forth its role and that of the Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its target of net-zero greenhouse gas ("GHG") emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020). The Department seeks to enable the Commonwealth to move into its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective natural gas service; minimizing the burden on low- and moderate-income households as the transition proceeds; and facilitating a just workforce and energy infrastructure transition.

In this proceeding, the Department reviewed eight potential decarbonization "pathways" to achieving the target of a 90 percent gross reduction in GHG emissions by 2050 as compared to 1990 levels, as well as interim GHG emissions reductions targets of 50 percent by 2030 and 75 percent by 2040. The decarbonization pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100-percent decommissioning of gas distribution infrastructure in the Commonwealth. The Department makes no findings as to a preferred pathway or technology; rather, our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy objectives.

The Department considered six regulatory design recommendations intended to facilitate the Commonwealth's transition: (1) support customer adoption of and conversion to electrified and decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department makes specific findings about each of these regulatory design recommendations as detailed in the Order.

As to supporting customer adoption of and conversion to electrified and decarbonized heating technologies, the Department finds that to achieve the Commonwealth's climate targets, there must be a significant increase in the use of electrified and decarbonized heating technologies. The Department and LDCs can play a pivotal role by enhancing incentives and expanding the Mass Save energy efficiency programs to facilitate customer use of heat pumps. The Department also addresses the critical need to minimize costs for customers, including through pursuit of outside funding sources, and prioritizing workforce development to enable a just transition framework for gas industry workers as well as customers.

The Department rejects the recommendation to change its current gas supply procurement policy to support the addition of renewable natural gas ("RNG") to LDC supply portfolios due to concerns regarding the costs and availability of RNG as well as its uncertain status as zero-emissions fuel. The Department does support the option for customers to be able to purchase RNG from their LDC or a supplier at full cost to the customer.

Given the critical importance of significantly decarbonizing the heating sector, the Department considered the proposal that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen. As detailed in the Order, the Department views networked geothermal projects as those with the most potential to reduce GHG emissions, and expresses support for targeted electrification as well.

The Department seeks to dissuade gas customer expansion and to align rate design with the Commonwealth's climate objectives. To achieve this, the Department instructs gas utilities to revise their per-customer revenue decoupling mechanism to a decoupling approach based on total revenues. Removing the incentive to add new customers aligns the LDCs' rate design with climate objectives and GHG emissions reductions targets. The Department finds it must examine the issue of depreciation, i.e., the period of time over which a capital investment is recovered, and stranded assets. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments, and to identify the impacts of accelerated depreciation proposals, as well as potential alternatives to accelerated depreciation.

The Department finds that consideration of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation, is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented. Going forward, the Department states that as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery.

The Department agrees with suggestions that the standards for investments to serve new customers be examined. The Department therefore directs the LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions. Further, in reviewing future applications for new service, the Department will examine the appropriateness of the existing standard—that there be no adverse impacts on existing natural gas customers—in the context of a broader climate mandate.

The Department observes that there are numerous concerns regarding affordability for customers, including the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity, and also higher rates for customers who remain on the system. Cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers from environmental justice populations, present equity challenges as well.

Finally, the Department finds that the clean energy transition will require coordinated planning between LDCs and electric distribution companies, monitoring progress through LDC reporting, and aligning existing Department practices with climate targets. To that end, the Department orders LDCs to submit individual Climate Compliance Plans to the Department every five years beginning in 2025, and to propose climate compliance performance metrics in their upcoming performance-based regulation filings, ensuring a proactive approach to achieving climate targets.

I. INTRODUCTION

The Department of Public Utilities ("Department") opened this inquiry on October 29, 2020, to examine the role of Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its 2050 climate targets, and to identify strategies for enabling the Commonwealth to move into its net zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80, Vote and Order Opening Investigation at 1 (2020) ("Vote and Order"). The Department specifically sought to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition that requires the Department to consider new policies and structures to protect ratepayers as the Commonwealth reduces its reliance on natural gas. D.P.U. 20-80, at 4. This proceeding is necessarily one step—not the first and certainly not the last—as we endeavor to chart a path forward that enables the Commonwealth to achieve its target of net zero GHG emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020), available at https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (last visited November 29, 2023). The Department docketed this matter as D.P.U. 20-80.

Through this investigation, the Department has gathered a significant body of information from the LDCs and a wide range of institutional and individual stakeholders, evincing the need for an evolving, multifaceted, broadly coalitional, and responsive process as we seek to define and meet the significant challenges and potential opportunities that are presented not only by the Commonwealth's climate targets, but also by the threat and reality of the climate crisis itself. The Department acknowledges and appreciates the time, commitment, and thoughtful contributions provided by many stakeholders throughout this proceeding. In this Order, we first enunciate a set of regulatory principles that will guide our decision-making in this and future dockets. We then address in more detail the reports and analyses produced by the LDCs and their consultants, as well the comments and analyses submitted by stakeholders. Our purpose here never has been to dictate one path forward, but to gather information and identify existing and potential means within our authority to remove barriers to the clean energy transition and find ways for the Department to facilitate and accelerate pursuit of our 2050 climate targets. To that end, in this Order we identify future areas of inquiry that will be explored and note those future proceedings (including technical conferences, adjudications, and additional investigations) where we will investigate and implement the issues and principles identified herein.

In enunciating regulatory principles, our intent is that these foundational propositions will inform many of the Department's processes and proceedings through a "whole of DPU" approach, not limited to those matters such as this where climate and GHG-reduction policies explicitly are at issue, but also inform rate design and other more traditional Department functions within our authority. We also note areas in which the Department cannot (or cannot yet) act unilaterally, observing where legislative change or other agency action is required as we seek to pursue vigorously our role in a "whole of government" response to the climate crisis. The Department is one governmental actor working toward the clean energy transition, and we anticipate necessary future legislative action, as well as implementation from the Executive Office of Energy and Environmental Affairs ("EEA"), Massachusetts Department of Energy Resources ("DOER"), Massachusetts Department of Environmental Protection ("MassDEP"), and the Massachusetts Clean Energy Center ("MassCEC"), among others. Finally, in establishing these guiding principles we take care to emphasize the role of communities, neighborhoods, and individuals within the clean energy transition, as we seek to facilitate active participation in a "whole of society" approach to electrification, decarbonization, a just and equitable workforce transition, and equitable investment in communities in pursuit of our 2050 climate targets. While the Department cannot dictate the choices of individual consumers, we can and will seek to maintain a safe, reliable, and affordable system while encouraging and facilitating the thousands of small transitions that must occur on household, neighborhood, and community levels for the Commonwealth as a whole to move into its clean energy future.

II. PROCEDURAL HISTORY

On October 29, 2020, the Department voted to open an investigation into potential policies that will enable the Commonwealth to reach its target of net zero GHG emissions by

2050 and the role of Massachusetts gas LDCs[1] in achieving that goal.[2] D.P.U. 20-80, at 1. The Department stated its intent to solicit utility and stakeholder input in this investigation, noting that EEA was (1) developing in consultation with MassDEP and DOER an evaluation of potential pathways to achieving the Commonwealth's 2050 GWSA statewide net zero emissions limit; and (2) preparing a Clean Energy and Climate Plan ("CECP")[3] for 2030. D.P.U. 20-80, at 3, citing Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); G.L. c. 21N, §§ 3, 4; Massachusetts 2050 Decarbonization Roadmap (December 2020), available at

---

1 The gas LDCs subject to the Department's jurisdiction are: The Berkshire Gas Company ("Berkshire Gas"); Boston Gas Company d/b/a National Grid ("National Grid (gas)"); Eversource Gas Company of Massachusetts ("EGMA") and NSTAR Gas Company ("NSTAR Gas"), each d/b/a Eversource Energy (together, "Eversource"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty").

2 Prior to the Department's issuance of the Order, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a petition ("Petition") requesting that the Department open an investigation to assess the future of the LDCs' operations and planning in light of the Commonwealth's target of net zero GHG emissions by 2050 (Attorney General Petition at 1 (June 4, 2020), citing GWSA; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); State of the State Address (January 21, 2020)). The Attorney General's request has been incorporated into this docket.

3 EEA prepares a CECP every five years, beginning in 2010. The CECP sets forth a policy/roadmap for the Commonwealth to meet the GHG emissions limits by 2050. The Interim 2030 CECP developed by EEA was released in December 2020. The final CECP for 2025 and 2030 was released in June 2022 ("2025/2030 CECP") and can be found at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download (last visited November 29, 2023). The Department stated its anticipation that the 2050 Decarbonization Roadmap ("2050 Roadmap") and 2030 CECP (together, the "Roadmaps") would set forth policies affecting ratepayers, LDCs, and the gas industry as a whole. D.P.U. 20-80, at 3. The Department therefore directed the LDCs to: (1) initiate a joint request for proposals ("RFP") for an independent consultant to conduct a detailed study of each LDC and analyze the feasibility of all pathways identified in the Roadmaps, as well as any additional strategies identified by the independent consultant, to help the Commonwealth achieve its goal of net zero GHG emissions by 2050; (2) submit a report prepared by the independent consultant that integrates the individual analyses of each LDC into one, collective report containing comparisons among the LDCs; and (3) submit individual proposals to the Department that includes each LDC's recommendations and plans for helping the Commonwealth achieve its 2050 climate targets, supported by the independent consultant's report, along with all analyses and supporting data. The Vote and Order further directed that the LDCs engage in a stakeholder process to solicit feedback and advice on the independent consultant's report and the LDCs' individual proposals prior to submitting these documents to the Department. D.P.U. 20-80, at 4-5.

On November 6, 2020, the Attorney General filed a motion requesting clarification ("Motion for Clarification") of the Department's Vote and Order with respect to its directives for stakeholder participation in (1) the development of the RFP to hire an independent consultant; and (2) the Massachusetts gas LDCs' development of the report and proposals

(Attorney General Motion for Clarification at 1). The Department received several responses to the Attorney General's Motion for Clarification from interested stakeholders.[4] On February 10, 2021, the Department issued an order on the Attorney General's request. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80-A (2021).

On March 1, 2021, the Attorney General filed a notice of retention of experts and consultants in this investigation at funding not to exceed $150,000, filed pursuant to G.L. c. 12, § 11E(b) ("Notice of Retention"). On May 21, 2021, the Attorney General filed a revised notice to retain experts and consultants seeking an amended funding at an amount not to exceed $350,000 ("Revised Notice of Retention"). The Department received no comments on the Attorney General's Notice of Retention or Revised Notice of Retention[5] and on June 29, 2021, the Department issued an order approving the Attorney General's Revised

---

4 The following stakeholders submitted responses to the Attorney General's Motion for Clarification: Conservation Law Foundation ("CLF"); the Sierra Club; Environmental Defense Fund ("EDF"); joint response by the gas LDCs; the Town of Hopkinton; the Gas Leaks Allies; and Mothers Out Front.

5 Pursuant to G.L. c. 12, § 11E(b), the Department must allow all full parties to a proceeding the opportunity to comment on the Attorney General's Notice of Retention. The only full party to this proceeding is the Attorney General. Nevertheless, the Attorney General served her Notice of Retention on the LDCs and the LDCs did not comment. It is unclear whether the Attorney General served her Revised Notice of Retention on the LDCs, but it was not required.

Notice of Retention. D.P.U. 20-80, Order on Attorney General's Revised Notice of Retention of Experts and Consultants (June 29, 2021).

On March 1, 2021, and September 1, 2021, and in accordance with the Department's directives, the LDCs provided status updates regarding the progress with respect to the RFP and stated that, through the RFP, the LDCs selected Energy & Environmental Economics ("E3"), with ScottMadden as subcontractor (together, "Consultants"), to be the independent consultant for the pathways analysis, and the retention of Environmental Resources Management ("ERM") to develop and facilitate the stakeholder process.

On March 18, 2022, pursuant to the Department's Vote and Order, each LDC submitted: (1) the company's individual proposals and plans for helping the Commonwealth achieve its 2050 climate targets within reports entitled "net zero enablement plan[s]" ("Net Zero Enablement Plan," or collectively, "Net Zero Enablement Plans"); and (2) a report on the technical analysis of decarbonization pathways ("Pathways Report") as well as a report on considerations and alternatives for regulatory designs to support transition plans ("Regulatory Designs Report") (collectively, the "Reports").[6] In addition, on this same date the LDCs submitted: (1) a stakeholder engagement report ("Stakeholder Engagement Report") prepared by ERM to develop and facilitate the stakeholder engagement process; (2) the gas LDCs' common regulatory framework and overview of the Net Zero Enablement

[6] The Reports were prepared by the LDCs' Consultants.

Plans ("Framework and Overview"); and (3) a proposed Net Zero Enablement Plan model tariff ("Model Tariff").

On March 23, 2022, the Department issued a Notice of Filing, Public Hearing, and Request for Comments ("Notice") along with an Order of Notice ("Order of Notice").[7] The

---

[7] On February 14, 2022, the Attorney General and DOER submitted correspondence outlining procedural recommendations, including a proposed procedural schedule for this matter, for which CLF, National Consumer Law Center ("NCLC"), Low-Income Energy Affordability Network ("LEAN"), and Home Energy Efficiency Team ("HEET") expressed support. In consideration of the recommendations submitted by the Attorney General and DOER, the Department set a procedural schedule in this matter on March 24, 2022.

On March 28, 2022, CLF, Acadia Center, EDF, HEET, and Sierra Club jointly filed a motion for reconsideration of the Department's Order of Notice issued on March 23, 2022 ("Joint Motion for Reconsideration"). The Joint Motion for Reconsideration requested that the Department: (1) rescind its March 23, 2022 Order of Notice; (2) extend the procedural schedule set forth by the Department on March 24, 2022; and (3) allow for additional process in this docket, including the opportunity to intervene or otherwise obtain party status, participate in discovery, present expert testimony, and to cross-examine witnesses (Joint Motion for Reconsideration at 11-12).

On April 4, 2022, the Department received a jointly filed response by the gas LDCs ("LDCs' Response to Joint Motion for Reconsideration") objecting to the Joint Motion for Reconsideration on the grounds that (1) the Joint Motion for Reconsideration is improper and contradictory to the purposes of this proceeding and (2) the process outlined in the Department's Notice and procedural schedule is consistent with both Department precedent for similar proceedings and the Attorney General's Petition in this matter (LDCs' Response to Joint Motion for Reconsideration at 3-4).

On April 15, 2022, the Department issued a Hearing Officer Memorandum noting that pursuant to the Notice of Filing and Public Hearing issued in this matter, the deadline for submitting written comments was May 6, 2022. The Department encouraged stakeholders to submit comments identifying issues with the consultants' reports and the LDCs' individual proposals and suggestions and recommendations of alternative

Department held technical sessions on the Reports and Net Zero Enablement Plans on March 30, 2022, and April 15, 2022. On May 3, 2022, and May 5, 2022, the Department held public hearings to receive comments on the Reports and Net Zero Enablement Plans.

The Department received more than 230 initial comments from various stakeholders and members of the public ("Initial Comments"). The Department directed the gas LDCs to respond to the Initial Comments, and the LDCs submitted their response on July 29, 2022 ("LDC Joint Comments"). On September 8, 2022, the Department requested all final comments from stakeholders in response to the LDCs' Joint Comments by October 14, 2022 ("Final Comments").[8, 9]

The Department issued seven sets of common information requests to the gas LDCs, one set of information requests each to Berkshire Gas and Unitil, and two sets of information

---

proposals, particularly alternative regulatory framework proposals (Hearing Officer Memorandum at 2 (April 15, 2022)). The Department stated that its goal is to develop an overall regulatory framework that will be used to guide statewide and company-specific proposals, so the Department specifically sought alternative proposals that will inform the Department's analysis on the regulatory framework. The Department further stated its intent to schedule additional technical conferences to explore regulatory framework proposals after the May 6, 2022 comment deadline (Hearing Officer Memorandum at 2 (April 15, 2022)).

8 The substance of the Initial Comments, LDC Joint Comments, and Final Comments is discussed further below in Sections V and VI.

9 DOER submitted late-filed Final Stakeholder Comments on October 17, 2022, pursuant to its request to submit its final comments one business day late. The Department herein accepts DOER's late-filed Final Stakeholder Comments.

requests each to Eversource, Liberty, and National Grid (gas). In total, the Department issued 113 information requests to the LDCs.

III. BEYOND GAS: A SUMMARY OF REGULATORY PRINCIPLES

Massachusetts has long been a national leader in adopting state policies to address climate change. Through our actions in this proceeding, we continue in that leadership role by tackling the challenging issues associated with developing a pathway for the transition in the natural gas industry that will be necessary for the Commonwealth to achieve its target of net-zero GHG emissions by 2050, as set forth in the GWSA, and to achieve the sector-specific emissions reductions established in the CECP for 2025 and 2030.[10]

---

[10] In addition to the GWSA, the Commonwealth has enacted An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"), and An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"). The GWSA, as amended by the 2021 Climate Act and implemented by the Secretary of EEA, requires the Commonwealth to reduce GHG emissions between 10 and 25 percent from 1990 levels by 2020, at least 50 percent from 1990 levels by 2030, at least 75 percent from 1990 levels by 2040, and achieve net-zero emissions by 2050 with a gross reduction in emissions of 85 percent from 1990 levels. G.L. c. 21N § 4; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020) (setting a legally binding statewide limit of net-zero GHG emissions by 2050, defined as 85 percent below 1990 levels); State of the State Address (January 2021) (Governor commits to achieving net zero greenhouse gas emissions by 2050), available at https://archives.lib.state.ma.us/handle/2452/816469 (last visited November 29, 2023). The CECP for 2025 and 2030 set sector-specific emissions reduction targets, as mandated by the 2021 Climate Act, setting an emissions reduction target for residential heating and cooling of 29 percent by 2025 and 49 percent by 2030 and an emission reduction target for commercial and industrial heating and cooling of 35 percent by 2025 and 49 percent by 2030 (2025/2030 CECP at 23). The 2025/2030 CECP and supporting information including sublimits is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

As we chart the path for this transition, we emphasize that nothing we do here is intended to jeopardize the rate recovery of the billions of dollars of existing investments in natural gas infrastructure by the LDCs operating within the Commonwealth. Traditional notions of the regulatory compact continue to apply to those investments and, accordingly, there generally must be some demonstration of imprudence before recovery of existing investments can be challenged. At the same time, however, it is fair to say that a different lens will be applied to gas infrastructure investments going forward. The Department will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. In this "beyond gas" future, we will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.

The ambitious mandates established by the Commonwealth require gas LDCs to move beyond "business as usual" in their gas system planning, whether involving proposed expansion of service to new areas or investments necessary to maintain the safety of existing natural gas infrastructure. As discussed in subsequent sections of this Order, we are acting, within our existing statutory authority, to discourage further expansion of the natural gas distribution system. We will do so by revisiting the "public interest" standard we apply in evaluating proposed expansions, by examining the line extension policies followed by LDCs that may be inconsistent with the broader public policy of achieving necessary GHG reductions, and by encouraging consideration of zero-carbon alternatives, such as electrification and thermal networked systems, to traditional gas system capital investments.

With respect to maintenance of the existing natural gas infrastructure, our "beyond gas" future will similarly involve close scrutiny of the extent to which additional investment is necessary, with an eye toward minimization of costs that may be stranded in the future as decarbonization measures are implemented in the natural gas industry. In particular, we will generally require the examination of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation.[11] Going forward, LDCs will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains. As discussed in later sections of this Order, we will continue to explore opportunities for strategic and targeted decommissioning of portions of LDC service territories, through demonstration projects deploying both electrification and thermal network technologies.

As in the case of the transition to clean energy in the electricity sector, the decarbonization of the natural gas industry may result in higher costs being imposed on ratepayers. Given the urgency of addressing the climate crisis, however, we are reluctant to slow the pace at which the transition must occur due to concerns about affordability for

---

11 The comprehensive analysis of NPAs that we envision incorporates many of the elements identified in the Attorney General's proposed "investment alternatives calculator" and the "geographic marginal cost analysis" proposed by DOER, both of which are discussed later in this Order.

low- and moderate-income utility customers. Rather, the Department will address these issues in a separate proceeding, to be commenced later this year, dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions. We are confident that we can develop a solution—which likely will require a change in our statutory authority—that will allow us to address affordability issues in an effective manner and still enable us to achieve the necessary progress toward the Commonwealth's GHG emission reduction limits.

The transition of the natural gas industry involves other important considerations that we will need to address in a thoughtful and deliberate manner. As the Commonwealth accomplishes greater penetration of building electrification and distributed energy resources, we need to prioritize opportunities for residents of environmental justice populations[12] to benefit from moving beyond gas. This includes electrification and thermal network projects as well as workforce development and employment prospects for people historically left out

---

[12] In Massachusetts, an environmental justice population is a neighborhood where one or more of the following criteria are true: (1) the annual median household income is 65 percent or less of the statewide annual median household income; (2) people of color make up 40 percent or more of the population; (3) 25 percent or more of households identify as speaking English less than "very well"; (4) people of color make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Executive Office of Energy and Environmental Affairs Environmental Justice Policy at 4 (2021). See https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts (last visited November 29, 2023).

of the clean energy transition (e.g., women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, people who were formerly incarcerated). We also will work with the LDCs to encourage workforce development training and employment opportunities for gas workers and steelworkers to participate in a just transition away from fossil fuels. Thermal network projects, for example, offer attractive opportunities for workers in the gas industry to perform similar work in the installation of the infrastructure to deliver decarbonized heating and cooling solutions to residential and commercial customers.

Finally, as is apparent from the vast number of issues addressed in this Order, developing a regulatory framework to guide the transition of the natural gas industry in Massachusetts is an exceedingly complex undertaking. It involves fundamental ratemaking issues regarding the continued financial viability of LDCs and preserving their ability to raise capital on reasonable terms, as well as developing an orderly means of recovering in rates the billions of dollars in existing investment in natural gas infrastructure while maintaining the safety of the gas distribution system so long as natural gas continues to be delivered through it. It involves maintaining the affordability of energy services, and being particularly mindful to avoid burdening low- to moderate-income households that may be left behind—and potentially bearing a greater burden of the fixed costs of maintaining existing natural gas infrastructure—as more affluent households transition away from natural gas appliances. It involves recognizing the potential for the disproportionate distribution of the negative impacts associated with building, operating, and maintaining gas infrastructure. And it involves addressing the workforce issues associated with a gradual decommissioning of the existing natural gas distribution system. As we continue to develop the regulatory framework in subsequent proceedings following the issuance of this Order, we emphasize the importance of the continued involvement of all relevant stakeholders in the process. It is important, for example, for LDCs to move beyond "business as usual" practices toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth's GHG emissions reduction targets. These exceedingly complex issues can be addressed effectively only with the broad participation of all the constituencies affected by this transition. We look forward to exploring these issues collectively in future proceedings.

IV. SCOPE AND AUTHORITY

The Department has broad authority to supervise gas companies pursuant to G.L. c. 164, § 76; Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239, 245 (1994). It is well established, however, that the Department's general supervisory authority cannot arise from a vacuum. Massachusetts Oilheat Council, Inc., D.T.E. 00-57, at 6-7 (2001) citing Massachusetts Electric Company, 419 Mass. at 246.

The Legislature has taken steps to focus the Department's regulatory mandate on GHG emissions reductions in addition to its traditional concerns of ensuring safety, security, reliability, equity, and affordability. Both the 2021 Climate Act and 2022 Clean Energy Act include changes to the Department's regulatory authority over gas companies. In the 2021 Climate Act, the Legislature added Section 1A to G.L. c. 25, which provides:

> In discharging its responsibilities under [chapter 25] and chapter 164, the department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in

> greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N.

The 2021 Climate Act also revised G.L. c. 21N, § 6, to charge the Secretary of EEA with establishing programs to meet GHG emissions limits and sublimits and implement the roadmap plans established by G.L. c. 21N. In addition, the 2022 Clean Energy Act amended G.L. c. 164, § 141, which now directs the Department, in all decisions or actions regarding rate designs, to consider, among other things, the impact of such decisions or actions on the reduction of GHG emissions as mandated by G.L. c. 21N to reduce energy use.

Recent legislation has not, however, amended or repealed other statutes that govern the Department's regulation of the natural gas industry. As we note in this Order, the Department may revisit its own precedent and standards of review in certain areas, and in other areas, legislative action may be required for the Department to be able to implement change or pursue particular pathways for achieving the Commonwealth's 2050 targets. For example, G.L. c. 164, § 30, establishes Department review of an LDC's petition to expand its service territory, which the Department has evaluated under a public interest standard. An Act Relative to Gas Leaks, St. 2014, c. 149, was enacted on June 26, 2014 ("Gas Leaks Act") and codified the uniform gas leaks classifications at G.L. c. 164, § 144; gas system enhancement plans ("GSEPs") at G.L. c. 164, § 145; and required the Department to, on or before January 1, 2015, authorize gas companies "to design and offer programs to customers which increase the availability, affordability, and feasibility of natural gas service for new customers." St. 2014, c. 149, § 3. In addition, the 2022 Clean Energy Act mandates that DOER establish a demonstration project in which up to ten municipalities may adopt zoning ordinances that restrict fossil fuel use in the construction sector. St. 2022, c. 179, § 84(b). As part of the demonstration project, DOER must collect data from the participants and submit reports to the Legislature every two years that include recommendations for the continuation or termination of the demonstration project. St. 2022, c. 179, § 84(e).

Finally and most specifically to our consideration of the Reports, Net Zero Enablement Plans, and other submissions in this proceeding, Section 77 of the 2022 Clean Energy Act provides:

> Notwithstanding any general or special law or rule, regulation or order to the contrary, the department of public utilities shall not approve any company-specific plan filed pursuant to the DPU Docket No. 20-80, Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, prior to conducting an adjudicatory proceeding with respect to such plan.

St. 2022, c. 179, § 77. Based on this clear directive, the Department will not approve the Net Zero Enablement Plans and/or the Model Tariff submitted by the LDCs in this investigation but will identify future adjudicatory proceedings and filings where we may properly consider company-specific plans.

The Department does not cite the above statutes as obstacles to the regulatory principles articulated in this Order. Rather, we do so only to acknowledge that our authority as a regulatory agency is bound by the limits established by law. Where pathways or proposals are inconsistent with existing statutes, the Department will note where additional legislative change or authority is necessary.

V. DECARBONIZATION REPORTS

A. Pathways to Net Zero

At the direction of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC, analyzing the feasibility of each decarbonization pathway identified by the Roadmaps. D.P.U. 20-80, at 3-5. In an effort to allow for meaningful comparisons among the LDCs and to ensure the consideration of all decarbonization strategies, the Department required the Consultants to identify any pathways not examined in the Roadmaps and employ consistent methods and considerations to analyze decarbonization opportunities for each individual LDC. D.P.U. 20-80, at 5. The Department instructed the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing for each identified pathway, among other requirements. D.P.U. 20-80, at 5-6.

To fulfill this requirement, the LDCs submitted the Pathways Report, which provides eight pathways designed to reflect different futures[13] for the LDCs and their customers

[13] The eight pathways are not forecasts, but rather narratives that allow for the identification and comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Pathways Report further notes that analyzing decarbonization pathways out to 2050 involves a multi-decade horizon that is inherently assumption-driven and uncertain across several factors, including cost, consumer behavior, technology development, deployment, and other factors (Pathways Report at 27).

(Pathways Report at 11). Each of the eight pathways achieves the Commonwealth's goals of 90 percent gross GHG emissions reductions and net-zero GHG emissions by 2050 compared to 1990 levels, as well as the interim statutory GHG emissions reduction goals of 50 percent by 2030 and 75 percent by 2040 (Pathways Report at 11, 48). Similar to the 2050 Roadmap, all pathways have approximately 4.5 million metric tons of gross economy-wide, non-energy emissions[14] remaining in 2050 (Pathways Report at 48).

The eight pathways include the deployment of seven space-heating technologies,[15] and leverage various levels of renewable fuels, energy efficiency,[16] and building electrification technologies (Pathways Report at 31, 49-57). The eight decarbonization pathways impute a range of uses and roles for the gas system over time, spanning from 100 percent decommissioning of the system to large amounts of renewable gases being supplied to high-efficiency gas appliances (Pathways Report at 11, 63-75). In parallel, the Pathways

---

[14] A more detailed description of GHG accounting (i.e., direct, electric sector, non-energy, and renewable fuels emission accounting methods) can be found in the Pathways Report, Appendix 1, at 21-28. Further information on common baseline economy-wide assumptions such as population growth and electrification of the transportation sector can be found in the Pathways Report, Appendix 1, at 8-9.

[15] The seven identified space-heating technologies include: (1) air source heat pumps; (2) ground source heat pumps; (3) hybrid heat pumps; (4) networked geothermal; (5) standard gas furnaces; (6) high efficiency gas furnaces; and (7) gas heat pumps (Pathways Report at 31).

[16] The Pathways Report states that energy efficiency is a foundational strategy to enable decarbonization of heating across all scenarios, reducing challenges associated with both electrification and decarbonized fuel-based strategies (Pathways Report at 47, 52-53, 110).

Report considers impacts on the electric system due to electrification-driven peaks and increased generation capacity (Pathways Report at 57-63).

The Pathways Report notes several key uncertainties across the pathways and develops sensitivity analyses to better capture assumptions in its modeling (Pathways Report at 34-35). Informed by a literature review,[17] the Pathways Report provides both optimistic and conservative views for the following six uncertainties: (1) incremental costs of cold-climate air source heat pumps ("cold-climate ASHPs"); (2) technical performance of cold-climate ASHPs; (3) incremental electric sector distribution system costs; (4) networked geothermal system installation costs; (5) cost and availability of renewable fuels;[18] and (6) opportunities for gas system cost avoidance (Pathways Report at 35). Additionally, the Pathways Report projects three pathways that would involve gas system departures through a geographically planned approach,[19] resulting in potential reductions in operation and maintenance expenses,

[17] The Consultants conducted a literature review of decarbonization strategies studied and implemented in the U.S. and internationally (Pathways Report at 28-29; App. 2).

[18] The Pathways Report defines renewable fuels as an umbrella term for renewably produced alternatives to fossil fuels, inclusive of renewable gases in the distribution system and renewable fuels in the transportation sector (Pathways Report at 9). The Report designates the following gases as renewable and having a net–zero GHG impact according to the Massachusetts GHG Inventory: (1) biomethane produced through anaerobic digestion or gasification; (2) hydrogen produced from electrolysis powered by renewable energy; and (3) synthetic natural gas produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9, 52, 110; App. 1, at 21-22). The Department does not necessarily consider biomethane, hydrogen, or synthetic natural gas to be renewable fuels.

[19] The Department further discusses geographically planned approaches and customer choice topics below in Section VI.B and Section VI.D.

GSEP expenditures,[20] and capital replacement costs (Pathways Report at 68-69). The Pathways Report further explores the cost and equity implications of combining the revenue requirement for the LDCs to maintain and operate both the gas and a networked geothermal system (Pathways Report at 72-75).[21]

The Pathways Report states that three pathways were modified from the Roadmaps: (1) high electrification, in which greater than 90 percent of the building sector electrifies primarily through the adoption of cold-climate ASHPs; (2) low electrification, in which 65 percent of the building sector electrifies with cold-climate ASHPs and gas customer count declines by 40 percent compared to today; and (3) interim 2030 CECP, in which the building sector electrifies at an accelerated pace, following the goals outlined in the Interim 2030 CECP (Pathways Report at 29-31). The 100 percent gas decommissioning pathway assumes that the building and industrial sectors fully electrify by 2050, with roughly 25 percent of the building sector converting to networked geothermal (Pathways Report at 31). The targeted electrification pathway assumes that greater than 90 percent of buildings electrify, with LDC customers converting to cold-climate ASHPs in a targeted approach (Pathways Report at 31). The networked geothermal pathway considers roughly 25 percent of the building sector

---

[20] The Department allows LDCs to recover certain costs associated with the replacement of leak-prone pipeline infrastructure, pursuant to G.L. c. 164, § 145.

[21] The Pathways Report posits that a combined rate base would exhibit increased system costs, but theoretically would mitigate costs per customer as a larger portion of the customers remain that may share in the recovery of the combined system costs (Pathways Report at 73-75).

converting to networked geothermal systems, with remaining LDC customers using renewable gas[22] (Pathways Report at 31). The hybrid electrification[23] pathway assumes that greater than 90 percent of buildings electrify through cold-climate ASHPs paired with RNG (Pathways Report at 31). Lastly, the efficient gas equipment scenario assumes that the building sector largely adopts high-efficiency gas appliances supplied by a combination of renewable gas, with the industrial sector converting to dedicated hydrogen pipelines (Pathways Report at 31). Table 1 below contains a summary of each decarbonization pathway.

Table 1: Key Narratives by Decarbonization Pathway (Pathways Report at 29-32)

Pathway	Overview
Low Electrification (inspired by 2050 Decarbonization Roadmap "Pipeline Gas")	High electrification in the transportation sector. Buildings partly electrify. Building sector electrifies 65 percent of buildings through the adoption of ASHPs. Gas customer count declines by 40 percent compared to today.
High Electrification (inspired by 2050 Decarbonization Roadmap "All Options")	High electrification in both buildings and transportation sector. Building sector electrifies more than 90 percent primarily through the adoption of ASHPs.
Interim 2030 CECP	Accelerated electrification and building shell measures based on the interim 2030 building sector target.

22 The Pathways Report defines "renewable gas" as "an umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system" (Pathways Report at 9, App. 1, at 15). Under this definition, renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and synthetic natural gas ("SNG"), further defined and discussed in Section VI.C of this Order (Pathways Report at 9, App. 1, at 15).

23 The Pathways Report describes hybrid electrification as a space heating strategy that combines electric heat pumps with a gas or fuel oil backup that can be powered by renewable fuels (Pathways Report at 8).

Hybrid Electrification	Heat pumps are paired with gas or fuel oil backup to mitigate electric sector impacts. More than 90 percent of buildings electrify through ASHPs paired with renewable gas back-up (hybrid heat pumps) that supply heating in cold hours of the year.
Networked Geothermal	Part of the gas system is strategically replaced by networked geothermal systems. LDCs evolve their business model and convert +/- 25 percent of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050.
Targeted Electrification	Part of the gas system is strategically decommissioned with customers adopting ASHPs. More than 90 percent of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach.
Efficient Gas Equipment	Building sector will adopt increasingly efficient gas appliances supplied by decarbonized gas. The industrial sector converts to dedicated hydrogen pipelines.
100 Percent Gas Decommissioning	Building sector and industry will fully electrify allowing for 100 percent decommissioning of the gas distribution system. Building and industrial sectors fully electrify by 2050. +/- 25 percent of the building sector converts to networked geothermal systems.

Developed with input from both LDCs and stakeholders, the eight pathways and their associated projected cumulative energy system costs (in 2020 dollars)[24] are calculated as follows: (1) high electrification, $87 billion to $111 billion; (2) low electrification, $73 billion to $95 billion; (3) interim 2030 CECP, $93 billion to $121 billion; (4) 100 percent gas decommissioning, $94 billion to $135 billion; (5) targeted electrification,

24 The Pathways Report calculates costs on a levelized basis, including a society-wide discount factor of 3.6 percent, noting that the study does not quantitatively consider the social costs of carbon or avoided costs related to potential health or environmental damages resulting from climate change (Pathways Report, App. 1, at 62).

$73 billion to $109 billion; (6) networked geothermal, $81 billion to $124 billion; (7) hybrid electrification, $63 billion to $92 billion; and (8) efficient gas equipment, $66 billion to $105 billion (Pathways Report, App. 1, at 62-65). The Pathways Report further presents cumulative energy system costs both annually and by decade relative to a reference scenario that does not meet the Commonwealth's 2050 climate targets, delineating the following cost components: (1) demand-side capital; (2) electricity supply; (3) gas system; (4) natural gas commodity costs; (5) liquid renewable fuels commodity costs; (6) renewable gas commodity costs; and (7) networked geothermal installation costs (Pathways Report at 13-14, 26-27, 79-82; App. 1, at 62, 65-66).

Further, the Pathways Report offers an evaluation of the feasibility and level of challenge[25] expected for each pathway across the following criteria: (1) cumulative energy system costs; (2) technology readiness; (3) air quality; (4) workforce transition; (5) customer practicality; (6) near-term customer affordability; (7) long-term customer affordability; and (8) customer equity (Pathways Report at 11-12, 76-79, 84-108). The Pathways Report states that all pathways were assumed to comply with Department and industry standards for safety and reliability (Pathways Report at 11-12, 77, 87-91).

Lastly, the Pathways Report presents several low-regret strategies and commonalities across the LDCs, while highlighting the need for further research and development ("R&D")

---

25 The Pathways Report defines challenge as the magnitude of change from current industry or customers practices and/or amount of policy intervention required (Pathways Report at 76).

and key distinctions among the LDCs (Pathways Report at 109-115). In conclusion, the Pathways Report finds that all pathways imply transformational changes for the Commonwealth, the LDCs, and their customers, and that strategies that use both the gas and electric systems to deliver low-carbon heat to a portion of the buildings in Massachusetts show a lower level of challenge across a range of evaluation criteria (Pathways Report at 11, 109).

B. Stakeholder Comments Concerning the Pathways Report

Many commenters disagree with the Pathways Report's conclusion that pathways utilizing both the gas and electric systems actually would present a lower level of challenge to the Commonwealth in reaching its climate commitments. For example, the Attorney General contends that the lower overall costs reported for the hybrid electrification pathway rest on unsound and unproven assumptions, arguing that the beneficial impacts of hybrid electrification on electric system infrastructure additions could be attained by focusing on building electrification in the near term. (Attorney General Technical Comments[26] at 6-8, 19-21 (May 6, 2022)). Although DOER acknowledges significant alignment between the Pathways Report and the 2050 Roadmap, DOER calls on the Department to acknowledge that electrification is the dominant strategy specified in the 2025/2030 CECP, and to find that the LDCs' proposed plans and framework are not sufficient to achieve decarbonization (DOER

---

26 The Office of the Attorney General's Initial Stakeholder Comments on Consultants' Technical Analysis of Decarbonization Pathways Report (May 6, 2022).

Comments at 6-7 (May 6, 2022) ("DOER Initial Comments"); DOER Comments at 6-8 (October 17, 2022) ("DOER Final Comments")).

Other commenters opine that electrification should not be the Commonwealth's sole decarbonization strategy, arguing that hybrid pathways are necessary for preserving optionality as renewable generation increasingly comes online (see, e.g., Associated Industries of Massachusetts ("AIM") Comments at 2 (June 17, 2022); Shell USA, Inc. Comments at 4-5 (May 6, 2022); Tufts Medicine Lowell General Hospital Comments at 1 (July 22, 2022); Lahey Hospital and Medical Center Comments at 1 (July 15, 2022); SFE Energy Massachusetts, Inc. ("SFE Energy") Comments at 3 (May 6, 2022)). Similarly, the National Fuel Cell Research Center calls for further quantification of the value of the increased reliability and resilience that could be provided by decarbonized gas and electric systems (National Fuel Cell Research Center Comments at 2 (May 6, 2022)).

Numerous commenters criticize the Pathways Report's assumptions regarding the availability, pricing, and emissions of renewable fuels (see, e.g., Attorney General Technical Comments at 8-19; Sierra Club Comments at 8-9 (May 6, 2022) ("Sierra Club Initial Comments"); Acadia Center Comments at 7-15 (May 6, 2022) ("Acadia Center Initial Comments")). The Attorney General notes that the annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway is roughly 70 trillion British thermal units ("TBtu"), whereas the total available RNG output nationwide as of 2020 was only 50 TBtu (Attorney General Technical Comments at 9). The Attorney General argues that both the exponential growth in RNG volumes and the practicality of Massachusetts securing a population-weighted "fair share" of 3.7 percent of all RNG volumes east of the Mississippi River are unrealistic (Attorney General Technical Comments at 9-12; Attorney General Final Comments at 20-21 (October 14, 2022)). Several other commenters question the availability and market clearing price of RNG modeled under the hybrid electrification pathway (see, e.g., Sierra Club Initial Comments at 10-12; Acadia Center Initial Comments at 10-15).

Relatedly, several commenters argue that the Pathways Report repeats known flaws in Massachusetts GHG Inventory[27] accounting, questioning whether renewable fuels are truly carbon neutral when combusted, and if upstream emissions related to the extraction and transmission of fuels should be counted (see, e.g., Acadia Center Initial Comments at 4-10; Sierra Club Initial Comments at 8; LexCAN Advocacy Committee Comments at 1 (May 9, 2022)). Some commenters question the leakage rates associated with the existing gas system, demanding greater transparency regarding leakage rates and lost and unaccounted for gas volumes (see, e.g., "Interested Persons"[28] Comments at 2-4; CLF Comments at 11, 27-31

---

27 Information about the Massachusetts GHG Inventory is available at https://www.mass.gov/lists/massdep-emissions-inventories (last visited November 29, 2023).

28 On October 14, 2022, individuals associated with the following organizations filed a joint set of comments as "interested persons": Greater Boston Physicians for Social Responsibility; Climate Reality Project Boston Metro Chapter; Gas Leaks Allies; Pipe Line Awareness Network for the Northeast; Fore River Residents Against the Compressor Station; Mothers Out Front; Ashland Sustainability Committee; Sierra Club; Acadia Center; Gas Transition Allies; Brookline GreenSpace Alliance; Emerald Necklace Conservancy; Elders Climate Action Massachusetts; and No Pipeline Westborough.

(May 6, 2022) ("CLF Initial Comments"); CLF Final Comments at 4 (October 14, 2022) ("CLF Final Comments"); Acadia Center Comments at 7). Finally, several commenters call for the use of a 20-year global warming potential ("GWP") value for methane, consistent with the most recent Intergovernmental Panel on Climate Change Fifth Assessment Report (see, e.g., CLF Initial Comments at 28; Acadia Center Initial Comments at 6-7).

Additionally, numerous commenters argue that the Pathways Report fails to vigorously pursue potential gas infrastructure cost savings, such as reduced GSEP spending and more optimistic networked geothermal cost assumptions (see, e.g., Attorney General Technical Comments at 21-23; CLF Initial Comments at 12, 51-53; Sierra Club Initial Comments at 20-21). Several commenters criticize the hybrid electrification pathway as being potentially skewed toward lower system-wide costs, noting that the Pathways Report's lower level of building shell retrofits and inclusion of residential hybrid fuel oil/ASHPs does not allow for an apples-to-apples comparison across pathways (see, e.g., Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5). Lastly, several commenters criticize the Pathways Report's consideration of health and air quality impacts, arguing that combining indoor and outdoor air quality into a single metric masks the risk of maintaining gas appliances in homes to the health of children, the elderly, environmental justice populations, and people with underlying health conditions (see, e.g., Greater Boston Physicians for Social Responsibility Comments at 7-9 (May 2, 2022); Massachusetts Medical Society Comments at 2-3 (May 3, 2022)).

C. LDCs Response to Stakeholder Comments

The LDCs reject the notion that the Pathways Report picks a preferred pathway, arguing that other pathways compare favorably to the hybrid electrification pathway, and that differences in the application of building shells and discount rates do not impact the Pathways Report's conclusions (LDC Joint Comments at 9, 40, 45-47). The LDCs contend the finding that decarbonization pathways that "strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge" is not unique to this study, and that similar findings have been identified in both the U.S. and abroad (LDC Joint Comments at 9, 42-45). The LDCs maintain that the Pathways Report is a product of a significant amount of discussion and feedback from stakeholders, and that it is imperative for the Department and key stakeholders to approve the Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 13, 96).

The LDCs argue that the Consultants' recommendations draw from common strategies identified across all pathways and that suggestions that the benefits of hybrid electrification can be captured by balancing all-electric and conventional gas heat demands are at odds with a targeted electrification strategy that substantially reduces gas infrastructure investment (LDC Joint Comments at 9, 47-49). The LDCs maintain that the Pathways Report considers the potential for substantial avoided reinvestment in gas infrastructure, including reductions in GSEP spending and detailed consideration of networked geothermal potential (LDC Joint Comments at 8, 32-37). The LDCs assert that the alternative gas infrastructure cost comparisons provided by stakeholders are not comparable to those in the Pathways Report (LDC Joint Comments at 8, 37-38).

With respect to the availability and pricing of renewable fuels, the LDCs insist that the Pathways Report includes both optimistic and conservative ranges that are heavily derated to assess potential availability to Massachusetts and are based on the best available literature (LDC Joint Comments at 8, 19-26). The LDCs maintain that the Pathways Report's approach to pricing renewable fuels is consistent with similar industry studies in the Northeast, including the 2050 Roadmap (LDC Joint Comments at 8, 26-29). Additionally, the LDCs state that the Pathways Report's approach to emissions accounting is consistent with the Massachusetts GHG Inventory, 2050 Roadmap, and international reporting standards, and that the use of a 20-year GWP value for methane would require a reevaluation of the Commonwealth's 1990 emissions baseline (LDC Joint Comments at 9, 30, 49-53). Lastly, the LDCs argue that the Pathways Report's modeling of leakage rates is consistent with the official accounting framework used in the Massachusetts GHG Inventory and 2050 Roadmap, and that the Pathways Report sufficiently addresses qualitative health and air quality impacts (LDC Joint Comments at 9-10, 53-59).

D. Analysis and Conclusions

Consistent with the directives of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC analyzing: (1) the feasibility of each decarbonization pathway identified by the Roadmaps; and (2) any pathways not examined in the Roadmaps, among other requirements. D.P.U. 20-80, at 3-5. The Department required the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing, for each identified pathway. D.P.U. 20-80, at 5-6.

To fulfill these directives, the LDCs submitted the Pathways Report, which identifies and discusses eight decarbonization pathways designed to allow for the comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Department commends the LDCs and their Consultants for their comprehensive effort in estimating the costs and economy-wide GHG emissions reductions[29] involved in transitioning the natural gas system. The Department fully recognizes the difficulty in assessing these multidimensional challenges and expresses its appreciation for the comprehensive Pathways Report.

DOER notes significant alignment between the Pathways Report and the 2050 Roadmap, stating that the two documents demonstrate several common assumptions and outcomes (DOER Initial Comments at 6-8). However, commenters predominantly disagree over the Pathways Report's finding that strategically using the state's gas infrastructure

---

[29] For each pathway involving electrification strategies, the Consultants were directed to provide a transparent depiction of key assumptions used in the analysis and a calculation of GHG emissions reductions, inclusive of GHG emissions from generation source. D.P.U. 20-80, at 5. The Department finds that the Pathways Report appropriately addressed this request (Pathways Report at 48; App. 1, at 21-28).

alongside and in support of electrification is likely to carry lower levels of challenge, most typified by the hybrid electrification pathway (see, e.g., Attorney General Final Comments at 6-19; DOER Initial Comments at 8-10; LDC Joint Comments at 40-48). Any further attempt to quantify alternative fuels, electrification technologies, and their associated GHG emissions reductions in a generic sense, is beyond the scope of the current investigation. The Department makes no findings related to a preferred pathway or technology here, as such considerations need to be made in the context of the distinct service territories of each LDC.[30] The Commonwealth's dominant building decarbonization strategy, however, is electrification as noted in the 2025/2030 CECP.[31] Our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates and comply with the 2025/2030 CECP.

In doing so, the Department acknowledges that there is potential for further refinement to capture more fully the intricacies and granularity needed to achieve the Commonwealth's 2050 climate targets. Ultimately, the transition toward the Commonwealth's net zero targets will be one that is driven by the willingness and ability of residential, commercial, and industrial customers to support the Commonwealth's

---

30 As noted above in Section IV, the Department must review LDC-specific plans in adjudicatory proceedings before approving any individual plan. St. 2022, c. 179, § 77.

31 2025/2030 CECP at 27, available at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last visited November 29, 2023).

environmental goals and climate targets through investments in their homes, businesses, and transportation infrastructure. The Department seeks to expeditiously attain the GHG emissions reductions necessary to achieve these targets and will begin by more thoroughly addressing the six regulatory design recommendations below. Indeed, as we discuss in more detail in the next section, we recognize that new regulatory support strategies will be needed to minimize customer cost impacts regardless of which pathway, or combination of pathways, is pursued. After due consideration of the record, we find that the Pathways Report satisfies the Department's directives in opening this investigation in D.P.U. 20-80.

VI. REGULATORY DESIGN RECOMMENDATIONS

A. Introduction

The Consultants identify six regulatory design recommendations: (1) support customer adoption of and conversion to electrified/decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department here analyzes the merits of the various regulatory pathways proposed by the Consultants, and also uses this framework as a vehicle for identifying areas where we intend to pursue future investigation.

B. Support Customer Adoption of and Conversion to Electrified/Decarbonized Heating Technologies

1. Introduction and Summary

To meet the Commonwealth's climate targets, the decarbonization pathways will require significant levels of customer adoption of electrification and decarbonization heating technologies (Regulatory Designs Report at 19). The Regulatory Designs Report explains that certain pathways, such as high electrification, will require swift and early action to increase customer utilization (Regulatory Designs Report at 19). The Consultants recommend the following regulatory approaches to support customer use of electrification and decarbonization heating technologies: enhance and increase funding of energy efficiency programs; restructure electric and gas distribution rates; and revise customer service standards and procedures (Regulatory Designs Report at 20-24). These recommendations are discussed in detail below.

a. Energy Efficiency

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend increasing energy efficiency program budgets, enhancing the programs to include new measures and strategies, and finding additional sources of funding (Regulatory Designs Report at 21). The Regulatory Designs Report emphasizes that the decarbonization pathways will require the deployment of new strategies and technologies (Regulatory Designs Report at 21). Since some decarbonization pathways target entire customer groups rather than individual customers to convert from natural gas to full electric service, energy efficiency programs will need to expand to support new incentive offerings and targeted electrification of entire customer blocks (Regulatory Designs Report at 21). The Consultants recommend evaluating the potential benefits of avoiding gas system infrastructure costs as part of targeted electrification or geothermal demonstration projects in the calculation of cost-effectiveness (Regulatory Designs Report at 21). The Regulatory Designs Report further explains that other enhancements may be necessary, including customer education and awareness, adoption of decarbonization strategies and technologies, and market transformation initiatives targeted at contractors, distributors, and manufacturers (Regulatory Designs Report at 21).

In addition, the Regulatory Designs Report states that the pathways will require larger energy efficiency budgets to support the enhanced initiatives discussed above (Regulatory Designs Report at 21). Since the current energy efficiency programs already are funded by ratepayers through the energy efficiency surcharge ("EES"),[32] the Consultants recommend evaluating additional funding sources to increase budgets and better align the benefits and cost responsibilities for certain programs between gas and electric companies (Regulatory Designs Report at 21-22). Specifically, the Consultants suggest offsetting some costs through a financial transfer from electric to gas utilities under a dual energy agreement (Regulatory Designs Report at 21-22).[33] A dual energy agreement involves a benefit-sharing mechanism

---

32 The EES is included in the Local Distribution Adjustment Factor ("LDAF") of a customer's bill (Regulatory Designs Report at 21).

33 The Consultants cite a "dual energy" agreement between a Canadian electric company, Hydro-Quebec, and Energir, a gas company, in which gas customers in targeted market areas are converted to electricity to operate on electric heat during

that allows for a financial transfer from the electric company to the LDC as compensation for its role in electrification (Regulatory Designs Report at 22). The Consultants claim that a financial transfer reflects the economic and reliability benefits of maintaining the gas system to support electrification for hybrid heating customers (Regulatory Designs Report at 22).

b. Restructuring of Electric and Gas Rates

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend examining electric and gas distribution rate policies to reflect the changing demand and infrastructure requirements of electrification (Regulatory Designs Report at 22-23). For example, the pathways analysis shows that increased use of electric heating shifts peak electric demand from summer to winter and, therefore, presents an opportunity to evaluate price signals associated with electric rates to reflect changing demand (Regulatory Designs Report at 22).

For electric distribution rates, the Consultants recommend exploring: (1) the potential of time-variant rates to reflect the cost of serving electricity demands during peak periods; and (2) critical peak-pricing rates that reflect the cost of serving higher electricity demands under extreme weather conditions (Regulatory Designs Report at 22). The Consultants explain that critical peak-pricing rates could be used to reflect the substantially higher cost of electricity generation, transmission, and distribution to meet demand during extreme weather

non-winter peak periods while operating on gas heat during winter peak periods (Regulatory Designs Report at 22).

conditions, and provide customers with an incentive to reduce electricity use during those weather conditions (Regulatory Designs Report at 22).

For gas distribution rates, the Consultants observe that the adoption of hybrid heating systems may change gas demand characteristics because these customers would be using the system only during peak winter periods (Regulatory Designs Report at 23). Because of this change, the Consultants suggest creating a rate class for customers with hybrid heating systems (Regulatory Designs Report at 23). The Consultants state that a hybrid rate class would establish rates to better reflect the costs associated with providing gas service exclusively during peak winter periods (Regulatory Designs Report at 23).

In addition to creating another rate class, the Consultants recommend changing the revenue decoupling mechanism ("RDM") (Regulatory Designs Report at 23-34). The current gas RDM is designed on a per-customer basis, which allows the LDCs to retain the incremental revenues associated with serving new gas customers to offset the incremental costs associated with those customers until distribution rates are reset (Regulatory Designs Report at 23-24). The Consultants explain that this mechanism has worked well with the historical increase in gas customers; most of the decarbonization pathways, however, anticipate a decrease in the number of gas customers over time (Regulatory Designs Report at 24). The Consultants recommend transitioning away from a revenues-per-customer approach to a reconciliation of total revenues (Regulatory Designs Report at 24). Under this approach, the LDCs would reconcile actual revenues and Department-authorized or target revenues rather than revenues per customer, and that reconciliation would include revenue from new customers (Regulatory Designs Report at 24).

c. Customer Service Standards and Procedures

The Consultants explain that certain decarbonization pathways will require updated customer service standards and procedures to support adoption of electrification and decarbonization technologies identified in the pathways analysis (Regulatory Designs Report at 24). Geographically targeted electrification, for example, would require all customers within a specific geographic area or neighborhood to convert from gas to electric or another alternative (Regulatory Designs Report at 24). The Consultants caution that such strategies may raise concerns over customer choice, cost, the LDCs' obligation to serve, and customer service protections (Regulatory Designs Report at 24). The Consultants recommend comprehensive measures to address various issues, including enhancing customer communication and education processes, expanding customer options for gas and electric services, providing financial support for customers, and fostering stronger relationships with contractors (Regulatory Designs Report at 24-25). These recommendations are aimed at facilitating and promoting the widespread adoption of electrification and decarbonization technologies among customers (Regulatory Designs Report at 24-25).

2. Summary of Comments

a. Energy Efficiency

Commenters agreed with increasing incentives and exploring new energy efficiency strategies to better support customer adoption of electrification and decarbonization heating technologies (see, e.g., Acadia Center Initial Comments at 21-22; OPOWER Comments at 3 (May 6, 2022)). Other commenters argue that energy efficiency incentives for gas appliances should be phased out (Sierra Club Comments at 21; CLF Initial Comments at 9). The Attorney General notes that the Department-approved 2022-2024 Three-Year Energy Efficiency Plans ("2022-2024 Three-Year Plans") include significant investments to promote the adoption of heat pumps, while also observing that the most recent plans already come with significant budget and bill impacts for customers (Attorney General Initial Comments,[34] App. C at 7). The Attorney General and Acadia Center support enhanced energy efficiency investment but encourage the LDCs to explore other funding sources beyond the EES to minimize customer bill impacts (Attorney General Initial Comments, App. C at 7; Acadia Center Initial Comments at 22-23). In addition to funding, commenters say workforce development needs further support to facilitate customer adoption (Attorney General Initial Comments at 54; Acadia Center Initial Comments at 22; HEET Comments at 7 (May 6, 2022) ("HEET Comments")). The Attorney General states that the Department should engage regularly with workforce stakeholders, through working groups or other means, to better inform the transition of gas distribution services (Attorney General Initial Comments at 54).

[34] Regulating Uncertainty: The Office of the Attorney General's Regulatory Recommendations to Guide the Commonwealth's Gas Transition to a Net Zero Future (May 6, 2022).

The LDCs maintain that the Pathways Report does not adopt one pathway, but recommends energy efficiency as a low-regret strategy (LDC Joint Comments at 40-41). The LDCs reiterate that energy efficiency measures may decrease the impacts of electrification on the electric system and reduce demands for natural gas (LDC Joint Comments at 40-41). According to the LDCs, additional investment in energy efficiency will play a critical role in meeting the needs of an electrified economy (LDC Joint Comments at 6).

b. Rate Restructuring

Many commenters agree with the Consultants' recommendation to investigate changes to gas distribution rates and revenue decoupling (see, e.g., Attorney General Initial Comments at 38-39; Acadia Center Initial Comments at 23; and DOER Final Comments at 2). The Attorney General argues that the Department should conclude its investigation in Investigation to Review and Revise the Standard of Review and the Filing Requirements for Gas Special Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U. 18-152, and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). According to the Attorney General, gas special contracts[35] should demonstrate net benefits to customers, and that the customer's use of natural gas is no more harmful in terms of GHG and air pollutant emissions than the customer's alternative energy resource(s) (Attorney General Initial Comments at 41-43). The Attorney General also

---

35 Gas special contracts allow LDCs to provide firm transportation service to customers at individually negotiated, off-tariff distribution rates. D.P.U. 18-152, Vote and Order Opening Investigation at 1 (2018).

recommends that the Department not permit LDCs to recover costs for marketing related to promoting gas service because these costs are not aligned with the Commonwealth's decarbonization goals (Attorney General Initial Comments at 41). Furthermore, the Attorney General asserts that any modifications to the current cost recovery mechanisms should consider equity, affordability, and preservation of customer choice (Attorney General Final Comments at 4).

Commenter RMI[36] posits that a hybrid heating scenario requires that customers do three things: electrify with heat pumps, retain utility gas backup, and use that gas backup sparingly (RMI Comments at 3 (May 6, 2022) ("RMI Initial Comments")). As a result, RMI argues, crafting an effective rate design for hybrid heating customers will be challenging given that to reduce emissions and remain economically viable, a hybrid rate design must both (1) recover the costs of the gas system without encouraging customers to use gas as their primary heating fuel, and (2) avoid customer departure from the gas system (RMI Initial Comments at 3). RMI argues that as gas demand declines and non-fossil gas is substituted for fossil gas, rising gas rates will become inevitable and may lead to significant cost recovery and equity challenges under a hybrid heating rate design (RMI Initial Comments at 3).

The LDCs maintain that there is still interest in natural gas service despite the momentum toward full electrification (LDC Joint Comments at 10). The LDCs acknowledge

---

[36] Formerly "Rocky Mountain Institute" (RMI Initial Comments at 1).

concerns over increasing costs but reaffirm that the Regulatory Designs Report proposes potential rate designs to align equitably the benefits[37] and cost of hybrid heating (LDC Joint Comments at 75). Specifically, the LDCs contend that rate designs, such as a new hybrid rate class and critical peak pricing, will help incentivize customers to adopt and remain on hybrid heating systems (LDC Joint Comments at 75). The LDCs explain that a combination of customer education, financial support, and supportive policy initiatives will be necessary to spur the level of conversion needed for electrification modeled in each pathway (LDC Joint Comments at 10).

Additionally, the LDCs state that the potential of financial transfers from electric to gas utilities would help reflect the economic and reliability benefits of maintaining the gas system to aid the electric system during peak weather events (LDC Joint Comments at 75). The Sierra Club, however, opposes the sharing of costs between electric and gas customers (Sierra Club Initial Comments at 19; Sierra Club Comments at 12-13 (October 14, 2022) ("Sierra Club Final Comments")). The Sierra Club argues that electric customers subsidizing the decarbonization of the gas sector would constitute an inappropriate cross-subsidization given that the electric sector already has "borne its share of decarbonization costs" (Sierra Club Initial Comments at 19; Sierra Club Final Comments at 12-13).

[37] The LDCs explain that hybrid electrification is beneficial because it allows customers to leverage their existing equipment as a backup heating system (LDC Joint Comments at 74).

The LDCs reaffirm that most of the decarbonization pathways will result in service to fewer gas customers over time (LDC Joint Comments at 90). The LDCs recommend revising the RDM from a per-customer basis reconciliation of actual and authorized revenues to a reconciliation of total revenues (LDC Joint Comments at 90, citing Regulatory Designs Report at 23-24). The LDCs agree that replacing the RDM per customer with a total revenues or revenue cap decoupling is better aligned with the Commonwealth's decarbonization goals (LDC Joint Comments at 90-91). The Attorney General likewise agrees with revising the RDM (Attorney General Initial Comments at 39).

c. Affordability and Customer Choice

Several commenters also expressed affordability concerns, particularly for low- and moderate-income ("LMI") customers. Many commenters called for the prioritization of LMI customers to ensure an equitable transition and protect them from bearing the increased energy burden associated with electrification (see, e.g., NCLC Comments at 32 (May 6, 2022) ("NCLC Initial Comments"); LEAN Comments at 2-3 (May 6, 2022) ("LEAN Initial Comments"); Sierra Club Final Comments at 12). Some commenters, such as Acadia Center, disagree with charging customers exit fees[38] to leave the gas system because it may hinder electrification affordability (see, e.g., Acadia Center Initial Comments at 24; RMI Initial Comments at 3). LEAN recommends increasing low-income discounts and offering an exemption from the bill impacts of accelerated deprecation for LMI customers (LEAN Initial

[38] An "exit fee" or "migration charge" which would be charged to customers leaving the natural gas system is defined and discussed further in Section VI.F.

Comments at 17). In sum, numerous commenters express concerns that the LDC transition plans may impose an unfair burden on LMI customers in the absence of regulatory intervention.

The Attorney General confirms that, absent regulatory reform, remaining gas customers will experience significant rate increases as other customers leave the system (Attorney General Initial Comments at 46). Many commenters agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., HEET Comments at 7; LEAN Initial Comments at 17). The Attorney General explains that LMI customers currently spend a higher percentage of their income on utility bills than any other income group (Attorney General Initial Comments at 48). The Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50). Specifically, the Attorney General states that there should be a cap on the amount an LMI customer is billed (Attorney General Initial Comments at 52). Other commenters agree that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., DOER Initial Comments at 15; LEAN Initial Comments at 18).

Regarding customer choice, many commenters support a full transition away from fossil fuels via electrification. A handful of commenters do not (see, e.g., Tufts Medicine Lowell General Hospital Comments at 1; Inovis Energy, Inc. Comments at 1-2 (July 13, 2022); Mass Coalition for Sustainable Energy Comments at 1 (October 6, 2022)). One commenter noted that full electrification should be contingent on adequate renewable energy production (Shell USA, Inc. Comments at 4). Other commenters support electrification alongside geothermal and other low-carbon heating options (see, e.g., CLF Initial Comments at 12; Martin Comment at 1 (May 6, 2022)). Commenters acknowledge the LDCs' obligation to serve current gas customers but suggest revising the obligation to serve standards (see, e.g., Pipeline Awareness Network for the Northeast, Inc. ("PLAN") Comments at 4 (May 6, 2022) ("PLAN Initial Comments"); CLF Initial Comments at 21). PLAN states that the obligation to serve criteria apply only to existing customers (PLAN Comments at 5 (October 14, 2022) ("PLAN Final Comments").

The LDCs reiterate that customer choice will drive the acceptance of electrification but maintain that there is public support for preserving the natural gas system (LDC Joint Comments at 93-94, citing Exh. DPU-Comm 2-13, Att.). The LDCs highlight the substantial upfront costs for electrification as a barrier to conversion (LDC Joint Comments at 95, citing Pathways Report, Figure 4, at 17). The LDCs state that the Net Zero Enablement Plans contain strategies to help educate customers around their energy options (LDC Joint Comments at 94). Furthermore, the LDCs assert that achieving the levels of electrification modeled in each pathway will hinge not only on customer education, but also on supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95). The LDCs view current and future pilot projects as an opportunity to test and evaluate different market transformation approaches, including various incentive strategies to facilitate customer implementation of electrification and decarbonization heating technologies (LDC Joint Comments at 96, citing Exh. DPU-Comm 5-6).

3. Analysis and Conclusions

a. Introduction

The Department recognizes that significant levels of customer acceptance of electrification and decarbonization technologies will be needed for the Commonwealth to achieve its climate targets. While LDCs already have begun to increase the level of customer implementation of energy efficiency and decarbonized technologies through their 2022-2024 Three-Year Plans, more will need to be done inside and outside of the energy efficiency rubric to prioritize electrification, equity, and workforce development (Regulatory Designs Report at 20). See also 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 42, 46-47, 51 (2022) ("2022-2024 Three-Year Plans Order"). The Consultants recommend enhancing energy efficiency programs and funding to incentivize customer participation; restructuring gas and electric distribution rates to reflect the changing demand and infrastructure requirements of electrification; and establishing new customer service standards and procedures to facilitate and promote the widespread use of electrification and decarbonization technologies among customers (Regulatory Designs Report at 20-21). Commenters offer a range of perspectives on the transition to cleaner energy sources, with a focus on mitigating the impact on customers, especially those with lower incomes, and the role of incentives, rate structures, and policy initiatives in shaping the energy landscape. We address these recommendations below.

b. Energy Efficiency

The Department recognizes the importance of programs with effective participant incentives to help facilitate increased electrification and use of decarbonization technologies. The LDCs have strategies to leverage their cost-effective energy efficiency plans and strategies to encourage electrification through heat pumps and other measures. 2022-2024 Three-Year Plans Order at 51-52. In addition, under the Green Communities Act,[39] three-year plans must achieve all cost-effective energy efficiency, pass the cost-effectiveness analysis using the total resource cost test,[40] direct 20 percent of budgets to low-income energy efficiency, minimize administrative costs, maximize competitive procurement, and be mindful of bill impacts on gas ratepayers. G.L. c. 25, § 21(b)(1). In addition, beginning with the 2025-2027 three-year energy efficiency plans, there shall be "no spending on incentives, programs or support for systems, equipment, workforce development or training as they relate to new fossil fuel equipment unless such spending is for low-income households, emergency facilities, hospitals, a backup thermal energy source for a heat pump, or hard to electrify uses, such as industrial processes." G.L. c. 25, § 21(b)(2)(xi). Further, the Department already must consider whether these plans are constructed to meet or exceed the GHG emissions reduction mandates set by the EEA Secretary pursuant to G.L. c. 21N,

39 An Act Relative to Green Communities, Acts of 2008, chapter 69, section 11.

40 In determining cost-effectiveness, the calculation of benefits shall include the social value of GHG reductions, except in the cases of conversions from fossil fuel heating and cooling to fossil fuel heating and cooling. G.L. c. 25, § 21(b)(1).

§ 3B. Finally, the Department considers whether the proposed plans adequately prioritize safety, reliability, security, affordability, and equity. 2022-2024 Three-Year Plans Order at 84.

The 2022-2024 Three-Year Plans have made significant steps in promoting both energy efficiency and electrification through customer incentives and performance incentives. See 2022 Energy Efficiency Annual Reports, D.P.U. 23-60, Berkshire Gas Company, App. 1, at 2-3 (June 1, 2023). The Department expects the LDCs to continue expanding the scope of ambition in their three-year plans to promote reductions in overall energy usage that result in cost-effective programs, while balancing increased electrification to meet GHG emissions reduction targets.

At the same time, the Department remains concerned about customer bill increases associated with enhancing the Commonwealth's energy efficiency programs. The Regulatory Designs Report recommends minimizing the potential bill impacts of these program enhancements by using other funding sources, such as government funding, gas system exit fees, and financial transfers from electric to gas utilities (Regulatory Designs Report at 44 n.57; Exh. DPU-Comm 3-3). Since 2010, the Department has required gas three-year plans to include all other sources of funding that program administrators have pursued to help fund the energy efficiency programs.[41] Investigation by the Department of Public Utilities on

[41] In approving an energy efficiency funding mechanism for the electric program administrators, the Department must consider the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii).

its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A, § 3.2.2.1 (2021), ("Guidelines"). The Department reminds program administrators that this requirement to pursue non-ratepayer sources of funding is more important now than ever, especially for residential and small-business customers who disproportionately bear the burden of higher energy efficiency surcharges as compared to other rate classes. The Department, however, declines to implement exit fees or financial transfers as viable outside funding sources to offset the cost of expanding energy efficiency budgets. As discussed in Section VI.F below, the Department is concerned that charging an additional fee to exit the gas system may disincentivize customers from fully electrifying. At the same time, in the absence of a gas exit fee, residential and small business customers who are not able to leave the system may bear even higher energy bills. The Department is open to reviewing any alternative funding sources so long as they help facilitate a safe, reliable, and equitable transition for all ratepayers.

Lastly, in response to the Attorney General's recommendation to engage with workforce stakeholders, the Department recognizes that the utility and energy contractor workforce will play an integral role in customer acceptance of electrification and decarbonization technologies. Workforce development is essential to safe and reliable gas operations and will be at the forefront of the industry transition. As required by G.L. c. 25, § 19(d), the annual workforce development program budget of $12 million is explicitly allocated from the 2022-2024 Three-Year Plans to MassCEC to grow and diversify a clean energy equity workforce and market development program in the Commonwealth.[42] 2022-2024 Three-Year Plans Order at 42. The Department accepts that significant efforts will be required to develop strategies to train and ensure family-sustaining wages for a workforce to support the energy transition. It is critical to train current gas system workers for employment opportunities in the clean energy sector. It is also important that jobs are available in the clean energy sector to support workers who are women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, and people who were formerly incarcerated. A comprehensive workforce strategy requires solutions that ensure the well-being of workers and communities, create jobs, and contribute to a thriving and sustainable economy. This strategy should be viewed as part of a just transition framework.

The Department, therefore, strongly encourages the LDCs to engage with other stakeholders, including labor unions, MassCEC, and existing workforce development programs, to establish a just transition framework for gas industry workers and people who have largely been left out of the clean energy workforce to start training for jobs that support

---

[42] General Laws c. 25, § 19(d), added by the 2021 Climate Act, requires the Department to annually collect and transfer not less than $12 million to MassCEC for the clean energy equity workforce and market development program established pursuant to G.L. c. 23J, § 13. MassCEC states that this funding will be used for assisting environmental justice populations to plan and develop career training programs for employment in high demand clean energy occupations, and to provide support for expansion and creation of minority- and women-owned business enterprises in business categories critical to state climate targets. Massachusetts Clean Energy Center Request for Fiscal Year 2023 Funding Pursuant to G.L. c. 25, § 19(d), D.P.U. 22-75, Letter Order at 1 (June 27, 2022).

electrification and decarbonization. The LDCs shall provide an update on this just transition framework in their future Climate Compliance Plans, which the Department details in Section VI.G below.

c. Rate Restructuring

The LDCs propose evaluating alternative rate designs to better reflect the changing demand and infrastructure requirements of electrification and agree with the recommendation to change the RDM structure (Regulatory Designs Report at 22-23). The Department supports the alignment of LDC rate designs with climate objectives and GHG reduction compliance pathways.[43] In particular, the Department agrees with the recommendation to replace the current per-customer RDM with a total revenues or revenue cap decoupling mechanism. The Department finds that a revenue cap approach, which subsequently disincentivizes LDCs to expand their gas customer base, better aligns with the policies of the Commonwealth expressed in current climate laws. The Department directs each of the LDCs to propose an RDM that implements this approach in its next rate case. The Department also encourages the LDCs to evaluate and propose alternative rate resigns and other cost recovery mechanisms that are consistent with the direction provided in this Order.

The Department acknowledges that the LDCs and Consultants identify hybrid heating systems as a low-regret strategy toward decarbonization and takes notice of the significant

---

43 When considering new rate designs, the Department is required to take into consideration the reduction of GHG emissions pursuant to the 2022 Clean Energy Act. G.L. c 164, § 141.

uptick in utilization of heat pumps under the current three-year plans.[44] As we discuss in Section VI.D, however, the Department is not persuaded that pursuit of a broad hybrid heating strategy that would necessitate maintenance of the natural gas system to support backup heating systems is a viable path forward. Given improvements in technology, the Department expects that cold-climate heat pumps generally will eliminate the need for backup heating systems. During this transition period, however, the Department accepts that customers may elect to retain their previous backup heating systems, such as gas-fired boilers, to support heat pumps, as discussed further in Section VI.D. The LDCs shall continue to track customer heat pump installations. Further, the LDCs must work with their energy contractors and vendors to provide sufficient information to customers about the capabilities of heat pumps so they may reach a more informed conclusion about the true need for backup heating systems. If the LDCs propose a new rate design for hybrid heating customers, then they must strike a balance between recovering the costs of the gas system without encouraging customers to use gas as their primary heating fuel, thereby enabling

44 To date, three gas program administrators have filed mid-term modification requests in 2023 for additional funding partially due to a higher-than-expected demand for heat pumps (see Berkshire Gas Company, D.P.U. 23-93, Pre-Filed Testimony of Hammad Chaudhry and Jillian Winterkorn at 3-4; Liberty Utilities, D.P.U. 23-91, Pre-Filed Testimony of Kimberly Gragoo, Stephanie Terach, and Autumn R. Snyder at 6-7; Fitchburg Gas and Electric Light Company, D.P.U. 23-70, Pre-Filed Testimony of Cindy L. Carroll and Mary A. Downes at 6).

GHG emissions reductions while maintaining low operating costs to retain customers.[45] The Department will consider all other rate restructuring proposals on a case-by-case basis.

With respect to special gas contracts, we acknowledge the Attorney General's suggestion that the Department conclude its investigation in D.P.U. 18-152 and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). The Department agrees that the requirements for gas special contracts should be improved and refined, and that the ongoing investigation in D.P.U. 18-152 is the proper vehicle for the pursuit of any such changes. Given that D.P.U. 18-152 remains an open proceeding, we decline to address the specifics or potential outcomes here other than to acknowledge that a re-examination of gas special contracts is part of the portfolio of actions we are taking to facilitate the necessary transition of the natural gas industry.

Finally, we agree with the Attorney General that LDCs should not be permitted to include in rates any costs associated with marketing geared toward the promotion or expansion of gas service. As noted by the Attorney General, these costs are not aligned with the Commonwealth's decarbonization targets and any continued funding of such advertising or marketing by ratepayers is the type of "business as usual" operations of LDCs that must

---

[45] In the context of hybrid heating and a hybrid heating rate design, the importance of customer retention via low operating costs is so that increasing costs do not incent those customers most able to afford full electrification to pursue that option (or delivered fuels) while leaving lower-income customers on a rate that potentially would rapidly increase to account for fewer customers supporting the system (RMI Initial Comments at 2-3). This is inconsistent with an equitable transition.

cease. Moreover, this prohibition on ratepayer funding of gas marketing extends not only to initiatives undertaken directly by LDCs, but includes indirect efforts to promote either natural gas expansion or policies geared toward promoting natural gas expansion. If and to the extent LDCs wish to continue participating in such efforts, the associated costs will be borne entirely by shareholders.

d. Affordability and Customer Choice

The pace of customer transition to alternatives to natural gas is a significant uncertainty facing gas industry sales and revenue projections. Many commenters argued for the prioritization of LMI customers to ensure an equitable transition (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). The Attorney General contends that that the Department should consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50).

The Department agrees that the pace of customer transition to gas alternatives will depend on a suite of available incentives, education, legislative change, and market transformation activities. Ensuring an affordable and equitable transition will be among the most potentially challenging aspects of this undertaking. A mass exodus of gas customers has the potential to shock rates to the detriment of remaining ratepayers and reduce utility revenues, jeopardizing the LDCs' continued provision of safe and reliable service to remaining customers, as well as posing a potential general safety risk to the public at large. Conversely, less competition from alternatives may result in a slower pace of transition and delay the necessary achievement of the climate targets. The Department and LDCs will need to take steps to minimize the impacts of long-term competitive losses. The Department will address the practicality of such strategies through the remainder of this Order, including modification of line extension policies that assume long-term sales revenue, shifting revenue from traditional rate base to performance-based mechanisms that incent reduced emissions, and rate structures that protect LMI customers.

As to preserving customer choice, it is not clear that the Department has the statutory authority to prohibit the addition of new gas customers. It is the Department's long-standing policy, however, that an LDC need not serve new customers in circumstances in which the addition of new customers would raise the cost of gas service for existing firm ratepayers. Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). An LDC must therefore first ensure that the incremental costs to expand its distribution network do not exceed the incremental revenues from such expansion to include the cost of expanding its distribution network in rates. Bay State Gas Company, D.P.U. 12-25, at 379 (2012); Boston Gas Company, D.T.E. 03-40, at 48 (2003). LDCs determine whether a main or service extension is economically feasible using a model to compare the estimated cost of the project to the estimated revenues over the expected useful life of the plant investment to ensure the internal rate of return exceeds the rate of return allowed in the Company's most recent base distribution rate case. See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 456-457 (2020) (reviewing the company's main extension policy in the course of analyzing a surcharge proposal pursuant to St. 2014, c. 149, § 3); Boston Gas Company, D.P.U. 89-180, at 16-17

(1990). When an investment needed to serve a new customer does not pass the internal rate of return test, the gas company may require the customer to pay a contribution in aid of construction ("CIAC") to make up the deficit. D.P.U. 19-120, at 456-457.[46] It thus appears that there is an opportunity to revise the process of making this cost determination, reviewing tariff provisions, and current LDC practices to disincentivize further customer expansion while still preserving customer choice to the extent necessary. These changes are further discussed in Section VI.E below.

C. Blend Renewable Gas Supply Into Gas-Resource Portfolios

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs develop a procurement strategy to add renewable gas options to their resource portfolios (Regulatory Designs Report at 25). As used by the Consultants, "renewable gas supply" is an umbrella term that refers to renewably produced alternatives to natural gas that includes biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and SNG produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9; Regulatory Designs Report at 6, 25). The Consultants note that blending limited amounts of renewable gases into the pipeline could result in a reduction of GHG emissions without a corresponding substantial increase in overall gas costs (Regulatory Designs Report at 25). The Consultants recommend

---

46 Property that has been contributed to a utility is not included in rate base. D.P.U. 12-25, at 380 n.220, citing Milford Water Company, D.P.U. 771, at 21 (1982); Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976).

that the LDCs investigate the deliverability of biomethane, hydrogen, and synthetic gases from a broader range of resources and regions to clarify further their role in supporting the state's decarbonization goals and ensure that these fuels in fact can meet the requirements of the pathways (Regulatory Designs Report at 25). Finally, the Regulatory Designs Report recognizes that renewable gas does not meet the Department's least-cost standard (Regulatory Designs Report at 25). The Consultants make three specific recommendations intended to enable LDCs to incorporate renewable gas supply into the system: (1) update the forecast and supply planning standards to add renewable gas; (2) provide customers with an option to purchase renewable gas from the LDC; and (3) provide customers with an option to purchase renewable gas from third-party suppliers (Regulatory Designs Report at 25-26).

According to the Regulatory Designs Report, the Department should update its forecast and supply planning[47] standards to require a minimum level of renewable gas and

---

[47] Pursuant to G.L. c. 164, § 69*I*, every gas company shall file for the Department's approval a long-range forecast with respect to the gas requirements of its market area for the ensuing five-year period, consisting of the gas sendout necessary to serve projected firm customers and the available supplies necessary to meet the projected demand. Further, the Department reviews a gas company's five-year supply plan to determine whether the plan is adequate to meet projected normal-year, design-year, design-day, and cold-snap firm sendout requirements. Fitchburg Gas and Electric Light Company, D.P.U. 21-10, at 3 (2022).

Under its current standards, the Department determines if a company's projection method is reasonable based on whether the method is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast method; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to incorporate the cost of carbon in the LDCs' supply plan economic analysis (Regulatory Designs Report at 25). The Consultants posit that either a Renewable Heating Fuel Standard ("RHFS") or a Renewable Portfolio Standard ("RPS") could establish a minimum level of RNG, similar to the electric industry (Regulatory Designs Report at 25). The Consultants suggest that either the Legislature or the Department via a generic proceeding could authorize an RHFS or RPS, and that the minimum level of renewable gas could be set low initially to address concerns with availability and cost, with subsequent increases subject to these considerations (Regulatory Designs Report at 25-26). A second approach to updating the forecast and supply standards discussed by the Consultants is the addition of a cost of carbon to the supply planning economic analysis, which would provide an economic advantage to low-carbon supplies (Regulatory Designs Report at 26). As in the context of the RHFS and RPS option, the Consultants assert the cost of carbon initially could be set low to address supply availability, cost, or customer affordability considerations and then increased gradually subject to these considerations (Regulatory Designs Report at 26).

The Consultants' second recommendation for incorporating renewable gas into the system is to provide LDC customers who want to reduce their carbon emissions the option to purchase renewable gas directly from the LDC (Regulatory Designs Report at 26). In this scenario, the Department would approve a tariff through either an LDC-specific rate-setting

---

occur. D.P.U. 21-10, at 3, citing Bay State Gas Company, D.T.E. 02-75, at 2 (2004); The Berkshire Gas Company, D.T.E. 02-17, at 2 (2003).

proceeding or through a generic proceeding applicable to all LDCs (Regulatory Designs Report at 26).

With respect to the third recommendation to facilitate use of renewable gas, the Regulatory Designs Report recommends that the Department provide customers with an option to purchase renewable gas from third-party suppliers via each LDC's delivery service (Regulatory Designs Report at 26). The Consultants posit that this approach may be appealing to customers, especially large commercial and industrial customers, seeking to purchase directly from a third-party supplier. The Regulatory Designs Report recognizes that a special tariff may be required to address interconnection requirements (Regulatory Designs Report at 26).

Finally, and applicable to all three design approaches discussed above, the Consultants recommend a procurement strategy that includes customer education, marketing, and incentives that promote the integration of renewable gas into the gas system. This would facilitate customer understanding of the benefits and cost implications of renewable gas and their options to incorporate it into their fuel mix (Regulatory Designs Report at 27).

2. Summary of Comments

Generally, commenters agree in their objections to the recommendations in the Regulatory Designs Report regarding renewable gas.[48] Numerous commenters raised issues

48 While the Pathways Report refers to "renewable gas," commenters also refer to renewable natural gas or "RNG," which along with SNG and hydrogen, may also be referred to as "decarbonized gas" (Attorney General Initial Comments at 11-12). The

and concerns related to emissions, system upgrades and related costs, and the availability of alternatives.

The Attorney General argues that the Pathways Report overstates the availability of RNG and understates RNG's costs (Attorney General Technical Comments at 8-16; Attorney General Final Comments at 20). The Attorney General asserts that there is no credible basis to assume that RNG can be made available in Massachusetts at the volumes needed to support the gas use in 2050 assumed under the hybrid electrification scenario, and further that the Consultants significantly understate the costs of obtaining RNG (Attorney General Technical Comments at 8-16). The Attorney General argues that, in developing their price projections for RNG, the Consultants developed a weighted average price for RNG instead of pricing it at the incremental price of the marginal unit of supply (Attorney General Final Comments at 21). Moreover, the Attorney General asserts that the continued use of biomethane is inconsistent with the Commonwealth's policy as set forth in EEA's 2025/2030 CECP (Attorney General Final Comments at 21-22). The Attorney General also questions the Consultants' assumption that RNG is carbon neutral (Attorney General Technical Comments at 16-19). Further, the Attorney General notes that RNG and hydrogen, although emerging, are unproven and uncertain technologies that carry significant investment risks (Attorney General Initial Comments at 32). The Attorney General therefore recommends that

---

Attorney General and others assert, however, that the term "decarbonized gas" is a misnomer (Attorney General Initial Comments at 11 n.48).

the Department ensure that investments in unproven or uncertain technologies are borne entirely by utility shareholders (Attorney General Initial Comments at 32).

DOER suggests that the Department consider R&D proposals intended to increase the supply of RNG and hydrogen (DOER Initial Comments at 11). DOER also proposes that the Department disallow long-term contracts that would lock customers into high-risk and high-cost resources for long periods (DOER Initial Comments at 16). Finally, DOER proposes that the Department should require the LDCs to complete R&D projects using RNG to demonstrate emissions reductions consistent with the GWSA methodology before it approves any long-term contracts for renewable gas or hydrogen (DOER Final Comments at 15).

Acadia Center argues that the proposals involving RNG: (1) fail to account for out-of-state emissions occurring during the productions and transmission of the fuels; (2) dramatically underestimate the level of methane leaks from the natural gas systems in Massachusetts; (3) assume that biofuels are GHG-neutral; and (4) underestimate the availability and price of RNG and hydrogen (Acadia Center Initial Comments at 5-15).

Similar to Acadia Center, Sierra Club asserts that the Consultants underestimate the levels of GHG emissions from RNG and SNG, and also underestimate the availability of and clearing prices for renewable gas (Sierra Club Initial Comments at 8-11). In addition, Sierra Club argues that hydrogen is an inefficient and unfeasible strategy to decarbonize buildings (Sierra Club Initial Comments at 14-17). Finally, Sierra Club argues that even if the LDCs' treatment of biofuels as zero-GHG emitting is consistent with both the Commonwealth's current GHG accounting methodologies and its 2050 Roadmap, that is an inadequate basis for assessing the relative merits of biofuel investments as part of a decarbonization strategy (Sierra Club Final Comments at 6-8).

CLF argues that there is insufficient evidence to support the claim that biomethane is a zero-emissions fuel over the course of its lifecycle (CLF Final Comments at 4). Regarding hydrogen, CLF argues that it is highly volatile and will have to be limited to applications and sectors that cannot be electrified (CLF Final Comments at 4). CLF contends that LDCs would have to prove that biomethane is a zero-carbon fuel before forecast and supply plan standards should be allowed to include RNG, or before customers should be given the option to purchase RNG from LDCs or from third parties (CLF Initial Comments at 14). CLF maintains that the Consultants' technical analyses around the impact of biomethane were based on assumptions not grounded in science or reality (CLF Initial Comments at 14). In addition, EDF contends that there is a good understanding of the climate and safety impacts of renewable fuels, noting that hydrogen emissions have global warming potential (EDF Comments at 6–8 (October 13, 2022) ("EDF Final Comments")).

Dozens of individual and group commenters raised concerns similar to those recited above, specifically arguing against the mandated use of RNG and/or hydrogen based on issues related to supply availability, GHG emissions, safety, and cost (see, e.g., Interested Persons Comments at 2-3; Elders Climate Action Massachusetts Comments at 1-3 (May 6, 2022); Callaway Comments at 1 (May 4, 2022); Fortuin Comments at 1-2 (May 6, 2022); Phillips Comments at 1 (May 6, 2022)).

The LDCs argue that RNG and other alternative fuel sources are a necessary component of any decarbonization future and that the path to net zero does not need to be a binary decision between fuel sources and a fully electrified system (LDC Joint Comments at 60). The LDCs contend that adding RNG to the supply portfolio will produce environmental benefits, contributing to achievement of the Commonwealth's objectives, and will improve supply availability and diversity, both critical gas supply planning considerations (LDC Joint Comments at 60-61). Further, the LDCs point out that to fully electrify, a significant overbuild of renewables will be required to ensure peak demand can be met by the electric network (LDC Joint Comments at 62). The LDCs assert RNG can complement electrification by supporting the intermittent nature of renewable generation resources like solar and wind (LDC Joint Comments at 62).

Regarding the various comments expressing skepticism that RNG can be scaled to the level needed and purchased at a reasonable cost, the LDCs state that they expect the availability of RNG to continue to grow as technologies to develop RNG continue to advance (LDC Joint Comments at 63). Finally, regarding the criticism that the Consultants treat renewable gases as carbon neutral, the LDCs assert that this approach is consistent with both the official GHG accounting methodology of the Commonwealth and the 2050 Roadmap (LDC Joint Comments at 30).

3. <u>Analysis and Conclusions</u>

The Consultants recommend that the LDCs develop a procurement strategy to add RNG supply to the resource portfolio. The Department has been presented with three specific means of enabling the LDCs to incorporate RNG supply into their gas system: (1) update the forecast and supply planning standards to incorporate RNG through either a RHFS/RPS or the addition of a cost of carbon; (2) provide customers with an option to purchase RNG from the LDC; and (3) provide customers with an option to purchase RNG from third-party suppliers (Regulatory Designs Report at 25-26).

Most commenters did not address directly the suggestion that the Department update the forecast and supply planning standards to incorporate RNG. Numerous comments did note, however, that RNG does not provide measurable benefits in terms of costs and emissions reductions.

Our policy regarding the LDCs' procurement of gas resources is well established. The Department first articulated its standard for commodity and capacity acquisitions in Commonwealth Gas Company, D.P.U. 94-174-A (1996), where the Department determined that to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition is (1) consistent with the company's portfolio objectives; and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27. In Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 22-32-C at 36 (2022), the Department also noted that we must consider whether the proposed acquisition is consistent with the GWSA and any applicable emissions limit or sublimit set by the Secretary of EEA. G.L. c. 25, § 1A. At this time, as we discuss below, we have been presented with no evidence convincing us to alter this gas procurement policy. On the contrary, we share the concerns raised by various stakeholders regarding costs, availability, and the treatment of renewable fuels as carbon neutral.

As the LDCs acknowledge, RNG currently does not meet the Department's least-cost supply planning standards given the higher cost of RNG relative to pipeline gas. Given this, the inclusion of RNG supplies in an LDC's resource portfolio would violate our goal of providing gas service at the lowest possible cost. Indeed, the higher cost of RNG raises customer affordability concerns as LDC rates will be higher than they otherwise would be if pipeline gas continued to be used.

We recognize that RNG and the use of hydrogen as a fuel are emerging technologies that have not yet been proven to lead to a net reduction in GHG emissions. The Consultants assume that RNG's emissions are carbon neutral under the Commonwealth's current GHG accounting framework (Regulatory Designs Report at 8 n.7). They acknowledge that if the GHG emissions accounting conventions change, however, the potential of RNG as a carbon-neutral fuel diminishes and its value in terms of decarbonization would be overstated (Pathways Report at 18 n.12). In our view, more studies are required in this area to support the claim that RNG is a zero-emissions fuel. For example, a full life-cycle analysis that considers all of the emissions profiles and captures emissions gains and losses throughout the entire production process may be necessary to determine the total carbon intensity of RNG.

Regarding the availability of RNG, we are not convinced that sufficient RNG stocks will be available to ensure the alleged potential environmental benefits. Record evidence shows that there is significant uncertainty regarding the availability of RNG (Pathways Report, App. 1, at 16). Indeed, the Consultants note that biomass resource availability in New England is relatively low compared to other regions in the United States. New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole, is 2.47 dry tons per person per year (Pathways Report, App. 1, at 15). According to the Coalition for Renewable Natural Gas, of the 300 RNG facilities in the U.S., only eight are located in New England.[49] In the long run, RNG supply shortages may lead to higher costs. For these reasons, we have no basis in the existing record for altering our existing gas procurement policy as established in D.P.U. 94-174-A to allow for the acquisition of RNG and or the imposition of a RHFS or cost of carbon in the LDCs' supply plan economic analyses. We recognize, however, that the technology is evolving and the process to produce RNG may possibly lead to measurable benefits in the future, particularly for hard-to-electrify industrial processes. We encourage LDCs to investigate all options that will lead to a reduction in their GHG footprint, including lifecycle emissions associated with system operations, and we will review any proposals that are consistent with existing standards as well as with the Commonwealth's GWSA and the 2021 Climate Act.

---

49 See https://www.rngcoalition.com/?gad=1&gclid=Cj0KCQjwpc-oBhCGARIsAH6ote-K_4nSXK5AbiPbzM5IqeZD-AfyAg7WWyM5sfivAv_6_Q3Uvs9i4sYaAgadEALw_wcB (last visited November 29, 2023).

As the Commonwealth strives to achieve its 2050 climate targets, we envision that the long-term use of the natural gas distribution system generally will be limited to strategic circumstances where electrification is not feasible for all natural gas applications. For example, we recognize that some C&I customers require natural gas for process heat applications for which there are currently no electric-driven alternatives. It would therefore be necessary to make RNG and/or hydrogen available to this category of end-use customers.

Regarding the recommendation that gas customers be provided with the option to purchase RNG from their LDC or a third-party supplier, the Department has endeavored to develop a competitive natural gas supply market that would allow customers the broadest possible choice and provide all customers with an opportunity to share in the benefits of increased competition. See Natural Gas Unbundling, D.T.E. 98-32-B at 3, 4 (1999). We anticipate that there may be situations where customers would like to purchase RNG from their gas company or directly from a third-party supplier. We encourage LDCs to begin assessing customer interest in RNG and, if so, determine the associated demand load and begin developing educational and marketing material. While we support customer choice as it relates to RNG, we recognize that due to its nature and current technology, RNG is more expensive than conventional natural gas (Regulatory Designs Report at 25, 41). The inclusion of RNG-related costs in an LDC's supply portfolio costs—i.e., costs currently recovered under an LDC's seasonal cost of gas adjustment clause—would therefore increase the average cost of gas. To avoid any cross-subsidization issues, participation in such a program must be voluntary with all associated costs, including program administration costs, allocated and recovered solely from the participants. As we will not authorize a mechanism that would socialize the higher commodity cost of RNG, the Department expects that customers selecting RNG, regardless of whether it was procured from the LDC or a third-party supplier, will be responsible for the costs. We expect that the LDCs will inform potential customers of the cost of RNG, its lifecycle GHG emissions, and the likely bill impacts associated with their participation. To ensure that no costs associated with such a voluntary option are assigned to non-participants, the LDCs must keep a separate accounting of RNG costs and develop a voluntary RNG opt-in sales tariff outlining the provisions for service for Department review and approval. In summary, subject to the conditions above, we will allow the option for consumers to purchase RNG from an LDC or a third-party supplier.

The Department cautions, however, that RNG and hydrogen may require system upgrades due to the density of the fuels. If the LDCs need to upgrade their systems or incur additional interconnection and metering equipment costs to make these fuels available, all of the relevant system-upgrade costs, in addition to traditional costs borne by gas ratepayers, must be assumed by those who will take RNG supply and not by all customers. In summary, all costs associated with RNG are to be borne solely by utility shareholders or program participants.

The Department may review proposals for RNG or hydrogen pilot programs, as discussed below in Section VI.D. However, we agree with the Attorney General that RNG and hydrogen blending are new, unproven, and uncertain technologies. LDCs may research and assess these technologies, but until they prove to be a viable alternative to the business-as-usual model and support the Commonwealth's climate targets, any infrastructure costs associated with RNG and hydrogen will be the sole responsibility of the utility shareholders and not their customers.

D. Pilot and Deploy Innovative Electrification and Decarbonized Technologies

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen (Regulatory Designs Report at 27-29). Further, the Regulatory Designs Report recommends that the Department develop guidance for review and approval of pilot projects and R&D programs, design additional cost recovery mechanisms, and track and report on performance metrics (Regulatory Designs Report at 29-30).

The Regulatory Designs Report explains that pilot opportunities for networked geothermal systems potentially could serve as strategic replacements for planned capital spending and be consistent with networked geothermal pilots approved for NSTAR Gas[50] and National Grid (gas);[51] however, the Regulatory Designs Report notes outstanding questions

---

[50] On October 30, 2020, the Department approved a networked geothermal demonstration project proposed by NSTAR Gas to evaluate the technology in a mixed-use, dense urban environment. D.P.U. 19-120, at 138-156.

[51] On December 15, 2021, the Department approved a networked geothermal demonstration proposal from National Grid (gas). Boston Gas Company,

exist regarding the technical implementation, financing, and role of networked geothermal in avoiding gas infrastructure investments (Regulatory Designs Report at 27). The Regulatory Designs Report also recommends an investigation into the most optimal operation of hybrid heating systems to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs necessary to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). Finally, the Regulatory Designs Report recommends that LDCs pursue pilot opportunities to investigate the extent to which hydrogen can be added to their systems without the need for customer equipment or pipeline upgrades, engage in R&D opportunities related to the commercialization of synthetic gases, and explore certified natural gas, which may have lower upstream emission intensity (Regulatory Designs Report at 28-29).

The Regulatory Designs Report posits that an updated process for approval of pilot and R&D programs could facilitate the timely evaluation and deployment of decarbonized technologies better than a project-by-project approach (Regulatory Designs Report at 29).

D.P.U. 21-24, at 32-33 (2021). National Grid (gas) will prioritize the installation of networked geothermal systems that evaluate one or more of the following concepts: (1) the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than a networked geothermal project completed by its New York affiliate; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacement; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and GHG emissions for low-income customers and environmental justice populations. D.P.U. 21-24, at 3-4.

The Regulatory Designs Report explains that pilot and R&D programs could establish a process to track and report on performance metrics of interest, such as achievement of defined objectives; installation and service provider participation; customer education, interest and adoption experience; and role of the project in achieving decarbonization goals (Regulatory Designs Report at 30). The Regulatory Designs Report states that LDCs could recover the costs associated with additional pilots and R&D either through the local distribution adjustment clause or a new fully reconciling funding mechanism (Regulatory Designs Report at 30).

In this Order, we evaluate the potential of the four specific technologies recommended by the Consultants, both in the context of this proceeding and future potential investigations, pilot programs, and targeted deployments, and we address the regulatory framework that exists and that will evolve for the review and approval of pilot programs to examine emerging decarbonization technologies.

2. Summary of Comments

Commenters generally agree with the recommendation that the Department should streamline its review of pilot opportunities to facilitate more timely evaluation and deployment of electrification and decarbonized technologies (see, e.g., DOER Initial Comments at 16; CLF Initial Comments at 60; Acadia Center Initial Comments at 25). However, commenters disagree about which technologies, fuels, and end uses merit ratepayer-funded R&D (see, e.g., Attorney General Final Comments at 11-12; AIM Comments at 2; RMI Final Comments at 4; EDF Initial Comments at 1-3). To that end, the

Attorney General urges the Department to acknowledge the technical uncertainty of decarbonizing the building heating sector, calling for a framework that provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates (Attorney General Final Comments at 3-4).

Several commenters express support for the LDCs' approved networked geothermal pilots, arguing for the accelerated deployment of this technology (see, e.g., Sierra Club Final Comments at 11-12; CLF Initial Comments at 12; Climate Action Now Western Mass Comments at 2 (May 5, 2022); Mothers Out Front Massachusetts Comments at 1, 4 (May 2, 2022)). The Attorney General calls on the Department to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies to examine possible regulation and ownership frameworks as the Department continues to learn about the costs, feasibility, and scalability of networked geothermal (Attorney General Initial Comments at 45-46). Similarly, HEET proposes a framework for the evolution of LDCs into thermal utilities, positing that pilots involving 100 customers or fewer could be approved by the Department within a month of filing (HEET Comments at 17, 22-32). The LDCs state that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

Numerous commenters call for R&D into other types of targeted electrification, including decommissioning of the gas system, that may demonstrate cost savings (see, e.g., CLF Initial Comments at 9, 55; DOER Final Comments at 16-17). The Attorney General calls for the adoption of comprehensive geographic distribution system and customer mapping,[52] in addition to an investment alternatives calculator to assist in reviewing traditional gas system capital investments (Attorney General Initial Comments at 22-24, 33-35; Attorney General Final Comments at 10-11). Similarly, DOER recommends that the Department require the LDCs to complete geographic mapping and marginal cost analyses before moving forward with any additional R&D proposals so that the LDCs can use these results in determining the appropriateness of any such projects (DOER Initial Comments at 14-15; DOER Final Comments at 7-10, 19-20).

Numerous commenters object to LDCs piloting alternative fuel blends (i.e., RNG, hydrogen, SNG) into their distribution systems, raising concerns about safety, affordability, GHG emissions, and leakage (see, e.g., Attorney General Initial Comments at 11-14; Acadia Center Initial Comments at 21; Sierra Club Initial Comments at 17; Massachusetts Medical Society Comments at 1-2). Other commenters acknowledge that alternative fuels may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in various hard-to-electrify end uses including certain industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments[53] at 1; Medical Area Total Energy Plant Comments at 1 (July 28, 2022)). The Attorney General

---

[52] The Department further discusses geographically planned approaches and gas/electric coordination topics below in Section VI.D and Section VI.G.

[53] Comments of the Rev. Mariama White-Hammond, Chief of Environment, Energy, and Open Space, City of Boston (May 5, 2022).

recommends that any investment in unproven technologies such as RNG and hydrogen be viewed as imprudent today with the associated costs being borne entirely by utility shareholders (Attorney General Initial Comments at 32-33). Regarding proposals for new technologies or fuels, DOER argues that the LDCs must identify "go/no go benchmarks," including when to abandon a project or program if the results show that longer-term implementation would not be cost effective for ratepayers and/or achieve net-zero emissions in the most cost-effective manner (DOER Final Comments at 12).

3. Analysis and Conclusions

a. Introduction

Demonstration projects or pilots are well-established and evaluated vehicles for the introduction of emerging technologies into the existing framework of broadly deployed programs such as energy efficiency. In Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, updating its energy efficiency guidelines, the Department compiled directives from recent orders that addressed the appropriate process and standard of review for approval and changes to demonstration project proposals. D.P.U. 20-150-A at 22. The Department described a demonstration project as "a relatively small, self-contained endeavor, such as a pilot, that may transition to a core initiative or program," and further clarified demonstration project evaluation, budgetary, and cost-effectiveness considerations. D.P.U. 20-150-A at 24-25; Guidelines § 3.9.[54]

In this proceeding, numerous commenters agree that the Department should develop additional guidance for its review and approval of pilot projects and R&D programs in an effort to study and deploy innovative electrification and decarbonized technologies (see, e.g., Regulatory Designs Report at 27-30; DOER Initial Comments at 16; Attorney General Initial Comments at 24, 33). The Department strives to foster the innovation necessary to ensure the safe and reliable delivery of low-carbon energy in an equitable manner; at the same time, the Department must consider the potential customer bill impacts of any additional cost recovery mechanisms for pilots, as ratepayers in the Commonwealth already experience significant energy supply and programming costs. See, e.g., 2022-2024 Three-Year Plans Order at 220, 223. The Department maintains that pilots are valuable because they are small in scale and allow for the collection of distinct data and insights that will advance knowledge in a specific field. See, e.g., D.P.U. 21-24, at 26; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 10-12 (2017).

The Regulatory Designs Report recommends that the LDCs pilot and deploy four specific technologies (Regulatory Designs Report at 27-29). As discussed below, the

54 The Department defines a demonstration project as a hard-to-measure offering, including pilots, limited in term and scope designed to provide the information required to assess its potential for measurable, cost-effective savings and benefits that can be scaled to be included in programs. Guidelines § 2.3. Demonstration projects are hard-to-measure offerings initially but are anticipated to have measurable savings and benefits at scale. Guidelines § 3.9.1.1.

Department welcomes networked geothermal and other targeted electrification technologies[55] in particular as promising decarbonization strategies and will require each LDC to identify pertinent demonstration projects in each of its service territories. In contrast, the Department is uncertain about the viability of hybrid heating and hydrogen technologies and their potential as economical long-term solutions for ratepayers, for the reasons we discuss below.

b. Hybrid Heating Systems

The Regulatory Designs Report recommends investigation into the optimal operation of hybrid heating systems, in support of both the gas and electric distribution systems (Regulatory Designs Report at 28). Specifically, the Consultants recommend further investigation of certain design elements for hybrid heating systems, such as the installation of integrated controls (Regulatory Designs Report at 28).[56]

---

55 The Department emphasizes that pilot projects, including those for networked geothermal and other targeted electrification technologies, funded by gas ratepayers must benefit those ratepayers and not constitute cross-subsidization. See D.P.U. 19-120, at 147-148 (networked geothermal project must be designed in a manner to provide direct benefits to ratepayers whether through participation or in a manner that will generate findings to inform the scalability of networked geothermal for its existing gas customers).

56 The Consultants note that during the 2019-2021 Three-Year Plan term, program administrators created initial integrated controls specifications and requirements to ensure that heat pumps installed to augment existing systems operate efficiently, and that additional studies were proposed in the 2022-2024 Three-Year Plan term (Regulatory Designs Report at 28). "Program Administrators" are the LDCs as well as electric distribution companies and approved municipal aggregators who develop and administer energy efficiency programs under the Green Communities Act. St. 2008, c. 169. D.P.U. 20-150-A at 1.

Several commenters express skepticism about hybrid heating systems, urging the Department to reject the hybrid electrification scenario completely (see, e.g., Attorney General Technical Comments at 3, 19, 21; Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5).[57] As mentioned above, the Attorney General argues that the Pathways Report's promotion of a hybrid electrification pathway rests on unsound and unproven assumptions, and that the benefits of hybrid electrification on electric infrastructure additions can be attained by focusing on building electrification in the near term (Attorney General Technical Comments at 6-21).

The LDCs maintain that hybrid electrification is a practical and relatively low-challenge strategy and opportunity to achieve the Commonwealth's decarbonization objectives (LDC Joint Comments at 70). The LDCs argue that hybrid electrification technologies: (1) reduce the need for electric system build out; (2) mitigate costs and winter peaking; and (3) provide energy security benefits as a cold-climate backup system (LDC Joint Comments at 70-75). Other commenters argue that a hybrid electrification approach to decarbonization preserves optionality and elements of customer choice as renewable generation increasingly comes online (see, e.g., AIM Comments at 2; Shell USA, Inc.

---

57 As noted above, Section 77 of the 2022 Clean Energy Act explicitly prohibits the Department from approving any company-specific plan pursuant to D.P.U. 20-80 prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, at present, the Department will not endorse or reject any specific pathway or space heating technology.

Comments at 4-5; Tufts Medicine Lowell General Hospital Comments at 1; Lahey Hospital and Medical Center Comments at 1; SFE Energy Comments at 3).

The Department cannot reject or prohibit hybrid heating systems as an option for customers. It is, after all, the customer who chooses the type of heating system to install in the home or building. The Department shares the concerns expressed by numerous commenters, however, that a customer's retention of a gas furnace or boiler to serve exclusively as a cold-climate backup may not be necessary.[58] In the short term, hybrid heating could be used to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). In the long term, however, it will be impractical to maintain the gas distribution system solely for backup furnaces in cold weather. The Department will therefore not approve the use of additional ratepayer dollars for hybrid heating system pilots and, as stated below, we expect LDCs to focus on targeted electrification and—pending the outcome of current pilots—networked geothermal projects to meet the long-term climate targets of the Commonwealth.

---

58 The Department notes that research priorities for the LDCs as Program Administrators of the 2022-2024 Energy Efficiency Plan include studying residential hybrid heat pump controls, optimization, and metering impacts, in addition to requiring integrated controls for certain residential and income-eligible applications (See D.P.U. 21-120 through D.P.U. 21-129, Exh. 1, at 77; Exh. 1, App. H at 21, 57-60).

Nevertheless, the Department must ensure that the information contractors relay to customers who are deciding between hybrid and full-electrification technologies is both informative and correct. Therefore, the Department will require the LDCs to report on hybrid heating switchover practices in their first Climate Compliance Plan filings. This first Climate Compliance Plan report must include a discussion of the technical resources provided to contractors in the Mass Save heat pump installer network such as heat pump capacity and temperature point heuristics, and address any service area specific guidance that differs from cold-climate sizing and design trainings offered by common manufacturers. The Department fully expects that the LDCs as Program Administrators will continue to explore hybrid heat pump shared benefit and incentive structures, particularly related to LMI participants.

c. Renewable Hydrogen and RNG

The Regulatory Designs Report recommends that the LDCs pursue pilot opportunities to investigate the extent to which hydrogen and RNG can be blended safely into the LDC distribution system without the need for customer equipment or pipeline upgrades (Regulatory Designs Report at 28). The Consultants further note R&D opportunities related to the commercialization of synthetic gases and recommend investigating certified natural gas which may have reduced upstream emissions from the production of gas (Regulatory Designs Report at 28-29).[59]

[59] The Department discusses synthetic and certified gas commodity above in Section VI.C.

Numerous commenters express concern with potential emissions and leakage issues associated with hydrogen blending, with the Attorney General arguing for all investments in hydrogen to be viewed as imprudent, and borne entirely by shareholders (see, e.g., Attorney General Initial Comments at 32-33; EDF Initial Comments at 1-3). Other commenters note that alternative fuels such as hydrogen may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in certain hard-to-electrify end uses such as industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments at 1; Medical Area Total Energy Plant Comments at 1). The LDCs acknowledge that the GHG effects of leaked, non-combusted hydrogen are not well understood, and that very few studies are available on its global warming potential (LDC Joint Comments at 56, citing Pathways Report at 113).

The Department agrees that significant research is necessary before hydrogen feasibly could be injected into an LDC's distribution system. The Department notes that the states of New York, New Jersey, Maine, Rhode Island, Connecticut, and Vermont along with the Commonwealth of Massachusetts announced the submission of a proposal for a Northeast Regional Clean Hydrogen Hub[60] to the U.S. Department of Energy ("DOE") to compete for a $1.25 billion share of the $8 billion in federal hydrogen hub funding available as part of the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021). In an announcement on October 13, 2023, DOE announced the first regional hydrogen hubs and the Northeast

---

60 See https://www.masscec.com/press/seven-states-northeast-regional-clean-hydrogen-hub-announce-submission-362-billion-proposal (last visited November 29, 2023).

Hydrogen Hub was not selected for funding.[61] The Department is optimistic that future funding opportunities may allow for the exploration of hydrogen R&D in the region without requiring additional ratepayer funds.

The Department also acknowledges, however, that there may be certain end uses, such as high-temperature industrial processes, that require a combustible molecule of a lower GHG emissions profile. In the short term, the Department will entertain hydrogen demonstration proposals for targeted end uses. Any proposals for hydrogen or RNG pilots, however, should include cost-effectiveness screening, and in the absence of cost-effectiveness screening, an appropriate analysis must support the potential of the proposal to deliver net benefits in the future. Guidelines § 3.9. Further, hydrogen and RNG demonstration project proposals must thoroughly explain how the targeted application is "hard to decarbonize," in addition to explaining electrification alternatives and alignment with the GWSA and the 2021 Climate Act. Further, RNG and hydrogen pilot proposals must take into consideration environmental justice populations and ensure that any such projects do not contribute to a decline of indoor air quality.

d. Networked Geothermal

Networked geothermal technology connects multiple, energy-efficient ground-source heat pumps ("GSHPs") to a loop system designed to provide heating and cooling to multiple buildings in a geographic area. The Department has found that: (1) geothermal networks

---

61 See https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving (last visited November 29, 2023).

have the potential to significantly reduce GHG emissions; and (2) geothermal demonstration projects designed to test the effectiveness and scalability of utility-owned geothermal networks have the potential to reduce current barriers to widespread adoption in furtherance of the Commonwealth's climate policies. D.P.U. 19-120, at 139.

Several commenters express support for networked geothermal technologies and their expedited deployment (see, e.g., Attorney General Initial Comments at 45-46; DOER Final Comments at 9, 15-16). The LDCs acknowledge that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

The Department commends the LDCs for exploring an innovative technology that has the potential to reduce GHG emissions and barriers to widespread deployment of clean heating technologies in furtherance of the Commonwealth's climate laws and policies. The Department notes the substantial progress in the construction of the Commonwealth's first utility-owned networked geothermal demonstration project in Framingham, with NSTAR Gas planning for the loop to be in operation prior to the 2023 heating season. See NSTAR Gas Company, D.P.U. 23-86, Exh. EVER-ANB/NLB-1, at 11.

Regarding the Attorney General's request to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies, the Department concludes that opening an investigation at this time is premature. The Department shares the optimism expressed by stakeholders concerning the operation and management of the approved networked geothermal demonstrations, and eagerly awaits successful evaluation data concerning their costs, feasibility, and potential scalability.[62] Depending upon the results of that evaluation, the Department can be expected to move expeditiously to develop broader guidance for networked geothermal, which may require specific performance metrics and strategies to target benefits toward environmental justice populations.

e. Targeted Electrification

Several commenters support additional targeted electrification demonstration projects, in which a participant would disconnect from the gas distribution system and fully electrify space heating and appliance loads (see, e.g., CLF Initial Comments at 9; RMI Final Comments at 3). To that end, numerous commenters recommend that the LDCs complete comprehensive geographic system and customer mapping, in addition to marginal cost analyses to explore cost-effective alternatives to traditional gas investment (see, e.g., Attorney General Final Comments at 14-15; DOER Initial Comments at 14-15).[63]

The LDCs respond to this proposition by citing several factors that require evaluation before targeted electrification is undertaken on parts of their systems (LDC Joint Comments at 68). The LDCs indicate, for example, that removing gas service from certain parts of

62 In addition, the Department has approved a settlement agreement in Eversource Energy/Bay State Gas Company, D.P.U. 20-59/19-140/19-141 at 61 (2020), that provided funding for the Attorney General and DOER to administer a geothermal microgrid pilot in the Merrimack Valley.

63 The Department further discusses comprehensive geographic distribution system and customer mapping below in Section VI.G below.

their systems may result in operational concerns regarding system pressures and flows elsewhere on their systems (LDC Joint Comments at 68). The LDCs also argue that decommissioning the gas distribution system would require greater education efforts, as removing gas service as an option for any of a customer's building needs will affect the viability of proposed targeted electrification options (LDC Joint Comments at 68). Generally, the LDCs raise concerns about the process, standards, and policies surrounding targeted electrification, while ensuring the safety and reliability of customers who choose to remain on the system (LDC Joint Comments at 68-69).

The Department is optimistic that targeted electrification through decommissioning parts of the gas system may serve as a promising approach to reaching the Commonwealth's GHG emissions targets; the Department also recognizes, however, that there are several operational constraints and unknowns as raised by the LDCs. To better understand these opportunities and constraints, the Department directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory. Each LDC, in coordination with the applicable electric distribution company, shall propose at least one demonstration project in its service territory for decommissioning an area of its system through targeted electrification. The LDC should target a portion of its system that suffers from pressure/reliability issues, leak-prone pipe, and/or that targets environmental justice populations that have borne the burden of hosting energy infrastructure. The Department expects the LDCs to engage with elected and appointed officials in the community, community-based organizations that work on energy, environment, labor, or ending poverty, and other interested residents. The Department directs each LDC to file its project proposal by March 1, 2026, for inclusion in its 2030 Climate Compliance Plan, working with its relevant electric distribution company and Program Administrator as necessary.[64]

f. Demonstration Project Process

In reviewing a proposed demonstration project, the Department considers the: (1) reasonableness of the size, scope, and scale of the proposed project in relation to the likely benefits to be achieved; (2) adequacy of the evaluation plan; (3) extent to which there is appropriate coordination among Program Administrators; and (4) bill impacts to customers, among other things. Guidelines § 3.9.1. Demonstration projects are not required to be cost effective at the initial testing and evaluation stage; however, an evaluation report at a demonstration project's conclusion requires detailed analyses of actual project costs and benefits, in addition to projected costs and benefits were the project to be delivered as a program at scale. Guidelines §§ 3.9.1.1, 3.9.2. In absence of cost-effectiveness screening,

---

64 The Department has found that, while pursuing energy and demand savings through strategic electrification, the Program Administrators must seek to reduce GHG emissions and minimize ratepayer costs. 2022-2024 Three-Year Plans Order at 84. Splitting incentives between gas and electric Program Administrators may mitigate bill impacts and produce a more equitable sharing of costs and benefits between gas and electric ratepayers. The Department notes that Program Administrators already are required to address fully how they considered a split incentive for both large traditional custom projects and large strategic electrification projects that involve offsetting natural gas consumption in its three-year energy efficiency plan, term report, and any applicable mid-term modification proposals. Liberty Utilities (New England Natural Gas Company Corp., D.P.U. 22-94, at 14 (2022).

detailed program descriptions and appropriate analysis must support the potential of a demonstration project to deliver net benefits in the future. Guidelines § 3.9.1.2.

The Department recognizes that both geothermal demonstration projects that have come before us required multiple proceedings, such as separate proposal, implementation, and cost-recovery filings, in addition to project-level evaluation studies.[65] See, e.g., Boston Gas Company, D.P.U. 20-120, Interlocutory Order on Proposed Demonstration Projects (December 11, 2020); NSTAR Gas Company, D.P.U. 21-53, Order on Phase I NSTAR Gas Company's Implementation Plan (January 4, 2022); NSTAR Gas Company, D.P.U. 22-125, Stamp Approval (December 5, 2022). Inasmuch as the Department had not reviewed a geothermal network proposal prior to 2020, however, such a proposal was considered a matter of first impression. The Department determined that these additional proceedings were therefore necessary to protect participating consumers, set the appropriate budgets, and maintain general oversight as the LDCs use ratepayer dollars to explore innovative solutions in support of Massachusetts' GHG emissions reductions targets. D.P.U. 19-120, at 138, 141, 148-149, 154; D.P.U. 21-53, at 8-9.

The Department has general supervisory authority over gas and electric companies, and must make all necessary examination and inquiries to keep itself informed as to the

[65] The Department acknowledges that multiple proceedings may serve as a barrier to meaningful engagement and participation by the public, and, to that end, the Department opened an investigation into procedures for enhancing public awareness of and participation in its proceedings. Notice of Inquiry by the Department of Public Utilities on its own Motion into Procedures for Enhancing Public Awareness of and Participation in its Proceedings, D.P.U. 21-50 (2021).

condition of the respective properties owned by such corporations, and the manner in which they are conducted with reference to the safety and convenience of the public. G.L. c. 164, § 76. The Department anticipates that the desired streamlining will occur as demonstration projects in support of the Commonwealth's GHG emissions reductions targets become more routine and as the LDCs understand what is expected of them in meeting the Department's standard of review.

Accordingly, the Department concludes that no further "streamlining" of its demonstration project review is required at this time, and that the LDCs have received sufficient guidance and cost-recovery avenues for researching and deploying innovative electrification and decarbonization technologies. The Department fully recognizes the financial and technological uncertainties that LDCs face in reaching the Commonwealth's mandated decarbonization targets; to minimize ratepayer costs, however, we continue to require that innovative technologies be rooted in cost-effectiveness and be offered in a cost-efficient manner.

Any demonstration project proposals related to innovative technologies must include detailed implementation plans and terms and conditions that are acceptable to and protective of participants. Each LDC seeking to demonstrate a new technology must propose novel objectives that will reasonably result in quantifiable GHG emissions reductions, and each LDC will be required to provide updates in its Climate Compliance Plan reports. As circumstances change, the Department may consider an alternative framework to incentivize the deployment of decarbonization technologies, as necessary.

E. Manage Gas Embedded Infrastructure Investments and Cost Recovery

1. Introduction and Summary

As discussed above in Section V.A, most of the pathways modeled predict declines in the number of LDC customers and system utilization over time (Regulatory Designs Report at 31-32). The Consultants raise two main concerns surrounding the issue of declining customers and throughput, namely the resulting higher costs for customers remaining on the natural gas system, and a mismatch between how infrastructure costs are currently recovered and the predicted system utilization (Regulatory Designs Report at 31-32). To mitigate the potential impacts associated with the recovery of embedded infrastructure costs and declining system usage, the Consultants recommend finding ways to minimize or avoid gas infrastructure investments where possible, pre-approval of non-GSEP investments, revisions to existing line extension policies, and accelerated depreciation (Regulatory Designs Report at 32-40).

a. Minimize Capital Investments

The Consultants recommend that the Department and LDCs develop a framework to examine opportunities to minimize or avoid gas infrastructure projects, while continuing to maintain safe and reliable service (Regulatory Designs Report at 32-33). The Regulatory Designs Report encourages geographically targeted electrification where possible as a way to address embedded infrastructure cost issues, as well as investigating various NPAs to replace non-cathodically protected steel, cast-iron, and wrought iron, and other aged pipe with new pipe (Regulatory Designs Report at 33). The Consultants acknowledge that these options are not without barriers, as targeted electrification requires all customers in an area to agree to terminate gas service and switch to electric service, and there are costs associated with switching (Regulatory Designs Report at 33). NPAs discussed include energy efficiency measures, demand response solutions, electrification, and networked geothermal systems (Regulatory Designs Report at 33-34).

b. Pre-Approval

The Consultants recommend the Department establish a process to review and pre-approve LDC capital investment plans relating to non-GSEP investments (Regulatory Designs Report at 34). They suggest conducting holistic, long-term capital planning that aligns safety and reliability investments with the Commonwealth's decarbonization targets (Regulatory Designs Report at 34). The Consultants propose reviewing LDC capital plans every three years—similar to the review process for energy efficiency plans—and that the process should evaluate changes in forecasted demand driven by decarbonization goals (Regulatory Designs Report at 34).

c. Line Extensions

Another recommendation for managing the concerns around embedded infrastructure is to revise the standards associated with line extensions and investments to serve new customers (Regulatory Designs Report at 34-36). The Consultants note that currently the standard for serving new customers is that existing customers must not subsidize the cost to serve new customers, and that to the extent the incremental revenues of the customer addition are not equal to or greater than the associated costs, the difference must be paid by the customer in the form of a CIAC (Regulatory Design Report at 36). The Consultants identify four potential changes to the current line extension policy: (1) shortening the investment payback period; (2) reducing customer revenues supporting the new investments; (3) increasing the target rate of return on the investments; and (4) requiring customers to guarantee the revenues supporting the incremental costs (Regulatory Designs Report at 36).

d. Accelerated Depreciation

Rather than the current practice of utilizing straight-line depreciation, the Consultants recommend accelerated forms of depreciation, such as the Units of Production method or implementing shorter service lives, to better align the recovery of infrastructure costs with the anticipated utilization and anticipated customer migration (Regulatory Designs Report at 37-40). The Consultants suggest that while accelerated forms of depreciation increase costs in the short term, the associated depreciation costs should remain stable compared to continued use of the straight-line method, which will result in increased future costs if system utilization declines (Regulatory Designs Report at 37-38). Accelerated deprecation is presented as not only a means of mitigating affordability and equity concerns, but also a way to mitigate concerns related to unrecovered rate base as customers leave the gas system by recovering costs in an accelerated fashion (Regulatory Designs Report at 38-39).

2. Summary of Comments

A number of commenters specifically argue that line extensions and new customer additions should cease as soon as possible, citing health concerns, the potential for stranded assets, and the ability to achieve net-zero emissions (see, e.g., McCord Comments at 3

(May 6, 2022); Muzzy Comments at 1 (May 6, 2022) ("Muzzy Comments"); PLAN Final Comments at 6; RMI Initial Comments at 12-13; Robinson Comments at 1 (May 4, 2022)). Other commenters express general concerns regarding stranded assets associated with increased capital investments, and some urge a transition away from investments in fossil fuels (see, e.g., Archbald Comments at 1 (May 6, 2022); Armstrong Comments at 1 (May 4, 2022); Boston Common Asset Management Comments at 2 (May 6, 2022); Burdick Comments at 1 (May 6, 2022); C. Rose Comments at 1 (May 4, 2022); Royce Comments at 1 (May 2, 2022)). Several commenters support implementing opportunities to minimize or avoid gas infrastructure projects generally (see, e.g., Acadia Center Initial Comments at 24); CLF Initial Comments at 9).

LEAN contends that furthering capital investments and any proposals to accelerate cost recovery will only increase financial risks and create affordability issues for low-income customers in particular (LEAN Initial Comments at 10, 18). Alternatively, the Attorney General suggests that the Department conduct a review of existing tariff provisions and line extension policies, as there is no current uniform model or costing matrix to assess the cost-benefit analysis of line extensions (Attorney General Initial Comments at 32); Attorney General Final Comments at 16). More specifically, the Attorney General states the Department should determine whether the current CIAC model is consistent with state policies and goals, reflects anticipated investment recovery, and results in mostly free extensions for new customers (Attorney General Initial Comments at 32). The LDCs acknowledge that not all utilities handle line extensions in a uniform way and do not oppose a collaborative review of the current models or the development of a common framework as proposed by the Attorney General (LDC Joint Comments at 93).

In addition to the suggested review of CIAC models and line extension policies, the Attorney General recommends that the Department retain consultants or work with utilities to develop an "investment alternatives calculator" that would review and compare the expected costs of new gas system investments with the short- and long-term costs of alternative solutions (Attorney General Initial Comments at 33-35; Attorney General Final Comments at 11). The Attorney General contends that a properly designed investment alternatives calculator would provide a set of prescribed assumptions for the cost of carbon, a range of values for the cost of gas commodity, the cost of avoided GHG emissions, and the cost of alternative technologies (Attorney General Initial Comments at 33-34)

Regarding depreciation, Acadia Center, CLF, and others argue that accelerated depreciation is worth investigating, and DOER contends that a geographic marginal cost analysis to address decommissioning plans should be required before accelerated depreciation is allowed (see, e.g., Acadia Center Initial Comments at 24; CLF Initial Comments at 54; DOER Initial Comments at 17; RMI Initial Comments at 13). CLF also suggests that investigations into any depreciation changes should begin promptly, as any delays could increase the risk of rate shock when changes are implemented, and that depreciation rates should reflect the utilization of different assets with different lifetimes (CLF Initial Comments at 49, 53).

The Attorney General asserts that accelerated depreciation inappropriately shifts market and climate policy risk from utilities to ratepayers while increasing the cost of gas service (Attorney General Initial Comments at 35-36). She suggests it is unrealistic for utilities to continue to invest in gas infrastructure without regard to market risks and decarbonization goals, and that the Department may choose to treat future infrastructure investments differently from those made historically (Attorney General Initial Comments at 36). The Attorney General contends the Department should order LDCs to file information on the magnitude of potential stranded costs and work to establish clear cost recovery timelines or guidelines to balance the costs and responsibilities of possible stranded assets (Attorney General Initial Comments at 35-37; Attorney General Final Comments at 16). The Town of Hopkinton opposes the adoption of accelerated depreciation, arguing that it shifts cost recovery to taxpayers from the LDCs and ratepayers (Town of Hopkinton Comments at 3-4 (May 6, 2022)). The LDCs disagree with the Attorney General's assessment regarding the shifting of risks, and instead argue that accelerated depreciation addresses affordability concerns for current and future customers while maintaining a safe and reliable system (LDC Joint Comments at 86). The LDCs argue that they must continue to make investments to maintain the gas system, and that the regulatory compact entitles utilities to an opportunity to earn a reasonable return on, and a return of, their prudent investments (LDC Joint Comments at 87). The LDCs also disagree with DOER's assertion that consideration of accelerated depreciation should be delayed until the completion of a marginal cost analysis addressing decommissioning plans, arguing that it would be subject to significant uncertainty and complexities (LDC Joint Comments at 87-88).

3. Analysis and Conclusions

a. Pre-Approval and Capital Investments

The Regulatory Designs Report recommends that the Department review and pre-approve certain future LDC capital investments as part of the reporting and planning process going forward in order to continue providing safe and reliable gas service (Regulatory Designs Report at 46). In the instant proceeding, the Department is not persuaded that pre-approval of investments is appropriate at this time. We observe that there are extensive federal and state regulations intended to ensure the safe maintenance and operation of the natural gas pipeline system, which include safety standards and mandated program improvements. The Department will not interfere with the mandates of the federal and state regulations. See, e.g., 49 C.F.R. §§ 192.907, 911, 1005, 1007; 220 CMR 101.00. The Department does, however, recognize that achieving state climate change goals necessarily requires the minimization of stranded investments to the extent possible. The Consultants recommend encouraging NPAs as alternatives to replacing aged pipes and/or installing new mains. The Attorney General argues that the Department should adopt a robust alternatives analysis or an "investment alternatives calculator" to ensure that any investments made represent the best alternative available at the time (Attorney General Initial Comments at 33; Attorney General Final Comments at 11). The Department agrees that consideration of NPAs will be an essential part of the regulatory landscape, and that companies should begin examining opportunities to minimize investments that may contribute to future stranded costs. As described in Section III above, the recoverability of additional investment in natural gas infrastructure will require an analysis of whether such investments are consistent with state emissions reduction targets and the thorough evaluation of NPAs. As part of any future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive in order to receive full cost recovery.[66]

b. Line Extensions

As discussed in Section III, the Commonwealth's climate laws, which include a 2050 GHG emissions reduction mandate and interim targets, require LDCs and the Department to move beyond a "business as usual" approach to system planning and expansion. Accordingly, the Department agrees with the Consultant and commentor suggestions that the standards for investments to serve new customers be examined and revised. The Attorney General specifically recommends that the Department address the standard for line extensions, along with other ratemaking policies, as part of a gas ratemaking regulatory reform in a separate proceeding or working group (Attorney General Final

---

66 The Attorney General suggests the use of a "investment alternatives calculator" to evaluate NPAs. The Department agrees that stakeholders should have the opportunity to review not only individual NPA analysis but the underlying assumptions and inputs. The Department therefore directs that in conducting the cost-benefit analysis underlying the consideration and evaluation of NPAs, the LDCs consult with stakeholders prior to submitting an NPA analysis for Department review and adjudication.

Comments at 16). The LDCs express a willingness to develop collaboratively a common framework for evaluating new service connections and a review of existing CIAC and internal rate of return ("IRR") models (LDC Joint Comments at 92-93). The Department directs all LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions.

The Department recognizes that certain statutory and legislative changes may be necessary going forward. In NSTAR Gas Company, D.P.U. 22-107 (2022), in the context of a proposed extension of natural gas service to the Town of Douglas, several parties and participants expressed concern that Section 3 of the Gas Leaks Act, which mandates that the Department review and approve proposals designed to increase the availability, affordability, and feasibility of natural gas service for new customers, is inconsistent with the Commonwealth's GHG emissions reduction targets and climate policies. D.P.U. 22-107, at 6-9, 12. Section 3 was enacted by the Legislature in 2014. D.P.U. 19-120, at 464. Prior to any approval and implementation of a program proposed under Section 3, the Department must review the company's determination that a main or service extension is economically feasible and review the gas company's CIAC policy and methodology. St. 2014, c. 149,

§ 3(a); D.P.U. 19-120, at 456. In D.P.U. 22-107, the Department found that the state's recent climate legislation neither repealed nor amended Section 3; however, we recognize the inherent conflict between the express goals of these statutes given that Section 3 encourages investments in new main and service extensions and increased use of natural gas, while climate legislation mandates a reduction in GHG emissions. See D.P.U. 19-120, at 464. For the Department to pursue fully its mandate to prioritize reductions in GHG emissions along with safety, security, reliability of service, affordability, and equity as directed by the Legislature in the 2021 Climate Act, we recommend that the Legislature repeal Section 3 of the Gas Leaks Act to eliminate any potential conflict of laws.

With respect to line extensions and applications specifically pursuant to G.L. c. 164, Section 30,[67] the Department determines whether a proposal is reasonable. As discussed in D.P.U. 22-107, we have found this includes the overarching consideration of the public interest, defined generally as requiring that there be no adverse impacts on existing natural gas customers. D.P.U. 22-107, at 3-4. In reviewing future applications, the Department will examine the public interest in the context of our broader climate mandates. In doing so,

---

67 The Department reviews petitions for authorization to expand a gas distribution company's service territory pursuant to G.L. c. 164, § 30, which states:

> The [D]epartment may, after notice and a public hearing, authorize a gas or electric company to carry on its business in any town in the commonwealth other than the town named in its agreement of association or charter, subject to sections eighty-six to eighty-eight, inclusive, and it may purchase, hold and convey real and personal estate in such other town necessary for carrying on its business therein.

we note that Section 30 does not require that the Department grant petitions in those circumstances where such a grant would not adversely impact existing customers. See D.P.U. 22-107, at 4. We also note that in D.P.U. 22-107, the Department found that the company had demonstrated that an alternative electrification approach was economically unviable, and that the expansion of services into the Town of Douglas was reasonable and consistent with the public interest. D.P.U. 22-107, at 15. While Section 30 does not expressly require a company to evaluate alternatives to expanding its gas system, going forward the Department will take the evaluation of alternatives into consideration along with any impact on achieving the state's climate targets. D.P.U. 22-107, at 15. Finally, although the adjudication of a specific standard of review is outside the scope of this proceeding, the Department anticipates that its consideration of a petition pursuant to Section 30 will presume a requirement of consistency with an LDC's Climate Compliance Plan, as discussed in Section VI.G.

c. Accelerated Depreciation

There is general consensus among the LDCs and stakeholders that the issue of depreciation and stranded assets must be examined. While stakeholders differ as to the exact approach to deal with the issue, the Department agrees that the matter is important and must be investigated. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments. As part of this review, the LDCs must identify the impacts of accelerated depreciation proposals and identify potential alternatives to accelerated depreciation.

The Consultants and LDCs specifically reference the "Units of Production" method of accelerated depreciation as a way of aligning cost recovery of capital investments with system utilization, noting that it is a method recognized by the National Association of Regulatory Utility Commissioners ("NARUC"), as well as the option of implementing shorter asset service lives (Regulatory Designs Report at 38). The Department notes there are various options to consider with respect to accelerated depreciation, and the LDCs should not limit their review to any one method such as the Units of Production method, as each has its own inherent benefits and limitations (see, e.g., Regulatory Designs Report at 38; NARUC Depreciation Manual at 52-53; 57-61). Accelerated depreciation methods currently are not used for regulatory purposes, with the straight-line method primarily utilized in utility depreciation studies (NARUC Depreciation Manual at 61). The Department previously has recognized, however, that there is a fundamental transition underway in the gas industry in Massachusetts, and further investigation of cost recovery of existing infrastructure investment is required. The goal of the review should be not only assessing the magnitude of stranded costs, but also to investigate ways to address cost recovery while balancing ratepayer and shareholder risk going forward in a way that adequately reflects system costs, shareholder awareness of risk, and realistic expectations of the future, while addressing customer affordability and equity concerns.

F. Evaluate and Enable Customer Affordability

1. Introduction and Summary

The fifth regulatory recommendation focuses on evaluating and enabling customer affordability as customers transition away from reliance on the gas system to decarbonized technologies. The Consultants caution that each of the identified decarbonization pathways raise cost considerations for customers as well as associated equity challenges, which will require regulatory and policy interventions to mitigate impacts on customers (Regulatory Designs Report at 40). In particular, the Consultants explain that given the magnitude of potential cost impacts, and the rate and equity implications associated with progress toward electrification, there is a need to expand the scope of the current cost recovery mechanisms for LDCs (Regulatory Designs Report at 41). The Consultants therefore recommend a specific set of regulatory designs and policy changes to address these concerns, which we discuss below (Pathways Report at 100-108; Regulatory Designs Report at 40-45).

a. Cost and Equity Implications of the Pathways

The Consultants highlight that the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity are a significant barrier for customers to migrate off the gas system (Pathways Report at 105-106). The Consultants further state that when a growing number of customers transition off the gas system, customers who remain on the system will experience increasing energy costs that they must absorb (Regulatory Designs Report at 40; Pathways Report at 106). Absent regulatory changes, the Consultants conclude the remaining customers will see higher rates due to varying increases in commodity or delivery costs[68] (Regulatory Designs Report at 41). The Consultants maintain that by 2050, some of the higher electrification pathways may result in unrealistic costs imposed on customers from $30,000 to more than $70,000 per customer per year (Pathways Report at 107). Pathways with more moderate levels of electrification result in less significant cost shifting, yet still yield costs per customer expected to be 40 percent to 50 percent above the reference case by 2050 (Pathways Report at 107).

In addition to affordability challenges, the pathways present equity challenges, including cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers designated as environmental justice populations (Regulatory Designs Report at 40; Pathways Report at 106). The Consultants explain that customers who are unable to fund the high upfront costs of switching to decarbonized technology (especially non-migrating customers who qualify for low income-rates and those who are designated as environmental justice populations) or otherwise face challenges in adopting clean technologies (i.e., the hard-to-electrify commercial sector) are more likely to remain stranded on the gas system and shoulder the growing costs (Pathways Report at 29, 106-109). The Consultants state that

---

68 According to the Consultants' projections, certain pathways that allow for higher continued gas system utilization (i.e., "Efficient Gas Equipment" and "Low Electrification") will experience increased commodity cost of renewable gas in the system, while others that allow for lower gas system utilization (i.e., "High Electrification") will see increases in delivery costs due to customers departing the gas system and leaving behind uncollected embedded gas infrastructure costs to be recovered over fewer customers and/or therms (Pathways Report at 101; Regulatory Designs Report at 41).

low-income customers remaining on the gas system likely will spend an increasingly higher share of their income on energy, from approximately seven percent to more than 15 percent in 2050 (Pathways Report at 101-102).

In addition, the Consultants caution that the pathways present various equity considerations with respect to existing infrastructure retirements, new energy infrastructure construction, and the decommissioning of LDC infrastructure, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of LDC infrastructure (Pathways Report at 108). The Consultants explain that policies will need to address and mitigate, to the extent possible, impacts on environmental justice and low-income populations associated with siting and construction of energy infrastructure as well as potential decommissioning of any LDC facilities. The Consultants state that these mitigation policies are particularly important for environmental justice populations, which generally are concentrated in communities already hosting energy infrastructure (Pathways Report at 108).

b. Recommended Regulatory and Policy Interventions

The Consultants propose to address affordability and equity concerns through a set of specific regulatory design recommendations, which focus on understanding and minimizing the impacts of decarbonization on customers (Regulatory Designs Report at 42). These regulatory design recommendations include identifying and quantifying transition costs, evaluating the impacts of transition costs on customers, and exploring alternative cost recovery mechanisms and securitization as methods for mitigating affordability issues

(Regulatory Designs Report at 42, 45). In addition, the Consultants suggest that policy interventions such as targeted incentives aimed at promoting a more equitable transition to clean technologies are warranted (Regulatory Designs Report at 20, Pathways Report at 108). Ultimately, the Consultants conclude that the magnitude and pace of electrification associated with a particular pathway will impact LDCs and the Department's ability to develop and implement regulatory policies that mitigate potential cost shifts and associated equity issues (Pathways Report at 108).

First, the Consultants recommend developing a framework to identity and quantify transition costs (i.e., uncollected costs from customers who have departed the gas system, costs associated with design and implementation of the regulatory reforms,[69] workforce transition costs, and costs associated with restructuring or realignment of gas supply portfolios) (Regulatory Designs Report at 42). The next step should be to evaluate the impact of those transition costs on customers under the various pathways (Regulatory Designs Report at 42).[70]

---

69 These proposed regulatory reforms include geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation (Regulatory Designs Report at 42).

70 The Consultants explain that under some pathways, such as 100 percent gas decommissioning, the transition costs grow quickly and have a substantial impact on customer rates much earlier in the decarbonization pathway, while under other pathways, such as hybrid electrification, the transition costs grow more slowly and have a substantial impact on rates later in the decarbonization pathway (Regulatory Designs Report at 42).

The Consultants next recommend mitigating transition costs by evaluating alternative approaches to cost recovery, such as charging customers leaving the gas system an exit fee or migration fee ("migration charge"),[71] and a statewide recovery mechanism through electric surcharges ("transition charge") (Regulatory Designs Report at 42). The first approach suggests a migration charge for customers leaving the gas system to cover costs that were incurred to serve them but not collected (Regulatory Designs Report at 42-43).[72] According to the Consultants, this would minimize the cost shift to customers remaining on the system as well as minimizing the potential for non-recovery of embedded costs (Regulatory Designs Report at 43). The second approach of charging transition charges seeks to align the benefits of decarbonization with the transition costs through sharing the transition costs more broadly with those who benefit from the transition (Regulatory Designs Report at 43). The Consultants acknowledge that the mechanism underlying this approach requires considerable review and evaluation, including its implications on LDC customers and, more broadly, on those who would pay for the transition costs, but they suggest that the process could start with establishing a fund and continue with attempts to identify other funding sources (Regulatory Designs Report at 43). The Consultants assert that the substantial transition costs

71 The Consultants refer to this fee as a "migration fee," while some commenters refer to the charge as an "exit fee." The Department uses the term migration charge, which has the same meaning as migration fee and exit fee, and references the terms used by commenters when summarizing comments.

72 The Consultants posit that this option likely would require legislative approval given the charge would be based on LDC costs charged to non-LDC customers (Regulatory Designs Report at 42).

associated with each pathway require a cost recovery mechanism consistent with the scope and scale of such costs (Regulatory Designs Report at 42).

The Consultants' final recommendation is to evaluate the use of securitization as a method to finance transition costs and lower a utility's borrowing costs, which, in turn, decreases the amount customers will have to repay, and allows both parties to benefit directly from the bond market (Regulatory Designs Report at 45).[73] The Consultants acknowledge that securitization poses the challenge of requiring a secure revenue stream, whereas the revenue stream under the decarbonization pathways is subject to significant uncertainty (Regulatory Designs Report at 45). The Consultants suggest that a possible, albeit untested, solution to this uncertainty would be through charges on both gas and electric bills (Regulatory Designs Report at 45).

In addition to the above set of regulatory design recommendations, the Consultants introduce a few policy interventions they claim are needed to address affordability and regulatory concerns. First, to address the burden of upfront capital costs of appliances, as well as the costs associated with decarbonization in the building sector (e.g., implementing building shell retrofits), the Consultants suggest that expanded policies aimed at providing additional customer incentives should be established (Pathways Report at 102, 106-107; App. 1, at 57).

---

73 The Consultants state that securitization has been used in the utility industry to finance the recovery of extraordinary costs (e.g., wildfire mitigation costs in California, coal plant decommissioning costs in New Mexico, and storm costs in Texas), serving to minimize the impacts on customer rates (Regulatory Designs Report at 45).

Next, the Consultants suggest that a means of mitigating the unintended consequences of inequitable cost shifting is to provide incremental incentives to low-income and environmental justice populations to promote decarbonization (Pathways Report at 108). In addition, the Consultants suggest that incentives designed to benefit both landlords and renters would help address the current misalignment of interests between these parties, especially for pathways with higher levels of customer transitions (Pathways Report at 108). Further, the Consultants caution that the pathways present various equity issues related to both existing infrastructure retirements and new energy infrastructure construction, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of gas infrastructure (Pathways Report at 108). Importantly, environmental justice populations are generally over-represented in communities already hosting energy infrastructure (e.g., LDC on-system LNG and propane assets). Given that each pathway has a significant level of energy infrastructure construction, the Consultants suggest that policies will need to specifically address and mitigate the disproportionate impacts on environmental justice and low-income populations associated with siting and constructing energy infrastructure as well as the decommissioning any LDC facilities (Pathways Report at 108).

2. Summary of Comments

Several commentors expressed affordability concerns, particularly for LMI customers (see, e.g., Attorney General Initial Comments at 50; DOER Initial Comments at 15; LEAN Initial Comments at 18; NCLC Initial Comments at 32; HEET Comments at 7). Several stakeholders call for the prioritization of LMI customers to ensure an equitable transition and protect those customers from bearing the increased energy burden associated with electrification (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). Stakeholders generally agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., Acadia Center Initial Comments at 22; LEAN Initial Comments at 17). To that end, several commentors suggest that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., Attorney General Initial Comments at 52; DOER Initial Comments at 15; LEAN Initial Comments at 18).

The Attorney General argues that the current gas regulatory framework does not protect LMI customers and customers in environmental justice populations from the increasingly high energy burdens that will disproportionately impact these customers as more ratepayers leave the gas system in the transition to a net-zero future (Attorney General Initial Comments at 46-47, 52; Attorney General Final Comments at 3-4). The Attorney General asserts that the high upfront investment required to transition to alternatives, such as heat pumps, creates inequities for LMI customers as these households often lack savings, disposable income, and access to credit, which prevents them from affording clean energy alternatives (Attorney General Initial Comments at 47-48). The Attorney General adds that likewise renters may be poorly positioned to participate in and benefit from the energy transition as renters often are responsible for heating bills yet have no control over the heating system and a landlord may not be motivated to make necessary upfront investments (Attorney General Initial Comments at 48; Attorney General Final Comments at 3-4). The Attorney General further observes there is a disproportionate impact to health and safety experienced in certain communities (e.g., due to pollution or the siting of energy infrastructure), including environmental justice populations (Attorney General Initial Comments at 50).

The Attorney General argues that protection for LMI ratepayers must be directionally consistent with reducing dependence on natural gas and should minimize the risk that customers unable to migrate end up with a disproportionate share of transition, embedded, or stranded costs (Attorney General Initial Comments at 52). To this end, the Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies, such as implementing a cap on the amount an LMI ratepayer is billed (Attorney General Initial Comments at 52). The Attorney General further recommends that the Department provide targeted support to LMI customers and customers in environmental justice populations when programs are designed to facilitate opportunities for residents to access cleaner energy alternatives (Attorney General Initial Comments at 52; Attorney General Final Comments at 17).

Several commenters disagree with implementing a migration charge as suggested by the Consultants (see, e.g., Acadia Center Initial Comments at 24-25; RMI Initial Comments at 3; Sierra Club Initial Comments at 18-19; CLF Final Comments at 6). Acadia Center agrees that customer affordability issues should be addressed through a Department investigation of various cost recovery options, but does not believe exit fees are the appropriate approach (Acadia Initial Comments at 24-25).

Sierra Club argues that a migration charge is unfair and undermines the Commonwealth's GHG emissions reduction goals by contradicting incentives to leave the gas system (Sierra Club Initial Comments at 18-19). Sierra Club further contends that this approach fails to account for system costs to which customers contributed but from which they did not benefit (e.g., system expansions and system upgrades to deal with growing demand in certain geographic areas), and questions whether customers would be compensated for those excess contributions when they leave the gas system as well (Sierra Club Initial Comments at 19). Sierra Club also argues that electric ratepayers should not be burdened with gas system transition costs (Sierra Club Initial Comments at 19). Sierra Club suggests that this approach would make the cost of electrification relatively more expensive and would affect not only the customer economics of electrifying from gas, but also of electrifying fuel oil and propane use (Sierra Club Initial Comments at 19).

According to Sierra Club, the best way to minimize low-income energy burdens is to fully electrify low-income housing as part of a high electrification strategy given that the Pathways Report shows that energy burdens of low-income customers would be lowest for those who fully electrify (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). Sierra Club states that while it is important to implement policies such as low-income rates to mitigate impacts on those low-income customers left on the gas system, the priority should be implementing policies and funding programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). LEAN also supports protection of low-income customers from rate increases under the pathways and advocates for an increase to low-income discounts (LEAN Initial Comments at 17; LEAN Final Comments at 2-3).

CLF also argues against imposing a migration charge or transition fee on customers leaving the gas system (CLF Final Comments at 6). CLF contends that doing so would essentially serve as a penalty for transitioning to decarbonized technologies (CLF Final Comments at 6). Further, according to CLF, such a framework would ensure that only those who can afford to pay the fee will be able to make the choice to use clean energy options, leaving the most vulnerable residents who are unable to afford the costs to transition to clean energy stranded on an increasingly high-cost gas system (CLF Final Comments at 6). In addition, CLF submitted a "Scoping a Future of Gas Study," which recommends that utility analyses must account for the differences between customer classes and reflect the impact of each scenario on customers in each category, including low-income ratepayers, moderate-income ratepayers, and renters within the residential class, as well as different types of commercial buildings and industrial consumption (CLF Initial Comments at 38). CLF suggests that LDCs must track the rate and bill impacts of each energy transition scenario on customers with reduced ability to make infrastructure choices in their homes, such as LMI households and renters, and find ways to mitigate the effects of any inequitable outcomes (CLF Initial Comments at 38). The analyses for customer affordability must compare overall costs associated with the use of gas as a "bridge" fuel versus direct transition to electricity (CLF Initial Comments at 39). CLF recommends that LDCs also should consider that customers might switch from pipeline gas to delivered fuels if pipeline service becomes uneconomic, and include recommendations to mitigate any negative effects resulting from such choices (CLF Initial Comments at 39).

DOER agrees with the Consultants that it is necessary to protect customers, particularly low-income customers and those in environmental justice populations, from rate shocks by evaluating decarbonization-specific rate structures (DOER Initial Comments at 9, 11). DOER argues that the Department should require the LDCs to conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, which includes recommendations for mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect low-income residents (DOER Initial Comments at 15). DOER asserts that LDCs must balance affordability concerns for customers against continuing to make necessary investments in the gas system to ensure safety and reliability (DOER Final Comments at 19).

The LDCs indicate support for the Commonwealth's climate goals and contend that customer choice should be at the center of any strategy to meet those goals as individual decisions about when and how to adopt electrification and efficiency measures will affect the nature, scale, and magnitude of electric and gas system transformations (LDC Joint

Comments at 93-94, citing Pathways Report at 15). The LDCs support the hybrid electrification pathway because it results in lower energy system costs, providing an incentive for customers to adopt hybrid heating systems (LDC Joint Comments at 75). The LDCs support the Consultants' suggestions for potential rate designs, such as a new hybrid heating rate class and critical peak pricing, to incentivize customers to adopt or remain on hybrid heating systems (LDC Joint Comments at 75). To ensure customer equity, LDCs are considering potential financial transfers from electric utilities to gas utilities as an approach to fund transition costs (LDC Joint Comments at 75). The LDCs assert this arrangement recognizes the multiple benefits of maintaining gas system functionality, including better utilization of the electrical system, avoidance of significant electrical system upgrade costs, and the maintenance of an alternative energy source in the event of blackouts (LDC Joint Comments at 75). The LDCs argue that achieving the levels of electrification modeled in each pathway will require significant customer education efforts, as well as development of supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95).

3. Analysis and Conclusions

a. Introduction and Summary

In opening this investigation, the Department sought to examine strategies to enable the Commonwealth to move into its net zero GHG emissions energy future while simultaneously safeguarding ratepayer interests. As detailed by the Consultants and LDCs and reinforced by several stakeholder comments, customers are expected to see considerable impacts through the affordability and equity implications of the transition to clean energy alternatives. Namely, customers will face challenges with respect to the upfront costs necessary to invest in clean technologies, rate increases for a declining number of customers remaining on the gas system, and resultant equity impacts, especially for LMI ratepayers and environmental justice populations.

In discharging our responsibilities under G.L. c. 25, the Department must prioritize affordability and equity in addition to safety, security, reliability of service, and reductions in GHG emissions to meet statewide emissions limits and sublimits. G.L. c. 25, § 1A. As electrification efforts expand, ensuring affordability and equity is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but other cumulative impacts. The Department acknowledges that the ability to meet these goals will depend on a variety of factors, including the magnitude and pace of customer transition, and legislative and regulatory changes. The Department remains committed to ensuring that its future regulatory policies are aimed at addressing barriers to expeditious customer transition to decarbonized energy options, while mitigating challenges with affordability and equity.

Throughout this proceeding, numerous stakeholders and individuals raised concerns regarding the ability of customers to afford the costs of the transition away from gas, as well the potential inequitable impacts to customers, especially those most vulnerable. The Consultants, as well as several stakeholders, propose a host of solutions to address these issues. Upon examination of the challenges and proposed strategies related to affordability identified during this proceeding, the Department has determined that further investigation is necessary and herein sets forth several areas for future evaluation that will focus on informing the strategies and any necessary regulatory changes to balance affordability and equity with the need to transition into a clean energy future as quickly and aggressively as is practicable. We discuss these areas of future investigation below.

b. Transition Costs

With respect to transition cost considerations, the Department recognizes that the increasing number of gas customers leaving the gas system likely will result in higher rates for those customers remaining on the system. The Department shares commenters' concerns regarding barriers preventing LMI customers from transitioning away from gas, while those same customers would bear a disproportionate energy burden by remaining on the gas system. We agree that new regulatory support and strategies will be needed to minimize the negative implications of this potential cost shifting and to maximize affordability.

The Department supports the Consultants' suggestion that an appropriate starting point is the development of a framework to identify transition costs and quantify these costs to understand the full scope of the cost impacts associated with the various decarbonization strategies, and then to evaluate the impact of those costs on ratepayers. The Department envisions that this framework should, at minimum, include identifying and quantifying the following transition costs: (1) uncollected costs from customers who have departed the gas system; (2) costs associated with design and implementation of regulatory reforms, including geographically targeted electrification, NPAs, coordinated planning efforts between electric and gas utilities, and accelerated depreciation; (3) workforce transition and training costs; and (4) costs associated with restructuring or realigning of gas supply portfolios (Regulatory Designs Report at 42).

Once quantified, the impact of transition costs on ratepayers, particularly LMI customers and environmental justice populations, should be evaluated fully. Importantly, this evaluation should encompass a broad range of considerations, including but not limited to: (1) bill impacts by customer class (short and long term as well as percentage of cost increase relative to household income); (2) GHG emissions reductions; (3) public health and safety; and (4) equity[74] under the various pathways. The Department is interested in DOER's recommendation that the LDCs conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, including potential mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect LMI ratepayers. As discussed in Section VI.E above, the Department favors a robust alternatives analysis, and we see a geographical marginal cost analysis to be a potentially valuable and informative part of that process. As suggested by the Attorney General, the Department will prioritize consideration

---

74 In this context, evaluation of equity considerations should include impacts on LMI customers, environmental justice populations, renters, and people of color, both in terms of energy burden and energy-related health and safety impacts. An equity analysis should consider the disproportionate and inequitable distribution of burdens and benefits that currently exist as well as future projections.

of any impacts that result in disproportionate and inequitable distribution of burdens and benefits when making any future regulatory decisions.

c. Alternative Cost Recovery

The Department agrees that we should evaluate and consider alternative cost recovery mechanisms. The Consultants suggest implementing migration and transition charges, along with financing transition costs through securitization, as potential cost recovery mechanisms to alleviate the increasing burdens on customers as more and more leave the gas system. Several commenters express support for types of mechanisms that help mitigate cost and equity impacts to customers, but also argue that implementing the Consultants' proposed mechanisms is inappropriate.

While the Department acknowledges the potential benefits of implementing a migration charge or exit fee for migrating off the gas system—such as reducing the costs that will shift to the remaining gas customers and minimizing the potential for non-recovery of embedded costs—the potential burdens and impacts on those customers and their decision to adopt clean alternatives remain unknown and untested. The Department is concerned that charging a fee to exit the gas system may disincentivize some customers from pursuing electrification. Similarly, while the Department acknowledges the potential benefit that securitization methods could yield (i.e., in terms of lowering borrowing costs and reducing customer rate shocks), the full scope of the impacts on customers and the gas and electric systems remains to be seen.[75] For these reasons, the Department declines to adopt the proposed alternative cost recovery mechanisms at this time and we will examine other cost recovery mechanisms in a future investigation.

Lastly, the Department agrees with several commenters that there is a need to adopt a rate mechanism aimed at protecting LMI customers from high energy burdens and potential rate increases as they transition from gas to electricity. As mentioned in Section VI.B above, the Green Communities Act directs that 20 percent of three-year energy efficiency plan budgets be allocated to low-income energy efficiency. G.L. c. 25, § 21(b)(1). We determine that there should be additional policies and programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy and, in fact, benefit in the near-term from electrification opportunities. The Department encourages the LDCs to work with the Energy Efficiency Advisory Council, including LEAN, to explore strategies to better reach underserved populations and hard-to-reach customers, including renters and landlords, LMI customers, and environmental justice populations. The Department also previously directed the LDCs to weatherize prior to or as part of an electrification project to ensure that overall energy consumption will decrease, while minimizing ratepayer bill impacts, particularly for LMI customers, for purposes of acquiring all cost-effective energy efficiency under the Green Communities Act. 2022-2024

[75] The Department notes that while G.L. c. 164, §1H, provides that the Department shall approve an electric company's securitization plan that maximizes rate affordability to ratepayers, the statute does not explicitly apply to LDCs.

Three-Year Plans Order at 107-108. An enhanced incentive structure that includes weatherization for low-income and environmental justice population customers in addition to incentives for heat pump conversions will ensure a reduction in energy consumption and minimize bill impacts. The LDCs should encourage, through education and enhanced incentives, proper weatherization of all customer homes in advance of heat pump installation. LDCs should also ensure that contractors properly size heat pumps prior to installation. Failing to do so potentially increases energy costs for customers. 2022-2024 Three-Year Plans Order at 107-108.

Further, we acknowledge the Recommendations of the Climate Chief, Melissa Hoffer, developed pursuant to Executive Order No. 604, §3(b), which recommends that the Department "prioritize any rate reform necessary to ensure that electric bills will be affordable for all households, particularly those with low and moderate incomes."[76] As noted in Section III above, the Department will investigate this issue further as we evaluate methods to ensure affordability and equity in light of higher energy burdens on LMI customers.

---

[76] Hoffer, Melissa, Office of Climate Innovation and Resilience, "Recommendations of the Climate Chief pursuant to Section 3(b) of Executive Order No. 604," pages 40-43 (October 23, 2023), available at: https://www.mass.gov/doc/recommendations-of-the-climate-chief-october-25-2023/download (last visited November 29, 2023).

G. Develop LDC Transition Plans and Chart Future Progress

1. Introduction and Summary

The sixth regulatory recommendation includes developing transition plans and evaluating progress toward the Commonwealth's climate targets. The Consultants state that the transition toward achieving climate targets will require (1) periodic reporting and (2) an iterative planning process that reflects lessons learned and new developments (Regulatory Designs Report at 46). The Consultants identify the following reporting and planning processes for inclusion in the new LDC transition plans:

1) Evaluation of LDC transition plan progress toward achievement of climate goals and addressing challenges;
2) Review and pre-approval of future LDC capital investments with a focus on necessary gas system replacements and identification of strategic opportunities to avoid new gas infrastructure through electrification and alternative options;
3) Establish a framework to review and optimize cross-coordination planning between gas and electric utilities;
4) Establish a framework for review and approval of cost recovery mechanisms for LDC capital investments and pilot projects;
5) Evaluation of customer affordability metrics;
6) Evaluation of key initiative data such as number of renewable natural gas customers, GHG emissions calculations, rates and bill impacts, and impacts on environmental justice populations with each plan filing; and
7) Incorporation of performance metrics and incentives to align LDCs' financial incentives with the goals of the Commonwealth (Regulatory Designs Report at 46-47).

Each LDC filed a Net Zero Enablement Plan, an initial transition plan for meeting the Commonwealth's 2050 goals (Framework and Overview at 17). The LDC Net Zero

Enablement Plans are designed to continue energy efficiency efforts consistent with the three-year energy efficiency plans, and to advance decarbonization and the Consultants' recommended regulatory designs in the short term. (Framework and Overview at 17). Included in the LDC transition plans is a proposed Model Tariff that would allow the LDCs to recover costs associated with their respective Net Zero Enablement Plans (Framework and Overview at 18-19). The LDCs seek Department approval of a framework for future iterations of the Net Zero Enablement Reports and the Model Tariff (Framework and Overview at 18-19). Each LDC proposes to file a Net Zero Enablement Plan on a three-year cycle, to align with the three-year energy efficiency cycle, using a five-year and ten-year planning horizon (Framework and Overview at 18). The Consultants note that GSEP capital investments would not be included in the transition plans because there is a process in place for Department review and approval for such expenditures (Regulatory Designs Report at 46). The LDCs propose that the Department review their initial and future three-year transition plans pursuant to the following standard of review: "The LDC's transition portfolio is reasonably designed to contribute to the reduction of GHG emissions to meet net-zero emissions by 2050, without compromising the safety, reliability and affordability of service offered to current customers" (Framework and Overview at 18).

2. Summary of Comments

a. Comprehensive and Coordinated Planning

Most commenters agree that comprehensive planning is needed to guide future investments and meet decarbonization objectives. The Attorney General recommends that the

Department take several steps to support LDC comprehensive planning such as: (1) requiring LDCs to file a comprehensive geographic distribution system mapping report; (2) implementing an investment alternatives calculator;[77] (3) mandating an alternatives analysis for approval of LDC proposals for alternative sources of methane or combustible gas; (4) directing LDCs to file plans that demonstrate the achievement of required GHG emissions reductions; and (5) reviewing LDC forecast and supply planning to better align GHG emissions reduction requirements (Attorney General Final Comments at 10-13). The Attorney General explains that without a full map of the gas system, the regulatory framework would continue to perpetuate piecemeal planning and siloed decision making which may impact the cost-effective achievement of net zero emissions by 2050 (Attorney General Final Comments at 10). The Attorney General maintains that such a map could help identify areas that are best suited for targeted electrification (Attorney General Final Comments at 14). DOER also supports requiring LDCs to submit a geographic distribution system map (DOER Final Comments at 10).

In addition, commenters agree that coordinated planning between gas and electric distribution system companies is necessary. The Attorney General recommends that the Department require electric distribution company participation in gas system investment proceedings (Attorney General Final Comments at 15). The Attorney General contends that the Department cannot adequately evaluate any proposed investment without joint electric and

---

[77] We address the suggestion of an investment alternatives calculator in Section VI.E.

gas planning (Attorney General Final Comments at 15). Other commenters such as Acadia Center and CLF oppose having LDCs lead the transition plans (Acadia Center Final Comments at 2; and CLF Final Comments at 7). Acadia Center and CLF argue that the LDCs have a financial interest in maintaining the gas system, which creates a conflict of interest in leading the transition plans (Acadia Center Final Comments at 2; CLF Final Comments at 7). CLF avers that LDCs should be treated as stakeholder participants in the "future of gas," while Acadia Center recommends implementing an independent planning authority to lead coordinated planning (CLF Final Comments at 7; Acadia Center Final Comments at 1; Acadia Center Initial Comments at 27-28). Public commenters conveyed support for developing transition plans, but many expressed concerns with the proposal that the LDCs lead the transition.

The LDCs disagree with Acadia Center's recommendation to create a third-party planning authority to oversee the transition plans (LDC Joint Comments at 78). The LDCs argue that creating a new third-party planning authority would conflict with prior Department precedent and the rights and obligations conferred upon utility companies by law and statute (LDC Joint Comments at 78). In particular, the LDCs posit that the Department has long deferred to the judgment and expertise of regulated utility companies when it comes to operating and maintaining their systems (LDC Joint Comments at 80, citing Boston Gas Company and Colonial Gas Company, D.P.U. 13-78, at 13 (2014)). Moreover, the LDCs maintain that it is appropriate for utilities to develop their own investment plans because they bear the responsibility of maintaining a safe and reliable service that is compliant with all federal and state regulatory and statutory requirements (LDCs Joint Comments at 81). Regarding specific analytical constructs for evaluating potential gas network investments proposed by the Attorney General and DOER (e.g., investment alternatives calculator or geographic mapping and marginal cost analysis), the LDCs argue such tools would reduce network planning to consideration of selected quantifiable parameters and, therefore, would be unable to capture the broad range of considerations that are required to make coordinated investment decisions (LDC Joint Comments at 82, citing Exh. DPU-Comm 7-2).

b. Limiting Incentives for Gas System Growth

Several commenters propose recommendations regarding GSEPs. The Attorney General asserts that the Department should consider climate objectives as part of GSEP review and require LDCs to demonstrate that the proposed investment is the least-cost alternative to improve safety and reduce leaks (Attorney General Initial Comments at 30). Additionally, the Attorney General proposes that the Department form a working group to make recommendations for potential changes to GSEPs (Attorney General Attorney General Initial Comments at 44). Similarly, DOER contends that LDCs should be required to address how specific GSEP investments correlate with a parallel geographical marginal cost analysis (DOER Final Comments at 18). DOER, Sierra Club, and CLF agree with revising the current GSEP process so investments in gas infrastructure can be minimized to the greatest extent practicable (DOER Final Comments at 17; CLF Initial Comments at 8; Sierra Club Initial Comments at 20). Several commenters echoed the importance of minimizing further gas system investments (see, e.g., HEET Comments at 8; LEAN Initial Comments at 10-11;

Muzzey Comments at 1). Commenters cited concerns regarding stranded assets and perpetuating the use of fossil fuel gas through gas system investments (see, e.g., RMI Initial Comments at 11; Werlin Comments at 1 (May 6, 2022); Lipke Comments at 1 (May 6, 2022)). Other commenters called for the end of both gas line extensions and the addition of new gas customers to the system (see, e.g., HEET Comments at 33; McCord Comments at 3; PLAN Initial Comments at 4).

The LDCs reiterate that the proposed transition plans exclude GSEP-related investments because there already is a process in place for Department gas system review and approval (LDCs Joint Comments at 81, citing Regulatory Designs Report at 46). The LDCs maintain that their respective GSEPs are consistent with the Gas Leaks Act and note that the Department consistently has found that the replacement of aging infrastructure under GSEPs achieves the goals of improvements in public safety, infrastructure reliability, and the reduction of lost and unaccounted for ("LAUF") natural gas. (LDC Joint Comments at 85, citing Fitchburg Gas and Electric Light Company, D.P.U. 20-GSEP-01, at 9 (2021)). Additionally, the LDCs note that they already are required to show that their respective GSEPs reduce emissions through annual filings with MassDEP (LDC Joint Comments at 85). The LDCs do not object to evaluating possible modifications to GSEPs as part of a working group provided they have adequate representation (LDC Joint Comments at 85).

Other recommendations are intended to further disincentivize gas system growth. For example, the Attorney General avers that LDCs should no longer be permitted to recover costs for marketing related to promoting gas service (Attorney General Initial Comments at 41). The Attorney General argues that these costs are not aligned with the Commonwealth's decarbonization goals and therefore expansion advertising should no longer be funded by ratepayers (Attorney General Initial Comments at 41). Similarly, the Sierra Club argues that incentives for gas appliances should be phased out (Sierra Club Initial Comments at 21). The Attorney General makes an additional recommendation to revise existing performance-based ratemaking ("PBR") mechanisms to establish incentives and disincentives designed around the gas utilities' progress in compliance with the Climate Act mandates (Attorney General Initial Comments at 40-41). The Attorney General states the Department should consider directing each LDC to submit revised PBR plans instead of waiting for the LDC to file its next base rate case (Attorney General Initial Comments at 40-41).

The LDCs disagree with the Attorney General's recommendation to revise the PBR mechanism (LDC Joint Comments at 88). The LDCs explain that PBR generates a level of revenue for a company to run its business, similar to an annual allowance to cover business operations, which enables the company to make system investments and attain operational and capital efficiencies (LDC Joint Comments at 89). According to the LDCs, these efficiencies create savings which are passed on to customers (LDC Joint Comments at 89). Additionally, the LDCs maintain that the existing PBR framework is not inherently inconsistent with progress toward decarbonization (LDC Joint Comments at 89). The LDCs argue that it is not necessary to revise the existing PBR because a new framework that aligns incentives with decarbonization still would apply with or without the current PBR framework (LDC Joint Comments at 89).

c. Net Zero Enablement Plans

Many commenters request that the Department reject the LDCs' individual Net Zero Enablement Plans and associated Model Tariff (see, e.g., Sierra Club Final Comments at 4; NCLC Initial Comments at 20; CLF Final Comments at 6). Some commenters express concerns that the proposed Net Zero Enablement Plans are biased, inaccurate, profit-driven, and ineffective to adequately transform energy use (Donaldson Comments at 1 (May 6, 2022); NCLC Initial Comments at 14-16; Sierra Club Final Comments at 13-14). In addition, other commenters contend that the Model Tariff is premature and that it is unfair for utilities to offer a product, such as RNG, as a tariffed utility service (see, e.g., Attorney General Initial Comments, App. C at 3-4; SFE Energy Comments at 3-4 (May 6, 2022)). The Attorney General criticizes the Net Zero Enablement Plans, contending that the LDCs are resisting change by seeking to maintain gas infrastructure (Attorney General Initial Comments, App. C at 2). The Attorney General proposes that the Department open a planning docket for the purpose of ensuring LDC compliance with climate mandates before considering the proposed Net Zero Enablement Plans (Attorney General Initial Comments, App. C at 3).

DOER recommends that the Department require the LDCs to develop more detailed three-year plans that propose decarbonization regulatory actions, evaluation of previous metrics, and recommendations for future plans (DOER Initial Comments at 13). DOER proposes that the Net Zero Enablement Plans should include the following: (1) a geographic mapping and marginal cost analysis to demonstrate the interaction of multiple strategies; (2) a demonstration of cost considerations; (3) enhanced proposals for regulatory actions to support decarbonization; and (4) metrics as a tool to evaluate successful strategies (DOER Initial Comments at 14). The LDCs maintain that each proposed Net Zero Enablement Plan pursues a portfolio of the various decarbonization pathways analyzed by the Consultants in an effort to meet the Commonwealth's targets while maintaining safety and reliability (LDC Joint Comments at 17). The LDCs request that the Department review and approve the individual Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 17).

3. Analysis and Conclusions

a. Introduction

The LDCs developed individual transition plans that articulate their role in supporting the Commonwealth's achievement of its climate mandates. The LDCs specifically propose to implement transition plans that include: (1) joint gas and electric planning; (2) periodic reporting; and (3) a Model Tariff to facilitate recovery of costs associated with the Net Zero Enablement Plans (Regulatory Designs Report at 46-47). The LDCs maintain that it is appropriate for utilities to develop their own transition plans and oppose recommendations to implement an investment alternatives calculator or geographic mapping report (LDC Joint Comments at 81-82). As we have stated from the beginning of this investigation, rather than selecting a single pathway for decarbonization, the Department will focus on creating a regulatory planning framework that is flexible, protects customers, and considers a suite of electrification and decarbonization technologies to facilitate the transition. Here we identify certain strategies and processes that will allow the Department and stakeholders to collect and evaluate information, establish common metrics and assumptions, and refine reporting review procedures to maintain and accelerate momentum toward achievement of the Commonwealth's climate targets. Consistent with our "whole of DPU" approach, these will include LDC reporting requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department.

b. Comprehensive and Coordinated Planning

The LDCs propose to establish a process for coordinated planning between gas and electric utilities (Regulatory Designs Report at 46). The Department agrees that coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition. Gas and electric infrastructure planning will be necessary as consumers transition from using fossil fuel-based heating systems to electric heat pumps. We note that going forward, evaluation of any proposed investments will have to take place in the context of joint electric and gas system planning. The Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome. The LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process that, while it is not Department led, may lead to proposals for Department review. We will continue to monitor and define these processes in future proceedings, as necessary.

Next, the Department addresses the practicality of requiring a comprehensive map of the gas distribution network. The Attorney General asserts that a map of all gas system infrastructure will better enable the Department to evaluate proposed gas system investment and alternatives (Attorney General Initial Comments at 23-24). The Department in Section III and Section VI.E above expressed its support of a robust alternatives analysis, for the first time mandating that LDCs must include and demonstrate analysis of alternatives as a prerequisite for cost recovery of infrastructure investments. As to the requirement of a gas system infrastructure map, the Department seeks to balance the need for comprehensive and useable information with the nature of the extensive critical energy infrastructure information ("CEII") inherent in such an undertaking, which is required by public records law to be protected from public disclosure.[78] We therefore decline to order public filing of such mapping with the Department in a Climate Compliance Plan or otherwise. We will, however, explore appropriate means of facilitating such information sharing without compromising CEII.

The Department finds that it would be inappropriate to issue any further directives that could impact potential changes to GSEPs here. The 2022 Clean Energy Act required the Department to convene a stakeholder working group to develop recommendations and

---

78 G.L. c. 66, § 6A(e); G.L. c. 4, § 7(26)(n).

legislative changes to align the gas system with statewide emissions limits, as well as encourage the development of geothermal systems. St. 2022, c. 179, § 68. The GSEP working group has met several times since its initial meeting in April 2023.[79] Each of the LDCs, as well as many of the parties to this proceeding, is participating in the GSEP working group process, and most of the topics raised by the Attorney General and other stakeholders are being explored in that forum. The GSEP working group is expected to produce its findings and recommendations to the Legislature by the end of the year.

c. Climate Compliance Plans

The Department appreciates the LDCs' efforts to design the initial Net Zero Enablement Plans. As a threshold matter, Section 77 of the 2022 Clean Energy Act dictates that the Department shall not approve any company-specific plan in this investigation prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, while the LDCs' Net Zero Enablement Plans lay out the companies' strategies to achieve compliance with climate objectives mandates,[80] which may inform the regulatory framework we seek to establish here, we cannot approve such a plan or a Model Tariff

---

79 See https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act (last visited November 29, 2023).

80 The LDCs explain that certain pathways evaluated in the Net Zero Enablement Plans, such as efficient gas equipment installation, may build on the three-year plan activities by offering additional incentives, complementary measures, or implementation practices that further advance efficient gas equipment installations, but that do not fall within the parameters of the Department's precedent for cost-effectiveness applicable to energy efficiency sectors, programs, or core initiatives (Exh. DPU-Comm 1-11).

without full adjudication. This proceeding is an investigation and not an adjudicatory proceeding. Consistent with the legislative directive, the Department will review and approve company-specific plans in subsequent adjudicatory proceedings.

To that end, the Department directs each LDC to file individual Climate Compliance Plans every five years, with the first such Plan being due on or before April 1, 2025.[81] Each Climate Compliance Plan should expand on previous Net Zero Enablement Plans by demonstrating how each LDC proposes to: (1) contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1[82] and Scope 3[83] emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably using known and market-ready technology available at the time of the filing; (3) use pilot or demonstration projects to assist

81 Subsequent Climate Compliance Plans would be due in 2030, 2035, and 2040. The plans should include a five- and ten-year planning horizon.

82 The U.S. Environmental Protection Agency ("EPA") defines Scope 1 emissions as "direct greenhouse emissions that occur from sources that are controlled or owned by an organization." Scope 1 and Scope 2 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance (last visited November 29, 2023).

83 The EPA defines Scope 3 emissions as emissions that "result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain." Scope 3 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-3-inventory-guidance (last visited November 29, 2023).

in identifying investment alternatives; (4) incorporate the evaluation of previous metrics[84]; and (5) implement recommendations for future plans.

Each electric distribution company operating in an LDC's service area will be required to participate in the Climate Compliance Plan gas planning process.[85] Each Climate Compliance Plan should detail the total investment required and should also include a description of at least one alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative. To track compliance with the Commonwealth's interim emissions reduction deadlines, each LDC will be required to file an informational Climate Act Compliance Term Report Filing nine months after each interim deadline (i.e., 2025, 2030, 2035, 2040) indicating whether or not the LDC achieved the required emissions reductions.

d. Climate Compliance Incentives

The LDCs state that the planning and evaluation process could be used to design performance metrics and incentives to align the LDCs' financial incentives with the Commonwealth's goals (Regulatory Designs Report at 47). A PBR mechanism can provide such an incentive for an LDC to take actions aligned with the Commonwealth's climate

---

[84] Evaluation of previous metrics would not be applicable to the first Climate Compliance Plan filed.

[85] The Climate Compliance Plans should also include customer, stakeholder, and community input where practicable.

policy and mandates to reduce its sales of methane gas through a series of measures to encourage gas efficiency, demand response, and electrification, as well as reducing LDC system and customer emissions of methane and carbon dioxide. In recent Orders, the Department has approved a PBR framework for LDCs, recognizing that there is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts.[86] Currently, the Department requires a utility seeking approval of an incentive proposal like PBR to "demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation."[87] To better align gas PBRs with the Commonwealth's long-term future of the gas system in a net-zero 2050 economy, the Department finds that it should amend the existing PBR framework to establish incentives and disincentives reflecting the gas utilities' progress toward compliance with the Climate Act mandates, and achievement of their approved Climate Compliance Plans. Accordingly, the Department directs the LDCs to propose climate compliance performance metrics in their next PBR filings.

---

86 See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 56; Boston Gas Company, D.P.U. 20-120, at 66-67 (2021).

87 See NSTAR Gas Company, D.P.U. 19-120, at 59.

VII. CONCLUSION

The Department herein has set forth a regulatory strategy for pursuing an energy future that begins to move the Commonwealth beyond gas and toward its climate objectives. As we have detailed, this will include new reporting and analysis requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department. Going forward, the Department will seek to facilitate a safe, orderly, and equitable transition for the LDCs and their customers through these processes while pursuing the Commonwealth's 2050 GHG emissions reductions mandate and interim targets.

VIII. ORDER

Accordingly, after due consideration, it is

ORDERED: That the Massachusetts gas local distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

James M. Van Nostrand, Chair

Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner

83rd OREGON LEGISLATIVE ASSEMBLY--2025 Regular Session

Senate Bill 1143

Sponsored by Senators LIEBER, SOLLMAN, Representatives LEVY B, ANDERSEN, MARSH; Senator PHAM K, Representatives HELM, LIVELY

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 **as introduced.** The statement includes a measure digest written in compliance with applicable readability standards.

Digest: Makes the PUC create a program to have each gas company create a thermal energy network pilot project. Makes each gas company apply to create a pilot project. (Flesch Readability Score: 65.7).

Directs the Public Utility Commission to establish a pilot program that allows each natural gas company to develop a utility-scale thermal energy network pilot project to provide heating and cooling services to customers. Requires each natural gas company to file a proposal and plan to develop a pilot project or an explanation for why the natural gas company is not submitting a proposal. Identifies criteria the commission shall take into consideration in evaluating a proposal.

Takes effect on the 91st day following adjournment sine die.

A BILL FOR AN ACT

Relating to thermal energy networks; and prescribing an effective date.

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

SECTION 1. (1) As used in this section:

(a) "Natural gas company" means a public utility, as defined in ORS 757.005, that provides natural gas services to customers.

(b) "Thermal energy network" means a network of pipes and heat pumps that uses noncombustible fluids within the network to distribute thermal energy between and among ground, air and surface water sources and buildings connected to the network.

(c) "Thermal energy network pilot project" includes all real estate, fixtures and personal property used for or in connection with developing or operating a thermal energy network.

(2) The Public Utility Commission shall establish a pilot program that allows each natural gas company to develop a utility-scale thermal energy network pilot project to provide heating and cooling services to customers. The purpose of the pilot program is to:

(a) Demonstrate the use and effectiveness of thermal energy networks to provide heating and cooling services while reducing or eliminating greenhouse gas emissions or improving energy efficiency;

(b) Allow each natural gas company to gain experience with using thermal energy networks to provide heating and cooling services to customers; and

(c) Provide the commission with experience on how to integrate thermal energy networks and thermal energy network projects into the commission's regulatory processes.

(3) The commission shall direct each natural gas company to file within 24 months from the effective date of this 2025 Act, and in a form and manner prescribed by the commission:

(a)(A) A proposal to develop and operate a utility-scale thermal energy network pilot project that serves customers; and

(B) A plan, for acceptance by the commission, for measuring the effectiveness of the

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.

thermal energy network pilot project. The plan must include specific metrics that the natural gas company proposes to use to evaluate the pilot project; or

(b) An explanation for why the natural gas company is not submitting a proposal for a thermal energy network pilot project.

(4) The commission shall evaluate a proposal to develop a thermal energy network pilot project with consideration to the following criteria:

(a) Whether the proposed project serves low income and energy burdened communities;

(b) Whether the proposed project serves a mix of building types;

(c) Whether the proposed project utilizes the existing gas utility workforce, creates jobs or uses labor agreements;

(d) The availability of local waste heat, ground heat sources and water bodies;

(e) The safety, reliability and resiliency objectives of the proposed project and whether those objectives may be reasonably achieved;

(f) Whether the proposed project tests technical, operational and financial approaches to achieving equitable and affordable decarbonization of buildings;

(g) Whether the proposed project leverages local and federal funding sources to offset costs recovery from customers for costs and expenses related to developing the proposed project;

(h) Whether the proposed project benefits the community by improving air quality, energy affordability and water conservation, avoiding or reducing electricity use or reducing greenhouse gas emissions;

(i) Collaboration by the natural gas company with the local community, governments and electric utility providers and regulators;

(j) Whether the proposed project will inform how thermal energy networks can help support joint planning by natural gas and electric utility providers;

(k) Whether the proposed project will inform how thermal energy networks can reduce overall and peak energy use;

(L) Whether the proposed project will inform how thermal energy networks can avoid costs that might be incurred absent the thermal energy network, including infrastructure, fuel, operations and maintenance costs; and

(m) Whether the proposed project provides learning to help the development of regulations that allow and facilitate thermal energy networks.

(5) The commission shall allow a natural gas company to recover costs from all customers of the natural gas company for prudent costs or expenses related to developing and operating a thermal energy network pilot project under this section.

SECTION 2. Section 1 of this 2025 Act is repealed on January 2, 2036.

SECTION 3. This 2025 Act takes effect on the 91st day after the date on which the 2025 regular session of the Eighty-third Legislative Assembly adjourns sine die.

ALJ/CF1/sgu **PROPOSED DECISION** **Agenda ID #21084 (Rev. 1)**
Ratesetting
12/1/2022 Item #35

Decision **PROPOSED DECISION OF ALJ FOGEL** **(Mailed 10/26/2022)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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	Rulemaking 20-01-007

DECISION ADOPTING GAS INFRASTRUCTURE GENERAL ORDER

TABLE OF CONTENTS

Title **Page**

DECISION ADOPTING GAS INFRASTRUCTURE GENERAL ORDER

Summary

This decision adopts a gas infrastructure General Order (GO), GO 177, as contained in Appendix A. The GO requires regulated gas corporations to file an application for a certificate of public convenience and necessity (CPCN) prior to commencing construction on any gas infrastructure that meets either of these criteria: (1) project is located within 1,000 feet of a "sensitive receptor" (including housing, educational institutions or health care facilities); and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for an increase in levels of (a) a toxic air contaminant; or (b) a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant. The GO outlines CPCN application information and notification requirements and specific types of exempt projects for which CPCN applications are not required.

The GO and this decision require gas corporations to annually file a Report of Planned Gas Investments (gas reports), starting March 1, 2023. This decision directs Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E) to jointly convene a Planned Gas Investments Workshop during the years 2023, 2024, and 2025. It authorizes parties to file comments on the gas reports, and on the reporting requirements contained in the adopted GO, in the years 2023, 2024, and 2025. This decision authorizes PG&E, SoCalGas, and SDG&E to submit a Tier 3 Advice Letter requesting changes to the reporting requirements contained in the GO in Appendix A suggested by parties and agreed to by the gas corporations, in the years 2023, 2024, and 2025.

Rulemaking 20-01-007 remains open.

1. Background

The California Public Utilities Commission (Commission) adopted an *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* on January 16, 2020. This is the fourth decision in this case.[1] This decision addresses Scoping Issue (a) of Track 2(a) as set forth in the *Assigned Commissioner's Amended Scoping Memo and Ruling* (Second Amended Scoping Memo) on January 5, 2022, which asks whether the Commission should consider adopting a gas General Order (GO).

Track 2 of this proceeding addresses long-term natural gas policy and planning. As discussed in the Order Instituting Rulemaking (OIR), compliance with local and statewide greenhouse gas legislation will cause demand for natural gas to decline over the next 25 years. California is transitioning away from natural gas-fueled technologies to meet decarbonization goals while simultaneously demanding less electricity from gas-fired generators as renewable electricity and energy storage resources increase. This portion of Track 2, consideration of a gas infrastructure GO, addresses an identified gap in the Commission's active regulation of gas infrastructure. It also serves as an intermediary step towards development of a more a comprehensive long-term gas planning process later in this proceeding.

[1] The first, Decision (D.) 21-11-021, established an Operational Flow Order structure for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively, the Sempra Companies). The second, D.22-04-042, extended year-round SoCalGas Rule 30 Operational Flow Order winter non-compliance penalty structure and applied it to the Sempra Companies and Pacific Gas and Electric Company (PG&E). The third decision in this case, D.22-07-002, established a framework for a citation program when a utility fails to maintain adequate backbone capacity, amongst other matters.

D.94-06-014 adopted GO 131-D, *"Rules Relating to the Planning and Construction of Electric Generation, Transmission/ Power/ Distribution Line Facilities and Substations Located in California,"* which addressed a similar gap in our active regulation of electric transmission lines of between 50 and 200 kilovolts (kV).[2]

On October 14, 2021, the assigned Commissioner issued an Amended Scoping Memo and Ruling addressing Track 2 issues and schedule and invited party comment. The assigned Commissioner issued an updated Second Amended Scoping Memo on Track 2 issues and schedule on January 5, 2022. On January 10, 2022, the Commission hosted a virtual workshop on Track 2(a) issues (a) – (d).

On February 4, 2022, an Administrative Law Judge (ALJ) issued a ruling inviting opening and reply briefs on the Track 2(a)(a) issue in this proceeding. On February 28, 2022, Environmental Defense Fund (EDF), the Sierra Club and the California Environmental Justice Alliance (Sierra Club/CEJA), Utility Consumer's Action Network (UCAN), PG&E, SDG&E, SoCalGas, the Southern California Generation Coalition (SCGC), Rocky Mountain Institute (RMI), and Central Valley Gas Storage, LLC (CVGS) filed Opening Briefs and the Center for Accessible Technology (CforAT) filed Opening Comments. On April 1, 2022, Sierra Club/CEJA, EDF, Wild Goose Storage, LLC and Lodi Gas Storage, LLC (Wild Goose and Lodi), SCGC, the Public Advocates Office (Cal Advocates), PG&E, SoCalGas, UCAN, SDG&E, Indicated Shippers, and RMI filed Reply Briefs.

---

[2] *See* D.94-06-014 and D.95-08-038. *See* also GO 131-D on the Commission's website, available as of September 14, 2022 at: https://www.cpuc.ca.gov/proceedings-and-rulemaking/cpuc-general-orders.

On March 1, 2022, an ALJ ruling provided a draft workshop report for the January 10, 2022 workshop, entered the draft report into the record of this proceeding, and invited comments on the draft workshop report, correcting inaccurate statements or informational gaps. On March 15, 2022, EDF, the Independent Energy Producers Association (IEPA), the Small Business Utility Advocates (SBUA), the Green Hydrogen Coalition (Hydrogen Coalition), the California Independent System Operator Corporation (CalISO), Indicated Shippers, SCGC, PG&E, SoCalGas, Cal Advocates, Southwest Gas Corporation (Southwest), and UCAN filed comments on the workshop report.

On March 1, 2022 an ALJ ruling required PG&E, SDG&E, SoCalGas, and Southwest to file gas distribution system and gas consumption information. The ruling invited the cities of Long Beach, Palo Alto, and Vernon to file the same information. On May 20, 2022, the Sempra Companies, Southwest, and PG&E each filed responses, and the cities of Long Beach, Palo Alto, and Vernon jointly filed a response to the March 1, 2022 ALJ ruling providing gas data.

On June 27, 2022, an ALJ ruling provided parties with a draft gas infrastructure GO proposed by Staff (Staff Proposal) and invited comment. The ruling included a number of specific questions for party comment. The ruling additionally directed PG&E, SDG&E, and SoCalGas to file a list of gas infrastructure projects completed over the last 10 years that exceeded $100 million in capital expenditure.

On June 28, 2022, EDF filed a Motion to Augment the June 27, 2022 ALJ ruling, requesting that the threshold for the list of gas infrastructure projects be lowered to $50 million. On July 8, 2022, an ALJ ruling granted the EDF motion, directed PG&E, SDG&E, and SoCalGas to file a list of gas infrastructure projects completed over the last 10 years that exceeded $50 million in capital expenditure, and provided other direction. On July 18, 2022, PG&E, SDG&E, and SoCalGas filed responses to the March 1, 2022 ALJ ruling requiring provision of gas infrastructure project data.

On July 25, 2022, CVGS, CforAT, Indicated Shippers, PG&E, UCAN, SCGC, Sierra Club/CEJA/RMI, SDG&E, Cal Advocates, SoCalGas, Southwest, and EDF filed comments on the draft proposed GO contained in the June 27, 2022 ALJ ruling. On August 1, 2022, Sierra Club/CEJA/RMI, CVGS, UCAN, SoCalGas, PG&E, SDG&E, SCGC, and EDF filed reply comments on the draft proposed GO.

2. Issues Before the Commission

This decision addresses issue (a) of Track 2(a) identified in the Second Amended Scoping Memo on Track 2 issues:

> Should the Commission consider adopting a GO analogous to GO 131-D for electric infrastructure projects, that would require site-specific approvals for gas infrastructure projects that exceed a certain size or cost?

In the course of reviewing party comments on the Staff Proposal, we identified the following sub-issues to the Second Amended Scoping Memo question. We use these sub-issues to structure this decision:

a. What should be the main objectives of the proposed GO?

b. Should the Commission adopt a monetary threshold to trigger a permit to construct (PTC) and/or a certificate of public convenience and necessity (CPCN) application requirement for gas infrastructure?

c. Should the Commission adopt different requirements for PTC versus CPCN applications regarding gas infrastructure?

d. Should the Commission adopt an environmental impact threshold to trigger a CPCN application requirement for gas infrastructure?

e. Should the Commission adopt any additional criteria to trigger a CPCN application requirement for gas infrastructure?

f. Should the Commission define the term "project" for purposes of the GO and, if so, how?

g. Should the Commission exclude or exempt emergency projects from the GO?

h. What types of gas infrastructure projects, if any, should be exempt from CPCN application requirements?

i. Should the Commission adopt any "exceptions" to exemptions from CPCN application requirements?

j. What notification requirements should the GO contain?

k. What information should CPCN applications covered by the GO contain?

l. What type of additional reporting on gas infrastructure projects should the GO require?

m. Are all terms appropriately defined in the GO?

3. Jurisdiction

The Public Utilities Code (Pub. Util. Code) Section 216 defines gas corporations as public utilities subject to this Commission's jurisdiction. Pub. Util. Code Sections 221, 222, and 891 define "gas plant," "gas corporations," and "gas utility," respectively.

Pub. Util. Code Section 451 requires gas rates to be just and reasonable. Pub. Util. Code Section 701.1(b) states that natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability. Consideration of cost-effectiveness shall include a value for any costs and benefits to the environment, including air quality.

Pub. Util. Code Section 454.52(a)(1)(I) states that the Commission should adopt a process for utilities to adopt plans that minimize localized air pollutants and other greenhouse gas emissions, with an early priority on disadvantaged communities.

Pub. Util. Code Section 701 states that the Commission may supervise and regulate every public utility in the State and may do all things which are necessary and convenient in the exercise of such power and jurisdiction. Pub. Util. Code Section 702 states that every public utility shall comply with every order, decision, direction, or rule made or prescribed by the Commission and shall do everything necessary or proper to secure compliance therewith by all of its officers, agents, and employees.

Pub. Util. Code Section 761 provides that, whenever the Commission, after a hearing, finds that the rules, practices, equipment, appliances, facilities, or service of any public utility, or the methods of manufacture, distribution, transmission, storage, or supply employed by it, are unjust, unreasonable, unsafe, improper, inadequate, or insufficient, the Commission shall determine and, by order or rule, fix the rules, practices, equipment, appliances, facilities, service, or methods to be observed, furnished, constructed, enforced, or employed.

Pub. Util. Code Section 762 provides that, whenever the Commission, after a hearing, finds that additions, extensions, repairs, or improvements to, or changes in, the existing plant, equipment, apparatus, facilities, or other physical property of any public utility or of any two or more public utilities ought reasonably to be made, or that new structures should be erected, to promote the security or convenience of its employees or the public, or in any other way to secure adequate service or facilities, the Commission shall make and serve an order directing that such additions, extensions, repairs, improvements, or changes be made or such structures be erected in the manner and within the time specified in the order. Pub. Util. Code Section 762.5 proposes that, the Commission shall give consideration to the factors of (a) community values; (b) recreational and park areas; (c) historical and aesthetic values; and (d) influence on the environment, when making orders pursuant to Pub. Util. Code Section 762.

Pub. Util. Code Section 1001 *et seq* sets forth requirements for gas infrastructure CPCN applications. Pub. Util. Code Section 1005.5(a) provides that the Commission should determine the maximum cost for gas infrastructure projects exceeding $50 million using an estimate of the anticipated construction cost and taking into consideration various factors. Section 1005.5(b) specifies that, after a CPCN has been issued, the gas corporation may apply to the Commission for an increase in the maximum cost specified in it.

Article XI, Section 8 of the California Constitution states that, "[a] city, county, or other public body may not regulate matters over which the Legislature grants regulatory power to the Commission."

4. Parties' General Responses to the Staff Proposal

Parties' responses to the Staff Proposal generally differ between gas corporations, on the one hand, and intervenors on the other. The gas corporations (PG&E, SoCalGas, SDG&E, Southwest) generally support the Staff Proposal, with some exceptions. The gas corporations support a $100 million threshold for an application requirement but raise concerns with Staff's proposed environmental criteria. Gas corporations also raise concerns about notification requirements for projects exempt from a permit requirement, particularly gas distribution lines less than 12 inches in diameter. Some gas corporations argue that the GO requirements should not apply to any distribution lines.

Intervenor parties generally support Staff's proposed environmental criterion and a lower monetary threshold ($50 million or $25 million), or no monetary threshold, and broader application requirements. Industry members represented by Indicated Shippers advocate stronger reporting requirements.

5. Adopting a Gas Infrastructure GO

This decision adopts a gas infrastructure GO, General Order 177, as contained in Appendix A. The GO and this decision require gas corporations to file CPCN applications under certain conditions described below. Three converging trends necessitate adoption of a gas GO at this time.

First, work to advance California's landmark greenhouse gas emission reduction goals has led to steadily declining gas consumption levels within California, at the rate of approximately one percent annually.[3] Declining gas consumption levels in turn have three main causes: the installation of more renewable electricity resources on the grid, city ordinances banning the installation of gas appliances in new homes and commercial buildings, and progression of the State's building code toward all electric buildings. As more renewable electricity resources are installed, demand for gas-powered base load generation declines.[4] Senate Bill (SB) 1477 (Stern, Stats. 2019, Chapter 582) promotes decarbonization of California's building supply. Incentive programs

---

[3] 2022 California Gas Report at 6, citing energy efficiency and fuel switching as primary drivers and stating "[u]tility-served, statewide natural gas demand is projected to decrease at an annual average rate of 1.1 percent per year through 2035." Available as of October 10, 2022 at: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf

[4] California Energy Commission, Final 2021 Integrated Energy Policy Report: Volume III: Decarbonizing the State's Gas System (2021 IEPR Decarbonization Report), at 3, 24, 26 and C-6, available as of October 10, 2022 at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report. Ramping needs from gas-powered generation may remain high.

and pilot projects to advance building decarbonization are rapidly emerging.[5] As of Fall 2022, nearly 50 cities and counties in California have adopted local ordinances requiring all-electric appliances in new homes or buildings, in some form.[6] These trends and related decreases in natural gas consumption in California are predicted to continue, particularly with the passage of Assembly Bill (AB) 1279 (Muratsuchi, Stats. 2022, Chapter 337) establishing an economy-wide target of carbon neutrality by 2045.

This decline in demand means there may be less need for large gas infrastructure projects in the future. It also means there may be a declining customer base across which to distribute the costs of existing and any new infrastructure.[7] Together, these trends amplify the Commission's responsibility to carefully scrutinize large gas infrastructure projects to ensure they are necessary. If a given facility is not necessary over its estimated useful life, a project could become a "stranded asset," imposing costs but providing limited benefits to a declining pool of ratepayers and increasing rates for the customers

---

[5] D.20-03-027 established two programs directed by SB 1477, the Building Initiative for Low-Emissions Development (BUILD) and Technology and Equipment for clean heating (TECH). BUILD is an incentive program for all electric new construction, mostly for low-income housing. TECH is a market development program that trains contractors, piloting actions to reduce barriers to adoption of heat pumps and providing incentives for heat pump installation. The Self-Generation Incentive Program and energy efficiency programs administered by IOUs also offer heat pump water heater incentives. Information on smaller pilots or programs providing incentives for heat pumps are available, as of October 13, 2022 at: https://www.cpuc.ca.gov/buildingdecarb. In late summer 2022, PG&E filed Application (A.) 22-08-003, proposing a zonal electrification pilot program located at California State University Monterey Bay. In late 2021, SCE filed A.21-12-009, proposing a building electrification program.

[6] *See* list of state and local government "zero emission building ordinances," available as of October 13, 2022 at: https://www.buildingdecarb.org/zeb-ordinances.html

[7] 2021 IEPR Decarbonization Report at 86 - 89.

left behind on the gas system.[8] Alternatively, some projects may be necessary for reliability in the next 10 to 25 years, even if they are not used for their full useful life. This balance between reliability and cost requires careful scrutiny in the years ahead.

The GO we adopt here provides a mechanism for project review for large and environmentally significant gas infrastructure projects in the near term as we continue to work towards developing a long-term gas planning process and strategy later in this proceeding. The long-term gas planning process and strategy will consider additional ways to avoid the risk of stranded assets and may build upon or refine the GO we adopt here.

Second, public controversy over large or environmentally significant gas infrastructure projects in recent years has demonstrated to us the need to strengthen public participation opportunities to ensure that impacted residents and stakeholders have appropriate means to voice concerns and shape project design. The Commission's Environmental and Social Justice (ESJ) Action Plan underscores the need for public participation opportunities in disadvantaged or historically pollution-burdened communities.[9] The California Environmental Quality Act (CEQA) applies to discretionary projects to be carried out or approved by public agencies.[10] However, this Commission has not previously required permit applications or CPCN for gas infrastructure projects. Instead, gas infrastructure projects have generally been included within Commission

[8] 2021 IEPR Decarbonization Report at Chapter 7.

[9] Commission Environmental and Social Justice Action Plan, available here as of September 6, 2022: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf

[10] Public Resources (Pub. Res.) Code Section 21080(a).

approvals of utility general rate case (GRC) applications. As a result, this Commission has conducted relatively few CEQA reviews of gas infrastructure projects.

This decision changes this framework to require CPCN applications for gas infrastructure projects under certain conditions. Following adoption of this decision, when a complete gas infrastructure CPCN application is filed with this Commission, we will complete a CEQA review pursuant to statutory requirements. Stakeholders and local communities will have the opportunity to review and comment on proposed gas infrastructure projects subject to a CPCN application requirement during both the application review process and the accompanying CEQA review process.

These two factors converge on a third rationale for, and benefit of, a gas GO at this time. The GO we adopt here aligns Commission gas infrastructure review processes with Pub. Util. Code Section 1001 *et seq*. Pub. Util. Code Section 1001 *et seq* provides that regulated energy utilities shall not begin the construction or modification of a gas line, plant, or system without having first obtained from the Commission a CPCN that the present or future public "convenience and necessity" require such construction.

To implement Section 1001 *et seq* for electric transmission projects, the Commission adopted GO 131-D in 1994.[11] The GO we adopt here draws on the design of GO 131-D as well as the unique circumstances surrounding gas infrastructure projects.

[11] *See* D.94-06-014 and D.95-08-038. *See* also GO 131-D on the Commission's website, available as of September 14, 2022 at: https://www.cpuc.ca.gov/proceedings-and-rulemaking/cpuc-general-orders.

The remainder of this decision reviews and adopts each element of the gas GO contained in Appendix A.

6. GO Purpose

6.1. Staff Proposal

Section II of the Staff Proposal contains the following explanation of purpose of the proposed GO:

The Commission has adopted this GO to be responsive to:

a. the requirements of CEQA (Public Resources (Pub. Res.) Code § 21000 et seq.);
b. the need for public notice and the opportunity for affected parties and members of the public to be heard by the Commission;
c. the obligation of the utilities to serve their customers in a timely and efficient manner; and
d. the need to review significant investments in gas infrastructure for consistency with California's long-term greenhouse gas emission reduction and safety and reliability goals.

6.2. Party Comments

Few parties comment directly on the purpose proposed by Staff. Sierra Club/CEJA/RMI suggest the purpose reference air quality and equity goals. PG&E observes that, other than the SoCalGas Ventura Compressor Station project and the Line 1600 project, there is little record supporting the need for a GO. PG&E notes a lack of complaints regarding its gas infrastructure projects.[12]

[12] PG&E discusses Line 57C, which it asserts triggered a discretionary permit and underwent CEQA review at the California Lands Commission. *See* PG&E Comments on Staff Proposal at 2 - 3, footnote 3.

6.3. Adopting Modified Version of Staff's Proposed Purpose

The recommendation of Sierra Club/CEJA/RMI to reference air quality and equity goals within Section II, Purpose of the GO, are reasonable and are adopted. Air quality issues often arise in relation to natural gas infrastructure projects. Additionally, equity is a primary goal of the Commission, as reflected in the ESJ Action Plan, and merits ongoing consideration as we implement the GO.

We retain Staff's proposed bullet stating that this GO is responsive to CEQA requirements. However, we emphasize that the CPCN application requirements we adopt here both initiate and are distinct from Commission CEQA review of a project.

A gas corporation's filing of a CPCN application pursuant to this decision will initiate the environmental review required by CEQA.[13] Depending on the results of this environmental review, the Commission may take several actions. Specifically, once a gas CPCN application is filed with this Commission, CEQA requires us to prepare and review an Environmental Impact Report (EIR) for the project or to issue a Negative Declaration, unless the project qualifies for an exemption under CEQA.

However, a gas corporation's filing of a CPCN application also entails the parallel review by this Commission of the application, pursuant to the Commission's Rules of Practice and Procedure (Rules). As set forth in the Rules, the application review process provides opportunities for party comment and discovery and may include evidentiary or public participation hearings or other steps. At the conclusion of this, and considering the outcome of the CEQA

[13] Pub. Res. Code Section 21065(c). *See also* D.85951.

review process, this Commission will render a decision on the public convenience and necessity of the proposed project as well as on any mitigations or alterations to the project identified as part of the CEQA review.

The Staff Proposal language otherwise aligns with the goals and objectives for this GO as discussed herein and is adopted with minor clarifications as set out in Appendix A.

7. Adopting a Monetary Trigger for a CPCN Application Requirement

7.1. Staff Proposal

Section IV(A) of the Staff Proposal proposed a $100 million threshold to require gas utilities to file a PTC application for all gas infrastructure other than new gas storage facilities. The Staff Proposal distinguishes between projects for which a PTC application would be required and those for which a CPCN is required. In Section IV(B), Staff recommended that the Commission require a CPCN application for "any entity seeking to operate a new gas storage field or to expand Commission-authorized footprint for an existing gas storage field."[14]

7.2. Party Comments

7.2.1. Monetary Trigger

PG&E, SoCalGas and SDG&E (collectively, investor-owned utilities or IOUs) and intervenors differ on the question of an appropriate monetary threshold to trigger PTC application requirements. The IOUs generally support a triggering threshold of $100 million while intervenors generally support lower thresholds of $50 million (EDF, CforAT) or $25 million (UCAN). Sierra Club/CEJA/RMI oppose any monetary threshold for PTCs but support a $50 million threshold for CPCN applications. Sierra Club argues the threshold for

[14] Staff Proposal, Section IV(B).

CPCNs should be $50 million to capture projects like expansion of compressor station capacity.

The IOUs argue that the $100 million threshold represents a balance between costs to customers and the costs of potential delays in projects versus the benefits of pre-construction review. The $100 million threshold would maintain a focus on the larger projects most likely to have significant environmental impacts, they argue. SDG&E supports a $100 million threshold and recommends this be annually automatically adjusted to address inflation, using a construction cost index (HIS/Markit Global Insight Utility Cost Information Service). In reply comments, SoCalGas supports a $50 million triggering threshold.

Cal Advocates argues there is insufficient evidence to support a $100 million threshold and the Commission should not exempt from review projects with potentially significant environmental impacts.
Sierra Club/CEJA/RMI concur, noting that the Commission has not adopted a monetary threshold to trigger application requirements for electrical or telecommunications projects. Cal Advocates argues that the Commission should review the environmental analyses undertaken by the IOUs for the 24 projects identified in their July 18, 2022 filings prior to making a decision on an appropriate monetary threshold.

Sierra Club/CEJA/RMI argue that precedent requires environmental review for any project that is discretionary and does not qualify for a CEQA exemption. These parties contend that monetary thresholds cannot be used to determine whether a project requires a PTC, because CEQA doesn't recognize monetary thresholds for determining whether a project has significant environmental impacts or not. Adopting a monetary threshold would violate

CEQA, they contend, as enabling legislation does not state that this is a legitimate basis to determine the applicability of CEQA. SoCalGas opposes these arguments, asserting that the Commission is not constrained by CEQA in exercising its authority to determine which projects require a permit. They argue that a monetary threshold that determines when a discretionary permit is required does not, in and of itself, violate CEQA, which still applies in full once an application has been filed.

UCAN proposes the Commission adopt a $25 million triggering threshold, stating that this would avoid including routine maintenance but would capture projects that could negatively impact communities.

Regarding determination of a project's actual costs for purposes of implementing a monetary trigger, SoCalGas states that project estimates should be based on "direct costs." SDG&E states that the $100 million level should be based on an IOU's prudent estimate of a project's cost before the utility proceeds with the project. SDG&E further contends that the Commission should evaluate utility compliance with the threshold based on a utility's reasonable, good-faith estimate before post-planning work begins.

In comments on the proposed decision, PG&E states that it understands "direct costs" to mean the "all-in cost of a project, including capital costs and indirect costs, such as allowance funds used during construction."[15] In reply comments on the proposed decision, PG&E recommends defining "direct costs" commensurate with Pub. Util. Code Section 1005.5(a) to use "an estimate of the anticipated construction cost, taking into consideration the design of the project,

[15] PG&E Comments on Proposed Decision at 2.

the expected duration of construction, an estimate of the effects of economic inflation, and any known engineering difficulties associated with the project."[16]

In comments on the proposed decision, SDG&E states that industry practice is to consider project costs in terms of either direct costs or fully loaded costs. SDG&E further states that "fully loaded costs are the sum of direct costs and indirect costs. Direct costs are costs for labor, material, services and other expenses incurred to design, engineer, plan, permit, execute and document a project. This includes the development costs, project management, material, construction, inspection, environmental and other project execution activities. Indirect costs are for Administrative & General, purchasing, warehousing, pension and benefits, payroll tax and other costs that are overhead in nature. Allowance for Funds Used During Construction (AFUDC) and property taxes are also costs that may be included in the presentation of fully loaded project costs."[17] SDG&E recommends that the Commission require gas utilities to "include direct costs and other capitalized expenditures, i.e. escalation, allowed overheads, allowance for funds used during construction and capitalized property tax" as the basis of determining costs for purposes of the GO.[18] Indicated Shippers also comments on cost issues in its comments on the proposed decision.

In comments on the proposed decision, PG&E, SoCalGas, and SDG&E object to the inclusion of an estimate of "utility proceeds" in the project cost for purposes of the monetary threshold. The Sempra companies observe that this idea was based on a misreading of SDG&E's comments. PG&E observes that

---

[16] PG&E Reply Comments on Proposed Decision at 1.

[17] SDG&E Comments on Proposed Decision at 4, footnote 15.

[18] *Id*. at iii.

including utility proceeds, defined in the proposed decision as an estimate of the guaranteed cost of capital investment benefit to a utility from a project, would alter the calculus of a project's cost and would bring additional projects under the monetary threshold. PG&E observes that the list of projects filed by the utilities on July 18, 2022 did not include utility proceeds. PG&E comments that a more appropriate location for inclusion of this information would be in the CPCN application itself.[19]

EDF recommends requiring utilities to use the high end of the cost range of a cost estimate or opinion of probable construction costs to determine whether a project meets the dollar threshold. PG&E responds that the GO should not direct a cost estimation method, as the IOUs meet industry standards, which are rigorous and proven to be accurate in their estimation methods. PG&E states that it uses the Association for the Advancement of Cost Engineering cost estimating methodology for "Class 2" estimates. In comments on the proposed decision, the IOUs state that the utility should be afforded the discretion to use a cost estimation method commensurate with the circumstances and stage of development of the proposed project.

In comments on the proposed decision, CforAT recommends the Commission review the monetary threshold in three years to assess the need for changes.

7.2.2. PTC vs. CPCN Application Requirement

Several parties, including SoCalGas, SDG&E, SCGC, and Cal Advocates, comment that the Commission should merge the separate categories of "PTC" and "CPCN" into a single unified category. SoCalGas observes that the

---

[19] PG&E Comments on Proposed Decision at 5.

requirements for the two categories are effectively the same in the Staff Proposal. This is because the Staff Proposal would require applications for both categories to explain why a project is necessary to promote the safety, health, comfort, and convenience of the public, and is required by the public convenience and necessity.[20]

Sierra Club/CEJA/RMI recommend maintaining the two categories and adopting differing qualifying thresholds for each—a $50 million threshold for CPCN applications and no threshold for PTC applications. Cal Advocates and SCGC express concerns that, as worded, the Staff Proposal is not clear whether the provisions of Pub. Util. Code Section 1005.5 apply to PTC applications.

7.3. Adopting a $75 million Threshold for Gas Infrastructure CPCN Applications

We adopt a monetary threshold of $75 million for gas infrastructure projects requiring a CPCN application and do not adopt Staff's recommendation for a separate PTC application requirement. A $75 million threshold for a CPCN application ensures focus on the largest projects with the greatest potential to create stranded assets and environmental impacts. As observed by several parties, we find the requirements for the CPCN and PTC categories proposed by Staff to be very similar, with no useful purpose served by maintaining them as separate. Close review of need, project alternatives, and ways to eliminate or mitigate environmental impacts will be helpful for all projects meeting our adopted monetary threshold.

---

[20] For PTC applications, this requirement is contained in Section IV(A)(1) of the Staff Proposal. For CPCN applications, this requirement is contained in Section IV(B) of the proposal. For both PTC and CPCN applications, the Staff Proposal would require a statement of the "reasons why and facts showing that the completion and operation of the proposed facility is necessary to promote the safety, health, comfort, and convenience of the public," in Section VI, "Information Required for PTC or CPCN Applications."

Review of gas infrastructure projects submitted by the gas corporations, other than Pipeline Safety and Enhancement Projects (PSEP) and Transmission Integrity Management Program projects (TIMP), which we exempt from CPCN application requirements as discussed below, leads to the conclusion that three gas infrastructure projects in the last ten years exceeded a $100 million cost threshold, five exceeded a $75 million cost threshold, and nine exceeded a $50 million cost threshold.[21] All SDG&E gas infrastructure projects over the last decade, which were all PSEP projects, fell within the $50 to $75 million cost range. Every project for which a CPCN application is required results in direct costs to ratepayers, including costs to prepare environmental reports, indirect costs, and other costs such as those arising from potential delays from the need to review projects. However, it is necessary to scrutinize large projects to ensure that they create net benefits for customers and local communities and avoid creating stranded assets. A $75 million threshold reasonably balances these costs, risks, and benefits to ratepayers and local residents.

We disagree with parties that propose a $50 million threshold (EDF, CforAT) or a $25 million threshold (UCAN) for the reasons indicated above: each CPCN application process entails costs as well as benefits and we elect to focus our Commission resources on the largest, most costly and potentially environmentally significant projects.

[21] Note that, although not stated in the submittal, PG&E's project numbers (4) and (6) are PSEP projects. *See* PG&E, PSEP Final Compliance Report, March 6, 2019, at Table 22-2, available as of October 21, 2022 at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=294992975. *See also* PG&E Response to the ALJ Ruling Directing Filing of Data and Extending the Filing Date for Comments, July 18, 2022.

We disagree with Sierra Club/CEJA and Cal Advocates that we have insufficient evidence to adopt a monetary threshold for an application requirement. Pursuant to Pub. Res. Code Section Code 21080(a), CEQA applies to discretionary projects approved by this Commission. Our adopted monetary threshold reflects a reasonable inference of the gas infrastructure projects that should receive additional scrutiny by the Commission – for both policy and environmental protection reasons. The Commission is creating a new discretionary review process for a class of projects where this level of scrutiny was previously not required. Correspondingly, CEQA creates no obligation for this Commission to require CPCN or PTC applications for gas infrastructure projects that do not meet the thresholds adopted here.

We decline to review utility environmental information regarding the project lists submitted on June 18, 2022 by the gas utilities, as recommended by Cal Advocates. This information is not currently part of the record of this proceeding. However, we may consider this information in the future as part of the long-term gas planning process that is scoped to occur later in this proceeding.

We do not use the physical properties of infrastructure projects that merit additional review because the monetary threshold concept aligns with a similar approach in Pub. Util. Code Section 1005.5 and is relevant for our consideration of potential stranded assets. We also do not adopt a $50 million monetary threshold as is included in Pub. Util. Code Section 1005.5 because legislation establishing that statute was adopted in 1985 and inflation since then results in an equivalent value in 2022 real dollars of approximately $130 million. Thus, a $75 million dollar threshold strikes an appropriate balance. It does not require the Commission to expend scarce resources to scrutinize routine repair, maintenance, replacement and minor projects that are necessary to ensure the safety and reliability of the gas system.

We direct the gas utilities to use cost estimation methods based on proven and rigorous industry standards. Utilities shall use "fully loaded" cost estimates that include both direct and indirect costs and shall take into consideration the design of the project, the expected duration of construction, an estimate of the effects of economic inflation, and any known engineering difficulties associated with the project.[22] We do not require the utilities to use a particular method as proposed by some parties. However, the utilities shall use a cost estimation method consistent with Association for the Advancement of Cost Engineering methodologies and appropriate to the project's stage of development and anticipated technical construction or scope change risk. This approach is reasonable and practicable.

We do not require utilities to include an estimate of "utility proceeds," defined in the proposed decision as the guaranteed cost of capital investment benefit, within its estimate of direct and indirect costs. The proposed decision's inclusion of this requirement was based on a misreading of SDG&E's comments and does not reflect our considerations regarding the appropriate monetary threshold level for a CPCN application requirement. However, we modify Section VI(A)(6) of our adopted GO to require utilities to include an estimate of the guaranteed cost of capital investment benefit to the utility in their CPCN

[22] Direct costs are costs for labor, material, services and other expenses incurred to design, engineer, plan, permit, execute and document a project. This includes the development costs, project management, material, construction, inspection, environmental and other project execution activities. Indirect costs are for Administrative & General, purchasing, warehousing, pension and benefits, payroll tax and other costs that are overhead in nature, as well as AFUDC and property taxes.

applications. We agree with PG&E that this information may be useful to consider as part of the application review process, rather than as part of the determination of a project's monetary cost for purposes of triggering a CPCN application.

We decline to annually automatically adjust our adopted monetary trigger level to address inflation, as suggested by SDG&E. Our threshold level is reasonable and clear. However, we may from time to time, in a Commission decision, reconsider this level and adjust it in the future.

We clarify that all projects meeting our adopted criteria and submitting a CPCN application will be required to comply with Pub. Util. Code Section 1001 *et seq.* Requiring this aligns this GO with Pub. Util. Code Section 1001 et seq. and ensures attention to the accuracy and reasonableness of the cost estimates provided in applications.

Specifically, when approving projects subject to this GO, we will specify the maximum cost determined to be reasonable and prudent for the facility pursuant to Pub. Util. Code Section 1005.5. Section 15.3 below outlines the cost information we require in CPCN applications to support determination of a maximum project cost pursuant to Pub. Util. Code Section 1005.5.

Additionally, we authorize Commission Staff, in approximately three years, or when feasible, to prepare a short review of implementation of this GO using the $75 million monetary trigger and to recommend revisions as warranted.

8. Sensitive Receptors Trigger Requirements

8.1. Staff Proposal

The Staff Proposal contains the following environmental trigger requirement for an application requirement:

> project is located within 1,000 feet of a sensitive receptor, and operation of the relevant plant, line or extension is likely to result in an increase in criteria air pollutants in a severe or extreme non-attainment area.[23]

Related to this, the June 27, 2022 ALJ Ruling asked parties to respond to the following questions:

- Should significant localized environmental impacts from a proposed gas infrastructure project beyond exposure to criteria air pollutants trigger review under the GO as specified in Section IV(A)(1)? If so, what types of environmental impacts should be considered?
- Should other types of parameters (*e.g.*, project size) be included in addition to, or instead of, the triggers specified in Section IV(A)(1)?

8.2. Party Comments

IOUs generally oppose Staff's proposed sensitive receptors trigger for an application requirement as being vague, and thus difficult to implement. The IOUs also allege that the requirement as worded is too broad. The IOUs recommend the Commission not adopt this criterion or revise it substantially if adopted.

Sierra Club/CEJQ/RMI argue that Staff's proposal in this area should be broadened, not further targeted. They state that the sensitive receptors trigger should apply to toxic air contaminants in addition to criteria air pollutants and the trigger should apply to all types of non-attainment areas including "serious" non-attainment areas, not just severe or extreme non-attainment areas.

Sierra Club/CEJA/RMI propose the Commission restructure this provision so that it serves as an exception to the exemptions included in the GO in Section IV(A)(4) rather than serving as a threshold to determine if a PTC

[23] Staff Proposal, Section IV(A)(1).

application is required. Sierra Club/CEJA/RMI propose that the Commission require an application for all gas infrastructure projects one mile or greater in length.[24]

Sierra Club/CEJA/RMI propose that the Commission reconceptualize this proposed trigger for areas experiencing legacy pollution impacts. These parties assert that in areas experiencing legacy pollution impacts, the Commission should use gas infrastructure applications as opportunities to examine pathways to more meaningful reductions of criteria air pollutant or toxic air contaminant emissions, rather than simply limiting levels of additional emissions.

SoCalGas opposes Sierra Club/CEJA/RMI's proposals. SoCalGas states that reworking this requirement to somehow trigger investigation of more meaningful criteria air pollutant or toxic air contaminant emission reductions could deter safety improvements.

SoCalGas opposes Sierra Club/CEJA/RMI's proposal that the requirement include "serious" non-attainment areas. SoCalGas states that nearly all of its gas infrastructure is located 1,000 feet from sensitive receptors and, if this trigger is adopted, it should be revised to only target more substantial projects.

CforAT recommends the GO require measurement of ambient noise prior to constructing gas infrastructure projects and a forecast of how much construction will increase ambient noise. CforAT contends the Commission should require an application for major infrastructure projects anticipated to have a substantial localized noise, traffic, vibrations, fugitive dust, or other air pollution effects on a neighborhood for more than three-months.

[24] Sierra Club/CEJA/RMI Comments on Staff Proposal at A-3.

IOUs oppose CforAT's suggestions. PG&E and SDG&E state that determining if significant impacts were occurring would require gas utilities to perform an environmental assessment for each project prior to submitting an application, subverting the appropriate sequence of assessment of impacts. PG&E states that local air quality permitting, traffic control and local encroachment permit requirements already address the issues identified by CforAT. SoCalGas states the majority of larger gas infrastructure projects require a discretionary permit. SoCalGas states that in the rare circumstance when a discretionary permit is not required from another agency, the utilities must obtain ministerial permits, which affords local agencies the opportunity to review the project for localized impacts, such as for dust control, drainage, and traffic management.

In comments on the proposed decision, PG&E recommends rewording the environmental criterion to require all qualifying projects to be located in a serious, severe or extreme non-attainment area. In comments on the proposed decision, SoCalGas states that toxic air contaminant emissions may sometimes increase when criteria air pollutant emission reduction technologies are installed. SoCalGas also states that local air districts sometimes have rules that establish "allowable risks" for equipment emitting toxic air contaminants.[25] SoCalGas recommends the Commission establish a procedure involving the Commission Executive Director to exempt projects resulting in only a "de minimis" levels of pollutant emissions from a CPCN application requirement. In comments on the proposed decision, Sierra Club/NRDC/CEJA recommend that the Commission delink toxic air contaminants from any requirement to be located in a serious,

[25] SoCalGas Comments on Proposed Decision at 8.

severe, or extreme non-attainment area, stating that these pertain to criteria air pollutants only. Sierra Club/NRDC/CEJS state that some toxic air contaminants may have no safe exposure levels.

In comments on the proposed decision, PG&E and SoCalGas express concerns that the environmental criterion should not trigger a CPCN application if a gas corporation installs or deploys an emergency backup generator at a compressor station particularly when the utility is replacing an older backup generator that was installed without a permit from a local air quality district with a cleaner one that now requires an air permit. In comments on the proposed decision, Southwest Gas suggests the Commission clarify that the entity obtaining the permit be clearly identified as the gas corporation operating the completed project, not a downstream industrial customer.

8.3. Adopting a "Sensitive Receptors" Trigger

We adopt a second trigger for when a CPCN application is required, namely, when "(1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant;[26] or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant."

This criterion will trigger a CPCN application requirement and public review for gas infrastructure projects projected to increase local criteria air pollution or toxic air contaminant emissions such that the gas corporation is required to acquire a permit from a local air quality district agency. Such

[26] Increase in levels of a toxic air contaminant is defined as an increase exceeding (1) de minimis levels or (2), where relevant, allowable limits set by the local air quality district.

projects should be closely scrutinized to identify potential alternatives, including non-pipeline alternatives. This additional scrutiny is necessary regardless of cost, where the potential gas infrastructure project would be located or what type of infrastructure project it is. Additionally, in Section 15.3 below, we adopt requirements that will trigger additional scrutiny of projects proposed to be located in disadvantaged or ESJ communities.

The approach we adopt contains a clear threshold, which will assist us with implementation and ensuring compliance with the GO. As such, the requirement will advance the aims of this GO. Parties did not identify an alternative practicable method to implement this criterion.

We include "toxic air contaminants" in this criterion, as air quality or air pollution permits are also often required for this class of pollutants. We define toxic air contaminants as "an air pollutant which may cause or contribute to an increase in mortality or an increase in serious illness, or which may pose a present or potential hazard to human health, pursuant to Section 39655 of the California Health and Safety Code," as suggested by Sierra Club/CEJA/RMI. The California Air Resources Board (CARB) has extensively reviewed toxic air contaminants as required by state and federal law and documented that they cause significant health impacts to humans at a variety of exposure thresholds. In such cases, alternatives to the proposed infrastructure and emission mitigation options must be carefully examined.

In response to comments on the proposed decision, we clarify the environmental criterion to delink toxic air contaminant emissions from non-attainment areas, which, as parties observe, apply to criteria air pollutants only. We also define "increase in toxic air contaminants" as "an increase exceeding (1) de minimis levels or (2), where relevant, allowable limits set by the local air quality district." These modifications retain the focus of this criterion on projects with the greatest potential for significant environmental impacts, wherever located, while reducing the likelihood that the criterion will result in a large number of CPCN applications for projects with only "de minimis" toxic air pollutant emission levels. Gas corporations must use discretion when claiming a project is exempt from the environmental criterion for this reason.

We include "serious" non-attainment areas in the definition of this criterion because we seek to ensure environmental protections to the most historically burdened communities that may be impacted by gas infrastructure. Areas designated as in a "serious non-attainment area" for a particular pollutant are likely to disproportionally implicate ESJ communities as defined in our ESJ Action Plan. Including "serious non-attainment areas" in this criterion provides a clear threshold and is reasonable.

We clarify in the definition of "project" included in our adopted GO that the replacement of an emergency diesel backup generator with a lower-emission emergency backup generator is not considered a "project" for purposes of GO 177 and does not trigger a CPCN application requirement. We agree with PG&E and SoCalGas that we do not intend to require a CPCN application for such projects as they do not represent the projects with the greatest potential environmental impacts or ratepayer costs.

We reject Sierra Club/CEJA/RMI's proposal to require an application for all gas infrastructure projects one mile or greater in length. This approach is impracticable to implement, and the record of this proceeding does not support such a broad requirement. We also reject SoCalGas's assertion that our adopted criterion impacts thousands of projects located within 1,000 feet of sensitive receptors, because our adopted criterion only addresses projects that additionally would result in an increase in permitted air pollutants during operation of the gas pipeline or facility.

We reject CforAT's suggestion for an additional assessment of ambient noise or to require an application for major infrastructure projects anticipated to have a substantial localized noise, traffic, vibrations, or fugitive dust on a neighborhood beyond those addressed by the sensitive receptors criterion adopted here or otherwise addressed in the course of the Proponent's Environmental Assessment (PEA) that will be filed concurrent with a CPCN application. We concur with PG&E and SoCalGas that the appropriate locus of review of such potential impacts is with local agencies.

Regarding local jurisdictions, we note that our adopted GO, Section VI, Complaints and Preemption of Local Authority, addresses distinctions between local and state jurisdiction on gas corporation infrastructure. This Commission retains exclusive authority to regulate gas corporations pursuant to Article XI, Section 8 of the California Constitution, which states that, "[a] city, county, or other public body may not regulate matters over which the Legislature grants regulatory power to the Commission." Section VII(B) of the GO restates this principle but also states that, in locating gas infrastructure projects:

> the public utilities shall consult with local agencies regarding land use matters. In instances where the public utilities and local agencies are unable to resolve their differences, the local agency should promptly file a complaint with the Commission.[27]

We emphasize Section VII(B) of the GO here, although no party commented on it. The Commission's complaint process is paramount should disputes arise in the course of such consultations and related CPCN applications.

---

[27] Staff Proposal at Section VII(B).

Pursuant to state law and statute, this Commission retains jurisdiction to respond to complaints from local agencies or others for ultimate resolution of any conflicts regarding gas corporation infrastructure. This Commission also retains jurisdiction over gas utility activities for which a CPCN application is not required.

Although we understand the concern, we decline to design this GO as a vehicle to reduce pollution in communities experiencing historical emissions burdens beyond what we can accomplish by closely reviewing every project subject to the adopted GO. The requirement of a CPCN application for projects that trigger an increase in permitted levels of a criteria air pollutant or a toxic air contaminant will result in significant scrutiny of such projects. The Commission's CPCN application requirement in such cases may result in a utility redesigning a project such that a CPCN application with this Commission is no longer triggered or relocating it. Both results should help avoid and decrease pollutant emissions in historically burdened communities. Beyond that, reducing pollution-burden in legacy communities through the targeted retirement of gas infrastructure is an element for consideration in our long-term gas planning efforts.

9. Other Potential Non-Monetary Triggers

9.1. Party Proposals

Several parties propose additional non-monetary triggers for an application requirement, including that an application should be required for:

a. Substantial projects located in an environmental and social justice community (ESJ community), as defined by the Commission's Environmental and Social Justice Action Plan, or in a disadvantaged community, as defined by SB 535 (De Leon, Stats. 2012, Chapter 830) (proposed by UCAN, EDF, CforAT);

b. Projects that may result in significant environmental impact as defined by CEQA (proposed by EDF);

c. Projects located in Location Classes #3 and #4 and/or Location Classes #1 and #2 that are also located in High Consequence Areas as defined in the PSEP program (proposed by EDF);

d. Projects entailing pipeline construction to increase the backbone system design capacity by more than 150 million cubic feet per day (proposed by SoCalGas);

e. Projects entailing construction adding an incremental increase of 4,000 compressor horsepower or greater at a compressor station or storage field (proposed by SoCalGas);

f. Projects that significantly expand backbone or compressor capacity (proposed by SDG&E); or,

g. Projects driving expansion or addition of capacity at the transmission and backbone level (proposed by EDF).

9.2. Declining to Adopt Additional Non-Monetary CPCN Application Triggers

We decline to adopt the additional non-monetary application triggers proposed by parties. Our adopted triggers as discussed above are practicable and will encompass the most potentially environmentally significant projects for which project alternatives should be most closely scrutinized.

We reject the proposal by UCAN, EDF, and CforAT to require applications for all projects located in ESJ or disadvantaged communities. We concur with the large IOUs that doing so could cause additional delays for projects located in such communities which may otherwise be benign. This has the potential to harm such communities by delaying implementation of necessary safety or reliability improvements. Instead, our sensitive receptors trigger, adopted above, will capture the most potentially impactful projects in communities most heavily impacted by poor air quality. Additionally, in Section 15.3 below we require additional scrutiny in a gas corporation's CPCN application of projects proposed to be located in ESJ or disadvantaged communities.

We decline to adopt EDF's proposal to adopt the criterion "project may result in a significant environmental impact as defined by CEQA" because this is not a clear threshold and determining whether the threshold was triggered would require an a priori assessment of environmental impacts of the nature intended to be conducted following a CPCN application, if it is determined that a full CEQA review is necessary. We also decline to adopt EDF's proposal regarding High Consequence Areas, as these areas were defined for a different purpose.[28]

We decline to adopt proposals (d) – (g) above proposed by SoCalGas, SDG&E, and EDF, as these specific types of infrastructure projects are likely to be captured in the $75 million monetary threshold adopted above. Adopting a monetary threshold is preferable to adopting thresholds based on specific project types as the monetary threshold will capture a greater number and type of high-cost projects of potential environmental concern that should be closely examined for alternatives and need.

10. Defining "Project" for Purpose of the GO

10.1. Staff Proposal

The Staff Proposal does not explicitly define a "project" for purposes of the GO. Instead, Staff align their proposed criteria for an application requirement with statutory language defining Commission jurisdiction over gas corporations.

[28] *See* PHMSA regulations establishing the pressure at which transmission pipelines can operate and regarding preventative maintenance requirements, at 49 CFR 192.5, 195.452 and 192.903.

The concept of "projects" in the Staff Proposal refers to activities involving the "construction or modification… of any plant, line or extension."[29, 30]

10.2. Party Comments

A number of parties recommend the Commission define "project" for purposes of the GO. EDF recommends the Commission adopt the definition of project included in CEQA Guidelines Section 15378, a definition which revolves around the concept of the "whole of an action." EDF posits this would help ensure that projects exceeding the adopted monetary threshold over a longer time period will be captured.[31] EDF further recommends the Commission direct gas corporations to consolidate "related projects" to ensure that multi-year projects are not allowed to circumvent the requirements of the GO. UCAN expresses similar concerns regarding "piecemealing."

SDG&E and SoCalGas oppose these recommendations. SDG&E contends the "whole of the action" concept is a "CEQA term of art," and the IOUs should not use this definition to determine applicability and requirements under the GO. If the Commission wishes to adopt a definition of "project," SDG&E suggests that it be defined as "a temporary endeavor with a defined scope that

---

[29] Staff Proposal at IV(A)(1).

[30] As defined in Pub. Util. Code Section 221, "gas plant" includes all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas…" Pub. Util. Code Section 222 defines "gas corporation" as every corporation or person owning, controlling, operating, or managing any gas plant for compensation within this state, except where gas is made or produced on and distributed by the maker or producer through private property alone solely for his own use or the use of his tenants and not for sale to others.

[31] EDF Comments on Staff Proposal at 5. Projects mentioned by EDF include: "the SoCalGas Ventura Compressor Modernization Project with an expected project cost of $209.5 million from 2022 to 2028; the SoCalGas Line 235 Repair and Replacement Project with an expected project cost ranging from $378.4 million (repair option) to $549.2 million (replacement option); and the SDG&E 49-1 Replacement Project with a capital cost of $64.3 million."

has independent utility in the gas system, has a start and completion date, and does not include routine maintenance."[32] SDG&E argues this definition would guard against UCAN's concern by defining a project as something that is "stand-alone," or "independent."[33] In comments on the proposed decision, SoCalGas observes that the definition of "gas plant" contained in Pub. Util. Code Section 221 includes office buildings.[34]

Southwest proposes that the Commission define project types covered by the GO to include only construction or physical modification of a: (1) liquified natural gas plant or storage facility; (2) compressor station; (3) gas storage facility; or (4) transmission line.

Cal Advocates recommends the GO explicitly identify hydrogen gas infrastructure projects as covered in the GO. SoCalGas opposes this, instead recommending that the Commission require an expedited permit review process for "clean fuel activities" such as hydrogen gas infrastructure to reflect the importance of these fuels to California's carbon-neutrality goals.

10.3. Adopting a Definition of "Project" for Purposes of the GO

We define "project" for purposes of this GO as the "construction or physical modification of any gas plant with independent utility in the gas system, including compressor or regulator stations, any pipeline or pipeline extension, or any expansion of an existing gas storage field." Defining a project in this way will help clearly demarcate individual projects within the broad range of utility infrastructure activities. Additionally, adopting this definition

---

[32] SDG&E Comments on Staff Proposal at 14.

[33] *Id.* at 18.

[34] *See* footnote summarizing Pub. Util. Code Sections 221 and 222 above.

will help ensure that infrastructure projects for which revenue recovery is requested sequentially over time will be considered as a single project and subjected to a single CPCN application requirement. Gas corporations must not skirt our CPCN application requirement by proposing various phases of a single project over time, each phase of which may cost less than our $75 million threshold.

For purposes of this GO, "gas plant" excludes gas corporation office buildings. This is a reasonable clarification to avoid unintended outcomes related to the installation of heating or cooling equipment at gas corporations' office buildings. The installation at a gas corporation office building of equipment such as a boiler or electric generator that requires a permit from an air quality management district does not trigger the requirement for the gas utility to obtain a CPCN. We add this exclusion to those listed in the footnote to the definition of a "project" of the GO in Appendix A.

We do not adopt CEQA language defining a "project," including with the phrase "whole of the action," as this is not necessary here. The CEQA review that accompanies the CPCN application will adhere to CEQA requirements, but a simple definition of project is sufficient for purposes of the application requirement under this GO. We do not adopt either SDG&E or UCAN's proposed definitions as they lacked clarity or were inappropriate for our purposes here.

We do not limit the types of activities that may qualify as a "project" under this definition to those identified by Southwest. This is because, as discussed in Section 12.6.3 below, we include all sizes of pipelines within the scope of the GO, with the exception of service pipelines connecting to customer facilities and work on customer meters.[35] As discussed with regard to our adopted sensitive receptors trigger threshold, it is appropriate for this Commission to require a CPCN application for any type of project that meets this criterion, regardless of size or cost, subject to the GO exemptions outlined here. Southwest does not provide any rationale to explain why an infrastructure project falling outside certain categories (*i.e.* (1) liquified natural gas plant or storage facility; (2) compressor station; (3) gas storage facility; or (4) transmission line) should not receive scrutiny under this GO if it meets the monetary or environmental triggers we adopt here.

We decline to specifically identify hydrogen gas infrastructure projects as covered by the GO at this time.

11. Emergency Projects

11.1. Staff Proposal

The preamble to Section IV of the Staff Proposal identifies certain work that would not be covered by the proposed GO, including emergency projects as defined by CEQA Guidelines Section 15269 and Pub. Res. Code Section 21060.3.[36] Staff propose, however, that gas utilities invoking an exemption for emergency projects shall nonetheless comply with the notification requirements set forth in Section V(C) ("Notification Requirements for Claimed Exemptions").[37]

---

[35] We use the term "service pipeline connecting to customer facilities" synonymously with the terms "service lateral," or "service pipe" as used in the gas utility's Gas Tariff Rule No. 16.

[36] The Staff Proposal additionally identifies projects excluded from the GO as those involving the installation of environmental monitoring equipment, or any soil or geological investigation, or work to determine feasibility of the use of a particular site for the proposed facilities that does not result in a serious or major disturbance to an environmental resource.

[37] Staff Proposal at Section IV.

11.2. Party Comments

SDG&E supports excluding emergency projects from the GO. SDG&E recommends that the Commission not require compliance with Section V(C) notification requirements for excluded emergency projects. SDG&E observes that the Staff Proposal would require notifications of emergency projects even if the emergency project would not otherwise trigger an application requirement, making the noticing requirement for emergency projects broader than for any other category of exempted projects. SDG&E argues that giving notice of such projects serves no useful purpose and adds burden to both the noticing utility and the receiving entities. SDG&E requests the Commission clarify, at minimum, that the required notice may be given after implementation of the emergency project has begun.

PG&E concurs with SDG&E on this point, observing that GO 131-D requires neither an application nor a notice for emergency projects. UCAN disagrees and recommends the Commission require notifications regarding temporary emergency repair projects.

In comments on the proposed decision, EDF requests that the filing deadline for notifications of claimed emergency exemptions be reduced from 90 to 60 days, stating that this better balances utilities' ability to carry out emergency projects and the opportunity for stakeholders to provide meaningful input. In comments on the proposed decision, Sierra Club/CEJA/NRDC indicate concerns that the definition of "emergency project" may be too broad.

11.3. Exempting Rather Than Excluding Emergency Projects

We add emergency projects as an exempted project type into Section IV(B)(c), defined as follows:

> emergency projects (for example: repairs, upgrades, replacements, restorations) as defined by CEQA Guideline § 15269 and Pub. Res. Code §§ 21060.3 and 21080(b)(2) & (4) to ensure reliable gas supplies.

We continue to require exemption notices for emergency projects, so defined, that also meet our adopted thresholds for a CPCN application requirement. However, we will not require gas corporations to submit notices of claimed exemptions for emergency projects until 60 days after the emergency project has commenced construction. We find this achieves a reasonable balance that allows gas corporations to begin work on urgent emergency projects as necessary, but that also provides an opportunity for affected community members, local governments, stakeholders and this Commission to learn about the project. A noticing requirement prior to commencement of construction of emergency projects is inappropriate because the focus at that time should be on addressing the emergency situation in an expedited fashion.

Based on comments on the proposed decision, we do not expand the definition of projects covered by this exemption from Staff's proposed language to include "emergency repairs or upgrades to ensure reliable gas supplies." Instead, the final decision clarifies the emergency situations where this exemption may be claimed. This retains the intent of the GO to not impede rapid implementation of repairs or improvements to address emergency situations, including when the ability of the utility's gas system to meet its backbone, peak day, and cold day design standards is threatened, while also minimizing potentially inappropriate exemption claims.

12. Exemptions

In Section IV(A)(3) of the Staff Proposal, Staff propose seven exemptions to the general application criteria included in Section IV(A)(1) of the GO. Staff propose that projects that meet the two threshold criteria for a CPCN application requirement that also meet the defined exemption criteria would not be required to file a CPCN application. However, Staff propose that such projects would be required to comply with notification requirements for claimed exemptions. Below are Staff's proposed exemption criteria:

a. replacement of existing facilities or structures with equivalent facilities or structures in a manner consistent with CEQA Guidelines §§ 15300.4 and 15302(c); or

b. minor relocation, repairs, maintenance or alterations of existing facilities in a manner consistent with CEQA Guidelines §§ 15300.4 and 15301(b); or

c. the placing of new equipment on or replacement of supporting structures already built consistent with CEQA Guidelines §§ 15300.4, 15301(b), and 15302(c); or

d. facilities to be relocated, modified or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA certified document (Environmental Impact Report (EIR) or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation; or

e. any plant, line or extension that is required by the California Geologic Energy Management Division (CalGEM) or the Pipeline and Hazardous Materials Safety Administration (PHMSA) for safety or reliability reasons; or

f. construction, replacement or repair of distribution pipelines that are 12 inches in diameter or less; or

g. projects previously approved in a General Rate Case or other Commission decision which are currently underway.

We adopt a modified version of the Staff Proposal for two of Staff's proposed exemptions, exemptions (e) and (g). We do not adopt Staff's proposal to exempt all pipelines 12 inches or less in diameter from a CPCN application requirement. Instead, any pipeline project, other than on service pipelines connecting to customer facilities and work on customer meters, that meets the threshold criteria adopted in Sections 7.3 and 8.3 above (Section IV(A) of the GO), will be required to file a CPCN application pursuant to the GO, unless one of our adopted exemptions apply.

We do not adopt Staff's proposed exemptions (a), (b), or (c), as we find these unnecessary given the other requirements adopted here. We do not adopt Staff's proposed exemption (d) because we do not find it reasonable.

We adopt Staff's proposal that gas corporations must submit notices of claimed exemptions for all exempted projects.

12.1. Replacement of Existing Structures by Equivalent Structures

12.1.1. Staff Proposal

The Staff Proposal at Section IV(A)(3)(a) would exempt from an application requirement "replacement of existing facilities or structures with equivalent facilities or structures in a manner consistent with CEQA Guidelines §§ 15300.4 and 15302(c)."[38]

12.1.2. Party Comments

SDG&E suggests this exemption use the same "replacement or reconstruction" language found in CEQA Guideline § 15302. SDG&E requests that the Commission clarify that the location of a replacement pipeline or other structure may be adjusted to enhance safety, ease construction or reduce costs. SDG&E contends that replacing gas system facilities in a somewhat different location often makes sense for safety, construction, cost or development reasons, and argues that concern about potential environmental impacts should be

[38] Staff Proposal at Section IV(A)(3)(a).

mitigated if the new location is located in franchise (usually roads) or existing utility easements.

Sierra Club/CEJA/RMI oppose SDG&E's recommendations stating that SDG&E fails to provide any evidence that pipeline relocation projects will not have a significant environmental effect.

12.1.3. Rejecting Staff's Proposed Exemption IV(3)(a), Replacement of Existing Structures by Equivalent Structures

We decline to adopt Staff's proposed exemption IV(3)(a). We anticipate that projects entailing replacement of existing structures by equivalent structures are unlikely to meet the $75 million monetary trigger or the sensitive receptors trigger, which are pre-requisites for a CPCN application requirement. Further, this exemption duplicates a CEQA categorical exemption that will apply as part of the Commission's CEQA review of any CPCN application. Once a CPCN application is filed, Commission staff will consider whether any CEQA exemptions apply as part of the Commission's environmental review process.

Including this exemption in this GO would make it more complicated without a corresponding benefit. Eliminating this exemption will simplify and streamline implementation of this GO.

12.2. Minor Relocations, Repairs, Maintenance or Alterations

12.2.1. Staff Proposal

The Staff Proposal at Section IV(A)(3)(b) exempts from an application requirement "minor relocation, repairs, maintenance or alterations of existing facilities in a manner consistent with CEQA Guidelines §§ 15300.4 and 15301(b)."[39] CEQA Guideline § 15301 exempts from CEQA "the operation,

[39] Staff Proposal, Section IV(A)(3)(b).

repair, maintenance, … or minor alteration of existing public or private structures [or] facilities … involving negligible or no expansion of existing or former use," including, under Section 15301(b), "[e]xisting facilities of both investor and publicly owned utilities used to provide electric power, natural gas, sewerage, or other public utility services."[40]

12.2.2. Party Comments

SDG&E supports Staff's proposal in this area and requests the Commission clarify that projects undertaken to comply with federal regulations are included in this exemption. SDG&E states that it is continuously undertaking thousands of such projects, and it is not helpful nor cost-efficient to require noticing of such projects under the GO.

SDG&E requests the Commission clarify that work undertaken to recondition an existing pipeline as defined in GO 112-F, Section 125.3(c) and work to install pressure regulation devices, automatic shut-off valves, block valves or similar devices on existing pipelines, or to retrofit existing pipelines to accommodate in-line inspection devices falls under this exemption, contending that such work is required to comply with Pub. Util. Code Section 957 and 958.5 and enhances the safety and reliability of the existing gas system.

12.2.3. Rejecting Staff's Proposed Exemption Section IV(3)(b), Minor Relocations, Repairs, Maintenance or Alterations

We decline to adopt Staff's proposal for exemption (b) regarding minor relocations, repairs, maintenance or alterations based on the same reasoning that we used to reject Staff's proposed exemption IV(3)(a), regarding replacement of existing structures by equivalent structures. Projects entailing minor relocations,

[40] SDG&E Comments on Staff Proposal at 9.

repairs, maintenance or alternations are unlikely to meet the $75 million monetary trigger or the sensitive receptors trigger, which are pre-requisites for a CPCN application requirement. Similar to Staff's proposed exemption IV(3)(a), this exemption duplicates a CEQA categorical exemption which will apply as part of the Commission's CEQA review of any CPCN application. Eliminating this exemption will simplify and streamline implementation of this GO.

12.3. Rejecting Staff's Proposed Exemption Section IV(3)(c)

No party commented on this element.

We decline to adopt Staff's proposal for exemption (c) regarding the placing of new equipment on or replacement of supporting structures already built consistent with CEQA Guidelines §§ 15300.4, 15301(b), and 15302(c)[41] based on the same reasoning that we used to reject Staff's proposed exemptions IV(3)(a) and IV(3)(b) above. Projects falling under this category are unlikely to meet the $75 million monetary trigger or the sensitive receptors trigger, which are pre-requisites for a CPCN application requirement. Similar to Staff's proposed exemptions IV(3)(a) and IV(3)(b), this exemption duplicates a CEQA categorical exemption which will apply as part of the Commission's CEQA review of any CPCN application. Eliminating this exemption will simplify and streamline implementation of this GO.

12.4. Projects with Completed CEQA Documents

12.4.1. Staff Proposal

The Staff Proposal Section IV(A)(3)(d) recommends the Commission exempt projects with completed final CEQA documents from application requirements, as follows:

> facilities to be relocated, modified or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA certified document (Environmental Impact Report (EIR) or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation.[42]

12.4.2. Party Comments

SDG&E, SoCalGas, and CVGS recommend the Commission exempt all gas infrastructure projects that have previously undergone CEQA review from application requirements, rather than identify a limited number of CEQA review outcomes where the exemption would apply.

Sierra Club opposes SDG&E's recommendation, stating that the Commission should instead analyze projects that have undergone prior CEQA review to see if CEQA supplemental review requirements apply.

12.4.3. Rejecting Staff's Proposed Exemption Section IV(3)(d), Projects with Completed CEQA Documents

We decline to adopt Staff's proposed exemption (d), projects with completed CEQA documents. Under CEQA, review by a lead agency does not relieve other agencies from their CEQA review obligations. Further, there may be circumstances under which another agency performs CEQA review of a proposed gas infrastructure facility as part of review of a larger project. It is not reasonable for a proposed project to be exempt from submitting an application to the Commission for review under this GO based on this criterion.

---

[42] Staff Proposal at IV(A)(3)(d).

12.5. Projects Required by CalGEM, PHMSA, or Other Regulatory Agency

12.5.1. Staff Proposal

The Staff Proposal at Section IV(A)(3)(e) recommends the Commission exempt from application requirements the following:

> any plant, line or extension that is required by the California Geologic Energy Management Division (CalGEM) or the Pipeline and Hazardous Materials Safety Administration (PHMSA) for safety or reliability reasons.[43]

12.5.2. Party Comments

The gas corporations support this exemption and recommend expanding it. SoCalGas contends the Commission should exempt from application requirements all activities required to ensure gas system safety and reliability required by any regulatory agency, not just by CalGEM or PHMSA. SoCalGas recommends this exemption apply to all regulatory compliance projects, including environmental compliance projects such as those required by air quality management districts and regional water quality control boards, not just safety regulatory compliance projects. SoCalGas states that requiring the utilities to seek approval from the Commission for mandatory compliance work being performed under the primary discretionary authority of another public agency with the greatest responsibility for approving the project is duplicative and risks causing undue delay.

SDG&E supports Staff's proposal and requests the Commission amend the exemption to include "modifications" and to apply to any work required by a regulatory agency with jurisdiction over gas infrastructure. SDG&E states this exemption should also apply to work undertaken to clear conflicts required by

[43] Staff's Proposed GO, Section IV(A)(3)(e).

franchise agreements when triggered by government road, water, or sewer projects and work pursuant to the requirements specified in GO 112-F.

Sierra Club/CEJA/RMI oppose exempting any safety or reliability work from application requirements, stating that there is no legal or evidentiary basis for this.

12.5.3. Adopting a Modified Version of Staff's Proposed Exemption Section IV(3)(e), Projects Required by CalGEM, PHMSA, or Other Regulatory Agency

We adopt Staff's proposed exemption (e) regarding projects required by CalGEM, PHMSA, or other regulatory agency with modifications to reflect IOU comments and to provide additional clarification, as follows:

> any plant, line, extension, <u>repair, replacement, or modification of existing facilities or structures</u> that is required <u>pursuant to a</u> California Geologic Energy Management Division (CalGEM) <u>Emergency Order or regulation,</u> the Pipeline and Hazardous Materials Safety Administration (PHMSA), <u>this Commission, or any other regulatory agency</u> for safety reasons.

We concur with the IOUs that projects required by any regulatory agency for safety reasons should be exempt from CPCN application requirements. Exempting projects required by other agencies for safety reasons from permit requirements helps ensure timely utility compliance with those regulations and the accompanying public safety or reliability of gas supplies. This includes PSEP projects previously approved by this Commission.

Our adopted GO will require gas corporations to file notices of a claimed exemption for such projects, so we will have the ability to study and revisit the scope of this exemption in the future, if warranted.

12.6. Distribution Pipelines

12.6.1. Staff Proposal

The Staff Proposal at Section IV(a)(3)(f) recommends the Commission exempt from application requirements the "construction, replacement or repair of distribution pipelines that are 12 inches in diameter or less." As with other exemptions, Staff propose requiring gas corporations to file a notice of claimed exemption for such projects.

The June 27, 2022 ALJ ruling requests party comment on the following questions:

- Should this exemption be modified? If so, how?
- Should other parameters such as pipeline length, volume of gas delivered, or pipeline operating pressure also be considered in determining whether a distribution pipeline should be exempt?

12.6.2. Party Comments

The gas corporations generally support Staff's proposed exemption for pipelines with a diameter of 12 inches in diameter or less. Intervenor parties generally oppose this exemption.

SoCalGas, PG&E, and SDG&E argue the Commission should exclude distribution pipelines 12 inches in diameter or less from the GO, rather than exempt such projects from application requirements. The gas utilities argue that excluding rather than exempting smaller distribution pipeline projects would mean that gas utilities would not be required to file thousands of notices of claimed exemptions for routine repair activities. This would reduce uncertainty and avoid unnecessary costs and delays to ratepayers, they argue. SoCalGas states that it installed 27,000 new customer meters in 2021 and such activities are unlikely to have significant environmental impacts.[44]

SDG&E proposes that the Commission exclude distribution mains and distribution service laterals as defined in Gas Tariff Rule 16 from the GO, rather than exempting them from an application requirement. PG&E supports excluding distribution pipelines from the GO and argues that stakeholders may use Commission complaint processes should they have concerns about small diameter distribution pipeline projects.

UCAN also supports excluding distribution networks and minor relocations of pipelines from the GO, stating that such projects are typically small, low cost, and necessary for safety. Instead, UCAN proposes that the gas utilities be required to file applications for any proposed line that will operate at 60 lbs. per sq. inch (psi) or higher, or where the combined lengths of the pipelines being built or replaced exceeds ten miles in length. PG&E and SDG&E oppose this UCAN suggestion. PG&E states that there is no evidence that higher pressure distribution lines result in significantly greater environmental impacts, costs or increased risk of stranded costs. SDG&E states that nearly all of SDG&E's distribution system operates at a Maximum Allowable Operating Pressure (MAOP) of 60 psi, thus UCAN's suggestion is impracticable.

Sierra Club/CEJA/RMI argue that some distribution projects are highly likely to create environmental impacts and this this type of activity should not be categorically excluded from the GO. Sierra Club/CEJA/RMI state that repurposing distribution lines to carry hydrogen or changes in large industrial companies' pipelines and throughput are examples of distribution projects that

---

[44] SoCalGas Comments on Staff Proposal at 9.

should be reviewed. Sierra Club/CEJA/RMI further contend that such projects should not be addressed through a complaint process because communities by pipeline projects are not likely to be aware of such projects without a notification process.

Sierra Club/CEJA/RMI recommend the Commission exclude residential meters and connections from claimed distribution pipeline exemption noticing requirements.

EDF proposes the GO apply to all distribution projects because all pipelines can leak methane, regardless of size. Design of an exemption from application requirements for distribution projects should consider factors like leakage rates, pipeline materials, and non-pipeline materials, EDF states.

PG&E and SDG&E oppose these intervenor recommendations. PG&E states that work on PG&E's distribution pipelines that are 12 inches in diameter or less includes dozens of categories of capital projects ranging from service replacements to installation of meters. SDG&E similarly argues that requiring an application for distribution pipeline projects could affect thousands of projects annually.

12.6.3. Including Distribution Pipelines in the Adopted GO and Rejecting Staff's Proposed Exemption Section IV(A)(3)(f)

With the exception of service pipelines connecting to customer facilities and work on customer meters, we neither exempt nor exclude distribution pipelines of 12 inches in diameter or less from the adopted GO. Instead, as discussed above, gas corporations are required to file a CPCN application for any distribution pipeline of 12 inches in diameter or less that meets one of our adopted threshold criteria, namely the $75 million monetary threshold and the sensitive receptors criterion (*see S*ections 7.3 and 8.3 above). We expect this to be a modest number of distribution pipeline projects.

In substantiating concerns with the inclusion of distribution pipeline projects in this GO, the gas utilities primarily refer to the potential for unnecessary delay and waste of resources if work on service lines and residential meters is subject to the CPCN application requirements we adopt here. We address these concerns by excluding service pipelines connecting to customer facilities and work on customer meters from the GO completely. This means that no exemption notices would be required for such projects in the extremely unlikely event that such a project would meet our CPCN application requirement thresholds. As noted above, the intent of the GO is to ensure that only projects likely to have significant environmental and/or community impacts are deeply scrutinized.

We decline to exclude smaller distribution pipelines entirely from the GO as recommended by the IOUs as this is not necessary given our threshold criteria. Additionally, we wish to collect information on planned distribution projects that meet our adopted threshold criteria but qualify for other exemptions. Section 16 below, addressing Section X (Report of Planned Gas Investments) of the GO discusses reporting requirements.

This approach ensures that we focus Commission review on the projects most likely to cause significant environmental harms or substantial costs to ratepayers.

We disagree with intervenor parties that this GO should be designed to result in Commission-level review of the majority of new distribution line extension projects. Such an outcome is impracticable and would not be a good use of Commission resources given that such projects are likely to have limited community and environmental impacts. We also do not believe this would support positive outcomes for local communities, as this could result in the delay of innocuous projects necessary to support reliable gas service in the short term. Instead, much of the remainder of Track 2 work in this proceeding will develop a process to identify criteria to selectively avoid new distribution line infrastructure and to "prune" existing gas distribution line infrastructure, where feasible and beneficial.

We decline to adopt UCAN's suggested criteria regarding gas infrastructure operating at 60 psi or greater, as we do not find this to be a practicable method to distinguish between projects. We also do not envision this GO as addressing leaking pipelines per se, and as such decline to adopt EDF's suggested approach as well. The Commission addressed the issue of leak abatement in D.17-06-015, which created a Natural Gas Leak Abatement Program in accordance with SB 1371.

12.7. Projects Previously Approved by this Commission

12.7.1. Staff Proposal

The Staff Proposal in Section IV(A)(3)(g) recommends that "projects previously approved in a GRC or other Commission decision which are currently underway" should be exempt from an application requirement.

12.7.2. Party Comments

IOUs and intervenors generally differ on which projects should be grandfathered in as exempt from an application requirement, with intervenors contending the grandfathering exemption as proposed by Staff is too broad, and gas corporations largely supporting it. Cal Advocates proposes defining projects that are "currently underway," as previously approved projects that have approved permits or are in construction. The Sierra Club and EDF propose the

Commission exempt from application requirements those projects that have commenced construction by June 1, 2022.

The gas corporations, particularly PG&E, disagree with limiting the grandfathering exemption to projects that have secured all required permits or have commenced construction. PG&E observes there are significant costs and that it takes many years to bring projects to the permitting phase. PG&E further contends that system planners assume that projects that have been previously approved by the Commission will be placed into service on their in-service date as planned. Delaying or discontinuing such projects creates risk, PG&E states.

SoCalGas opposes any "relitigation" of projects previously approved in a GRC application. SoCalGas states that requiring additional Commission review of such projects could halt authorized projects that have been under development for many years.

SDG&E contends that work undertaken according to the gas PSEP plans required in D.11-06-017 or D.14-06-007, pursuant to Pub. Util. Section 958, should be exempt from the application requirement. SDG&E opposes the intervenor's proposals for defining work "currently in process," stating that adopting them could cause delays of up to 38 months for necessary safety or reliability work.

In comments on the proposed decision, SoCalGas and SDG&E suggest that the "grandfathering" clause should be revised to include projects that have submitted an application for the approval of a compliance project from an air district, prior to the effective date of the GO.

12.7.3. Adopting a Modified Version of Staff's Proposed Exemption Section IV(3)(g), Projects Previously Approved by this Commission

We modify Staff's proposed exemption (g) to address previously approved projects. We determine that projects that have a scheduled in-service date occurring before January 1, 2024, and projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule, prior to the effective date of this GO, shall be exempt from filing a CPCN application. We agree with PG&E that significant work and costs are incurred to bring large infrastructure projects to the point of readiness to apply for required permits, of which there may be many. However, PG&E did not provide us with information to substantiate this concern or identify the types of projects it may be referring to. The record of this proceeding lacks information on how significant the expenses incurred to bring a project to the permitting application stage might be. We anticipate that many such projects are likely to be exempt under other provisions of the GO.

It is reasonable that we require CPCN applications for projects with a scheduled in-service date on or after January 1, 2024 that are not otherwise exempt. Adopting an in-service date that is over 12 months away from the date of this decision gives utilities sufficient planning and lead time while exempting projects that are relatively close to fruition.

Likewise, it is reasonable to exempt from a CPCN application requirement projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule prior to the effective date of this GO. Including this exemption allows projects planned to comply with local air quality management district environmental requirements that required substantive time and resources to develop to move forward in a streamlined fashion.

We agree with parties that Section IV(A)(3)(g) of the Staff Proposal – which recommends that "projects previously approved in a General Rate Case or other Commission decision which are currently underway" should be exempt from the application – lacks clarity and is subject to interpretation without the adopted clarification.

Within 60 days of issuance of this decision, each respondent gas utility[45] shall file and serve a list of gas infrastructure projects that are scheduled to be in-service before January 1, 2024 that have a cost exceeding $75 million or where (1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant;[46] or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant. Each respondent shall include in this list, clearly indicated, projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule, prior to the effective date of this GO. Each respondent gas utility shall provide, for each project listed, the information identified in Section V(C)(2) of the adopted GO.

---

[45] *See 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*, Section 6. Respondents to this rulemaking are Alpine Natural Gas, PG&E, SoCalGas, SDG&E, Southwest Gas, West Coast Gas Company, Inc., Wild Goose Storage, Lodi Gas Storage, Gill Ranch Storage, Central Valley Gas Storage, Sacramento Natural Gas Storage, LLC.

[46] Increase in levels of a toxic air contaminant is defined as an increase exceeding (1) de minimis levels or (2), where relevant, allowable limits set by the local air quality district.

12.8. Additional Exemptions Proposed by Parties

12.8.1. Party Proposals

In response to the June 27, 2022 ALJ ruling, several parties propose additional exemptions from an application requirement. PG&E and SDG&E propose the Commission exempt from an application requirement the following:

a. Projects in an existing franchise or public utility easement;
b. Projects required for reliability purposes; and,
c. Projects statutorily or categorically exempt from CEQA.

CVGS requests the Commission clarify that projects undertaken by independent storage providers included within the scope of existing CPCN and CEQA approvals are exempt from any additional application requirements. CVGS identifies the natural gas facility approved by the Commission in D.10-10-001 as an example of the type of storage project that should be exempt from any additional application requirement.

12.8.2. Party Comments

Sierra Club/CEJA/RMI oppose the additional exemptions from application requirements proposed by SDG&E and PG&E.

UCAN opposes CVGS's proposal, stating that if a substantial expansion such as the installation of a compressor station is planned, the project should be required to file an additional application.

12.8.3. Declining to Adopt Additional Exemptions

We do not adopt any of the additional exemptions proposed by parties. These exemptions are too broad as proposed. In Section 11.3 above, we adopt a new exemption for emergency and emergency repairs or upgrades to ensure safe and reliable gas service. This appropriately limits the types of safety and reliability projects that should be exempt from additional scrutiny. We do not adopt PG&E and SDG&E's proposed exemption for projects statutorily or categorically exempt from CEQA, because this is too broad.

We clarify that independent storage projects that have previously undergone CEQA review and are included in the existing property boundary of a current CPCN are excluded from additional CPCN application requirements under the GO. However, any storage expansion project that meets the criteria and definitions adopted here must apply for a CPCN application as stated in our adopted GO. Amongst other issues, this GO is concerned with ensuring prudent investments in the gas infrastructure system, and this includes gas storage infrastructure expansions beyond the existing property boundary of a CPCN. Section 17.3 defines "expansion of an existing gas storage field."

13. Exceptions to Exemptions

13.1. Staff Proposal

The Staff Proposal recommends the Commission adopt six exceptions to the exemptions listed in Section IV(A)(3). As proposed by Staff, an "exception to an exemption" means that a project that would otherwise not be subject to a CPCN application, because it met the GO's exemption criteria, would have to file such an application if it met the criteria of an exception to an exemption. Staff's proposed exceptions to the exemptions are as follows:

a. there is a reasonable possibility that the project may impact an environmental resource of hazardous or critical concern designated, precisely mapped, and officially adopted pursuant to law by federal, state, or local agencies;
b. the cumulative impact of successive projects of the same types, in the same place, over time is significant;
c. there is a reasonable possibility that the project will have a significant effect on the environment due to unusual circumstances;

d. the project may result in damage to scenic resources, including but not limited to, trees, historic buildings, rock outcroppings, or similar resources, within a highway officially designated as a state scenic highway. However, this exception does not apply to improvements which are required as a mitigation by an adopted negative declaration or certified EIR;

e. the project is located on a site which is included on any list compiled pursuant to Section 65962.5 of the Government Code; or,

f. the project may cause a substantial adverse change in the significance of a historical resource.

13.2. Party Comments

Party comments on Staff's proposed exceptions to exemptions in the GO address three areas: (1) how the Commission should structure exceptions to exemptions; (2) disadvantaged communities; and (3) Staff's proposed sensitive receptors criterion.

SoCalGas argues that the Staff Proposal inappropriately incorporates CEQA exceptions into utility determinations of whether an application is required. SoCalGas recommends Commission delete all of Staff's proposed exceptions from the adopted GO. SoCalGas argues that doing so would help restructure the adopted GO to better align it with CEQA requirements. SoCalGas contends that, under CEQA, the exceptions determine if a project no longer qualifies for a CEQA exemption only after an application has been submitted.

With regards to disadvantaged and ESJ communities, PG&E proposes that the Commission add a new exception to the list of Staff's proposed exemptions as follows:

> there is a reasonable possibility that the activity will have a significant effect on the environment due to its location within an [ESJ or SB 535 disadvantaged] community."[47]

PG&E argues that projects occurring in disadvantaged or ESJ communities deserve special consideration. As such, PG&E contends the Commission could consider a project's location within a disadvantaged or ESJ community as a factor in determining whether an application is required for an otherwise-exempt project. PG&E states that this is preferable to adopting a permit trigger for all projects located in disadvantaged or ESJ communities, which PG&E opposes.

As discussed in Section 8.2 above, Sierra Club/CEJA/RMI argue that the Commission should adopt a sensitive receptors criterion as an exception to the list of exemptions rather than as a threshold trigger for an application requirement.[48]

13.3. Declining to Adopt Exceptions to Exemptions as Proposed by Staff (Section IV(A)(4))

We do not adopt the exceptions to exemptions contained in the Staff Proposal. These broadly worded exceptions can introduce uncertainty into implementation, and as SoCalGas notes, create a frequently disputed, and unnecessarily burdensome administrative process to determine applicability of the GO. Further, the exceptions as written are in some cases vague. Exceptions (b) and (c) overlap substantially with our adopted sensitive receptors criterion, especially since the criterion is triggered in heavily impacted air communities.

We believe that it is preferable to omit these exceptions at present. There may, however, be instances where a gas utility's exemption claim is not well

---

[47] PG&E Reply Comments on Staff Proposal at 17. Use of [ ] in the original.

[48] Sierra Club/CEJA/RMI Comments on Staff Proposal at 6.

supported. The Commission's complaint process gives stakeholders a mechanism to contest a gas utility's exemption claim. Similarly, Commission Staff should inform the Executive Director, and the assigned ALJ and Commissioner in this or any successor proceeding of any instances where Staff believe a gas utility has inappropriately claimed an exemption under our adopted GO. This Commission will investigate such instances as warranted.

We also do not adopt the additional exceptions to exemptions proposed by PG&E and Sierra Club/CEJA/RMI. Instead, regarding PG&E's proposal, we address the potential location of a gas infrastructure facility in a disadvantaged or ESJ community by requiring additional information in relevant project CPCN applications, as discussed in Section 15.3 below. Requiring corporations to consider, and for the Commission to undertake, additional evaluation of alternatives for projects proposed to be located in a disadvantaged or ESJ community addresses the similar concerns identified by PG&E, but with greater clarity and specificity to the circumstances surrounding actual proposed projects.

We do not adopt Sierra Club/CEJA/RMI's proposal because in Section 8.3 above we have adopted a threshold criterion for sensitive receptors that is clear and practicable.

14. Notification Requirements for Claimed Exemptions

14.1. Staff Proposal

Section V of the Staff Proposal sets forth Staff's proposed notification requirements for claimed exemptions.

The June 27, 2022 ALJ ruling asks the following regarding Staff's proposed notification requirements:

> Should certain types of infrastructure projects be exempt from any of the notification requirements in Section V? If so, what types of projects should be exempt? Should any modifications be made to the notification…requirements provided in Section V?

14.2. Party Comments

Intervenor parties generally support Staff's proposal regarding notification requirements, while gas corporations generally oppose them. The gas corporations state that the notification requirements in the Staff Proposal are too broad. SoCalGas proposes deleting the entirety of Section V(C) of the Staff Proposal from the adopted GO. Section V(C) addresses notification requirements for all claimed exemptions.

SDG&E objects that the Staff Proposal as worded would require noticing for thousands of maintenance projects. SDG&E asserts that it undertakes thousands of maintenance, repair and relocation of existing gas infrastructure projects for service lines each year. SDG&E states these projects are typically triggered by requirements specified in GO 112-F and PHMSA regulations, as well as by work to clear conflicts required by franchise agreements relating to government road, water, or sewer projects. SDG&E states that although this work would be exempt from application requirements under Staff's proposed exemptions in Sections IV(A)(3), notification pursuant to Staff's proposed Section V(C) would still be required. SDG&E states that at a minimum, new service lines should not require advice letters or other notifications. SDG&E further argues that maintenance, repair, and relocation work on the existing gas system should be excluded from the Section V(C) notification requirement.

Sierra Club/CEJA/RMI state that notifications should be required in all instances when a gas corporation asserts an exemption to a permit requirement. Sierra Club/CEJA/RMI propose additions to Staff's proposed Section V to reflect requirements contained in recently passed legislation, AB 819 (Levine, Stats. 2021, Chapter 97), regarding CEQA notice and reporting requirements.[49] Sierra Club/CEJA/RMI suggest changes to Staff's proposed Section V(C) to require noticing provisions contained in the Commission's ESJ Action Plan related to accessibility, understandability and availability of information. They further assert that the GO should require that all requests for exemptions and notices of exemption are posted on the Commission's website and are easy to access.

PG&E opposes the suggestion that information required of CEQA lead agencies under AB 819 is required in the GO. PG&E observes that Staff's proposed Section V governs the notices provided by the utilities to various agencies and stakeholders to alert them to the filing of applications at the Commission, or to claims of exemptions from Commission permit requirements. As such, these actions by private companies are not subject to CEQA noticing requirements as contained in AB 819, PG&E asserts.

PG&E states that the other suggestions provided by Sierra Club/CEJA/RMI about noticing are reasonable, for instance that notices of a gas corporation's application filing should include references to the Commission's website. The Commission's Public Advisor's Office could consider these Sierra Club/CEJA/RMI suggestions when working with IOUs to develop an agreed-upon template for the notices, PG&E states.

[49] Sierra Club/CEJA/RMI note that AB 819, for example, requires the posting of CEQA notices to an agency's website and requires agencies to allow members of the public to file comments electronically and accept comments via email (Pub. Res. Code Section 21082.1.d and Section 21091.d.3). Sierra Club/CEJA/RMI Comments on Staff Proposal at 10.

14.3. Adopting a Modified Version of Staff's Proposed Notification Requirements (Section V)

We adopt a modified version of Staff's proposed Section V regarding notices of projects and notices of claimed exemptions. First, regarding distribution lines, as discussed in Section 12.6.3 above, the way we have structured the CPCN application thresholds of this GO (adopted in Sections 7.3 and 8.3 above, *see* Section IV(A) of the GO) means that only a limited number of distribution pipeline projects will meet these thresholds. Thus, a manageable number of CPCN applications are likely to be required pursuant to our adopted GO for distribution projects, which in turn means that the number of exemption notices for distribution projects are also likely to be manageable.

Second, regarding Section V(A), we incorporate some of the changes suggested by Sierra Club/CEJA/RMI. To the extent possible, we require gas corporations to submit notices regarding a CPCN application pursuant to our adopted GO in a format accessible to the visually impaired and to serve them to relevant service lists, which shall include the service list of R.20-01-007 and any successor proceeding, as well as the service list of each utility's most recent general rate case application proceeding. We require gas corporations to consult with the Commission's Public Advisor's Office regarding the format of both project CPCN application and exemption notice requirements, including ways to ensure the notices are easily accessible. Further, we direct Commission staff to post submitted notices to the webpage on Long-Term Gas Planning on the Commission's website within 30 days of receiving it.

Third, regarding Section V(B), which addresses the information required in CPCN application notices, we require gas corporations to include information about how individuals or organizations may electronically file comments on the application. We also require the notices to include a summary of potential environmental impacts, including emissions, from the proposed facility.

Fourth, regarding Section V(C), which addresses notification requirements for claimed exemptions, we clarify that gas corporations must submit the required information no later than 60 days prior to the planned commencement date of construction. Setting a date certain for the notices of claimed exemptions will contribute to orderly implementation of the GO and provide Staff and stakeholders with a reasonable level of advance notification.

Fifth, as discussed in section 11.3 above, we clarify that notices of a claimed exemption for emergency projects must be submitted no later than 60 days after the commencement of construction on the project. This achieves a reasonable balance that allows gas corporations to begin work on urgent emergency projects as necessary, but that also provides an opportunity for affected community members, local governments, stakeholders and this Commission to learn about the project within a reasonable amount of time from project commencement.

Finally, we retain the requirement that gas corporations must submit a Tier 1 information-only advice letter when claiming an exemption under the GO. Pursuant to GO 96, Tier 1 information-only advice letters are effective immediately upon submittal and protests are not permitted.[50] As discussed above, Commission Staff should inform the Executive Director, and the assigned ALJ and Commissioner in this or any successor proceeding, of any instances where Staff believe a gas utility has inappropriately claimed an exemption under our adopted GO. This Commission will investigate such instances as warranted.

[50] GO 96-B at 10, Section 6.2. Available as of October 21, 2022 at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF.

15. CPCN Application Information Submittal Requirements (Section VI)

15.1. Staff Proposal

Section VI of the Staff Proposal contains Staff's proposed information submittal requirements for CPCN applications. Amongst other required information, Staff propose that gas utilities file a PEA with each CPCN application.

15.2. Party Comments

Party comments address three main areas regarding Staff's proposed application information requirements. These are: (1) non-pipeline alternatives; (2) health impacts; and (3) unique considerations for gas storage projects.

Regarding non-pipeline alternatives, several intervenors (CforAT, EDF, UCAN) recommend the Commission adopt more detailed requirements regarding how gas corporations should assess non-pipeline alternatives in their applications. EDF states that additional clarity will help the Commission more fully evaluate proposed projects, support safe and reliable natural gas service for Californians at just and reasonable rates, and help achieve California's decarbonization goals.

CforAT provides a number of specific recommendations in this area, namely:

a. The analysis should describe who is intended to be served by proposed project and what options for efficiency or managed consumption may be available to reduce need for project;

b. If a project is primarily intended to serve residential customers, electrification options should be considered, including direct support for electrification if it could be done at lower cost than the construction project;

c. Consideration of cost should include external costs, such as the environmental impacts and the public health impacts of the proposed gas infrastructure project, as well as the direct dollar costs; and,

d. If the project is primarily intended to serve commercial and industrial customers, consideration should be included regarding alternative methods to provide necessary energy supplies, again considering both direct and externalized costs of new infrastructure.51

UCAN proposes that the Commission require applications to demonstrate:

a. That the potential facility will be needed in light of the California Energy Commission's long-term projections of natural gas demand;

b. That existing facilities are inadequate or need repair to meet applicable safety standards;

c. That no reasonable alternatives exist to the proposed project;

d. That the adverse environmental effects of the project can be adequately mitigated; and,

e. That the proposed project does not substantially increase the density of existing infrastructure facilities in a given location without offsetting substantial economic benefits.52

SoCalGas opposes adopting additional details regarding how non-pipeline alternatives should be evaluated by permit applicants at this time. SoCalGas observes that questions regarding non-pipe alternatives are scoped into Track 2a of this proceeding regarding initial steps to develop a long-term gas planning process in this proceeding. SoCalGas contends that requiring analysis of non-pipeline alternatives in the proposed GO is therefore premature.

---

[51] CforAT Comments on Staff Proposal at 3.

[52] UCAN Comments on Staff Proposal at 4.

Regarding health impacts, CforAT recommends the Commission modify Staff's proposal to ensure more meaningful review of the public health impacts of proposed gas infrastructure projects. CforAT suggests the Commission require consideration of the impacts of new gas infrastructure on public health, including risks of air pollution, increased rates of asthma and other chronic health issues in communities located near gas infrastructure, and the public health risks of gas leaks.

The gas corporations oppose CforAT's suggestion. PG&E and SDG&E state that Commission PEA requirements, which include a Health and Safety Plan and a Health Risk Assessment, already address these concerns. SoCalGas observes that there is substantial oversight from various agencies to evaluate air emissions and public health impacts from projects, through PHMSA requirements, the Environmental Protection Agency (EPA), CARB, and regional air quality districts.

Regarding independent storage projects, CVGS argues that such projects should not be required to comply with several Section VI information requirements because the projects were not approved under cost-based rates. CVGS states that independent storage providers' CPCN applications should not have to consider alternative routes or non-pipeline alternatives or provide capital and budget estimates. CVGS asserts that independent storage providers should not have to provide the information requested in Staff's proposed Section VI(A)(10), which addresses government agencies that have been consulted on the route of a proposed project and their responses.

Sierra Club/CEJA/RMI object to the exclusion of information required in Section VI from the CPCN applications of storage projects.

In comments on the proposed decision, SoCalGas states that considerations surrounding the Ventura Compressor Station mean that it would be helpful if the requirement for submittal of a draft PEA at least three months prior to filing a CPCN application could apply to an amended application.

15.3. Adopting a Modified Version of Staff's Information Requirements (Section VI)

We adopt a modified version of Staff's proposed CPCN application information requirements. We adopt many intervenor recommendations, including providing more guidance on our expectations for utility evaluation of non-pipeline alternatives. The suggestions are reasonable and adopting them will ensure that the information contained in the CPCN applications is sufficiently robust for this Commission to appropriately review and take action on the application. Requiring the additional information proposed by intervenors will help avoid unnecessary costs to ratepayers and will assist this Commission in evaluating and addressing potential environmental harms to local communities surrounding proposed infrastructure.

Specifically, we require the following elements to be included in any analysis of non-pipeline alternatives:

a. The customers to be served by the proposed project, and whether direct support for electrification, consumption reduction (energy efficiency, conservation and demand response), and/or alternative methods to provide necessary energy supplies for these customers could be accomplished at a lower cost and/or with lesser environmental impact than the proposed project;

b. The potential environmental impacts of alternatives, including emissions; and

c. An estimate of the environmental and health impacts of the project, as well as the direct costs of the project.

We also direct the inclusion in CPCN applications of information required pursuant to Pub. Util. Code Sections 1003[53] and 1005.5.[54] Requiring this information is reasonable and will prepare this Commission to make a determination regarding the maximum cost that is reasonable and prudent for each infrastructure project for which a CPCN application is filed. Information added for this purpose is contained in Section VI(A)(5) and Section VI(A)(6) of the adopted GO in Appendix A.

We disagree with SoCalGas that the GO should not explicate expectations regarding consideration of non-pipeline alternatives. Undertaking this type of analysis for large infrastructure projects is a central rationale driving the need for this GO. Although questions regarding analysis of non-pipeline alternatives are scoped into other elements of Track 2a of this proceeding, it would be inappropriate to delay to a later date consideration of such alternatives for projects subject to a CPCN application. There is an urgent need to minimize the risk of stranded assets and rising energy bills, which place an especially heavy burden on low-income customers. As needed, we can refine our requirements

---

[53] Pub. Util. Code Section 1003 requires inclusion of the following information:

(a) Preliminary engineering and design information on the project;

(b) A project implementation plan showing how the project would be contracted for and constructed;

(c) An appropriate cost estimate;

(d) A cost analysis comparing the project with any feasible alternative sources of power; and

(e) A design and construction management and cost control plan which indicates the contractual and working responsibilities and interrelationships between the corporation's management and other major parties involved in the project.

[54] Pub. Util. Code Section 1005.5(a) requires consideration of the maximum cost using an estimate of the anticipated construction cost, taking into consideration the design of the project, the expected duration of construction, an estimate of the effects of economic inflation, and any known engineering difficulties associated with the project.

for evaluating non-pipeline alternatives for projects subject to this GO as work on a long-term gas planning strategy continues.

In this regard, we require an additional information element to reflect recommendations from Sierra Club/CEJA/RMI, EDF, CforAT, PG&E and other parties regarding disadvantaged communities. If the proposed project is located within an ESJ Community as defined in the most recent version of the Commission's ESJ Action Plan, we require gas corporations to consider in their CPCN applications, as part of consideration of alternatives, whether it is possible to relocate the project and, if so, steps taken to locate the project outside such areas. This requirement reflects the Commission's ESJ Action Plan and helps minimize environmental impacts from gas infrastructure in such communities, reflecting the equity purpose of the GO. It also helps implement Pub. Util. Code Section 454.52(a)(1)(I), which states that the Commission should adopt a process to develop plans that minimize localized air pollutants and other greenhouse gas emissions, with an early priority on disadvantaged communities. We also require in Section VI(A)(7)(b), as proposed by Staff, that gas corporations provide a summary of outreach to, and engagement undertaken with, local communities (including relevant community-based organizations), likely to be impacted by the proposed project.

We do not modify our adopted GO to reflect CforAT's comments on health impacts. We concur with the gas corporations that these issues are adequately addressed in the PEAs that must be filed concurrent with the CPCN applications.

Regarding information requirements for independent storage providers, we modify our adopted GO to clarify that independent storage providers need not include an analysis of non-pipeline alternatives in their CPCN applications, as outlined in Section VI(A)(4)(a), nor an analysis of alternative routes, as outlined in Sections VI(A)(4)(b), VI(A)(4)(d) and VI(A)(5)(c). Additionally, regarding cost information required in Section IV(A)(6), independent storage providers may file a motion for this information to be filed under seal as confidential. These are reasonable modifications to required information elements to reflect the different circumstances of independent storage providers as compared to other gas corporations.

Review of the required cost information will enable a broader understanding of the pass-through costs from gas storage to utility customers, which will in turn support broader consideration of alternatives to minimize costs to ratepayers and stranded costs in this era of declining gas consumption.

15.4 Clarifying PEA Requirements (Section VI(A)(12))

Regarding the required PEA, we modify and adopt here Staff's proposed Section VI on CPCN application requirements to indicate that the PEA filed with the CPCN application must be prepared according to the most recent version of the Commission's Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments (PEA Guidelines).[55] We clarify Staff's proposed Section IV to indicate that that gas corporations may provide the required information elements as part of their PEA if they provide a clear mapping to the location of the required information within the PEA. We modify Staff's proposed Section IV to require gas corporations to initiate a prefiling meeting with Commission CEQA Staff no later than 60 days prior to filing of the application to assist with ensuring the completeness of the CPCN filing. With the exception of CPCN applications filed

[55] 2019 Version available as of September 13, 2022 at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/c/6442463239-ceqa-pre-filing-guidelines-pea-checklist-nov-2019.pdf.

within 120 days from issuance of this decision, we require gas corporations to submit a draft PEA to Commission CEQA Staff at least three months prior to application filing. These are reasonable requirements that will ensure the Commission has a robust PEA with which to consider potential environmental impacts and to initiate CEQA review of the proposed project. Exempting the requirement for submittal of a draft PEA three months before a CPCN application is filed for CPCN applications filed within 120 days from issuance of this decision is reasonable because this helps avoid delay in timely application filings or the filing of both an initial and an amended application, review of which expends scarce Staff resources with little gain.

Commission Staff will conduct the CEQA review simultaneous to the consideration within the formal proceeding of the substantive policy issues associated with the project. The CEQA review may inform the policy considerations of the proceeding - especially the costs and benefits of alternatives and impacts on overburdened communities.

We note that this decision adopts Staff's proposed definition of a PEA in Section III of the GO. This definition indicates that the PEA filed as part of the CPCN application must include all information and studies required under the Commission's Information and Criteria List adopted pursuant to Chapter 1200 of the Statutes of 1977 (Government Code Sections 65940 through 65942), which is published on the Commission's website (Section 1701, Public Utilities Code).

16. Reporting Requirements

16.1. Staff Proposal

In Section X of the Staff Proposal, Staff recommend gas corporations report annually on planned gas investments for any system expansions or projects that are expected to exceed $100 million. Staff recommend the Commission require gas corporations to provide a 15-year forecast for investments subject to a CPCN application requirement. Staff recommend the Commission require gas corporations to file additional detailed information for projects scheduled to be in-service within five years.

The June 27, 2022 ALJ ruling invited comments on the following questions:

- Should certain types of infrastructure projects be exempt from the reporting requirements in Section X? If so, what types of projects should be exempt?
- Should any modifications be made to the… reporting requirements provided in… Section X?

16.2. Party Comments

Gas corporations generally support Staff's proposed reporting requirements with few changes. Intervenors and Indicated Shippers generally advocate expanding Staff's proposed reporting requirements.

Indicated Shippers, Sierra Club/CEJA/RMI, and EDF propose lowering the reporting threshold to $50 million and requiring utilities to provide detailed descriptions of each planned system expansion including its intended purpose. Indicated Shippers recommends this detailed description include:

a. the projected capital expenditure;

b. a detailed description of the gas infrastructure project that includes what will be modified or constructed, what specific actions will be taken, and why the project will be conducted;

c. projected operating costs over the expected life of the asset as of the year the report is filed (in both nominal and net-present value terms);

d. a description of the cost drivers; and

e. total projected quantified reliability benefits over the expected life of each project expected to come online within the next 5 years from the date the report is filed.56

In addition to helping the Commission avoid stranded infrastructure costs, Indicated Shippers contends that the report, with the additional information recommended, would benefit new and existing gas industrial customers by providing information about the repair and replacement schedule of relevant transmission and distribution lines. Indicated Shippers asserts that annual reports reflecting planned infrastructure investments would provide new industrial customers with insight into these schedules and help them to understand the potential risks and costs of interconnection. Indicated Shippers recommends the Commission require use of a reporting template.

Sierra Club/CEJA/RMI assert the Commission should require reporting on all planned capital investments, regardless of cost. Sierra Club/CEJA/RMI state the report should indicate if the project is located in a disadvantaged or ESJ community or in a High Consequence Area, the expected level of gas throughput over the project's useful life, and the expected customer utilization of the project by customer class. These parties recommend the Commission undertake a systematic review process of the contents of the reports to provide visibility into future planned investments and to provide opportunities to identify non-pipeline alternatives. UCAN proposes a $25 million threshold for reporting requirements.

CVGS suggests the Commission exempt independent storage projects within the scope of existing CPCN and CEQA approvals from Staff's proposed reporting requirements. CVGS states it would be competitively damaging for

---

[56] Indicated Shippers Comments on Staff Proposal at 9.

these entities to provide the cost data recommended by Staff in Section X(D)(2). CVGS argues that Indicated Shippers' concerns about the risks of stranded costs do not apply to independent storage projects as these projects don't recover costs through rates, including any reporting costs. CVGS observes that D.10-10-001 waived both cost caps and cost data reporting requirements for independent storage projects.

SoCalGas asserts that only projects subject to the GO should be required to comply with reporting requirements. SDG&E requests clarification whether exempt projects are subject to the GO's reporting requirements.

PG&E supports Staff's proposed $100 million reporting threshold but observes that the 10 to 15-year forecast period is inconsistent with GO 131-D, which only requires a five-year forecast for smaller projects.

PG&E and SoCalGas contend that GRC applications already contain the additional information suggested by Indicated Shippers. PG&E states that GRC applications review the prudency of projected operating costs, a description of the cost drivers, and quantification of projected reliability benefits over the life of the asset and would contain more accurate information than a 15-year projection. PG&E asserts that it would be inefficient and problematic to litigate the need for projects in multiple proceedings.

In comments on the proposed decision: (a) UCAN expresses concern with allowing gas utilities to file annual gas reports in the years 2023, 2024, and 2025 that have been revised to respond to party comments; (b) PG&E requests additional time for utilities to consider changes to reporting requirements proposed by parties, from 60 to 90 days; and (c), SDG&E requests gas utilities be given 45 rather than 30 days to respond to party comments on their reports.

16.3. Adopting a Modified Version of Staff's Proposed Reporting Requirements (Section X)

We adopt a modified version of Staff's proposed reporting requirements. First, we lower the reporting threshold to projects with a cost of $50 million or more, with "costs" defined as the "fully loaded" cost estimate, including direct and indirect costs, and taking into consideration the design of the project, the expected duration of construction, an estimate of the effects of economic inflation, and any known engineering difficulties associated with the project.[57] This lower threshold will help provide transparency into utility infrastructure planning processes and will give us insight into a greater range of planned projects than will be covered by our CPCN application requirements. The additional information will allow us to evaluate the impact of our adopted threshold of $75 million and adjust this threshold as necessary. The reporting requirements in Section X, as adopted, are not overly burdensome or onerous enough to justify a higher monetary value reporting threshold.

Second, we clarify that reporting shall include projects that the gas corporations anticipate claiming as exempt from CPCN application requirements pursuant to the GO. Including projects for which gas corporations intend to claim exemptions in the annual reports will enhance transparency and give stakeholders and Commission staff visibility into planned projects. This will also give stakeholders the opportunity to track projects and assess whether there is a sufficient basis for potential exemption claims.

For projects for which the gas corporation anticipates claiming as exempt from a CPCN application requirement, the gas corporation is not required to

[57] Explanations of "direct" and "indirect" costs are provided in the GO in Appendix A.

include in the annual report information describing non-pipeline alternatives considered, as required in Section X(D), and information regarding cumulative environmental impacts of successive projects, as required in Section X(C)(6). It is reasonable to not require gas corporations to report this information for exempt projects, as these will consist of required safety projects, minor relocations or repairs, emergency projects, and other exempt project types as outlined in Section IV(B) of the adopted GO.

Third, we reduce the forecast period for reporting from 15 to 10 years. This will allow for more accurate and useful reporting. Requiring a 15-year projection could introduce too much uncertainty into the reporting on anticipated projects because so many contingencies may play out in unexpected ways over such a long time period. We disagree with PG&E and SoCalGas that requiring cost and related information in the annual gas reports conflicts with information provided in GRC applications. The filings serve different purposes at different time frames in project development and the information we require here is reasonable to provide on a 10-year advance timeframe.

Fourth, we require the gas corporations to include for all reported projects the following information recommended by Indicated Shippers:

- detailed description of the gas infrastructure project that includes what will be modified or constructed, what specific actions will be taken, and why the project will be conducted; and,
- the projected capital expenditure and a description of the cost drivers.

Including this basic information in the report will contribute to the Commission and parties' understanding of the planned investment and support long-term planning.

Fifth, we augment the information that we require gas corporations to include in the reports regarding facilities scheduled to be in-service within five years of the date of the report. Based on Indicated Shippers' recommendations, we add to the information elements proposed by Staff. We require gas corporations to include in their annual reports for facilities scheduled to be in-service within five years of the date of the report the following additional elements:

- total projected quantified reliability cost savings over the expected life of the project;[58] and,
- projected operating costs over the expected life of the asset as of the year the report is filed (in both nominal and net-present value terms).

We clarify Indicated Shippers' suggestion regarding quantified reliability benefits by requiring a projection of anticipated cost savings from the project, and by specifying that gas corporations shall consider "1 in 10" winter days when making such projections. The definition of gas demand on a 1-in-10 winter day should reflect the approach used by the gas utility in its design standard, including adjustments based on changing weather patterns, adapted to extend over the life of the project. Gas corporations shall disclose the methods and assumptions used to make these projections in their CPCN applications. Including this information in the report will contribute to the Commission and parties' understanding of the planned investment and support long-term planning.

Sixth, regarding facilities scheduled to be in-service within five years of the date of a given report, we retain Staff's recommended information element –

[58] Based on inclusion of an appropriate number of 1 in 10 winter days.

"analysis of non-pipeline alternatives" – and specify that gas corporations should summarize the analysis conducted. Gas corporations should address at a high level the analytical questions regarding non-pipeline alternatives adopted in Section 15.3 above (pertaining to Section VI(A)(4) of the GO regarding CPCN application information requirements).

Seventh, we require gas corporations to indicate if the planned project is located in an ESJ community as defined in the Commission's ESJ Action Plan. This is not an onerous requirement and requiring this will advance ESJ Action Plan aims.

Eighth, with the exception of the information required in Section X(D)(1) regarding non-pipeline alternatives, we do not exempt independent storage providers from our adopted reporting requirements. We emphasize, however, that independent storage providers may file concurrent with their annual reports a motion to file information under seal as confidential. Review of the required cost information will enable a broader understanding of the pass-through costs from gas storage to utility customers, which will in turn support broader consideration of alternatives to minimize costs to ratepayers and stranded costs in this era of declining gas consumption.

Finally, we adopt a process that will support careful review of the filed reports in the initial implementation years of this GO and provide an opportunity for parties to recommend revisions to the report, and to the reporting requirements, as needed.

We direct PG&E, SoCalGas, and SDG&E to jointly convene a "Report of Planned Gas Investments Workshop" no less than 60 days from the date of filing their annual gas reports pursuant to Section X of the GO adopted here, for the years 2023, 2024 and 2025. The workshop shall be designed so that utility representatives provide an overview of projects listed in the report and stakeholders are afforded an opportunity to ask questions. Each utility's overview shall provide explanatory information on listed projects that is additional to that included in the filed report. To the extent a gas corporation other than PG&E, SoCalGas, and SDG&E has upcoming projects listed in that year's annual Report of Planned Gas Investments, the gas corporation shall participate in the workshop and present on such projects. PG&E, SoCalGas, and SDG&E shall provide 30-day advance notice to the service list of R.20-01-007, or a successor proceeding, of each annual workshop.

Parties may serve and file comments on the annual reports recommending changes to them, as needed, to the docket of R.20-01-007, or a successor proceeding, in the years 2023, 2024, and 2025, no later than 15 days from the date of each annual Report of Planned Gas Investments Workshop. In their comments, parties may also suggest changes to the reporting requirements adopted here and contained in the GO in Appendix A that would improve the usefulness of the reports.

During the years 2023, 2024, and 2025, gas corporations shall consider filed party comments on their reports, and shall refile their reports, with revisions that add additional information or clarifications to address party comments, no later than 45 days from the date party comments are filed. Gas corporations shall include in their refiled reports an appendix that summarizes how each party comment was addressed. If no party comments on a gas corporation's annual Report of Planned Gas Investments during the years 2023, 2024, and 2025, the gas corporation is not required to refile a revised report as described here. These are reasonable requirements that add transparency to the reporting process.

No later than 90 days from the date party comments are filed in 2023, 2024, and 2025, PG&E, SoCalGas, and SDG&E, and other gas corporations as interested, shall jointly submit a Tier 3 Advice Letter requesting any changes to the reporting requirements suggested by parties and agreed to by the gas corporations. If no changes to the reporting requirements were proposed by parties and agreed to by the gas corporations, PG&E, SoCalGas, and SDG&E are not required to file a Tier 3 Advice Letter.

Requiring an annual Report of Planned Gas Investments Workshop during the years 2023, 2024, and 2025, and providing an opportunity for parties to comment on the reports and reporting requirements in a way that may result in revisions to them, adds transparency, accountability, and the opportunity for engagement. This process will help improve the report information and its use in the early years of implementation of this GO.

17. Definitions

17.1. Staff Proposal

Section III of the Staff Proposal contains proposed definitions for a variety of terms used in the draft GO.

17.2. Party Comments

Several parties propose modest refinements to definitions included in Section III of the Staff Proposal.

SoCalGas recommends modifying definitions of the terms:

a. "non-attainment area," which SoCalGas states should be adjusted to align with the Federal Clean Air Act, Part D;[59]

b. "severe and extreme non-attainment area," which SoCalGas states should be revised to align with the US EPA's "Green Book" of National Ambient Air Quality

[59] SoCalGas Comments on Staff Proposal at 10.

Standards based on the area's design value for a specific criteria pollutant;60

c. "sensitive receptor," which SoCalGas states should be adjusted to align with the California Health & Safety Code, which is the same definition used in the Commission's PEA Guidelines.61

SoCalGas recommends that the Commission define "gas storage field" to ensure that CPCN applications are only required for a "new storage field or the expansion of the property boundary of a storage field due to acquisition in fee of property with the intent to install new gas infrastructure on the newly acquired property."[62] SoCalGas states that expansion or construction within "buffer areas"— land acquired to establish a greater distance between an adjacent landowner and a gas storage facility—should not trigger a CPCN application requirement.

In line with its proposal that the sensitive receptors criterion include toxic air contaminants, Sierra Club/CEJA/RMI propose the Commission define toxic air contaminants as:

> Air pollutants identified by the California Air Resources Board that may cause or contribute to an increase in mortality or an increase in serious illness, or which may pose a present or potential hazard to human health.[63]

17.3. Adopting Modified Versions of Staff's Proposed Definitions (Section III)

We adopt many of the parties proposed revisions to Staff's definitions. We also define three new phrases.

[60] Id. at 11.

[61] *Ibid.*

[62] SoCalGas Comments on Staff Proposal at 17.

[63] Sierra Club/CEJA/RMI Comments on Staff Proposal at Appendix A-2.

First, we define the following new phrases:

a. "Toxic air contaminant"— an air pollutant which may cause or contribute to an increase in mortality or an increase in serious illness, or which may pose a present or potential hazard to human health, pursuant to Section 39655 of the California Health and Safety Code;

b. "Project"— construction or physical modification of any gas plant with independent utility in the gas system, including any compressor or regulator stations, any pipeline or pipeline extension, or any expansion of an existing gas storage field.[64]

c. "Expansion of an existing gas storage field"— expansion of the property boundary of a Commission-authorized storage field to increase natural gas storage inventory capacity.

We discussed the first two terms and definitions earlier in this decision. These are reasonable clarifications. We also adopt here SoCalGas's suggested definition of "expansion of an existing gas storage field." We agree with SoCalGas's suggestion because this clarifies that the "expansion" in question pertains to the land base where equipment is located rather than to expansion of equipment placed on the land for which a CPCN has already been granted. This definition excludes land acquired to create or expand a buffer zone. We agree this is a reasonable clarification. As we stated in Section 12.8.3, although gas utilities need not submit applications for new projects within the existing property boundary, any storage expansion project that otherwise meets the criteria and definitions adopted here must apply for a CPCN application as stated in our adopted GO.

[64] Exclusions from the definition of "project" are indicated in the GO in Appendix A.

We redefine the term "non-attainment area" as recommended by SoCalGas, such that our adopted definition is:

> for any air pollutant, an area which is designated "nonattainment" with respect to that pollutant within the meaning of Section 7407(d) of the Clean Air Act (CAA). CAA Section 7501(2).

We clarify the definition of "severe and extreme non-attainment areas" so that our adopted definition reads:

> non-attainment areas designated as "serious," "severe" or "extreme" by the US EPA in the "Green Book" of National Ambient Air Quality Standards (NAAQS) based on the area's design value for a specific criteria pollutant type.

We do not modify the definition of sensitive receptors in response to SoCalGas's comments. The phrase we adopt in Section 7.3 originates with Pub. Util. Code Section 1103(b), which pertains to CPCN requirements for gas storage facilities, and is appropriate for use here. The definition of sensitive receptors in the Commission's PEA guidelines, referencing the California Health and Safety Code, is more general, and we decline to change the definition to this usage.

These are reasonable modifications that add clarity and will assist in the efficient and beneficial implementation of the GO.

18. Adopting All Other GO Sections as Proposed by Staff or With Minor Modifications

Parties generally did not file comments concerning Section I (General), Section VII (Complaints and Preemption of Local Authority), Section VIII (Review of Gas Infrastructure Projects by Other State or Federal Agencies), or Section IV (CEQA Compliance). These sections are reasonable and are adopted in full or with minor modifications to provide clarity.

19. Comments on Proposed Decision

The proposed decision of ALJ Cathleen A. Fogel in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. On November 15, 2022, CVGS, SoCalGas, SDG&E, EDF, Southwest, PG&E, Indicated Shippers, UCAN, CforAT, and Sierra Club/CEJA/RMI filed opening comments. On November 21, 2022, NRDC/Sierra Club/CEJA, PG&E, SoCalGas, EDF, UCAN, and SDG&E filed reply comments.

The final decision contains revisions based on party comments on the proposed decision in the Summary section, in sections 7.2.1, 7.3, 8.2, 8.3, 10.2, 10.3, 11.2, 11.3, 12.7.2, 12.7.3, 14.3, 15.3, 15.4, 16.2, 16.3, 17.3., in several Findings of Fact, Conclusions of Law, and Ordering Paragraphs, and in the GO contained in Appendix A.

20. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Cathleen A. Fogel is the assigned ALJ in this proceeding.

Findings of Fact

1. Utility-served statewide natural gas consumption is projected to decrease at an annual average rate of 1.1 percent per year through 2035.
2. Declining gas consumption means there may be less need for large natural gas infrastructure projects in the future.
3. Declining gas consumption suggests there may be a declining customer base across which to distribute the costs of existing and any new infrastructure.
4. If a given gas infrastructure facility is not necessary over its estimated useful life, it could become a stranded asset, imposing costs but limited benefits

to a declining pool of ratepayers, and increasing the cost burden on individual ratepayers.

5. Recent controversies and the Commission's ESJ Action Plan underscore the need for public participation opportunities regarding gas infrastructure projects.

6. The Commission has not previously required permit or CPCN applications for gas infrastructure and has conducted relatively few CEQA reviews of gas infrastructure projects.

7. Establishing a gas infrastructure GO will allow the Commission to exercise discretionary approval authority over certain gas infrastructure.

8. A gas infrastructure GO is responsive to:

    a. the requirements of CEQA;

    b. the need for public notice and the opportunity for affected parties and members of the public to be heard by the Commission;

    c. the obligation of the utilities to serve their customers in a timely and efficient manner; and

    d. the need to review significant investments in gas infrastructure for consistency with California's long-term greenhouse gas emission reduction, air quality, equity, safety and reliability goals.

9. The CPCN application requirements we adopt here both initiate and are distinct from Commission CEQA review of a project.

10. Stakeholders and local communities will have the opportunity to review and comment on proposed gas infrastructure projects subject to a CPCN application requirement pursuant to this decision during both the application review process and the accompanying CEQA review process. Section VI(A)(7)(b) of the adopted GO requires gas corporations to undertake outreach to and

engagement with local communities likely to be impacted by proposed projects (including relevant community-based organizations) and to provide a summary of these activities in their CPCN applications.

11. A $75 million threshold for a CPCN application under a new gas infrastructure GO will ensure Commission focus on the largest projects with the greatest potential to create stranded assets and environmental impacts.

12. Requiring gas utilities to use "fully loaded" cost estimates, including direct costs and indirect costs, in their estimates of project costs, for purposes of assessing if a project cost exceeds $75 million for purposes of a gas GO, will help ensure that the full costs to ratepayers of the project and potential alternatives are considered.

13. Requiring a CPCN application if (1) a project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant (as defined in this decision); or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant, will focus Commission review on those gas infrastructure projects most likely to have significant local air pollution impacts, including projects located in historically pollution-burdened communities.

14. Areas designated as a "serious" non-attainment area for a particular pollutant are likely to disproportionally implicate ESJ communities as defined in our ESJ Action Plan.

15. It is reasonable to base the criterion described in Finding of Fact 13 on criteria pollutants for which there is an established National Ambient Air Quality Standard (40 C.F.R. Part 50), and to limit application of the criterion, for any air

pollutant, to any non-attainment area within the meaning of Section 7407(d) of the CAA Section 7501(2) for that air pollutant, with "serious," "severe" or "extreme" based on an area's design value for a specific criteria pollutant in the US EPA's Green Book of NAAQS.

16. Including toxic air contaminants in the criterion described in Finding of Fact 13 is reasonable because such pollutants may cause or contribute to an increase in mortality or an increase in serious illness, have been extensively reviewed by CARB, and are documented to cause significant human health impacts at a variety of exposure levels.

17. The appropriate locus of review of localized noise, traffic, vibrations, or fugitive dust effects on a neighborhood associated with gas infrastructure projects is with local agencies.

18. Requiring gas utilities to consult with local agencies regarding land use matters involving gas infrastructure supports resolution of conflicts between utilities and local agencies in a timely manner.

19. Because the Commission has exclusive jurisdiction over state gas infrastructure, in instances where the public utilities and local agencies are unable to resolve their differences, the local agency should promptly file a complaint with the Commission.

20. Defining a project for purposes of a gas GO as the "construction or physical modification of any gas plant with independent utility in the gas system, including compressor or regulator stations, any pipeline or pipeline extension, or any expansion of an existing gas storage field" helps ensure that gas corporations' proposed projects address a single set of infrastructure modifications over time, regardless of the time period over which the project is implemented.

21. This decision does not address whether hydrogen gas infrastructure projects should be covered by the adopted GO.

22. This GO is intended to minimize potentially inappropriate exemption claims while not impeding rapid implementation of gas infrastructure repairs or improvements to address emergency situations, including when the reliability of gas supplies is urgently threatened.

23. Requiring utilities to file claims of exemptions for gas emergency projects no later than 60 days from commencement of the project allows utilities to begin work on urgent emergency projects while providing an opportunity for affected community members, local governments, stakeholders and this Commission to learn about the project.

24. Exempting projects required by any regulatory agency for safety reasons from CPCN application requirements ensures timely utility compliance with those regulations and the accompanying public safety of gas supplies.

25. Excluding service lines connecting gas infrastructure to customer facilities and work on customer meters from the GO is reasonable as these projects are unlikely to cause significant environmental impacts.

26. Requiring a CPCN application for any sized distribution pipeline, other than service pipelines that connect to customer facilities and work on customer meters, that otherwise meet our adopted criteria, will focus Commission review on the distribution projects most likely to cause environmental harms or substantial costs to ratepayers.

27. The record of this proceeding lacks information on the costs incurred to bring a project from conception to the permit application stage.

28. Authorizing an exemption from filing a CPCN application for projects that have an in-service date scheduled to occur before January 1, 2024 gives utilities

sufficient planning time while exempting projects that are relatively close to fruition.

29. Authorizing an exemption from filing a CPCN application for projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule prior to the effective date of this GO allows projects planned to comply with local air quality management district environmental requirements that required substantive time and resources to develop to move forward in a streamlined fashion.

30. It is not necessary to adopt exemptions to CPCN application requirements for projects involving the replacement of existing facilities by equivalent facilities, minor relocations, repairs, maintenance or alternations of existing facilities in a manner consistent with CEQA guidelines, or the placement of new equipment on structures already built consistent with CEQA guidelines because these projects are unlikely to meet our adopted threshold criteria and these exemptions duplicate CEQA categorical exemptions that will apply as part of the Commission's CEQA review of any CPCN application.

31. It is not reasonable to exempt from a CPCN application requirement those projects with completed CEQA documents because project review by one agency does not relieve other agencies from their CEQA review obligations and there may be circumstances under which another agency performs CEQA review of a proposed gas infrastructure project only as part of a larger project.

32. Adopting broadly worded exceptions to the exemptions adopted here could introduce uncertainty into implementation of the GO and is not necessary.

33. The notification requirements in the adopted GO are reasonable.

34. Requiring a robust set of information in gas CPCN applications filed under this GO will help avoid unnecessary costs to ratepayers and will assist this

Commission in evaluating and addressing potential environmental harms to local communities.

35. The need for analysis of non-pipeline alternatives is a central rationale for adoption of a gas infrastructure GO at this time.

36. Requiring gas corporations in their CPCN applications, if a proposed project is located within an ESJ community, to consider whether it is possible to relocate the project outside such areas, and, if so, steps taken to do so, reflects the Commission's ESJ Action Plan, helps minimize environmental impacts from gas infrastructure in such communities, and reflects the equity purpose of the GO.

37. Due to the unique circumstances of independent storage providers, it is reasonable that such gas corporations are not required to provide information elements contained in Section VI(A)(4)(a) Section VI(A)(4)(b), VI(A)(4)(d) and VI(A)(5)(c), regarding non-pipeline alternatives and alternate routes, in their CPCN applications, or information element Section X(D)(1) in their annual Report of Planned Gas Investments.

38. Review of cost information provided by independent storage providers will enable a broader understanding of the pass-through costs from gas storage to utility customers, which will in turn support broader consideration of alternatives to minimize costs to ratepayers and stranded costs in this era of declining gas consumption.

39. Requiring gas corporations to initiate prefiling meetings with Commission Staff and, with the exception of CPCN applications filed within 120 days from issuance of this decision, to submit a draft PEA at least three months prior to filing a CPCN application will ensure the Commission has a robust PEA

with which to consider potential environmental impacts and to initiate CEQA review of the proposed project.

40. Requiring gas utilities to report on projects they intend to claim as exempt from a CPCN application requirement in their annual Report of Planned Gas Investments will assist stakeholders and the Commission in evaluating the effectiveness and implementation of these exemptions.

41. Adopting an annual reporting requirement for projects with costs in excess of $50 million over a 10-year horizon and projects meeting the sensitive receptors criterion described in Finding of Fact 13, including projects a gas corporation plans to claim as exempt from a CPCN application requirement, adds transparency, is not onerous, and will provide stakeholders and the Commission with insight into a greater range of planned projects than addressed by our CPCN application requirements.

42. For projects the gas corporation anticipates claiming as exempt from a CPCN application requirement, it is reasonable that gas corporations not be required to include in the annual Report of Planned Gas Investments information describing non-pipeline alternatives considered (Section X(D)), and information regarding cumulative environmental impacts of successive projects (Section X(C)(6)).

43. Requiring an annual Report of Planned Gas Investments Workshop during the years 2023, 2024, and 2025, and providing an opportunity for parties to comment on the reports and reporting requirements in a way that may result in revisions to them, adds transparency, and accountability, and provides an opportunity for engagement in and improvement in the report information and its use in the early years of implementation of this GO.

44. Requiring additional information in the annual Report of Planned Gas Investments on projects planned to be in-service within five years of the date of a given annual report provides transparency and is reasonable.

45. The definitions contained in the adopted GO are reasonable.

46. The information required to be included in the annual Report of Planned Gas Investments is reasonable.

Conclusions of Law

1. This Commission retains exclusive authority to regulate gas corporations pursuant to Article XI, Section 8 of the California Constitution, which states that, "[a] city, county, or other public body may not regulate matters over which the Legislature grants regulatory power to the Commission," including jurisdiction to regulate all aspects of the design, construction, modification, or relocation of public utilities.

2. The Commission has discretion to require CPCN applications for gas infrastructure projects with costs exceeding $75 million or where (1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant (as defined in this decision); or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant.

3. The $75 million monetary threshold we adopt here for a CPCN application encompasses all phases of a project.

4. Projects meeting the criteria described in Conclusion of Law 2 should be subject to CEQA review and closely scrutinized to determine need, identify

potential alternatives including non-pipeline alternatives, and identify ways to eliminate or mitigate environmental impacts.

5. Declaring that CPCN applications are not required for gas infrastructure projects that do not meet the criteria in Conclusion of Law 2 allows the Commission to focus its resources on costs and need for and the environmental impacts of projects most likely to effect local communities.

6. Requiring a CPCN application would serve no useful regulatory purpose for projects that meet the following criteria:

   a. any plant, line, extension, repair, replacement, or modification of existing facilities or structures that is required pursuant to a CalGEM Emergency Order or regulation, PHMSA, this Commission, or any other regulatory agency for safety reasons;

   b. projects that have a scheduled in-service date occurring before January 1, 2024 and projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule, prior to the effective date of this GO; or,

   c. emergency projects (for example: repairs, upgrades, replacements, restorations) as defined by CEQA Guideline § 15269 and Pub. Res. Code §§ 21060.3 and 21080(b)(2) & (4) to ensure safe and reliable gas supplies.

7. The Commission should require, within 60 days of the issuance of this decision, each respondent gas corporation to this rulemaking to file and serve a list of gas infrastructure projects that are scheduled to be in-service before January 1, 2024, that have a cost exceeding $75 million or where (1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant (as

defined in this decision); or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant, should require this list to include, clearly indicated, projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule prior to the effective date of this GO, and should require each respondent gas utility to provide for each project listed the information identified in Section V(C)(2) of the adopted GO.

8. For gas infrastructure projects with costs below $75 million or where (1) the project is not located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation does not require a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant (as defined in this decision); or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant, the Commission's complaint procedure is adequate for addressing concerns public agencies or the public may have with regard to utility projects.

9. Requiring gas corporations, if a proposed project is located within an ESJ community, to consider in their CPCN applications whether it is possible to relocate the project outside such areas, and, if so, steps taken to do so, reflects the intent of Pub. Util. Code Section 454.52(a)(1)(I).

10. Independent storage projects that have previously undergone CEQA review and are included in the existing property boundary of a current CPCN should be excluded from additional CPCN application requirements under the GO. However, any storage expansion project that meets the criteria and definitions adopted here should apply for a CPCN application as stated in our adopted GO.

11. The Commission should require independent storage providers to provide the same information as other gas corporations in CPCN applications and annual reports, with the exception, in CPCN applications, of the information elements contained in Section VI(A)(4)(a) Section VI(A)(4)(b), VI(A)(4)(d) and VI(A)(5)(c), and with the exception, in the annual Report of Planned Gas Investments, of information element D(1) in Section X.

12. The Commission should direct PG&E, SoCalGas, and SDG&E to jointly convene a Report of Planned Gas Investments Workshop no less than 60 days from the date of filing their annual gas reports pursuant to Section X of the GO adopted here, for the years 2023, 2024 and 2025. To the extent a gas corporation other than PG&E, SoCalGas, and SDG&E has upcoming projects listed in that year's annual Report of Planned Gas Investments, the Commission should require that gas corporation to participate in the workshop and present on such projects.

13. The Commission should allow parties to file and serve comments on the annual Report of Planned Gas Investments and to recommend changes to the reports and to reporting requirements, as needed, in R.20-01-007 or a successor proceeding, in the years 2023, 2024, and 2025, no later than 15 days from the date of each annual Report of Planned Gas Investments Workshop. During the years 2023, 2024, and 2025, the Commission should require gas corporations to consider filed party comments on their report, and to refile their reports, with revisions that add additional information or clarifications to address party comments, no later than 45 days from the date party comments are filed, including in the refiled reports an appendix that summarizes how each party comment was addressed.

14. The Commission should require PG&E, SoCalGas, and SDG&E, and other gas corporations as interested, no later than 90 days from the date party comments are served and filed on the annual Report of Planned Gas Investments in 2023, 2024, and 2025, to jointly submit a Tier 3 Advice Letter requesting any changes to the reporting requirements suggested by parties and agreed to by the gas corporations. If no changes to the reporting requirements were proposed by parties and agreed to by the gas corporations, the Commission should not require PG&E, SoCalGas, and SDG&E to file a Tier 3 Advice Letter.

15. The Commission should adopt the GO set forth in Appendix A.

O R D E R

IT IS ORDERED that:

1. The General Order attached to this decision as Appendix A, General Order 177, which prescribes the rules relating to the planning and construction of gas infrastructure located in California, is adopted.

2. Gas infrastructure planned or constructed by California gas utilities under this Commission's jurisdiction shall adhere to the rules set forth in General Order 177.

3. Prior to the construction or physical modification of any gas plant with independent utility in the gas system with a cost exceeding $75 million, or where (1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant, defined as an increase exceeding de minimis levels or, where relevant, allowable limits set by the local air quality district; or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant, the gas utility shall file an application for

a certificate of public convenience and necessity, unless the project qualifies for exemption as prescribed in General Order 177.

4. Gas utilities invoking exemptions (a)-(b) listed under Section IV(B) of General Order 177 shall provide 60 days' prior notice of claimed exemptions to General Order 177 as described therein. Gas utilities invoking exemption (c) under Section IV(B) shall provide notice of claimed exemptions to General Order 177 no later than 60 days of initiating the project as described therein.

5. Gas projects as defined in General Order 177 that have a scheduled in-service date occurring before January 1, 2024 and projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule prior to the effective date of General Order 177, shall be exempt from the requirements adopted here.

6. Within 60 days of issuance of this decision, each respondent gas utility shall file and serve a list of proposed gas infrastructure projects that have a scheduled in-service date occurring before January 1, 2024 that have a cost exceeding $75 million or where (1) the project is located within 1,000 feet of a sensitive receptor; and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for: (a) an increase in levels of a toxic air contaminant, defined as an increase exceeding de minimis levels or, where relevant, allowable limits set by the local air quality district; or (b) an increase in levels of a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant. Each respondent gas utility shall include in this list, clearly indicated, projects for which an application for approval has been submitted to an air quality management district for compliance with an environmental rule prior to the

effective date of General Order 177, and shall provide, for each project listed, the information identified in Section V(C)(2) of General Order 177.

7. The gas utility shall annually serve and file, in Rulemaking 20-01-007 or a successor proceeding, a Report of Planned Gas Investments on or before March 1 of each year, starting March 1, 2023, as described in Section X of the General Order 177.

8. Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company shall jointly convene a Report of Planned Gas Investments Workshop as specified in this decision no less than 60 days from the date of filing their annual Report of Planned Gas Investments reports pursuant to Section X of the General Order 177, for the years 2023, 2024 and 2025.

9. To the extent a gas corporation respondent to this rulemaking, other than those listed in Ordering Paragraph 8, has upcoming projects listed in their 2023, 2024, or 2025 annual Report of Planned Gas Investments, the gas corporation shall participate in the workshop described in Ordering Paragraph 8 and shall present on such projects.

10. Parties to Rulemaking 20-01-007, or a successor proceeding, may serve and file comments on the annual Report of Planned Gas Investments recommending changes to the reports, or to the reporting requirements included in the General Order 177, in the years 2023, 2024, and 2025, no later than 15 days from the date of each annual Report of Planned Gas Investments Workshop.

11. During the years 2023, 2024, and 2025, gas corporations shall consider filed party comments on their annual Report of Planned Gas Investments, and shall refile their reports, with revisions that add additional information or clarifications to address party comments, no later than 45 days from the date party comments are filed. Gas corporations shall include in their refiled reports

an appendix that summarizes how each party comment was addressed. If no party comments on a gas corporation's annual Report of Planned Gas Investments during the years 2023, 2024, and 2025, the gas corporation is not required to refile a revised report as described here.

12. Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E) shall, and other gas corporations may, no later than 90 days from the date party comments are filed on the Report of Planned Gas Investments in 2023, 2024, jointly submit a Tier 3 Advice Letter requesting any changes to the reporting requirements contained in General Order 177 suggested by parties and agreed to by the gas corporations. If no changes to the reporting requirements were proposed by parties and agreed to by the gas corporations, PG&E, SoCalGas, and SDG&E are not required to file a Tier 3 Advice Letter.

13. Rulemaking 20-01-007 remains open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

Service Date: December 23, 2024

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, D/B/A AVISTA UTILITIES, Respondent.	DOCKETS UE-240006 & UG-240007 (Consolidated) **CORRECTED ORDER** ORDER 08 FINAL ORDER

SUMMARY

Synopsis: *The Commission rejects the tariff sheets filed by Avista Corporation, d/b/a Avista Utilities (Avista or the Company) on January 18, 2024, including the Company's proposed multi-year rate plan. The Commission, considering the full record, authorizes and requires Avista to file tariff sheets reflecting a two-year multi-year rate plan that will result in an increase in revenue of $11.882 million, or 2.01 percent in rate year 1 and approximately $44.4 million, or 7.51 percent in rate year 2 after adjusting for offsetting factors related to Colstrip, for its electric operations and an increase in revenue of approximately $14.2 million, or 11.15 percent in rate year 1 and approximately $4.0 million, or 2.81 percent in rate year 2, for its natural gas operations, in accordance with the decisions below*

The Commission adjusts the Company's return on equity to 9.80 percent and does not authorize a flotation cost adjustment. The Commission accepts Avista's cost of debt of 4.99 percent. The Commission accepts the Company's proposed capital structure and authorizes and sets rates with a capital structure of 48.5 percent equity, 51.5 percent debt. This results in a rate of return for Avista of 7.32 percent.

The Commission authorizes an increase or adjustment to the energy recovery mechanism baseline consistent with this Order to account for the increases in Washington's allocated share of power costs and transmission costs. While the Commission allows the power cost baseline to be reset in this proceeding, the Commission will continue to consider carefully

any future adjustments to the baseline and will change it only under extraordinary circumstances.

TABLE OF CONTENTS

BACKGROUND

1 **PROCEDURAL HISTORY.** On January 18, 2024, Avista Corporation d/b/a Avista Utilities (Avista or Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its electric service tariff, Tariff WN U-28, and its natural gas service tariff, Tariff WN U-29 (Initial Filing).[1] Through these filings, Avista seeks to increase rates and charges for the electric and natural gas services the Company provides to its Washington customers.

2 Avista's Initial Filing proposes a rate of return of 7.61 percent (with 48.5 percent equity and a 10.40 percent return on equity). Avista proposes a Two-Year Rate Plan, which would begin with new base rates effective in December 2024 (Rate Year 1) and December 2025 (Rate Year 2).

3 For Rate Year 1, Avista proposes an increase to electric base revenue of $77.1 million, or 13.0 percent, and an increase to natural gas base revenue of $17.3 million, or 13.6 percent. For Rate Year 2, Avista proposes an increase to electric base revenue of $53.7 million, or 11.7 percent, and an increase to natural gas base revenue of $4.6 million, or 3.2 percent.

4 On January 31, 2024, the Commission entered Order 01 consolidating dockets UE-240006 and UG-240007, suspending the tariffs, and setting the matters for adjudication.

---

[1] *WUTC v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-240006 & UG-240007 (*consolidated*), filed Revisions to Tariff WN U-28 (Electric) and Tariff WN U-29 (Natural Gas) (Jan. 18, 2024).

5 On February 20, 2024, the Commission convened a virtual prehearing conference before Administrative Law Judges James E. Brown II and Paige Doyle.

6 On February 27, 2024, the Commission entered Order 02 Prehearing Conference Order; Notice of Hearing, establishing the Procedural Schedule, granting petitions to intervene, and noticing an evidentiary hearing for September 30, 2024, continuing if needed to October 1, 2024. On the same day, the Commission entered Order 03, establishing a protective order.

7 On March 20, 2024, Commission staff (Staff) filed a Motion for Partial Summary Determination (Motion). In its Motion, Staff asked for summary determination that Avista's proposed portfolio forecast error adjustment, as included in Avista's proposed Tariff WN U-28, should not be incorporated into Avista's pro forma power cost adjustment, or its Energy Recovery Mechanism (ERM).2

8 On August 7, 2024, following extensive briefing by the parties, the Commission issued Order 07 Denying Staff's Motion For Partial Summary Determination (Order 07), Order 07 denied Staff's Motion because granting the motion would decide a substantial portion of the matter "without the benefit of a full proceeding where the testimony and evidence are examined" and cross-examined.3 Order 07 reiterated the importance of the Commission's discretion and having the ability to weigh the evidence, hear witness testimony, and ask questions of the parties so the Commission can reasonably balance the interests of the parties and issue a decision in the public interest.4

9 Beginning on September 30, 2024, the Commission held a two-day evidentiary hearing in this matter before the Commissioners, with Administrative Law Judges, James E. Brown II and Connor A. Thompson presiding.

10 The parties submitted initial and responsive briefs in the proceeding on October 28, 2024, and on November 12, 2024, Alliance of Western Energy Consumers (AWEC) filed a Motion to File a Limited Response to Public Counsel's Post-Hearing Brief.

11 **PARTY REPRESENTATIVES.** David Meyer, in-house counsel, represents Avista. Jeff Roberson, Josephine R. K. Strauss, Lisa Gafken, Nash Callaghan, Liam Weiland, and

[2] Dockets UE-240006 & UG-240007, Commission Staff's Motion for Partial Summary Determination (Motion) (Mar. 20, 2024).

[3] Dockets UE-240006 & UG-240007, Order 07, Denying Staff's Motion for Partial Summary Determination pg. 36 ¶ 105 (Aug. 7, 2024).

[4] Dockets UE-240006 & UG-240007, Order 07, pgs. 36-37 ¶¶ 103-07.

Colin O'Brien, Assistant Attorneys General, Olympia, Washington, represent Commission staff (Staff).[5] Tad Robinson O'Neill, Jessica Johanson-Kubin, and Robert Sykes, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Tyler C. Pepple and Sommer J. Moser, of Davison Van Cleve, P.C., represent the Alliance of Western Energy Consumers (AWEC). Michael Goetz, in-house counsel, represents the Northwest Energy Coalition (NWEC). Yochi Zakai and Josh Kirmsse, of Shute, Mihaly & Weinberger LLP, represents The Energy Project (TEP). Gloria Smith, of Sierra Club Environmental Law Program, represents Sierra Club. Justina A. Caviglia represents Walmart, Inc (Walmart).

12 **COMMISSION DETERMINATIONS.** Based on the decisions we make in this Order, we authorize an increase in Avista's revenue requirement of $11.882 million, or 2.01 percent in rate year 1 and approximately $44.4 million, or 7.51 percent in rate year 2 after adjusting for offsetting factors related to Colstrip, for the Company's electric operations and an increase in revenue of approximately $14.2 million, or 11.15 percent in rate year 1 and approximately $4.0 million, or 2.81 percent in rate year 2, for its natural gas operations. Summaries of both the electric and natural gas revenue requirements are attached hereto at Appendix C (electric) and Appendix D (natural gas).

13 **PRELIMINARY MATTERS.** We note that on November 12, 2024, AWEC filed a Motion to File a Limited Response to Public Counsel's Post-Hearing Brief (Motion) along with a Limited Response to Public Counsel's Post-Hearing Brief (Response).[6] According to AWEC's Motion, the Limited Response addresses an alleged inaccuracy in Paragraph 132 of Public Counsel's Post-Hearing Brief. AWEC claims that it filed its response with the intent to ensure a clear evidentiary record. No other parties, including Public Counsel, filed an Answer to AWEC's Motion. Upon review and consideration, we grant AWEC's motion to ensures a clear and complete record in this proceeding.

---

[5] 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.

[6] Dockets UE-240006 & UG-240007, AWEC's Motion to File a Limited Response to Public Counsel's Post-Hearing Brief (Motion) (November 12, 2024).

MEMORANDUM

I. STANDARD OF REVIEW

- **Regulating in the public interest and determining equitable, fair, just, reasonable, and sufficient rates**

14 The Legislature has entrusted the Commission with broad discretion to determine rates for regulated industries. Pursuant to RCW 80.28.020, whenever the Commission finds after a hearing that the rates charged by a utility are "unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order."[7]

15 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company.[8] The burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[9]

16 More recently, in 2019, the Legislature expanded the traditional definition of the public interest standard. As Washington state transitions to a clean energy economy, the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[10] In achieving these policies, "there should not be an increase in environmental health impacts to highly impacted communities."[11]

17 In 2021, the Legislature again expanded upon the public interest standard in the context of reviewing multiyear rate plans. RCW 80.28.425 provides that "[t]he commission's consideration of a proposal for a multiyear rate plan is subject to the same standards

---

[7] *See also* RCW 80.01.040(3) (providing that the Commission shall "[r]egulate in the public interest").

[8] RCW 80.04.130(1).

[9] *WUTC v. Pacific Power and Light Company*, Cause No. U-76-18 (December 29, 1976) (internal citations omitted).

[10] RCW 19.405.010(6).

[11] *Id.*

applicable to other rate filings made under this title, including the public interest and fair, just, reasonable, and sufficient rates." The statute continues, "In determining the public interest, the commission may consider such factors including, but not limited to, environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission."[12]

18 Following the passage of RCW 80.28.425, the Commission indicated its commitment to considering equity while regulating in the public interest: "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."[13] The Commission also indicated that regulated companies should be prepared to address equity considerations in future cases: "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."[14]

19 During general rate case proceedings, the Commission may determine the prudence of utility actions by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[15] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[16] Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives which the Commission might find prudent.[17]

DISCUSSION AND DECISION

II. CONTESTED ISSUES

CCA Costs/Inclusion of Costs in Dispatch

---

[12] *Id.*

[13] *WUTC v. Cascade Natural Gas Corporation,* Docket UG-210755 Order 10 ¶ 58 (August 23, 2022).

[14] *Id.*

[15] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (Apr. 7, 2004).

[16] *See*, *id.*

[17] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG—090705 (*consolidated*), Order 11 at ¶ 337 (Apr. 2, 2010).

Avista's Direct Testimony

20 Company witness Kinney testifies that Avista has added significant work processes to both its power and natural gas supply departments to account for increased activity associated with CCA compliance.[18] Currently, this added CCA work has been performed by existing employees. However, Kinney states that this resource approach cannot be sustained as other critical work has been either delayed or not adequately supported.[19]

21 As such, Kinney states that the Company plans to hire four more positions in 2024 to support compliance with CCA. These include a Climate Compliance Manager, a CCA Portfolio Manager, an Energy Supply Analyst, and an Investment Program Manager.[20] The Company notes that it expects it will need to hire additional positions beyond these four as it continues to understand what it characterizes as the broad reaching effects of the CCA.[21]

22 Avista witness Kinney states that the CCA labor adjustment is the only pro forma adjustment in this case where the Company is seeking approval of incremental costs incurred to comply with CCA.[22]

23 Kinney testifies that its Pro Forma CCA Labor Expense adjustment reflects the incremental labor expense of four additional employees in 2024, totaling approximately $494,000 ($381,000 to electric and $113,000 to gas).[23] This adjustment decreases Net Operating Income (NOI) by $301,000 for electric and $89,000 for gas.[24]

24 The Company testifies that its strategy for natural gas decarbonization includes diversifying and transitioning from conventional fossil fuel natural gas to Renewable Natural Gas (RNG), hydrogen, other renewable fuels, and reducing consumption via conservation and energy efficiency.[25] Additionally, Avista testifies that it will purchase carbon offsets as necessary to meet the CCA compliance obligations.[26]

---

[18] Kinney, SJK-1T at 9:3-4.

[19] Kinney, SJK-1T at 9:4-7.

[20] Kinney, SJK-1T at 9:7-9.

[21] Kinney, SJK-1T at 10:4-8.

[22] Kinney, SJK-1T at 10:18-20.

[23] Schultz, Exh.KJS-1T at 69:13-15.

[24] Schultz, Exh.KJS-1T at 70:1-2.

[25] Thackston, Exh. JRT-1T at 9:5-8.

[26] Thackston, Exh. JRT-1T at 9:9.

25 Avista contends that based on the CCA's cap-and-trade program's current allowance price range of $22-$82 USD, natural gas with a carbon offset or Renewable Thermal Credits (RTC) will continue to most cost effectively serve Washington customers.[27]

26 The Company also argues that in the short term, the best approach to recover CCA costs is to have them flow through a 95/5 Energy Recovery Mechanism (ERM) without deadbands.[28] Kinney states that allowing those CCA costs to flow through the ERM at 95/5 obligates the Company to pay 5 percent of anticipated CCA costs but avoid disagreements among parties over the magnitude of costs that cannot be known at this point.[29]

27 Kinney contends that requesting 100 percent recovery of CCA costs would be the fairest outcome and reflect the legislation's intent.[30] However, as part of an overall package to simplify the ERM and address increasing forecast costs, he states that the Company is offering this 95/5 split as a compromise.[31]

Staff's Response Testimony

28 Staff witness Erdahl testifies that Avista does not currently and, unless ordered by the Commission, does not plan to incorporate the cost of carbon allowances in future dispatch decision.[32]

29 Erdahl contends that the failure to include allowance costs in dispatch may result in polluting thermal units being dispatched too frequently, which creates equity concerns when those thermal units are located in or near vulnerable populations or highly impacted communities.[33] Erdahl identifies the Boulder Park facility and the Northeast Combustion Turbine as thermal units located within vulnerable population census areas, and the Kettle Falls Biomass Facility which is located within a highly impacted community (HIC).[34]

---

[27] Thackston, Exh. JRT-1T at 9:12-15.

[28] Kinney, Exh. SJK-1T at 64:18-19.

[29] Kinney, Exh. SJK-1T at 64:19-20 and 65:1-2.

[30] Kinney, Exh. SJK-1T at 65:4-5.

[31] Kinney, Exh. SJK-1T at 65:6-9.

[32] Erdahl, Exh. BAE-1T at 21:16-17, 22:3-4.

[33] Erdahl, Exh. BAE-1T at 22:6-10.

[29] Erdahl, Exh. BAE-1T at 23:15-17.

30 She recommends that the Commission direct Avista to include the cost of carbon allowance instruments in its forecasting and day-to-day dispatch decisions.[35]

31 Erdahl notes that Puget Sound Energy (PSE) applies a CCA allowance instrument cost adder into costs associated with thermal fleet dispatch to supply secondary and wholesale market sales.[36]

32 Erdahl acknowledges that the inclusion of CCA allowance costs in dispatch decision could result in reduced dispatch of Avista's thermal resource under certain conditions, which could reduce the Company's wholesale and secondary sale revenues.[37] However, Erdahl emphasizes that several of Avista's thermal resources are located within vulnerable populations and highly impacted communities.[38]

33 Staff Witness Wilson testifies that it does not appear that Avista's carbon allowances are being tracked consistently with the CCA.[39] According to Wilson, in the Company's CCA Compliance Model, Avista expects that its no-cost allowances are intended to be used both for emissions associated with serving retail load and for emissions associated with wholesale sales whose revenues benefit its retail customers.[40]

34 However, Wilson states that this understanding is incorrect as Ecology allocated no-cost allowances to Avista based on its requirements to serve Washington retail load, and that Avista remains responsible for obtaining allowances for its wholesale load.[41]

35 To the extent that Avista is relying on the understanding that Ecology is allocating no-cost allowances to Avista for emissions associated with wholesale sales, Staff believes that such reliance is likely to lead to imprudent decisions.[42]

36 Wilson also contends that the Company has placed too much weight on Ecology's "true-up" mechanism.[43] According to Staff, Ecology has said that it anticipates that future

---

[35] Erdahl, Exh. BAE-1T at 24:1-2.

[36] Erdahl, Exh. BAE-1T at 24:7-8.

[37] Erdahl, Exh. BAE-1T at 24:21-22 and at 25:1-2.

[38] Erdahl, Exh. BAE-1T at 25:6-9.

[39] Wilson, Exh. JDW-1TC at 17:5-6.

[40] Wilson, Exh. JDW-1TC at 17:6-10.

[41] Wilson, Exh. JDW-1TC at 17:11-17.

[42] Wilson, Exh. JDW-1TC at 17:18-20.

[43] Wilson, Exh. JDW-1TC at 20:7-9.

allocation decisions will be based on concepts such as the reasons for the difference between forecast and actual emissions as well as the expectation that allowance costs will be a factor in dispatch.[44] Given Ecology staff's statement that the true-up will not be one-for one, Staff witness Wilson emphasizes that Avista may need to purchase some allowances for its retail load and especially for its wholesale load, unless those loads are served by energy that does not incur a CCA compliance obligation.[45]

37 Wilson asserts that this strongly suggests that Avista should consider the price of carbon allowances in its dispatch decisions and, hence, in its Net Power Expense (NPE) forecast.[46]

38 Witness Wilson further opines that Avista's no-price dispatch approach puts its allocation of no cost allowances at risk. Given that Ecology is going to consider the reasons for any difference between allocated allowances and actual emissions, if Avista excludes the cost of carbon allowances from its dispatch decisions, Ecology staff will likely look unfavorably on a request to fully true-up Avista's allowances.[47]

39 Staff Witness Wilson testifies that a key complication for the Commission's review of the forecast and actual NPE is that Ecology's CCA compliance requirements do not occur at the end of each calendar year, but require partial and then final surrender of required allowances over a four-year compliance period.[48] Therefore, Wilson contends that the Commission must determine if it will expect Avista to record allowance costs to show compliance on an annual basis or not.[49]

40 If the Commission chooses to do so, then witness Wilson states that Avista's actual NPE would include the actual net cost of CCA allowance transactions in its annual NPE filing *and,* for any surplus or deficit in allowance transactions, Avista would determine an *additional* net cost on a mark-to-market basis.[50] According to Staff, this option would have at least two disadvantages:[51]

---

[44] Wilson, Exh. JDW-1TC at 20:24-26, 21:1.

[45] Wilson, Exh. JDW-1TC at 21:7-10.

[46] Wilson, Exh. JDW-1TC at 21:11-12.

[47] Wilson, Exh. JDW-1TC at 21:13-17.

[48] Wilson, Exh. JDW-1TC at 23:3-7.

[49] Wilson, Exh. JDW-1TC at 23:7-9.

[50] Wilson, Exh. JDW-1TC at 23:10-13.

[51] Wilson, Exh. JDW-1TC at 23:13-16.

- The methods for pricing its unsold (or unpurchased) allowances would need to be developed; and
- Reviews and the resulting net value would need to be carried forward to subsequent years.

41 Wilson notes that this option would have the advantages of providing the Commission with a clear opportunity to review the prudence of Avista's transactions and pricing decisions.[52]

42 If the Commission does not require Avista to show compliance on an annual basis, then Avista could simply record its actual net transaction costs for the year and defer the valuation of any allowance surplus or deficit to the future.[53] Wilson notes that this option would be far more administrable and eliminate the need to develop a mark-to-market pricing method.[54]

43 However, since Avista would only encounter a compliance date at which it is required to fully account for its emissions by surrendering allowances every four years, Wilson identifies that the Commission could find it more challenging to review the prudence of Avista's transactions and pricing decisions.[55]

44 Wilson believes that the Commission will find it most efficient to review the prudence of Avista's CCA allowance use and transactions in annual NPE review proceedings due to the Commission every year.[56]

45 Accordingly, Staff argues that in future NPE proceedings, Avista should demonstrate that throughout each reporting year, it has identified an appropriate carbon allowance price and that its unit dispatch and power purchase decisions were prudent, which should include a clear demonstration that those decisions were consistent with its current estimate of the carbon allowance price.[57] Wilson also argues that in future NPE proceedings, Avista will also need to demonstrate that its purchase or sale of allowances is prudent.[58]

[52] Wilson, Exh. JDW-1TC at 23:16-18.

[53] Wilson, Exh. JDW-1TC at 23:19-20.

[54] Wilson, Exh. JDW-1TC at 23:20-22.

[55] Wilson, Exh. JDW-1TC at 23:22-23, 24:1-3.

[56] Wilson, Exh. JDW-1TC at 24:16-17.

[57] Wilson, Exh. JDW-1TC at 24:22-25:3.

[58] Wilson, Exh. JDW-1TC at 25:4-5.

46 Wilson also suggests the following five factors for the Commission to weigh when determining how to review the prudence of CCA use and transactions:[59]

- Administrative simplicity;
- Necessity of reviewing the allowance price and other factors that should be considered in unit dispatch and power purchase decisions during the annual NPE proceeding;
- Consideration that decisions to transact (or not transact) in the carbon market and carbon auctions depend on the reasonableness of the carbon price estimate and carbon price forecast as it existed during the year;
- Consideration that it is preferable to account for the costs (or benefits) resulting from decisions to transact (or not transact) in the year in which those transactions affect NPE (using mark-to-market valuations for unused allowances, as discussed above); and
- Consideration that it will be easier to review the reasonableness of a utility's carbon price forecasting method after that method is exposed to a variety of real-world circumstances, which may take several years to manifest.

47 While Avista has not estimated CCA costs, Wilson states that in response to a data request[60], Avista provided an illustration of how CCA costs might affect the ERM. In its illustration, Avista suggests that a "bad case, representing approximately a 25% overrun of current (2023) allowance grant levels" would result in an annual cost of as much as $30 million.[61]

48 Witness Wilson recommends that the Commission direct Avista to include CCA allowance costs in the dispatch of its thermal generation plants, whether to serve customer load or to sell electricity into the wholesale market. Wilson opines that Avista should then offset the allowance costs for its retail customer load with no-cost allowances.[62]

49 Wilson also believes that it is most appropriate for the prudence of allowance costs to be reviewed in each utility's respective NPE true-up proceeding —in Avista's case, its annual ERM proceeding.[63]

AWEC's Cross-Answering Testimony

---

[59] Wilson, Exh. JDW-1TC at 25:12-27 and at 26:1-3.

[60] See Staff DR-171 Supplemental.

[61] Wilson, Exh. JDW-1TC at 27:12-16; *see also* JDW-11 Avista's Response to DR No. 171.

[62] Wilson, Exh. JDW-1TC at 31:19-22.

[63] Wilson, Exh. JDW-1TC at 32:12-14.

50 AWEC Witness Mullins contends that the decision for how to respond to the uncertainty in the rule is best made by Avista, not the Commission. He states that it is appropriate for Avista to take on the risk of a prudence disallowance if it is not appropriately considering CCA allowance costs in dispatch (both for operations and forecast NPE) or incorrectly interpreting guidance or regulations from Department of Ecology ("Ecology").[64] Mullins recommends that the Commission not adopt a prescriptive approach as advocated by Staff in this case.[65]

51 Mullins also states that the impacts of including CCA costs in plant dispatch may produce different impacts for differing customer classes.[66]

52 He also expressed concerns about the Commission committing at this time to undertake a prudence review on an annual basis as part of Avista's ERM.[67] Since the CCA has four-year compliance periods, Mullins argues that it is not clear what the benefits of annual prudence reviews would be if performed within compliance periods,[68] and that committing to annual prudence reviews now may create different compliance incentives that ultimately put upward pressure on rates.[69]

53 Mullins recommends that the Commission not direct Avista to alter its modeling of CCA costs in the net power supply expense baseline in this case.[70] Mullins also recommends that the Commission not commit to the process and venue for a prudence review of Avista's CCA costs at this time.[71] Finally, Mullins recommends that the Commission not impose any obligations on Avista with regards to the way that it operates its system and with regard to participation in the carbon allowance market at this time.[72]

Public Counsel's Cross-Answering Testimony

[64] Mullins, Exh. BGM-8T at 10:5-9.

[65] Mullins, Exh. BGM-8T at 10:10-11.

[66] Mullins, Exh. BGM-8T at 11:2-3.

[67] Mullins, Exh. BGM-8T at 11:13-15.

[68] Mullins, Exh. BGM-8T at 11:16-18.

[69] Mullins, Exh. BGM-8T at 11:18-20.

[70] Mullins, Exh. BGM-8T at 12:21-22.

[71] Mullins, Exh. BGM-8T at 13:9-10.

[72] Mullins, Exh. BGM-8T at 13:11-14.

54 Public Counsel Witness Earle argues that while review of CCA allowance costs in the annual ERM review may be useful to provide guardrails, full determination of prudency cannot be reasonably determined until the compliance period and 10-month balancing period is over.[73] He says the Commission should only provide a final determination of prudency after the four-year compliance period and 10-month balancing period is over.[74]

Staff's Cross-Answering Testimony

55 Staff witness Wilson contends that considering the basic economics, it is cost-efficient for Avista and other Washington utilities to include the cost of CCA allowances in their dispatch decisions.[75]

56 Additionally, Wilson testifies that Avista's modeling found that including a CCA allowance price of $71.15 per ton resulted in a net increase of $73,333,559 in power costs.[76]

57 Wilson argues that a $71.15-per-ton allowance price is not representative of recent market prices.[77] He states that a recent forward market price for CCA allowances was $38.09 per ton, which traded at about $38 per ton according to the Intercontinental Exchange (ICE) forward price for December 2025 from August 1, 2024.[78] Using this price, Staff forecasts a CCA allowance cost of $43.1 million.[79]

58 Wilson contends that if Avista dispatches its system using a market price for CCA allowances, its 2025 emissions are forecast to be reduced by 18 percent relative to its proposal.[80]

Avista's Rebuttal Testimony

---

[73] Earle, Exh. RLE-17T at 6:1-3.

[74] Earle, Exh. RLE-17T at 6:4-5.

[75] Wilson, Exh. JDW-24CTr at 14:2-4.

[76] Wilson, Exh. JDW-24CTr at 9:1-2.

[77] Wilson, Exh. JDW-24CTr at 10:14-15.

[78] Wilson, Exh. JDW-24CTr at 13:1-3.

[79] Wilson, Exh. JDW-24CTr at 12:2-3.

[80] Wilson, Exh. JDW-24CTr at 13:4-5.

59 Company Witness Kinney disagrees with Staff's recommendation that it include CCA allowance costs in thermal plants dispatch.[81] Kinney states that there is no requirement for Avista to include carbon prices and emission allowance obligation in all unit dispatch and power supply decisions.[82]

60 To help illustrate the impact of including CCA allowance costs in thermal plant dispatch is, the Company ran a scenario based on its original filing. The result was a $73.3 million (system) increase (42%) in NPE, caused by lower surplus sales and additional market purchases to serve load in cases where the "phantom" carbon cost prevents dispatching lower-cost generation.[83]

61 Kinney asserts that including CCA costs in dispatch would require base rates requested in this proceeding to be substantially increased and lists the following arguments against its inclusion:[84]

- The CCA does not require carbon to be added to dispatch, which is an operational decision;
- The Commission has not provided any policy and direction to include carbon in dispatch decisions;
- As illustrated in the modeled scenario, adding the price of carbon could add $73.3 million (system) to the annual NPE;
- The Department of Ecology has not finalized the true-up mechanism, and Avista expects it could be granted no-cost allowances covering wholesale transactions made on behalf of customers; and
- Even if Avista is not given no-cost allowances for wholesale transactions, the Company has multiple ways to mitigate allowance requirements associated with these sales.

62 Kinney contends that it would be imprudent to add the cost of carbon in Avista's resource dispatch resulting in $73.3 million (system) of additional cost to customers.[85] Additionally, Company witness Kinney asserts that adding a carbon price to thermal resource dispatch

[81] Kinney, Exh. SJK-17T at 30:21-22 and at 31:1.

[82] Kinney, Exh. SJK-17T at 31:5-6.

[83] Kinney, Exh. SJK-17T at 31:18-22.

[84] Kinney, Exh. SJK-17T at 32:12-22 and at 33:2-4.

[85] Kinney, Exh. SJK-17T at 33:17-19.

reduces wholesale revenue to Idaho customers not obligated to meet CCA compliance and who do not receive no-cost allowance grants from the Department of Ecology.[86]

63 Kinney testifies that absent publicly available guidance, it remains unclear if the Department of Ecology will essentially "claw back" or withhold a commensurate number of allowances in future distribution allocations as part of the true-up process. As such, it is just as plausible for Avista to assume the true up mechanism will apply to wholesale market transactions (in effect a "one-for-one" application) as it is to assume it will not.[87]

64 Kinney also argues that contrary to the statement by Staff Witness Wilson, Avista's view of allowance costs is correct – namely, that the CCA is not intended to be the primary means of carbon reduction for electric customers.[88] While Wilson suggests engaging in auctions or bilateral markets to counter the impacts of reduced sales. Kinney contends that there are no statutory or regulatory requirements for utilities to sell their no-cost allowances in at least the initial two compliance periods, to do so may be premature.[89]

65 Regarding the necessity of prudency reviews, Kinney states that if the Company incurs any costs associated with the purchase of CCA allowances to cover the emissions associated with wholesale transactions, those costs will flow through Account 509 in the ERM.[90] FERC accounting requires that all costs and benefits associated with a single transaction must be recorded during the same period and should be recovered (or passed back to customers) at the same time.[91] Thus, Kinney argues this necessitates the need to evaluate the prudency of certain costs and benefits associated with the CCA in the annual ERM filing, but only when it has incurred CCA allowance costs.[92]

66 Kinney contends that it makes sense for the prudence review of procuring allowances for natural gas local distribution company (LDC)-related emissions to occur at the end of the compliance period because of the requirements to consign no-cost allowances and turn in 30 percent of current year vintage allowances annually, and because natural gas companies must procure significant allowances to cover emissions.[93] However, the Company argues

[86] Kinney, Exh. SJK-17T at 34:1-3.

[87] Kinney, Exh. SJK-17T at 35:7-11.

[88] Kinney, Exh. SJK-17T at 35:19-21.

[89] Kinney, Exh. SJK-17T at 37:8-11.

[90] Kinney, Exh. SJK-17T at 40:13-15.

[91] Kinney, Exh. SJK-17T at 40:15-18.

[92] Kinney, Exh. SJK-17T at 40:18-20.

[93] Kinney, Exh. SJK-17T at 41:1-4.

that prudence of CCA purchases on the electric side likely will need to be reviewed both annually and then in totality after the 4-year compliance period due to the lag between forecasted and actual emissions.[94]

Parties' Briefs

Avista

67 In its post-hearing brief, the Company maintains its position that CCA allowance costs should not be included in thermal plant dispatch. To do otherwise, Avista argues would be to require something that was contained in a retracted Policy Statement and is not well understood, but could result in increased power costs of $73.3 million, or a 42 percent increase to NPE.[95]

Staff

68 In its post-hearing brief, Staff reiterates its position that the costs associated with the CCA should be reviewed annually to ensure prudent management and that CCA costs should be included in dispatch decisions as it pertains to meeting Washington retail load.[96]

69 Regarding annual reviews, Staff notes that despite Public Counsel and AWEC disagreeing with Staff's proposal, Public Counsel witness Earle acknowledges annual reviews might be useful to guard against overruns and AWEC witness Mullins admits there is uncertainty about overruns until the end of the compliance period.[97] This uncertainty, Staff states is the exact reason there should be annual reviews coinciding with review of power costs, which will avoid rate shock to customers and ensure prudent management of costs.

70 For inclusion of CCA costs in dispatch, Staff argues that the economic benefits of thermal dispatch should not be overstated and the risk of emissions exceeding no-cost allowances, resulting in higher costs, "outweigh the lower surplus sales revenues that will result from excluding CCA costs."[98] Staff counters arguments from Avista against inclusion of CCA costs, stating that Avista will still be able to market thermal resources into states such as

---

[94] Kinney, Exh. SJK-17T at 41:9-11.

[95] *WUTC v. Avista Corp.*, Dockets 240006 & 240007, Avista's Post-Hearing Brief ¶¶ 91-92 (Oct. 28, 2024) (Avista's Post-Hearing Brief).

[96] *WUTC v. Avista Corp.*, Dockets 240006 & 240007, Staff's Post-Hearing Brief ¶ 88 (Oct. 28, 2024) (Staff's Post-Hearing Brief).

[97] Staff's Post-Hearing Brief, at ¶¶ 94-95.

[98] Staff's Post-Hearing Brief, at ¶ 96.

Oregon, which do not require CCA compliance, excluding the CCA adder.[99] Staff also notes that Avista's arguments regarding wheeling thermal power into Washington ignore Ecology's rules on the issue, which would still require Avista, as the "first jurisdictional deliverer" to hold the compliance obligation.[100]

71 In response to AWEC's criticism of including CCA costs in dispatch, Staff argues that the Commission has a duty to regulate rates and that necessitates consideration of CCA costs, despite witness Mullins assertion that the Commission should not enforce CCA compliance.[101] Further, Staff takes issue with witness Mullins example of Coyote Springs dispatch decisions being binary, that is either to dispatch Coyote Springs or buy unspecified power, which also has a compliance obligation. Staff argues that this is an oversimplification, and in fact, power is available that is bundled with renewable energy certificates, and that not including CCA costs in dispatch favors thermal dispatch of Avista assets like Coyote Springs because CCA costs would need to be assigned to unspecified wholesale power.[102]

Public Counsel

72 Public Counsel opposes Staff's recommendation to review CCA allowance costs annually for prudence. Public Counsel specifically argues that "the four year and 10-month CCA compliance period does not align with an annual review process" and would be better addressed on an interim basis during GRCs and ultimately decided at the conclusion of the compliance period.[103]

AWEC

73 In its post-hearing brief, AWEC argues against including CCA costs in dispatch because it will increase the amount actually paid by customers based on a forecast of CCA costs and does not in any way impact Avista's operations or ability to comply with the CCA.[104]

---

[99] Staff's Post-Hearing Brief, at ¶ 97.

[100] Staff's Post-Hearing Brief, at ¶ 98.

[101] Staff's Post-Hearing Brief, at ¶ 99.

[102] Staff's Post-Hearing Brief, at ¶ 100.

[103] *WUTC v. Avista Corp.*, Dockets 240006 & 240007, Public Counsel's Post-Hearing Brief ¶ 77 (Oct. 28, 2024) (Public Counsel's Brief).

[104] *WUTC v. Avista Corp.*, Dockets 240006 & 240007, AWEC's Post-Hearing Brief ¶ 31 (Oct. 28, 2024) (AWEC's Post-Hearing Brief).

74 Further AWEC argues there is no statute, rule, or formal requirement mandating inclusion of CCA costs in dispatch for retail or wholesale sales when forecasting NPE, and the Ecology guidance on a true-up mechanism that Staff points to for support of its position is not finalized.[105]

75 AWEC also argues that Staff's proposal needlessly shifts CCA compliance risks from shareholders to customers, arguing that Staff's proposal artificially imposes a "bad case" compliance obligation on customers prior to Avista incurring those costs and a Commission prudence determination.[106] AWEC also points out that Staff's position is inconsistent with other dockets and that if the Commission is to set a policy, it should be done in Docket U-230161 so that policy and implementation is consistent for all regulated utilities.[107] AWEC argues the same concerns over shifting costs to customers and uncertainty from Ecology should weigh against inclusion of forecast CCA costs in wholesale sales transactions in NPE.[108]

76 Finally, AWEC argues the Commission should refrain from conducting an annual review and prudence determination of CCA costs because of the uncertainty from Ecology and because the law includes a four-year compliance period.[109]

Decision

77 The Commission recognizes the gravity of the need to meet the goals as outlined in the CCA and the Clean Energy Transformation Act (CETA). The emissions reductions required by Washington law creates a situation where Washington's regulated utilities are faced with being first movers on decarbonization compared to most utilities across the country, a place utilities are often uncomfortable being in. This is all happening in a time when technologies and emissions reduction techniques are rapidly improving and being developed. Additionally, as the parties seem to agree, compliance and enforcement rules, policies, and guidance from Ecology and the Commission are still being developed, and when combined with the statutory compliance period of four years, there is still uncertainty in how utilities will comply with the law and how they might achieve their statutorily required goals.

[105] AWEC's Post-Hearing Brief, at ¶ 35.

[106] AWEC's Post-Hearing Brief, at ¶¶ 38-39.

[107] AWEC's Post-Hearing Brief, at ¶¶ 40-42.

[108] AWEC's Post-Hearing Brief, at ¶¶ 43-47.

[109] AWEC's Post-Hearing Brief, at ¶ 48.

78 Due to this uncertainty, the Commission finds it prudent to carefully address the issues presented by the parties. The Commission is faced with a seemingly precarious balance to maintain, ensuring that the Commission fulfills its duties to regulate rates in the public interest, provide guidance for the regulated community, and retain flexibility for the Commission and the regulated community to achieve ultimate CCA compliance. All of this must be done in a way that achieves the mandates of CCA and CETA, while maintaining affordable and reliable service.

79 In balancing these interests, the Commission must make decisions based on the record before it. Public Counsel and AWEC oppose annual review and prudence determinations of the CCA costs, arguing that an annual prudence determination is impractical due to the four-year compliance period plus ten months in which the utilities must comply with allowance submission requirements.[110] We agree.

80 RCW 70A.65.120 and 70A.65.130 discuss the allocation of allowances to both electric and natural gas investor-owned utilities, respectively. RCW 70A.65.200 discusses penalties and enforcement. All three sections reference and frame compliance, allowance allocations, and penalty enforcement around the "compliance obligation" and "compliance period." RCW 70A.65.020(19) defines "compliance obligation" to mean "the requirement to submit to the department the number of compliance instruments equivalent to a covered or opt-in entity's covered emissions during the compliance period." RCW 70A.65.020(20) defines "compliance period" to mean "the four-year period for which the compliance obligation is calculated for covered utilities."

81 Given the structure of the CCA, and the timing of the "compliance obligation" which may significantly impact a utility company's cost of compliance and subsequent penalties, we find that the costs are unlikely to be known and measurable with finality until the "compliance obligation" date. Said differently, the Commission finds it would be premature to conduct prudence reviews of CCA costs and compliance on an annual basis. To do otherwise may result in the Commission wrongly predetermining prudence when decisions later turn out to be imprudent, or imprudent when they later appear prudent. This may inappropriately shift costs to customers before final compliance obligations are known. Moving forward, as the first compliance period comes to a close, and the rules surrounding compliance become more developed, the Commission may be able to perform more frequent reviews in later compliance periods, but at this time finds the potential perils of annual compliance reviews outweigh the benefits put forward by Staff.

82 Despite our decision to decline annual prudence reviews at this time, Staff's arguments and witness Wilson's five factors presented for consideration do weigh in favor of

---

[110] *See, e.g.*, Earle, Exh. RLE-17T at 5:13-19.

increased scrutiny of CCA costs on an annual basis.[111] While the compliance obligation may not be final until the end of the compliance period, Avista and others are making decisions now which will undoubtedly impact the costs Washingtonians will ultimately face at the conclusion of the current compliance period. Wilson's first and second factors are particularly persuasive in outlining just two of many decision points the Commission feels should be addressed annually.

83 Accordingly, the Commission finds that during Avista's annual submission of updates to its CCA tracker tariff, the Company shall submit and present information pertaining to where CCA costs are being included in decision making to include, but not limited to Integrated Resource Plans (IRPs), Clean Energy Implementation Plans (CEIPs), dispatch, power purchase, carbon market transactions, and capital projects. This annual report will be addressed and acknowledged through the Open Meeting process and will help the Commission assess a utility's progress and decision making leading up to the Commission's prudency determination at the conclusion of the compliance period.

84 Aside from recommending an annual prudence review as part of the ERM filing, Staff also recommends the Commission require Avista to account for CCA costs in dispatch. Specifically, Wilson recommends adjusting the ERM to account for CCA costs by adding $21,591,885 to account for CCA allowance prices in dispatch and market purchases and $43,128,017 to account for CCA allowance costs for market sales.[112] The adjustments are calculated using a $38.09 per ton allowance price multiplied by emissions.

85 While the Commission sees merit to Staff's approach, we are concerned that the proposal is not fully developed and would result in disparate treatment with the approaches taken with other utilities. These concerns are described by AWEC in their post-hearing brief.[113] Further, the price point used for calculating CCA costs remains a point of contention between the parties. At this time the Commission notes that there is a lack of trading data on which the Commission can reasonably rely to determine a single price point for CCA allowances for inclusion in dispatch decisions, considering that the price of CCA allowances will change multiple times annually. Accordingly, we decline to require CCA allowance prices and costs in dispatch, market purchases, and market sales at this time.

86 The Commission finds that CCA allowance prices and costs in dispatch, market purchases, and market sales, and the Commission's policy surrounding their inclusion in NPE, should be addressed in Docket U-230161 so that policy and implementation is consistent for all

---

[111] Wilson, Exh. JDW-1TCr at 25:4-26:9.

[112] Wilson, Exh. JDW-24CT at 7 (Table 1).

[113] AWEC's Post-Hearing Brief, at ¶¶ 38-47.

regulated utilities, and each impacted utility has an opportunity to comment on the issue. However, regulated utilities should consider accounting for the prices and costs as proposed by Staff. The Commission will continue to monitor how Avista and others are addressing CCA compliance in their decision making moving forward and will ultimately determine whether their actions were prudent when Avista seeks cost recovery and a prudence determination of CCA costs. Further, Avista and other regulated utilities will need to demonstrate the impacts of the CCA on their decisions including dispatch, market purchases, and market sales moving forward. We expect the utilities will continue to develop compliance strategies in response to the adoption of rules and guidance established by Ecology and the Commission, as we collectively move towards meeting the mandates of both the CCA and CETA.

Energy Recovery Mechanism/Net Power Expenses

Avista – Direct Testimony

87 Avista's proposed authorized NPE and revenue in its initial filing is $112.8 million for RY1 and $146.4 million for RY2 (Washington-basis).[114] Company witness Kalich provides a list of non-modeled NPE items in Exhibit CGK-3, which includes the Forecast Error Adjustment of $65.8 million, as well as miscellaneous fuel, transmission, and other costs related to power supply.[115] Kalich also notes that forecast NPE rises significantly in RY2, approximately $89 million, due to the removal of Colstrip coal-fired generation Units 3 and 4 from Avista's portfolio. This increase is partially offset by a $35 million decrease in depreciation and fixed O&M costs.[116]

ERM

88 Beyond the increase to NPE, the Company also proposes modifying its Energy Recovery mechanism, or ERM, by moving to a single 95% customer / 5% Company (95/5) sharing level applied to the entire difference between actual and authorized power supply costs[117] as well as eliminating the deadbands.[118] The Company cites Forecast Error, Regional Resource Adequacy, Lack of Market Liquidity, Carbon Emission Policy, and Changing

---

[114] Kalich, Exh. CGK-1T at 31:9-20.

[115] Kalich, Exh. CGK-1T at 23:20-24:6.

[116] Kalich, Exh. CGK-1T at 14:23-15:10.

[117] Kinney, Exh. SJK-1T at 50:3-5.

[118] Kinney, Exh. SJK-1T at 50:9.

Market Dynamics as the reasons for making their recommended changes to the ERM and deadbands.[119]

89 The ERM and deadbands are currently structured as follows:

Table 1: ERM and deadbands

	Power Supply Costs in Rate Bases
Surcharge (Power costs higher than authorized)	First $4M absorbed by AVA
	Next $6M, 50/50 split between customers and AVA
	Over $10M, 90/10 split between customers and AVA
$0	
Rebate (Power costs lower than authorized)	First $4M absorbed by AVA
	Next $6M, 50/50 split between customers and AVA
	Over $10M, 90/10 split between customers and AVA

90 Company Witness Kinney argues that deadbands skew risks in favor of one party or the other, are not an industry standard, and focus utility rate proceedings on power supply expense deadband management instead of overall costs estimation.[120] He further contends that for deadbands to be beneficial, two criteria must be met at minimum:

- The Company has the opportunity for actions resulting in significant cost reductions and the commensurate benefits of the deadband, and
- The net power cost forecast must be accurate and without significant error.[121]

91 Kinney argues that neither criteria is currently met, leaving risk unshared and one party benefiting at the expense of the other.[122]

92 While forecast error has always existed, Kinney argues that new Company analysis prepared for this filing demonstrates that power supply costs cannot be forecasted accurately for reasons outside of utility control.[123]

---

[119] Kinney, Exh. SJK-1T at 50:11-34.

[120] Kinney, Exh. SJK-1T at 53:7-9.

[121] Kinney, Exh. SJK-1T at 53:9-13.

[122] Kinney, Exh. SJK-1T at 53:13-16.

[123] Kinney, Exh. SJK-1T at 54:6-8.

93 Regarding the Forecast Error Adjustment, Kinney claims that due to volatile market conditions, the Company is incapable of forecasting power supply costs accurately, and therefore managing the forecast error is outside of the Company's control.[124] Kinney further testifies that though NPE forecast error has always been present, forecasts continue to get worse with new and "nearly impossible to predict" variables,[125] such as the implied market heat rate,[126] rising market volatility,[127] falling market liquidity,[128] the CCA,[129] and the increasing value of Avista's thermal generation fleet.[130]

94 The Company further argues that a shift to a 95/5 split would benefit customers as looking at individual years of history, customers would have benefitted with the 95/5 approach in nine of twelve years, or 75 percent of the time.[131]

95 Beyond the significant forecasting error, Kinney argues that the Commission should re-consider the removal of deadbands, despite rejecting this request in 2012, due to the uncertainty caused by CCA regulations.[132] The Company considered including a CCA cost estimate in a pro forma adjustment but decided against it because of uncertainty in the implementation and impacts of the CCA.[133] Kinney contends that depending on Commission guidance, the Company may have to include carbon costs in its dispatching decisions, which the Company argues would increase NPE by tens of millions of dollars.[134] Kinney argues that not including this estimate could harm the company if deadbands remain.[135] Kinney also notes that had the Company included an estimate in its NPE and thus overstated its cost, customers would be harmed by the first $4 million flowing directly to the Company in the first deadband, and another $1.5 million through the 50/50 sharing band.[136]

---

[124] Kinney, Exh. SJK-1T at 50:11-15.

[125] Kinney, Exh. SJK-1T at 54:2-9.

[126] Kinney, Exh. SJK-1T at 58:6-60:3.

[127] Kinney, Exh. SJK-1T at 60:14-62:8.

[128] Kinney, Exh. SJK-1T at 62:9-63:2.

[129] Kinney, Exh. SJK-1T at 64:3-65:9.

[130] Kinney, Exh. SJK-1T at 69:15-71:14.

[131] Kinney, Exh. SJK-1T at 54:22-23.

[132] Kinney, Exh. SJK-1T at 56:8-10.

[133] Kinney, Exh. SJK-1T at 56:11-12.

[134] Kinney, Exh. SJK-1T at 56: 15-17.

[135] Kinney, Exh. SJK-1T at 56:17-19.

[136] Kinney, Exh. SJK-1T at 56:19-22.

96 According to the Company, throughout the history of the ERM, sharing bands were a means to distribute the impacts of varying electric and natural gas prices, along with hydro variability risk. When the Company's thermal fleet had an expected annual value of $30 to $50 million, even 10 to 20 percent error resulted in costs falling within the deadbands. However, with today's annual thermal fleet value estimated at $500 million, that same 10 to 20 percent error becomes multiples of the deadbands and overwhelms Company efforts to reduce costs.[137]

97 Kinney asserts that because of a lack of liquidity and the much higher expense of margin calls to hedge forward transactions, hedging in the forward markets to lock in projected value no longer is an option for most of Avista's business.[138] He further argues that being unable to capture forward resource value results in the Company taking more of the financial risk with the current ERM deadbands and recovery structure.[139]

98 The Company argues that in the short term, the best approach to recover CCA costs is to have them flow through a 95/5 ERM without deadbands.[140] Kinney states that allowing those CCA costs to flow through the ERM at a sharing level of 95/5 obligates the Company to pay 5 percent of anticipated CCA costs but avoids disagreements between parties over the magnitude of costs that cannot be known at this point.[141]

99 Kinney contends that requesting 100 percent recovery of CCA costs would be the fairest outcome and reflect the legislation's intent.[142] However, as part of an overall package to simplify the ERM and address increasing forecast costs, he states that the Company is offering this compromise.[143]

100 Avista also notes that while the transformation to new markets creates efficiencies and lower NPE, it also reduces the Company's ability to affect costs.[144] Thus, when the

---

[137] Kinney, Exh. SJK-1T at 60:17-21, 61:1.

[138] Kinney, Exh. SJK-1T at 62:19-21.

[139] Kinney, Exh. SJK-1T at 62:22-23, 63:1-2.

[140] Kinney, Exh. SJK-1T at 64:18-19.

[141] Kinney, Exh. SJK-1T at 64:19-20 and 65:1-2.

[142] Kinney, Exh. SJK-1T at 65:4-5.

[143] Kinney, Exh. SJK-1T at 65:6-9.

[144] Kinney, Exh. SJK-1T at 65:11-16.

benefits of new markets are reflected in power supply modeling, as is currently the case, it is reasonable to remove deadbands.[145]

101 The Company also argues that the existing deadbands were identified as a significant credit weakness, and that the ERM's current design disadvantages Avista compared to other regional utilities.[146]

Colstrip

102 Regarding Colstrip, the Company includes Colstrip's net power supply costs in Pro Forma Power Supply Adjustment 3.00P and the ERM baseline in RY1. The breakdown of Washington's Electric RY2 revenue requirement without Colstrip can be seen in Table 2.[147]

Table 2: Washington Electric RY2 revenue requirement – Colstrip Offset

Breakdown of Washington Electric RY2 Revenue Requirement ($000s)		
Net Expense/Capital Investment Increase	$	18,618
Colstrip Power Supply Increase	$	59,512
Subtotal - Base Rate Increase	$	78,130
Schedule 99 Colstrip Tracker Reduction	$	(24,419)
Overall Bill Impact	**$**	**53,711**

EIM Benefits

103 Finally, Avista witness Kalich details the methodology the Company uses to quantify the value gained from participation in the intra-hour Energy Imbalance Market (EIM)[148]

[145] Kinney, Exh. SJK-1T at 65:17-20.

[146] McKenzie, Exh. AMM-1T at 18:11-14.

[147] Andrews, Exh. EMA-1T at 6:15-8:21

[148] The acronyms EIM and WEIM are used interchangeably by the parties throughout their testimony and briefs. They appear as used by the parties throughout their filings.

offered by CAISO, developed with the help of consulting firm Borismetrics.[149] Kalich states that Avista has determined an EIM system benefit of $5.5 million in 2025.[150]

Staff's Response Testimony

ERM

104 Staff Witness Wilson testifies that Staff is unconvinced that the current sharing/deadband schedules provide the Company with material incentives that affect its current resource decisions.[151] Wilson further testifies that considering both base rates and NPE, the cost-effectiveness of Avista's wind and hydropower procurements could easily have a more substantial rate impact than the natural gas plants. However, he does acknowledge that once procured, any impacts of wind and hydropower on NPE are largely indirect and outside a utility's control.[152]

105 Staff contends that in the PacifiCorp order, the Commission pointed out that the effect of the sharing/deadband schedules is to insulate customers from cost increases and provide a balancing effect between years in which power costs are under- or over-forecast.[153] Staff agrees that this is a reasonable policy position to take and gives it strong deference.[154]

106 Staff recommends simplifying the current sharing portion of the mechanism to a symmetric 90/10 sharing.[155] Staff asserts that this ratio equitably shares risk between customers and Avista, while continuing to provide the Company with a reasonable incentive to manage or control power costs.[156]

107 Additionally, with respect to the deadband, Staff recommends reducing the deadband from $4 million to $3 million.[157] The Commission retained the $4 million deadband in the

---

[149] Kalich, Exh. CGK-1T at 4:14-14:7. The detail provided by Kalich in direct testimony does not specifically pertain to arguments made in response by intervening parties, since those arguments consider what is absent from the analysis.

[150] Kalich, Exh. CGK-1T at 13:14-14:7.

[151] Wilson, Exh. JDW-1TC at 35:19-21.

[152] Wilson, Exh. JDW-1TC at 36:1-5.

[153] Wilson, Exh. JDW-1TC at 36:8-11.

[154] Wilson, Exh. JDW-1TC at 36:11-12.

[155] Wilson, Exh. JDW-1TC at 37:3-4.

[156] Wilson, Exh. JDW-1TC at 37:4-6.

[157] Wilson, Exh. JDW-1TC at 37:7-8.

PacifiCorp case, which is approximately 2 percent of its net power costs.[158] Since Avista's proposed NPE is much smaller than that of PacifiCorp, Staff finds it inequitable to expose Avista to a relatively larger deadband risk.[159]

Forecast Error Adjustment

108 Staff witness Wilson recommends that the Commission reject Avista's proposed Forecast Error Adjustment as not justified.[160] Wilson describes the Forecast Error Adjustment as a pre-payment of revenue requirement that Avista expects based on historical NPE trends but is not itself an expense.[161] Wilson argues that "Avista is proposing to include in its NPE forecast recovery of a revenue requirement that does not yet exist."[162] While acknowledging that some drivers of NPE are outside of Avista's control, Wilson also claims that several significant drivers remain in the Company's control[163,] and that it is unreasonable to forecast a cost that may not even occur. [164]

109 Wilson also notes concern that Avista does not appear to pay attention to its responsibilities to help minimize NPE costs to customers in direct testimony.[165] Wilson contends that while there are increased challenges for Avista with respect to hedging, it has not provided detailed information regarding the carbon allowance or natural gas markets Avista participates in.[166]

Errors

110 Wilson identifies several forecast errors in Avista's net power cost filing and recommends that the Commission accept Staff's corrections to Avista's 2025 and 2026 forecast NPE.[167] Wilson also recommends that the Commission direct Avista to update its model to address the input errors identified by Staff, specifically the Lancaster PPA and the Rattlesnake

---

[158] Wilson, Exh. JDW-1TC at 37:8-9.

[159] Wilson, Exh. JDW-1TC at 37:9-11.

[160] Wilson, Exh. JDW-1TCr at 4:9-12.

[161] Wilson, Exh. JDW-1TCr at 8:1-16.

[162] Wilson, Exh. JDW-1TCr at 9:9-10.

[163] Wilson, Exh. JDW-1TCr at 9:18-11:5.

[164] Wilson, Exh. JDW-1TCr at 14:19-15:3.

[165] Wilson, Exh. JDW-1TCr at 11:6-10.

[166] Wilson, Exh. JDW-1TCr at 12:1-14:9.

[167] Wilson, Exh. JDW-1TCr at 5:6-8.

Flats Wind Project.[168] Avista already acknowledged multiple other errors Wilson identified in the Company's forecast NPE.[169]

Colstrip

111 Regarding Colstrip, Wilson claims that the modeling assumption used by Avista to determine the marginal fuel price for Colstrip is dependent on an extremely unlikely circumstance where Avista does not meet its minimum contractual fuel consumption in 2025. Since Avista is currently projected to exceed the minimum annual amount, Wilson argues that the marginal price of fuel should be the highest annual marginal price.[170] Wilson further argues that failure to dispatch Colstrip to the proper marginal cost would be imprudent.[171]

Power Cost Update (In Case of MYRP Rejection)

112 Should the Commission accept Staff's recommendation and reject the MYRP, Staff witness Erdahl recommends that the Company should be allowed to file a power cost update with a rate effective date of December 31, 2025. This update would provide Avista an opportunity to update power costs while removing Colstrip from rates on or before December 31, 2025. Erdahl recommends that the power cost update also update fuel expenses and market sales for resale.[172]

EIM Benefits

113 Staff witness Wilson claims that Avista does not include non-energy expenses and revenues from the Western Energy Imbalance Market (WEIM), such as congestion charges. While Wilson notes that Avista's methodology seems reasonable for forecasting energy transaction costs, Wilson argues that the Company has earned on average $1.4 million per year in non-energy benefits from the WEIM which is not reflected in the model.[173]

---

[168] Wilson, Exh. JDW-1TCr at 42:3-6; 40:15-41:3; 41:5-13.

[169] Wilson, Exh. JDW-1TCr at 37:16-38:6.

[170] Wilson, Exh. JDW-1TCr at 39:1-40:7.

[171] Wilson, Exh. JDW-1TCr at 40:9-13.

[172] Erdahl, Exh. BAE-1T at 15:9-17.

[173] Wilson, Exh. JDW-1TCr at 38:13-22. The $1.4 million figure does not include a citation.

114 Wilson recommends that the Company update its dispatch to include the non-energy WEIM charges and benefits. Staff does not have an estimate of how this recommendation would ultimately affect NPE.[174]

Public Counsel's Response Testimony

ERM

115 Public Counsel contends that the Company's entire argument is based on its self-declared inability to forecast or prepare for market changes.[175] Witness Earle argues that the Company is effectively testifying that it lacks the competency to adapt to normal occurrences in the market, and as a result the Company wants to shift 95 percent of the risk for its decision onto ratepayers.[176]

116 Earle contends that it is apparent that the ERM is working as it was designed to as there are some years in which costs are shared, and other years in which benefits are shared.[177] The existence of years such as 2022 with large shortfalls is concerning and may be an indication of insufficient hedging.[178] Before considering altering the ERM deadbands and sharing bands, Public Counsel urges the Commission to order Avista to provide a comprehensive report on its hedging policies and practices.[179]

117 Earle also contends that both conditions that Avista states are needed for deadbands to be beneficial are met.[180] Earle argues that Avista can take actions to reduce costs, and the NPE forecast, while not perfect, has a track record that supports the idea that costs are forecastable.[181]

118 Public Counsel testifies that the Commission should reject any conclusions from Avista's historical comparison as being dispositive.[182] Public Counsel states that the historical comparison the Company makes is problematic as it unreasonably assumes that changes to

---

[174] Wilson, Exh. JDW-1TCr at 42:3-6.

[175] Earle, Exh. RLE-1CT at 8:11-12.

[176] Earle, Exh. RLE-1CT at 8:19-20, 9:1-2.

[177] Earle, Exh. RLE-1CT at 14:12-15.

[178] Earle, Exh. RLE-1CT at 14:15-17.

[179] Earle, Exh. RLE-1CT at 14:17-19.

[180] Earle, Exh. RLE-1CT at 16:7-11.

[181] Earle, Exh. RLE-1CT at 16:11-13.

[182] Earle, Exh. RLE-1CT at 17:5-6.

the incentive structure would not have changed behavior.[183] A proper calculation of the different outcomes under various risk sharing mechanisms should consider the effects of the risk sharing mechanisms on NPC variance.[184]

119 Public Counsel also argues that Avista's justifications for changing the ERM are not new and that between 2012-2022, actual NPE was less than the authorized level for eight of those years.[185]

120 Public Counsel further states that the history of the difference between authorized and actual NPE shows Avista's claims such as "our forecasts continue to get worse" and "power supply costs cannot be forecasted accurately, and for reasons outside of utility control" are unsubstantiated.[186]

121 Public Counsel also finds Avista's complaints on market liquidity to be unreasonable.[187] Earle states that the Company's forward electricity purchases were at low levels in 2020 and 2021 compared to previous years and then disappear from 2022 onwards.[188] Earle contends that this is concerning and surprising given the ability of other utilities to buy electric power forward, contributing to the unreasonableness of the Company's complaint.[189]

122 While Public Counsel agrees that Avista should address the uncertainty in the carbon emissions policy, Earle argues uncertainty is not a reason for inaction and placing nearly all of the risk on ratepayers.[190] Contrary to Avista's claims of having no control, Earle argues that the Company can modify its operations in response to observed costs and purchase and sell allowances in the market to mitigate risk.[191] Additionally, Earle emphasizes that compliance periods for allowances are four years followed by 10 months to transfer compliance instruments for the compliance period, allowing Avista to perform substantial risk mitigation over a period of almost five years.[192]

---

[183] Earle, Exh. RLE-1CT at 16:15-18.

[184] Earle, Exh. RLE-1CT at 17:3-5.

[185] Earle, Exh. RLE-1CT at 9:9-10.

[186] Earle, Exh. RLE-1CT at 10:20-24.

[187] Earle, Exh. RLE-1CT at 13:2-3.

[188] Earle, Exh. RLE-1CT at 12:7-8.

[189] Earle, Exh. RLE-1CT at 13:1-3.

[190] Earle, Exh. RLE-1CT at 13:5-8.

[191] Earle, Exh. RLE-1CT at 13:8-11.

[192] Earle, Exh. RLE-1CT at 13:11-14.

123 Earle also emphasizes that unplanned changes in the weather are not a new phenomenon.[193] While climate change may make variation more severe, it does not mean planning cannot occur or contingencies be put into place to handle them.[194]

Forecast Error Adjustment

124 Earle recommends that the Commission reject Avista's proposal to add a forecast error adjustment of $65.8 million to the forecast NPE. Earle states that the adjustment does not entail actual costs that Avista has incurred, or will incur, on behalf of its customers and the Commission has repeatedly rejected the premise that it is impossible to forecast NPE.[195]

125 Citing Avista witness Kinney, Earle describes the Forecast Error Adjustment as the difference between Avista's forward looking evaluation and after-the-fact evaluation of its generation resources, which Avista proposes to be $65.8 million on top of the standard forecast NPE.[196] Earle argues that the Forecast Error Adjustment is not a separate cost that the Company incurs on behalf of ratepayers, and that the ERM already accounts for various forecast errors.[197] Earle claims that the Company's argument that forecasting has continued to get worse and that power supply costs cannot be forecasted accurately are disproved by Avista's performance forecasting NPE since the ERM was implemented in 2003. Earle includes the following figure in his testimony, a waterfall graph of Avista's performance calculating forecast NPE since 2003.[198]

[193] Earle, Exh. RLE-1CT at 14:2-3.

[194] Earle, Exh. RLE-1CT at 14:3-5.

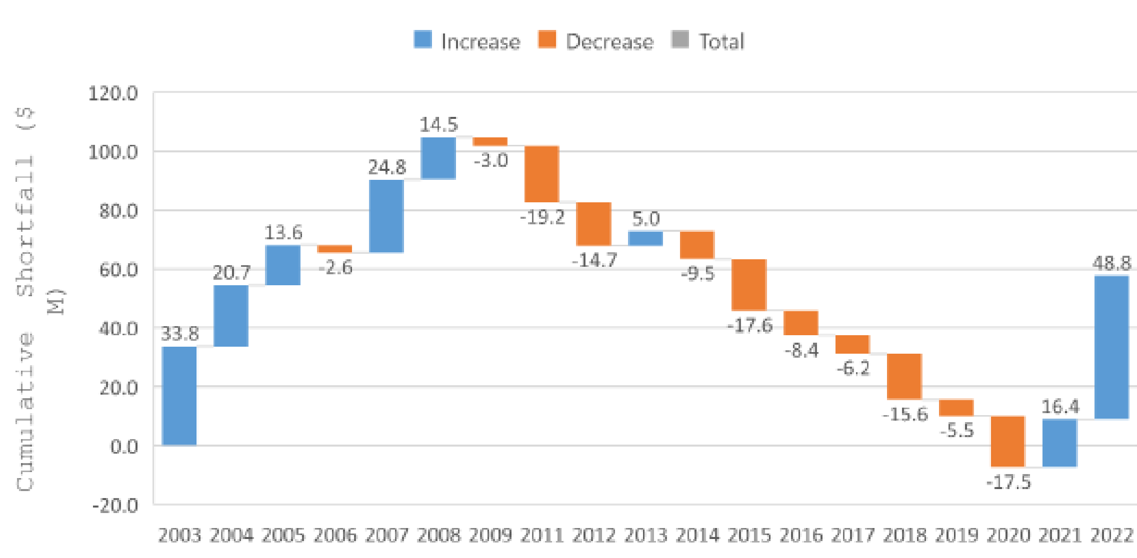
[195] Earle, Exh. RLE-1CT at 2:19-26.

[196] Earle, Exh. RLE-1CT at 3:18-4:3.

[197] Earle, Exh. RLE-1CT at 4:4-11.

[198] Earle, Exh. RLE-1CT at 5:8-7:10.

Figure 1: Waterfall diagram of Avista's (Actual NPE – Authorized NPE) ($million).[199]



126 Earle highlights that the 2022 NPE forecast as authorized to be $72.3 million with a final incurred NPE of $121.1 million, under-collecting by $48.8 million. However, Avista had calculated its 2022 portfolio error to be $202.7 million, which would have resulted in an over-collection of $154 million if it had been allowed into the NPE forecast for 2022.[200]

EIM Benefits

127 Earle finds Avista's estimate of EIM benefits to be unreasonable. Earle asserts that the Company's modeling methodology contains errors, including gaps in pricing data used in its regression analysis[201] and flawed assumptions that reduce the variability of intra-hour prices.[202] As a result of these flaws, Earle recommends rejecting Avista's estimate of WEIM benefits.[203]

---

[199] Earle, Exh. RLE-1CT at 6:5.

[200] Earle, Exh. RLE-1CT at 4:10-5:2.

[201] Earle, Exh. RLE-1CT at 27:8-28:17.

[202] Earle, Exh. RLE-1CT at 28:18-29:13.

[203] Earle, Exh. RLE-1CT at 29:14-16.

128 Earle also recommends that the Commission reject Avista's use of the 2017 E3 study to support the Company's forecast of EIM benefits since the study is outdated, using prices and results that are listed in 2017 dollars.[204]

129 To counter Avista's estimate, Earle points to CAISO's estimated benefits for Avista's Balancing Authority Area (BAA). Earle claims that CAISO estimates $25.3 million in benefits annually for the Company's BAA,[205] and states that the Company earned $24.1 million in 2022 and $20.1 million in 2023 from WEIM participation.[206] Earle also claims that E3 previously endorsed the CAISO WEIM benefits methodology as an accurate measure for benefits Puget Sound Energy received from its participation in the WEIM.[207]

130 Earle provides an alternative "bootstrapping analysis" to calculate the benefits that Avista receives from EIM participation and recommends that the Commission order Avista to develop a new forecasting methodology using either this methodology or a different approach such as Monte Carlo modeling or scenario-based forecasting. The new methodology should align with CAISO's WEIM benefit estimates.[208] Earle also recommends that the Commission order the adoption of an annual WEIM benefits forecast of $20.7 million, based on the bootstrapping analysis.[209]

The Energy Project's Response Testimony

131 The Energy Project argues that the Commission should reject Avista's ERM proposal for two reasons:

- Individual customers do not understand regional energy market structures, nor can they make a significant impact on the Company's power costs, and
- In SB 5295 the Legislature directed the UTC to establish and maintain regulatory processes that measure and incent utility performance.[210]

---

[204] Earle, Exh. RLE-1CT at 29:17-6. Earle estimates that the value of EIM benefits from the 2017 E3 study, converted to 2025 dollars, would be $7.4 million instead of $5.5 million.

[205] Earle, Exh. RLE-1CT at 30:7-14.

[206] Earle, Exh. RLE-1CT at 31:4-6. In Public Counsel's cross testimony, Earle provides the updated data and does not significantly change the recommendation.

[207] Earle, Exh. RLE-1CT at 35:9-11.

[208] Earle, Exh. RLE-1CT at 35:12-36:7.

[209] Earle, Exh. RLE-1CT at 33:5-9.

[210] Stokes, Exh. SNS-1T at 40:5-8,10-11.

132 Since customers have such little ability to impact power costs, Stokes argues that it is inappropriate to change the ERM to place nearly all the costs on customers.[211] Additionally, TEP argues that moving from a deadband that gives shareholders a $4 million incentive to contain energy costs to one in which shareholders only have a 5 percent incentive runs counter to the Legislature's direction in SB 5295.[212]

AWEC's Response Testimony

133 AWEC testifies that the ERM is functioning as the Commission intended, and that the Commission has repeatedly rejected arguments to eliminate deadbands from cost sharing mechanisms. As such, AWEC recommends that the Commission reject Avista's proposal.[213]

134 Mullins argues that none of the issues Avista raises have any relevance to the ERM.[214] He asserts that power costs have always been volatile – that is why the ERM exists.[215] Mullins further contends that even if one were to assume that power costs are more volatile today than they were in the past, Avista's risk is no greater because the deadbands and sharing bands have remained the same since 2006.[216] He argues that the ERM does not create power cost risk for Avista, it insulates it from this risk by allowing for a true up of amounts that exceed the deadbands.[217]

135 Additionally, AWEC contends that like PacifiCorp in its 2023 GRC, Avista argues that customers have been harmed by the current ERM structure relative to Avista's proposed 95/5 sharing structure. Mullins states that the Commission rejected this argument, noting that the deadbands have insulated both customers and PacifiCorp from unreasonable risk and appropriately assign power cost risk.[218]

136 Mullins further testifies that the concerns related to policy changes are speculative at best.[219] Mullins states that beyond the CCA, Avista merely references the Energy

---

[211] Stokes, Exh. SNS-1T at 40:8-9.

[212] Stokes, Exh. SNS-1T at 40:13-16.

[213] Mullins, Exh. BGM-1T at 59:10-13.

[214] Mullins, Exh. BGM-1T at 60:1, 61:1.

[215] Mullins, Exh. BGM-1T at 61:1-2.

[216] Mullins, Exh. BGM-1T at 61:2-5.

[217] Mullins, Exh. BGM-1T at 61:5-7.

[218] Mullins, Exh. BGM-1T at 61:16-20.

[219] Mullins, Exh. BGM-1T at 62:7.

Independence Act and CETA, stating that "[m]any unknowns exist on the path to decarbonization that likely are not reflected in our normalized NPE modeling and forecast."[220] As such, AWEC contends that deviating from Commission policy and precedent to the detriment of ratepayers based on speculation is unreasonable.[221]

137 AWEC asserts that Avista's arguments about organized markets reducing the Company's ability to affect costs were expressly rejected in PacifiCorp's most recent rate case, with the Commission finding them to be "unsettling."[222]

Forecast Error Adjustment

138 Mullins recommends that the Commission reject Avista's proposed Forecast Error Adjustment, which would reduce the revenue requirement for electric service in RY1 by $45.2 million.[223] Mullins argues that the mark-to-market calculations Avista performed to generate the Forecast Error Adjustment do not represent a cost to Avista since power supply expenses are influenced by many other factors.[224] Mullins also claims that Avista's back-casting analysis is best used as a model validation exercise, not a method of remedying a model that was shown to be invalid.[225] Mullins asserts that Avista's backwards-looking calculation simply demonstrates that there was major market volatility between 2018 and 2022, the period over which the Company calculated the Forecast Error Adjustment.[226]

California-Oregon-Border Sales

139 Regarding California-Oregon-Border (COB) sales, Mullins recommends an adjustment to NPE to account for COB margins, resulting in a reduction to revenue requirement for electric services of $142,054 for RY1.[227] Mullins notes that Avista has previously included a line item in Forecast NPE to account for sales at the COB market hub since Avista holds

[220] Mullins, Exh. BGM-1T at 62:10-12.

[221] Mullins, Exh. BGM-1T at 62:12-14.

[222] Mullins, Exh. BGM-1T at 62:17-20.

[223] Mullins, Exh. BGM-1T at 44:8-13.

[224] Mullins, Exh. BGM-1T at 41:19-42:20.

[225] Mullins, Exh. BGM-1T at 43:8-22.

[226] Mullins, Exh. BGM-1T at 43:1-7.

[227] Mullins, Exh. BGM-1T at 46:8-12.

a contract with Portland General Electric (PGE) for 100 MW of transmission capacity at COB.[228]

Colstrip

140 Regarding Colstrip's NPE impact, Mullins objects to Avista's use of a mark-to-market calculation to determine this impact. Mullins claims that since the removal of Colstrip Units 3 and 4 from rates is the principal driver of the RY2 revenue requirement increase, it would be inappropriate to determine its rate impact using only a mark-to-market calculation performed in 2024. Mullins recommends that the Commission require Avista to perform a full update to NPE for RY2 through a PCORC or a limited update.[229] If the Commission opts for a limited update, Mullins recommends that it be submitted in August 2025 with an update to forward market prices effective November 1, 2025. Mullins' recommendation includes no modeling updates, only prices, contracts, and resources.[230] Mullins also recommends the removal of wheeling costs associated with Colstrip as a part of the RY2 NPE update, since they will no longer be used to benefit ratepayers once Colstrip Units 3 and 4 are removed from rates.[231]

141 Finally, Mullins also recommends the transfer of plant balances associated with Colstrip's transmission assets to being classified as "plant held for future use" and excluded from the revenue requirement, while removing associated expenses from the revenue requirement for RY2. Mullins justifies this recommendation by noting that Avista is transferring all ownership interest in Colstrip Units 3 and 4 to Northwestern and claims that the Company has shown no evidence that it will utilize the transmission assets.[232]

EIM Benefits

142 Mullins claims that Avista's WEIM benefit forecasting does not capture the benefits of market settlements, such as neutrality charges, flex awards, and greenhouse gas revenues resulting in an understatement of net power expense.[233] Mullins also states that the Company does not include revenues received for providing carbon free resources into the

[228] Mullins, Exh. BGM-1T at 44:14-45:11.

[229] Mullins, Exh. BGM-1T at 55:1-56:2.

[230] Mullins, Exh. BGM-1T at 56:3-19.

[231] Mullins, Exh. BGM-1T at 57:1-19.

[232] Mullins, Exh. BGM-1T at 57:20-58:21.

[233] Mullins, Exh. BGM-1T at 47:6-12; 53:7-14.

WEIM in its benefits forecast, compared to peer utilities Puget Sound Energy, PacifiCorp, and Portland General Electric.[234]

143 To account for the omission of these WEIM benefits, Mullins recommends an increase of $3.0 million to Avista's WEIM benefits calculation. This recommendation would reduce revenue requirement by $2.1 million.[235]

Avista's Rebuttal Testimony

ERM

144 While Avista initially proposed a 95/5 sharing mechanism for the ERM, upon review of Staff's testimony, the Company is willing to accept a 90/10 sharing of costs and benefits, but with a slightly modified "deadband."[236] The Company supports an asymmetric deadband, so that when power supply costs are higher than authorized, the Company would absorb $2.5 million before the 90/10 sharing.[237] When actual power supply costs are lower than authorized, the Company would only retain $2 million, before sharing 90/10 with customers.[238]

145 Avista contends that the proposed asymmetrical deadbands of $2.5 and $2.0 million are justified based on the relative size metrics of Avista and PacifiCorp and the Company's corresponding ability to absorb the "deadband" in a way that would still be meaningful without being punitive.[239]

146 The Company also agrees with Staff to eliminate the second asymmetrical sharing band that currently refunds 75 percent of surplus dollars to customers or equally splits surcharge dollars.[240]

---

[234] Mullins, Exh. BGM-1T at 53:15-54:5.

[235] Mullins, Exh. BGM-1T at 54:6-15.

[236] Christie, Exh. KJC-4T at 13:21-22, 14:1-2.

[237] Christie, Exh. KJC-4T at 14:2-4.

[238] Christie, Exh. KJC-4T at 14:4-6.

[239] Christie, Exh. KJC-4T at 14:15-18. Relative to NPE, Avista's sharing of deviations from authorized bands is approximately two times that of either PacifiCorp or PSE, which demonstrates the fairness of moving to a lower sharing band. Kinney, Exh. SJK-17T at 17:16-19, 18:6-8.

[240] Kinney, Exh. SJK-17T at 16:13-14.

147 Avista disagrees with AWEC and Public Counsel's contention that the PacifiCorp order precludes ERM modifications for Avista.[241] Kinney argues that the risk inherent in Avista's deadbands is more impactful to it given the Company's relative size, which alone should warrant ERM modification.[242] He further argues that the Company's modified proposal retains the "guardrails" desired by the Commission and keeps the customer-focused intent of the asymmetry in the second-band, while adjusting the deadband size to a risk level more in line with Avista's regulated peers.[243]

148 Avista argues that by retaining customer-favored asymmetry in the deadband, the Company believes its modified ERM proposal addresses the concerns voiced by Witness Mullins.[244]

149 Avista argues that while it is not possible to address CCA fully in this proceeding, because so many unknowns still exist with CCA, it is prudent, however, to recognize the risk that may be borne by the Company for these costs in the pro forma period, and to address them as much as reasonably possible in this proceeding with tools available – namely, by recognizing recent under-collection of costs by including a forecast error adjustment and modifying the ERM.[245]

150 Regarding Performance Based Ratemaking requirement in ESSB 5295, Avista testifies that the ERM has not been separately identified by the Commission as an area to apply performance measures geared towards evaluating how a utility performs. The incentive to perform is already part of the sharing mechanism.[246]

151 Avista suggests that Public Counsel misunderstood the forecast error adjustment to include only market variability associated with generation assets, when in fact the proposed forecast error represents components of actual costs.[247] The Company argues that Public Counsel's broader argument, that over the life of the ERM the average forecast error was small, is gravely mistaken.[248] Kalich emphasizes that the 20-year *average* error to which

[241] Kinney, Exh. SJK-17T at 19:7-9.

[242] Kinney, Exh. SJK-17T at 19:9-11.

[243] Kinney, Exh. SJK-17T at 19:24-26, 20:1-2.

[244] Kinney, Exh. SJK-17T at 21:4-6.

[245] Kinney, Exh. SJK-17T at 22:10-15.

[246] Kinney, Exh. SJK-17T at 23:15-18.

[247] Kalich, Exh. CGK-7T at 8:9-10, 8:13-14.

[248] Kalich, Exh. CGK-7T at 8:14-15.

Earle cites incorrectly masks very large forecast errors occurring year-to-year and over contiguous years.[249]

152 In response to Public Counsel, Kalich states that the market for electricity has fundamentally changed and opportunities to make forward electricity purchases and provide beneficial sale transactions on behalf of customers and the Company do not exist today as they did in the past.[250]

153 Avista currently defines CCA costs as NPE and these costs flow through the ERM. Kalich argues that it has no way to lower NPE through actions under the CCA, but that it is only a question of what the unknown costs will be.[251] Kalich argues that Avista should not be responsible for a large share of CCA costs, claiming that CCA wasn't intended to increase utility costs for electric utilities.[252] However, Kalich notes that CCA costs will almost certainly increase NPE, and argues that modifying the ERM will help mitigate the issue by reducing the Company's unreasonable exposure to CCA costs through the ERM.[253]

154 The Company argues that it should not provide a comprehensive report on its hedging practices and policies before any modification of the ERM is made because it already provides this information to the Commission.[254] Further, Avista contends that issues presented in this case will not be solved by modifying hedging policies and practices.[255] Kalich states that Earle presents no evidence to refute the primary reason hedging has become less relevant in today's marketplace, as the market liquidity for forward hedging has diminished.[256]

General Forecast NPE

155 Kinney states that the Company has rerun its Power Supply Model, updating wholesale gas and electricity prices, new and incremental contracts, non-gas fuel prices, and

---

[249] Kalich, Exh. CGK-7T at 8:15-17.

[250] Kalich, Exh. CGK-7T at 11:16-20.

[251] Kalich, Exh. CGK-7T at 12:15-16.

[252] Kalich, Exh. CGK-7T at 12:16-18.

[253] Kalich, Exh. CGK-7T at 12:19-20.

[254] Kalich, Exh. CGK-7T at 13:6-10.

[255] Kalich, Exh. CGK-7T at 13:11-12.

[256] Kalich, Exh. CGK-7T at 13:12-16.

adopting certain positions shared by other parties. As a result, the forecast NPE is reduced from $175.1 million to $119.0 million.[257]

156 Kalich testifies that Avista updated wholesale electricity and gas prices to a three-month average of forward prices for the period ending July 15, 2024. Kalich also states that suggestions from Staff for the forecast NPE were incorporated, including startup fuel costs, corrected long-term wholesale power contract revenues, updated marginal dispatch pricing for Colstrip, increased expected Rattlesnake Flat Wind generation levels, and new tariff rates associated with BPA transmission and gas transport contracts.[258]

157 Kinney asks that the Commission make explicit findings of fact with respect to multiple items, including changing market fundamentals, a large forward premium in the implied market heat rate (IMHR), the increased value and risk associated with Avista's thermal fleet, diminished market liquidity that precipitates forecast error, the increased difficulty of hedging, and the difficulty of the Company to properly forecast NPE.[259]

158 Kalich suggests convening a new workshop series after the conclusion of the rate case to revisit power supply modeling methodology, address new changes in the energy space, inform the new representatives of the intervening parties, and consider alternatives to AURORA model.[260]

Forecast Error Adjustment

159 Kinney states that Avista reduced the Forecast Error Adjustment from $65.8 million to $29.7 million.[261] Kinney offers a change to the Forecast Error Adjustment calculation methodology; using three historical years instead of five, and simply averaging the annual average of actual ERM variances instead of the average annual difference between the calculated Forecast Value and Actual Value of NPE.[262] Kinney claims that this methodology consists of actual costs, addressing Public Counsel's concern that the Forecast Error Adjustment does not consist of costs that Avista has incurred in the past. Kinney also claims that the new methodology incorporates feedback from AWEC

---

[257] Kinney, Exh. SJK-17T at 3:7-11, 3:18-3:22.

[258] Kalich, Exh. CGK-7T at 5:18-6:20.

[259] Kinney, Exh. SJK-17T at 5:5-6:17.

[260] Kalich, Exh. CGK-7T at 7:10-23. AURORA or Aurora is an energy forecasting and analysis software.

[261] Kinney, Exh. SJK-17T at 3:12-14.

[262] Kinney, Exh. SJK-17T at 10:19-11:12.

criticizing the futility of using a model validation technique for recalibrating results,[263] and that the new methodology for the Forecast Error Adjustment addresses all concerns held by Staff in Order 07 with which the Commission agreed.[264]

160 Kinney argues that AURORA modeling methodology, to which all stakeholders previously agreed, cannot reflect all the changes to input assumptions happening now in the regulatory and market environments.[265] In response to Public Counsel witness Earle's claim that Avista is providing new modeling changes that have not been vetted by the Commission, Kalich contends that Avista is not claiming to change its modeling methodology but is instead listing the Forecast Error Adjustment as a line-item adjustment, instead of burying it within the AURORA model.[266] Further, Kalich rejects Staff and AWEC's characterization of the Forecast Error Adjustment as simply a mark-to-market valuation of the Company's generation portfolio , arguing instead that it captures the entire portfolio since the calculation is based on metrics that capture the entire portfolio.[267]

161 Kinney further states that the Forecast Error Adjustment is known and measurable, and captures underlying offsets because it is based on previously approved values and captures all power supply expenses.[268] Kalich contends that forecast error is neither less nor more known than other assumptions already making up the forecast NPE value, and that if the Forecast Error Adjustment is rejected, so too should other NPE pro forma adjustments used in prior rate cases.[269] Kalich also rejects Staff witness Wilson's claim that forecast error difference is not an expense, calling it a cost "by definition" because it is driven by differences between authorized and actual expenses.[270] He rejects Wilson's assertion that including the Forecast Error Adjustment is "unprecedented," saying that recovering known and measurable costs is not unprecedented.[271]

---

[263] Kinney, Exh. SJK-17T at 12:11-20.

[264] Kinney, Exh. SJK-17T at 13:5-15:10.

[265] Kinney, Exh. SJK-17T at 10:8-19.

[266] Kalich, Exh. CGK-7T at 21:8-22:2.

[267] Kalich, Exh. CGK-7T at 15:13-16:13.

[268] Kinney, Exh. SJK-17T at 13:5-15:10.

[269] Kalich, Exh. CGK-7T at 39:5-41:20.

[270] Kalich, Exh. CGK-7T at 24:2-16.

[271] Kalich, Exh. CGK-7T at 25:15-26:2.

162 Kalich also contests Wilson's categorizations of factors as within Avista's control. Kalich describes hedging costs, physical depreciation, fuel procurement practices, and bilateral transactions outside of the EIM as outside of utility control.[272]

163 To support the inclusion of a Forecast Error Adjustment, Kalich claims that the calculated value of the implied market heat rate (IMHR) -- the price of power on the market divided by the price of natural gas -- has been higher than its realized value in the spot market. According to Kalich, this discrepancy prevents Avista from being able to realize the potential economic value that underpins forecasted NPE benefits. Kalich further argues that including the Forecast Error Adjustment would help to adjust the differences between forward prices and actuals, and that if it results in an overcorrection, the following rate case's Forecast Error Adjustment would account for that miss.[273]

164 Kinney rejects the arguments made by Staff, AWEC, and Public Counsel that the ERM captures forecast error instead of allocating the results through sharing bands.[274]

165 Kalich clarifies that in some years, the Forecast Error Adjustment could be a negative value, such times as when natural gas prices are falling.[275]

Colstrip

166 Avista witness Kinney states that Colstrip expenses are removed from the 2026 NPE based on its 2025 net value (market value minus fuel), and that no further power supply updates to 2026 are necessary.[276] Company witness Andrews states that the Company has updated the value of Colstrip to match the value from the most current power supply baseline for RY1. As a result, forecast NPE increases by $54.2 million in RY2, partially offset by a $24.4 million reduction in expenses to Washington customers through Colstrip Tariff Schedule 99.[277]

167 Avista rejects AWEC's recommendation that the Colstrip Transmission Assets be removed from rates. Kinney testifies that Avista still plans to use its Montana and BPA point-to-point transmission rights to take advantage of Montana wind resources, which the Company identified as part of its Preferred Resource Strategy in its 2025 IRP. Avista also

[272] Kalich, Exh. CGK-7T at 26:3-32:9.

[273] Kalich, Exh. CGK-7T at 34:3-36:3.

[274] Kinney, Exh. SJK-17T at 9:12-21.

[275] Kalich, Exh. CGK-7T at 23:8-24:3, 25:4-14.

[276] Kinney, Exh. SJK-17T at 3:15-17.

[277] Andrews, Exh. EMA-6T at 78:1-80:4.

plans to maintain transmission rights the Company expects it will need in the future. If the transmission assets are underutilized, Avista can sell access in short-term contracts to recover costs. In general, Avista takes the position that the Colstrip transmission assets still provide value to Avista and its customers.[278] Kinney also notes that if Avista were to stop paying its share of system upgrades and annual maintenance costs for Colstrip transmission assets, it would be in contract breach.[279]

California-Oregon-Border Adjustment

168 Kinney rejects AWEC's COB adjustment. Kinney claims that an adjustment for COB transmission was not included in previous cases and is not included in the power supply modeling methodology because the Company models an aggregated wholesale electric market comprised of all markets used by the Company.[280]

EIM Benefits

169 Company witness Kalich generally defends Avista's methodology for forecasting WEIM benefits.[281] Kalich notes that the Company uses the same methodology that PSE used in a previously approved general rate case, UE-200980.[282] After reviewing response testimony and consulting with PSE, Kalich states that Avista is adjusting its WEIM benefits forecast from $5.5 million to $6.6 million due to changes in the baseline model used to calculate incremental WEIM benefits.[283]

170 Regarding Public Counsel's recommendation that the Commission order Avista to develop a valid WEIM benefits forecast methodology, Kalich replies that the Company does not object to the Commission establishing a specific methodology in its order. However, Kalich states that a change in methodology would not be available in a timeline suitable for the current rate case.[284]

---

[278] Kinney, Exh. SJK-17T at 25:9-30:6.

[279] Kinney, Exh. SJK-17T at 28:23-29:3.

[280] Kinney, Exh. SJK-17T at 30:7-18. AWEC argues that Avista witness Kinney accepted the adjustment during the hearing, despite Avista's arguments against AWEC's proposal to continue modeling sales transactions at the COB market hub. AWEC's Post-Hearing Brief, at ¶ 52 (*citing*, Hearing Tr. Vol. III at 221:7-23).

[281] Kalich, Exh. CGK-7T at 48:19-53:22.

[282] Kalich, Exh. CGK-7T at 48:13-18.

[283] Kalich, Exh. CGK-7T at 45:18-46:5.

[284] Kalich, Exh. CGK-7T at 48:13-18.

171 Kalich recommends that the Commission reject Public Counsel's recommendation that the Company use of CAISO's estimates of WEIM benefits instead of its own. Kalich argues that the CAISO calculation overstates the WEIM benefits that Avista receives,[285] and that the historic data detailing revenues from the WEIM do not factor in the loss of revenue the Company would have earned in bilateral markets.[286] Kalich also argues that the reported benefit data from CAISO contains only 25 months, a small dataset that occurred under low hydro conditions.[287]

172 Regarding AWEC witness Mullins recommendation that Avista include greenhouse gas revenues, neutrality charges, and Flex Ramp revenues, Kalich states that the Company no longer receives greenhouse gas revenues since the CCA was passed and that Flex Ramp revenues are immaterial. As a result, the value of increased WEIM benefits resulting from Mullins' recommendation should be reduced to $0.9 million.[288]

173 In response to Staff witness Wilson's recommendation that WEIM benefits be increased $1.4 million following an analysis of EIM "cost codes," Kalich testifies that cost codes provided by CAISO are not granular enough to determine whether benefits included in those cost codes are already being captured in AURORA. Upon review of the cost code data, Kalich found that an analysis utilizing cost code data would indicate that NPE should increase by $0.3 million. Avista does not recommend an increase to NPE based on WEIM cost codes.[289]

Staff's Cross-Answering Testimony

174 Staff witness Wilson recommends that the system NPE forecast be increased from $175.1 million to $175.7 million, as adjustments to account for CCA costs and removing the Forecast Error Adjustment nearly balance each other out.[290] Regardless of the Commission's treatment of CCA costs, Staff recommends removing Avista's Forecast Error Adjustment. Staff further recommends including CCA allowance prices in dispatch and market purchases.[291] Staff's estimate of Washington NPE revenue requirement is

---

[285] Kalich, Exh. CGK-7T at 46:6-47:6.

[286] Kalich, Exh. CGK-7T at 44:1-19.

[287] Kalich, Exh. CGK-7T at 53:23-54:21.

[288] Kalich, Exh. CGK-7T at 43:12-21, 47:7-16. Kalich does not comment on whether the Commission should accept the resulting $0.9 million increase to EIM benefits.

[289] Kalich, Exh. CGK-7T at 47:17-48:5.

[290] Wilson, Exh. JDW-24CTr at 19:1-5.

[291] Wilson, Exh. JDW-24CTr at 20:4-9.

increased from $112.8 million to $113.0 million.[292] Wilson claims that the $71.15 per CCA allowance estimate is not reasonable and details the forecasting assumptions that go into Staff's estimate of CCA costs.[293] However, if the Commission determines that the cost of CCA allowances associated with forecast wholesale market sales should not be included in NPE as recommended by Staff, Staff's forecast system NPE recommendation would decrease to $132.4 million with a corresponding reduction to Washington NPE.[294]

175 Wilson also points out potential errors in Avista's AURORA modeling of unit commitment when including CCA allowance prices. Wilson does not believe that this is a material problem requiring immediate action but recommends that the Company investigate this for future filings.[295] In the event the Commission accepts AWEC's position on COB market sales, Wilson provides minor adjustments to Staff's recommended values for System Account 447, System Total Revenue, System Total Net Expense, and Washington NPE Revenue Requirement.[296]

EIM Benefits

176 In cross testimony, Wilson notes that WEIM benefits are not included in Avista's calculation of NPE forecast. Wilson further testifies that it is not necessary for Avista to include WEIM benefits in the NPE forecast, as AURORA does not differentiate between market platforms. Wilson did not investigate Public Counsel witness Earle's benefits calculation and does not take a position on whether the Company's or Public Counsel's WEIM benefits calculations are more accurate, assuming that they are immaterial to an NPE forecast.[297]

177 Wilson disagrees with Public Counsel witness Mullins' recommendation to include greenhouse gas revenues in the EIM benefits forecast. Wilson reaches this conclusion based on Kalich's testimony that the Company does not participate in California's greenhouse gas cap and trade program, which would be the source of greenhouse gas revenue.[298]

---

[292] Wilson, Exh. JDW-24CTr at 20:1-2.

[293] Wilson, Exh. JDW-24CTr at 22:14-26:19.

[294] Wilson, Exh. JDW-24CTr at 19:6-9.

[295] Wilson, Exh. JDW-24CTr at 21:7-22:12.

[296] Wilson, Exh. JDW-24CTr at 27:1-7.

[297] Wilson, Exh. JDW-24CTr at 2:21-4:4.

[298] Wilson, Exh. JDW-24CTr at 4:15-18.

178 However, Wilson does agree with Mullins that some WEIM settlement charges are inappropriately omitted from Avista's forecast of EIM benefits. Wilson's estimate of those non-energy benefits to be $1.4 million annually.[299]

179 After reviewing Avista's data request responses providing more detailed WEIM settlement charge information, Wilson finds reasonable the resulting increased $.5 million adjustment in forecast NPE.

Public Counsel's Cross-Answering Testimony

ERM

180 In cross-answering testimony, Public Counsel witness Earle reiterates arguments that the Commission should reject both Avista's and Staff's proposed changes to the sharing bands because they would make the dead and sharing band mechanism less effective.[300]

181 Witness Earle contends that Staff's comparison of Avista to PacifiCorp's deadband fail in two primary ways:

- Staff does not consider that even if Avista's dead band is relatively large compared to PacifiCorp's, this could mean PacifiCorp's is too small, and

- Staff provides no reason why the width of the dead band should be based on proposed power costs alone.[301]

182 As such, Public Counsel argues that the Commission should reject both Avista and Staff's proposals as unwarranted and unsupported by the factual record and maintain the current ERM deadband and sharing bands.[302]

183 Earle supports AWEC's recommendation for an update to Avista's forecast NPE in August 2025, with an additional update of forward market prices effective November 1, 2025. This would reduce forecast lag from 14 months to two months.[303]

---

[299] Wilson, Exh. JDW-24CTr at 5:1-7.

[300] Earle, Exh. RLE-17T at 3:12-14.

[301] Earle. Exh. RLE-17T at 3:19-20, 4:1-7.

[302] Earle. Exh. RLE-17T at 4:11-13.

[303] Earle, Exh. RLE-17T at 6:16-7:18.

184 Based on CAISO's newly released estimate of 2024 WEIM benefits, Earle makes a minor adjustment to Public Counsel's previous recommendation, and recommends the Commission order an adoption of an annual WEIM benefits forecast of $20.1 million.[304]

AWEC's Cross-Answering Testimony

185 In cross-answering testimony, Mullins continues to argue that the Commission should reject Avista's ERM proposal, assert:[305]

- The ERM is functioning as intended,
- Avista's arguments are irrelevant and unconvincing, and
- The Commission rejected similar arguments in PacifiCorp's 2023 GRC.

186 He states that Staff's conclusion that a 90/10 split is equitable is at odds with the Commission's decision in the PacifiCorp GRC,[306] and that Staff provides no evidence to support its contrary conclusion.[307]

187 Mullins argues that Staff's rationale for a reduction to the deadband does not consider the rapid growth and higher volatility experienced and noted by the Commission with respect to PacifiCorp's power costs.[308]

188 Mullins argues that Avista's forecast power costs are at a similar level to when PacifiCorp's PCAM was first established ($112 million in the current case compared to $108 million when PacifiCorp's PCAM was established).[309] As a result, Mullins emphasizes that the Commission's PacifiCorp order supports maintaining the ERM structure as is.

NPE

189 Mullins recommends the Commission not direct Avista to alter its modeling of CCA costs in its NPE forecast, given the uncertainty of Avista's ability to monetize its no-cost

[304] Earle, Exh. RLE-17T at 8:1-15. Earle's previous recommendation was an annual EIM benefits forecast of $20.7 million in response testimony.

[305] Mullins, Exh. BGM-8T at 2:29-30, 3:1-2.

[306] Mullins, Exh. BGM-8T at 3:10-14.

[307] Mullins, Exh. BGM-8T at 3:14-15.

[308] Mullins, Exh. BGM-8T at 3:15-19.

[309] Mullins, Exh. BGM-8T at 5:7-11.

allowances and the fact that the relevant Ecology rulemakings have not yet occurred.[310] Mullins states that Staff's recommendation of handling the removal of Colstrip from rates is consistent with AWEC's. Mullins would support Staff's recommendation provided that AWEC's recommendations for wheeling costs, transmission assets, and scheduling and modeling parameters are met.[311] Mullins also provides backup options to remove Colstrip from rates if the Commission rejects the MYRP, Avista files a new rate case in 2025, and the effective date of that rate case is after December 31, 2025.[312]

Decision

Restructuring the ERM

190 The Commission has previously addressed the purpose of risk sharing through mechanisms like the ERM, most recently in Dockets UE-230172 and UE-210852. There we reiterated that power cost risk sharing mechanisms are intended "to encourage effective management and reduction of power costs."[313]

191 The sharing mechanisms provide guardrails to ensure a utility manages fuel price volatility and does not engage in overly risky behavior because the guardrails ensure the utility will share in cost overruns with customers.[314]

192 Like PacifiCorp, Avista points to several factors that it claims necessitate changes to the ERM, including "nearly impossible to predict" variables,[315] such as the implied market heat rate,[316] rising market volatility,[317] falling market liquidity,[318] the CCA,[319] and the increasing value of Avista's thermal generation fleet.[320]

---

[310] Mullins, Exh. BGM-8T at 12:18-13:8.

[311] Mullins, Exh. BGM-8T at 18:1-19.

[312] Mullins, Exh. BGM-8T at 18:20-19:9.

[313] *WUTC v. PacifiCorp*, Dockets UE-230172 & UE-210852 ¶ 389 (Mar. 19, 2024).

[314] *See*, *WUTC v. PacifiCorp*, Dockets UE-230172 & UE-210852 ¶ 390 (Mar. 19, 2024).

[315] Kinney, Exh. SJK-1T at 54:2-9.

[316] Kinney, Exh. SJK-1T at 58:6-60:3.

[317] Kinney, Exh. SJK-1T at 60:14-62:8.

[318] Kinney, Exh. SJK-1T at 62:9-63:2.

[319] Kinney, Exh. SJK-1T at 64:3-65:9.

[320] Kinney, Exh. SJK-1T at 69:15-71:14.

193 We recognize that during the past three to four years, energy markets have looked somewhat different for Avista, as they have for all utilities. However, the evidence in this case shows that the ERM is working as it should for now.[321]

194 AWEC and Public Counsel correctly argue that fuel prices have been volatile since the ERM was implemented in 2006.[322] During that time fracking was just starting and natural gas was becoming more available and at a lower cost. The ERM functioned through a Great Recession and then through record low interest rates and a booming stock market. The ERM is intended to share risks in good times and in bad, to ensure that the utility retains a certain level of risk even when external pressures increase, because ultimately the utility has control, or at least some level of control, over the resources it procures and the contracts it enters for fuel and power. There is inherently informational asymmetry, where the utility knows far more about its operations and choices than intervenors and certainly than customers.

195 To ensure that rates remain just and reasonable, the utility should carry a certain level of risk through the ERM or a similar mechanism.

196 We are not convinced here that comparisons to the relative size of the risk that other utilities face means Avista's ERM should be modified. As Avista points out, each utility is different. Avista's resource position is different than from PacifiCorp's or Puget Sound Energy's.[323] Because of this, a simple comparison of relative risk through the dead and sharing bands is unconvincing and as Public Counsel and AWEC point out, perhaps raises the question of whether instead of decreasing the bands for Avista, the bands should not be increased for other utilities.

197 Accordingly, the Commission denies Avista's and Staff's proposals to modify the ERM at this time. This is not to say that the Commission simply will not modify the ERM under any circumstances. We are open to entertaining changes to the ERM, however, as AWEC and Public Counsel rightfully point out, there is a modeling issue present, as evidenced by Avista's admissions in relation to the Forecast Error Adjustment. The Commission finds that the parties should address the modeling errors, and only then might the Commission revisit the issue, if necessary, to assess whether further adjustments are needed.

Forecast Error Adjustment

---

[321] *See*, Kalich, Exh. CGK-7T at 23:1-7; *see also* Mullins, BGM-1T at 60:14-61:6; BGM-8T at 2:29-30.

[322] *See*, *Avista Corp.*, Docket UE-060181, Order 3 ¶ 3 (June 16, 2006).

[323] Avista's Post-Hearing Brief, at ¶¶ 74-81.

198 We next address Avista's proposal to add a forecast error adjustment to their baseline NPE. On direct, the Company proposed a forecast error of $65.8 million, which it reduced on rebuttal to $29.7 million. Avista argues the Commission should approve the new forecast error, using a new methodology, as the new forecast error is known, measurable, considers any indirect offsets, and is generally supported in the record by contracts, receipts, ledgers, and other proof as are other approved adjustments like median hydro, averages for outages, and forward market prices.[324] No other party supports this adjustment.

199 Staff argues the Commission should reject the forecast error adjustment "as arbitrary, and thus as unfair, unjust, or unreasonable."[325] Staff argues the revised forecast error adjustment (1) is untested and only offered on rebuttal, (2) unfairly shifts power cost risks away from Avista, and (3) is unknown, unmeasurable, and normalized on a biased sample.[326]

200 Public Counsel argues the proposal lacks analytical rigor, does not meet the known and measurable standard, and fails to match with offsets.[327] Further, Public Counsel argues that the events and costs represented in 2021, 2022, and 2023, represent a small sample in time, which was impacted by a series of unfortunate events, all of which make basing an adjustment for 2025 and 2026 on events during that time extremely problematic.[328] Finally, Public Counsel notes the adjustment only improves Avista's results and provides Avista a windfall.[329]

201 We largely agree with Staff and Public Counsel. While we do find the issues Avista is facing to be problematic, we find that as with the ERM, the methodology Avista uses to forecast power expenses needs to be re-examined, and that a large adjustment, which Avista would collect from customers to account for modeling errors, is not just or reasonable.

---

[324] Avista's Post-Hearing Brief, at ¶¶ 56-59, 61.

[325] Staff's Post-Hearing Brief, at ¶ 66.

[326] Staff's Post-Hearing Brief, at ¶¶ 67-87 (Oct. 28, 2024) (*citing*, *Wash. Utils. & Transp. Comm'n v. Harbor Water Co., Inc.*, Docket U-87-1054-T, 1988 Wash. UTC Lexis 68, * 37 (May 7, 1988); Kalich, Exh. CGK-7T at 19:14-20; *Wash. Utils & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, 11-12 ¶ 14 (Mar. 25, 2011); *Avista Corp.*, Dockets UE-090134, UG-090135 & UG-060518, Order 10, at 21 ¶ 45).

[327] Public Counsel's Post-Hearing Brief, at ¶¶ 62-63.

[328] Public Counsel's Post-Hearing Brief, at ¶¶ 64-65.

[329] Public Counsel's Post-Hearing Brief, at ¶ 68.

202 The Commission expressed some concerns with the forecast error adjustment in Order 07 of this docket, but ultimately decided that the record needed to be further developed on the $65.8 million adjustment. As Staff points out, that record was not developed because Avista revised the error amount and changed the methodology on rebuttal.

203 While the Commission understands Avista's change in methodology and adjustment on rebuttal, the Commission has held "at some point, the company's positions must be made clear in order for the other parties to respond to those positions. That point is prior to rebuttal. The parties in a rate case should not have to constantly respond to a moving target."[330]

204 Here, the record is not well developed on Avista's updated proposal, in part because the proposal changed on rebuttal. For an adjustment of this magnitude, the Commission encourages companies to vet such proposals with parties ahead of time and allow reasonable time and opportunity for response.

205 Further, as Staff, Public Counsel, and AWEC point out, the original and revised proposal do not meet the known and measurable standard. "Washington uses a hybrid test year approach that allows pro forma adjustments only for known and measurable changes–not budgeted or projected changes–that occur, generally within a reasonable time after the end of the test year."[331] Further, "[a]n event is 'known' if it occurred during or shortly after the historical test year and it is 'measurable' if it is not an estimate, projection, or product of a budget forecast."[332]

206 Moreover, as Public Counsel states, Avista's proposal "does not help predict future gas or electricity prices, the implied market heat rate, or how forward prices are inadequate inputs because they collapse as they reach real time."[333]

207 We agree with Public Counsel and note that Public Counsel's criticism gets to the underlying problem with the forecast error adjustment. Rather than identifying known and measurable causes of the error, and recommending modeling adjustments to account for those errors, the Company notes the error is and remains present. The Company averages

---

[330] *Wash. Utils. & Transp. Comm'n v. Harbor Water Co., Inc.*, Docket U-87-1054-T, 1988 Wash. UTC Lexis 68, * 37 (May 7, 1988).

[331] *Pac. Power & Light Co.*, Dockets UE-140762, UE-140617, UE-131384 & UE-140094, Order 08, 3 ¶ 8.

[332] Public Counsel's Post-Hearing Brief, at ¶ 55 (Oct. 28, 2024) (*citing*, *Wash. Utils. & Transp. Comm'n v. Avista Corp.,* Dockets UE-090134 & UG 090135 *(consol.)* Final Order 10 ¶ 43 (Dec. 22, 2009)).

[333] Public Counsel's Post-Hearing Brief, at ¶ 62.

recent unfavorable amounts to calculate a solution which might cover the error but does not solve the underlying condition. In fact, the exact cause of the error appears to remain elusive and is not known.

208 Because the Company does not persuasively support the proposed forecast error adjustment, and because the proposal fails to meet the known and measurable standard, the Commission rejects inclusion of the forecast error adjustment.

209 However, we agree with Avista that further discussions by all parties should take place in relation to the ERM and forecast error. Witness Kalich suggested convening a new workshop series after the conclusion of the rate case to revisit power supply modeling methodology, address new changes in the energy space, inform the new representatives of the intervening parties, and consider alternatives to or modifications to the AURORA model.[334] We agree with this suggestion and find, following the close of this proceeding, that Avista shall convene a workshop series with interested parties to address modeling inputs, power supply modeling methodology, use of AURORA, and a changing energy landscape. These conversations should include discussions regarding inclusion of CCA costs and address the forecast error as well as other issues raised by the parties in this proceeding.

210 Based on the evidence in the record and the Commission's denial of the forecast error adjustment, the Commission authorizes a Washington Total Power Supply Base of $34,116,983 for rate year 1, and $85,733,975 for rate year 2.

Western Energy Imbalance Market (WEIM) Benefits

211 Avista justifies their WEIM benefits methodology by claiming it is the same as that PSE used and the Commission approved in their rate case in Docket UE-200980.[335] However, Staff, Public Counsel, and AWEC each suggest adjustments to Avista's WEIM benefits calculation methodology.

212 AWEC proposes to include greenhouse gas (GHG) revenues in the evaluation of WEIM benefits. However, Avista argues that those revenues are no longer available after passage of the CCA.[336] In its post-hearing brief, AWEC argues that despite Avista's arguments that

---

[334] Kalich, Exh. CGK-7T at 7:10-23.

[335] Kalich, Exh. CGK-7T at 48:13-18.

[336] Kalich, Exh. CGK-7T at 43:12-21, 47:7-16.

GHG revenues are no longer received, there must be exceptions and the Commission should at least adopt Avista's own recalculation of $0.9 million.[337]

213 We disagree. Avista asserts and the record shows that Avista is not receiving GHG revenues.[338] Despite AWEC's assertion that there are exceptions, pointing to the testimony of witness Kalich, the Commission finds such exceptions to be speculative and generally unsupported by the record. For clarity, AWEC argues Avista received some GHG revenues in 2022 and 2023. Avista admits this in Exhibit CGK-7T.[339] However, as Kalich testifies and the record shows, the revenues that AWEC asserts should be included are based on transactions in 2022. The transactions through 2022 decreased to a negligible amount in the test year of 2023 before ceasing in the later part of 2023.[340] To adopt an adjustment based on an assertion of exceptions – or revenue which the record shows is no longer being received – would violate the known and measurable standard. Therefore, we find that AWEC's proposed adjustment should be rejected.

214 AWEC and Staff propose to include other non-energy benefits in the evaluation of benefits.[341] Specifically, AWEC proposes the Commission should order Avista to adjust for WEIM settlement transactions. Staff witness Wilson agrees some WEIM settlement charges are inappropriately omitted from Avista's forecast of WEIM benefits. Wilson's estimate of those non-energy benefits is $1.4 million annually.[342] However, Avista uses an approved methodology to calculate those benefits, which does not produce surplus revenues that need to be redistributed. Accordingly, we reject the adjustments proposed by AWEC and supported by Staff for including additional non-energy benefits.

215 Finally, Public Counsel proposes adopting CAISO's estimate of WEIM benefits, which would result in $20.1 million in benefits. On rebuttal, Avista witness Kalich argues that the CAISO calculation overstates the WEIM benefits that Avista receives and does not factor in the loss of revenue that would have been earned by the Company in bilateral markets. Kalich also argues that the reported benefit data from CAISO contains only 25 months, a small dataset that occurred under low hydro conditions. On this, we agree with Avista.

216 The CAISO estimate does not account for the opportunity cost of leaving the bilateral market, thus it should not be used to calculate WEIM benefits for Avista at this time as the

---

[337] AWEC's Post-Hearing Brief, at ¶ 51 (*citing*, Hearing Tr. Vol. III at 221:7-23).

[338] Kalich, CGK-7T at 47:14-15; fn. 53.

[339] Kalich, CGK-7T at 47:14-15; fn. 53.

[340] Kalich, CGK-7T at 47:14-15; fn. 53.

[341] *See*, Wilson, Exh. JDW-24CTr at 5:1-7.

[342] Wilson, Exh. JDW-24CTr at 5:1-7.

evidence suggests its adoption would likely result in an overestimation of benefits not likely to be realized. Accordingly, the Commission finds the WEIM benefits calculation methodology proposed by Avista, resulting in $6.6 million in benefits, reasonable and rejects the proposals to adjust WEIM benefits put forward by Staff, Public Counsel and AWEC.

Colstrip

217 AWEC also requests the Commission order Avista to remove Colstrip transmission assets from rates and to file a Power Cost Only Rate Case (PCORC) or other limited update to rates to improve Avista's mark-to-market valuation of Colstrip in RY2 before the costs of Colstrip Units 3 and 4 are removed from rates.

218 We reject both proposals at this time. First, Avista has identified as part of its Preferred Resource Strategy in its 2025 IRP the use of the assets for transmission of Montana wind resources. Further, as Avista points out, if underutilized, Avista will sell access through short-term contracts to recover costs. Either use would provide value to Avista and its customers. Indeed, if Avista stopped paying its share of transmission upgrades and annual maintenance, it would be in breach of contract. We find that as of today, Avista's transmission assets are used and useful and the Company has provided evidence and testimony showing that they will remain so. Accordingly, we find that the Colstrip transmission assets should remain in rates at this time. However, if the assets cease to be used and useful, we will revisit the issue in the next GRC.

219 Second, Avista argues, and we agree, that a further power supply update to update the mark-to-market valuation of Colstrip in 2026 is not necessary. As Avista provides, the Company updated the value to match that from the most current power supply baseline for Rate Year 1. While AWEC argues that valuation may not account for offsetting benefits from dispatching other resources, there is no evidence supporting the need for an update and the Commission does not find that the benefits would outweigh the costs of such a proceeding. Accordingly, we reject AWEC's proposals.

California-Oregon-Border Adjustment

220 AWEC recommends "an adjustment to NPE to account for COB margins, resulting in a reduction to revenue requirement for electric services of $142,054 for RY1."[343]

---

[343] Mullins, Exh. BGM-1T at 46:8-12.

221 In its post-hearing brief, AWEC argues that Avista witness Kinney accepted the adjustment during the hearing.[344] While Avista does not directly address the COB adjustment in its post-hearing brief, the Company notes in a footnote the following:

> An adjustment for COB transmission was not included in previous cases and is not included in the agreed power supply modeling methodology. One primary goal of the Workshops on power supply modeling was to simplify inputs. The parties agreed to a balanced modeling approach that included a single wholesale electric market and a single wholesale natural gas market, instead of representing all markets used by the Company. The parties agreed this simplification was fair and no further adder for COB transmission was included in the power supply methodology.[345]

222 From reviewing the hearing transcript, however, it does appear Avista accepted the adjustment.[346] Accordingly, the Commission finds that the adjustment AWEC proposes to account for COB margins should be made.

Capital Projects and Timing/Classification of Provisional Plant

Avista's Direct Testimony

223 Avista witness Benjamin provides testimony regarding the Company's overall approach for the inclusion and classification of capital projects (plant or plant additions) and the Company's proposal to continue the existing provisional plant review methodology. Witnesses Alexander, DiLuciano, Manuel, Howell, and Hydzik provide the business cases related to the capital projects included in the Company's MYRP proposal.[347]

224 Benjamin testifies that the Company uses a test period ending on June 30, 2023, includes pro forma adjustments for July 2023 (actuals), and expected additions through December 2023. Further, Benjamin asserts that plant additions through 2024 are classified as "pro forma" on an End of Period (EOP) basis as the Commission already approved that rate base in its 2022 GRC. Therefore, only capital projects for 2025 and 2026 are classified as provisional and are included on an Average of Monthly Averages (AMA) basis.[348]

---

[344] AWEC's Post-Hearing Brief, at ¶ 52 (*citing*, Hearing Tr. Vol. III at 221:7-23).

[345] Avista's Post-Hearing Brief, at fn. 121.

[346] Hearing Tr. Vol. III at 221:7-23

[347] Benjamin, Exh. TCB-3.

[348] Benjamin, Exh. TCB-1T at 8:12-9:3, 10:19-11:2.

Benjamin testifies that provisional plant is categorized according to the Commission's Used and Useful Policy Statement.[349]

225 Regarding the pro forma classification of 2023 and 2024 plant additions, Benjamin appears to contemplate that the 2023/2024 plant additions remain subject to the Provisional Capital Reporting process as ordered in the 2022 GRC, despite the change in terminology.[350] Benjamin proposes that the 2025 and 2026 plant additions be subject to the same provisional reporting and review requirements as ordered in the 2022 GRC. Further, the Company intends to update the actual capital additions through 2023 and any changes to the expected additions through 2026.[351]

226 Benjamin's testimony incorporates the "Pro Forma Studies" provided by Company witness Schultz which results in an approximate increase to net plant of $305 million for electric and $72.5 million for natural gas over the course of the MYRP.[352] Benjamin testifies these balances include all direct Operations & Maintenance (O&M) offsets, a 2 percent O&M efficiency adjustment for those business cases without direct offsets, offsetting revenues attributed to growth, incremental reductions to depreciation expense, and net impact to net plant when including retirements occurring over the rate plan.[353]

Staff's Response Testimony

227 Staff witness Erdahl makes two recommendations related to provisional plant. First, Erdahl disagrees with the Company's reclassification of provisional plant from its 2022 GRC to traditional pro forma for the plant additions in 2023 and 2024.[354] Erdahl states that "[p]ro forma plant is not refundable," arguing customers should retain the benefits of the

---

[349] Benjamin, Exh. TCB-1T at 12:11-17. The Commission notes that Avista does not utilize the exact categories specified in the Used and Useful Policy Statement (specific, programmatic, and projected) but rather four categories (large or distinct, programmatic, mandatory and compliance, and short-lived). However, this is consistent with the way the Company classified provisional plant in its 2022 GRC. *See In re Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful After Rate Effective Period*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date (Jan. 31, 2020). Herein referenced as the Used and Useful Policy Statement.

[350] Benjamin, Exh. TCB-1T at 28:15-29:1.

[351] Benjamin, Exh. TCB-1T at 29:2-30:17. Benjamin also provides testimony that reiterates that provision plant review process as established in the 2022 GRC at Exh. TCB-1T at 30:18-32:32

[352] Benjamin, Exh. TCB-1T at 26:24-27:13.

[353] Benjamin, Exh. TCB-1T at 18:9-21.

[354] Erdahl, Exh. BAE-1T at 9:1-3. 2023 Provisional Plant was under review at the time response testimony was due. The Provisional Plant for 2024 would not be under review until April 2025.

review process including potential refunds.[355] Further, Erdahl contends reclassifying plant between MYRPs creates duplicative work for Staff and other parties as the same plant would be evaluated at three separate points in time (past GRC, retrospective plant review, and current GRC). Erdahl also argues that these evaluation points create the possibility of inconsistent prudency findings by the Commission.[356]

228 Second, Erdahl proposes that Avista be required to establish separate tariff schedules for plant that is provisionally approved in rates, like those created in PSE's 2022 GRC.[357] Erdahl argues this process provides clear delineation between plant that is approved into rate base and that rate base which is subject to refund. However, citing "administrative efficiency," Staff proposes these tariffs for Avista's next GRC, not in this proceeding."[358]

229 Erdahl also provides Staff's opinion that the methodology employed to develop the rate case should prevent double counting of rate base from a company's prior GRC. Specifically, Erdahl testifies that Avista employed a new modified historical test year rather than building incrementally from the prior proceeding.[359]

230 Staff witness Sofya Shafran Atitsogbe Golo (Atitsogbe) provides testimony expressing concern about Avista's distribution system planning and the initial prudency of associated investments. While Staff does not request a prudency determination now, they recommend the provisional distribution plant be included in rates, subject to refund, and comply with two proposed conditions during the annual provisional plant review process, which are discussed below.[360] Staff argues the Commission should allow these investments on a provisional basis to avoid immediate negative financial impacts and provide "balance[ ]for regulatory compliance with the practical necessity of maintaining a stable and reliable distribution system for customers."[361]

---

[355] Erdahl, Exh. BAE-1T at 9:3-5.

[356] Erdahl, Exh. BAE-1T at 9:17-22. Alternatively, Erdahl recognizes that the Commission could, in this proceeding, order refunds subject to review for "pro forma" plant if the Commission does not accept Staff's position of retaining the provisional plant status. Erdahl, BAE-1T at 10:3-10.

[357] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-220066 and UG-220067 *(consolidated)*, Settlement Agreement Joint Testimony, Exh. JAP-SEF-JJJ-1JT at 20:5-22:10. The concept for a separate tariff was proposed by PSE in its direct testimony (SEF-1Tr) and then incorporated into the settlement agreement.

[358] Erdahl, Exh. BAE-1T at 10:13-21.

[359] Erdahl, Exh. BAE-1T at 8:12-18.

[360] Atitsogbe, Exh. SSAG-1T at 30:13-19.

[361] Atitsogbe, Exh. SSAG-1T at 30:20-21.

231 Atitsogbe expresses specific concerns about Avista's lack of planning for distributed energy resources (DERs) and evaluation of non-wire alternatives (NWAs). Atitsogbe emphasizes that distribution planning exists in various utility filings (*e.g.,* IRPs, Clean Energy Action Plans CEAPs, and CEIPs) that Staff rely upon when evaluating investments in a GRC.[362] Further, Atitsogbe points to various statutory requirements and Commission rules that require specific utility actions within utility distribution planning efforts.[363]

232 Staff's analysis finds five distinct deficiencies with the Company's distributed energy resources (DER) integration efforts. These include: (1) non-compliance with the DER rules; (2) an incomplete DER potential study; (3) failure to meet conservation and demand response goals; (4) unclear project coordination; and (5) delayed implementation of its Advanced Distribution Management System (ADMS). Atitsogbe contends these issues demonstrate the Company's failure to meet its obligations in distribution planning.[364] Further, Atitsogbe contends that distribution investments account for the majority of total plant investment during 2025, and nearly half in 2026, leading to Staff's concern that the Company continues to undertake costly distribution investments that reinforce the traditional grid structure rather than transitioning to a modern grid.[365]

233 Regarding NWAs, Atitsogbe contends that an evaluation of investment alternatives must be considered in determining prudency.[366] Atitsogbe testifies that only one project made mention of NWAs, and that the Company failed to provide any details of the analysis conducted.[367] Further, Atitsogbe argues the Company failed to follow its own internal "playbook" to evaluate NWAs.[368]

234 Staff recommends Avista comply with two conditions during the provisional plant review process; otherwise, the provisional distribution plant should be refunded to customers.

---

[362] Atitsogbe, Exh. SSAG-1T at 13:12-14:10.

[363] Witness Atitsogbe includes references to: RCW 19.405.010(1); WAC 480-100-610(4); RCW 19.280; WAC 480-100-620; WAC 480-100-640; Laws of 2023, Chapter 200, sec. 1; Avista's 2022-2023 Electric Biennial Conservation Plan, Docket U-210826; RCW 19.285; Northwest Power Act in 16 USC Chapter 12H; Avista's 2021 CEIP, Docket UE-210628, Order 01 (June 23, 2022).

[364] Atitsogbe, Exh. SSAG-1T at 19:8-20:14. Witness Atitsogbe acknowledges the Company proposed three projects that may assist in accommodating DERs but maintains it is not sufficient to meet their planning obligations.

[365] Atitsogbe, Exh. SSAG-1T at 7:1-5, 8:2-6, 16:14-18.

[366] Atitsogbe, Exh. SSAG-1T at 21:12-14. Atitsogbe references footnote 34 in the Commission's Used and Useful Policy Statement interpreting the property valuation provision of RCW 80.04.250.

[367] Atitsogbe, Exh. SSAG-1T at 22:14-17.

[368] Atitsogbe, Exh. SSAG-1T at 22:1-6. The playbook is provided in Atitsogbe Exh. SSAG-2.

First, Atitsogbe proposes requiring additional data for the past five years that includes: financial data related to distribution system investments for the preceding five years; interconnection charges; information about routine operational activities by category for projects exceeding $2 million; data and narrative for distribution system O&M costs; and a five-year forecast for both distribution plant and O&M expenses.[369]

235 Second, Atitsogbe recommends conditions be placed on Avista's 2025 electric IRP to ensure the Company "conducts a comprehensive, transparent, and forward-looking distribution planning [process]."[370] These requirements include information about DERs in Avista's distribution system, compliance with RCW 19.280.100(2)(e), and specific requirements for its grid development scenarios.[371]

AWEC's Response Testimony

236 AWEC witness Mullins testifies that the MYRPs and provisional plant review process have resulted in greater administrative burden, created capital spending budgets that are difficult to challenge, and which shift risk to ratepayers. He notes that they are not permitted but not required under R CW 80.28.425 (MYRP Statute). Mullins calls for the Commission to limit the forecasted capital allowed in rates and revise the provisional plant review process from a portfolio approach to a project-by-project review.[372]

237 Mullins argues the statutory changes that shift determination of a utility's revenue requirement away from the modified historical test year and limited pro forma adjustments have not curbed the frequency of rate cases, reduced t administrative burden, or provided appropriate protections against utility cost escalations. Mullins contends that instead, rate cases have become more complicated, contain aggressive forecasting assumptions, provide no incentive for utility cost containment, and provide for a review period that is irrelevant so long as the utility spends within the approved budget. Further, Mullins takes issue with Avista including capital expenditures for business cases not included in its 2022 GRC during the provisional plant review process.[373]

238 For these reasons, Mullins recommends a 'course correction' to limit capital project costs to plant in service on or before the rate effective date for each rate year within the MYRP.

---

[369] Atitsogbe, Exh. SSAG-1T at 26.

[370] Atitsogbe, Exh. SSAG-1T at 27:18-19.

[371] Atitsogbe, Exh. SSAG-1T at 27:21-29:14. RCW 19.280.100 requires a ten-year plan for distribution system investments and analysis of NWAs.

[372] Mullins, Exh. BGM-1T at 12:3-13:2.

[373] Mullins, Exh. BGM-1T at 5:15-7:3, 7:17-8:10.

Mullins argues that not only is the statutory language allowing MYRPs permissive, but that the Commission's Used and Useful Policy Statement also affirms the Commission's intent for the continued use of the modified historical test year approach.[374]

239 For RY1, this recommendation would limit capital expenditures to those in service on or before December 21, 2024. However, Mullins recognizes this approach still requires projected costs and therefore recommends that Avista submit a compliance filing with an attestation confirming that all estimated plant through December 21, 2024, was placed in service. Additionally, Mullins proposes the Commission require this attestation on a project-by-project basis with a refund for any underspent project with costs exceeding $1 million. Further, if the Commission does not accept AWEC's recommendation to limit capital additions or the attestation process, Mullins argues that the Commission should still adopt a project-by-project methodology for the provisional plant review filing.[375]

240 For RY2, Mullins testifies that due to the complexities of removing Colstrip from rates, it may be more efficient to limit this GRC to a single year. However, if the Commission authorizes a two-year rate plan, Mullins recommends the same limitations and attestation process occur for the second year (calendar year 2025).[376]

241 Mullins contends this approach would eliminate the need for the after-the-fact capital review process, thus mitigating the administrative burden of MYRPs. AWEC's recommendations would reduce electric total rate base by $25.8 million for RY1 and $9.0 million for RY2. For natural gas, AWEC would reduce total rate base by $3.2 million in RY1, with an increase of $5.9 million for RY2.[377]

Avista's Rebuttal of Staff

242 Company witness Andrews responds to Staff witness Erdahl's testimony regarding the classification of pro forma and provisional plant, the request for an extended review period, and Staff's proposal for separate tariffs to track provisional plant. Avista is "amenable" to Staff's classification of plant, and supportive of the extended review period, but disagrees with creating separate tariff schedules for provisional plant.[378]

---

[374] Mullins, Exh. BGM-1T at 9:9-11:10, referencing the MYRP Statue RCW 80.04.250 and paragraph 20 of the Commission's Used and Useful Policy Statement.

[375] Mullins, Exh. BGM-1T at 11:13-12:6.

[376] Mullins, Exh. BGM-1T at 13:5-18.

[377] Mullins, Exh. BGM-1T at 13:20-14:3.

[378] Andrews, Exh. EMA-6T at 3:18-4:11.

243 While Avista does not oppose Staff's position regarding the classification of projected plant, Andrews testifies that the Company's classification of provisional plant for 2023 and 2024 (included in the 2022 GRC) was not intended to circumvent the established review process. Andrews agrees to maintain the classification of provisional plant for any projected plant beyond the test year.[379]

244 However, Andrews disagrees with Staff's perspective that changing the label of provisional plant creates duplicative review and the possibility of inconsistent prudency determinations. Andrews argues that the existing provisional plant review process would remain intact despite the naming convention and that many of Avista's projects are ongoing, as demonstrated in other Company witnesses' testimony and supporting business cases. Andrews argues that these business cases are not changing, just the project funding levels. Combined with an extended review timeframe from four to six months, Andrews submits that the fact that business cases remain unchanged further alleviates pressures for Staff and other parties to complete review of these filings.[380]

245 The Company also disagrees with Staff's proposal for separate tariffs to track provisional plant. Andrews argues the utilization of separate tariffs introduces complexity and additional burden by requiring: (1) the review of revenue requirement through both base rate and individual trackers, (2) the Company to adjust its accounting system and processes, and (3) management of additional tariffs which could lead to errors with more complicated rate structure. Andrews also points to the Commission's Used and Useful Policy Statement that allows for either process. Finally, she contends that the deferral process for any required refunds is reasonable, especially given that no refunds have yet been required through the provisional plant review for 2022 or 2023.[381]

246 Avista witness DiLuciano responds to Staff witness Atitsogbe's testimony related to the Company's electric distribution system planning. DiLuciano wholly disagrees with Staff's assessment of the Company's distribution system planning, its determination that Avista has not met the prudency standard, and its claims that the Company has not complied with various RCWs, WACs, and Commission orders.[382]

247 First, DiLuciano states the Company has already demonstrated through direct testimony and exhibits that it has met the prudence standard with a "robust planning standard that sets the foundation," for its distribution planning and investments. DiLuciano testifies the

---

[379] Andrews, Exh. EMA-6T at 11:4-12:12.

[380] Andrews, Exh. EMA-6T at 13:3-14:17.

[381] Andrews, Exh. EMA-6T at 15:2-16:16.

[382] DiLuciano, Exh. JDD-3T at 3:4-4:1.

business cases in this proceeding contain the necessary documentation, including consideration of alternatives, that Staff claims is lacking.[383]

248 Second, DiLuciano takes issue with Staff's assertions that the Company has not changed its planning process related to an increased focus on DERs as required by RCW 19.280, and that it is not making progress to modernize its distribution grid. He cites the Company's refinements in its distribution planning and subsequent collaboration with Modern Grid Solutions (MGS) to integrate new approaches including NWAs.[384] Further, DiLuciano testifies that the Company has also engaged with interested parties through its Distribution Planning Advisory Group (DPAG) and its transmission planning process.[385] DiLuciano argues that Avista has made progress in meeting RCW 19.280.100 as evidenced by: (1) deployment of grid-monitoring capable smart devices, (2) utilization of Advanced Metering Infrastructure data, (3) publication of its ten-year plan, (4) and inclusion its 2023 electric IRP of a chapter related to DERs and data specific to Avista's territory.[386]

249 Next, DiLuciano provides examples of projects that help inform the Company in its interconnection process, hosting capacity assessment, DER behavior, or document Avista's consideration of DERs in its grid modernization efforts. These projects included a collaboration to refine microgrid designs, battery installation to reduce load on a substation transformer, considerations of rooftop solar to mitigate capacity constraints, and consideration of batteries for part of the North Spokane transmission system.[387]

250 While DiLuciano argues that although the Company did not meet its 2022-2023 conservation targets, it employed adaptive management efforts in an attempt to reach the targets but was hampered by circumstances that were both unforeseen and extraordinary in nature. DiLuciano references the continued COVID-19 emergency and lasting impacts such as supply chain issues, labor shortages, and high interest rates and inflation. Also, DiLuciano testifies that notwithstanding those efforts and impacts, there was no material strain placed on the distribution system from the missed targets.[388]

---

[383] DiLuciano, Exh. JDD-3T at 4:4-21.

[384] DiLuciano, Exh. JDD-3T at 5:1-6:19. MGS is the consulting firm that assisted Avista with its NWA/DER Playbook referenced by Staff and Sierra Club.

[385] DiLuciano, Exh. JDD-3T at 9:5-10:12.

[386] DiLuciano, Exh. JDD-3T at 14:1-11.

[387] DiLuciano, Exh. JDD-3T at 10:14-11:7, 11:18-12:10. *See* JDD-7, JDD-8, and JDD-9 for the referenced business cases.

[388] DiLuciano, Exh. JDD-3T at 16:14-17:14.

251 To refute Staff's claim that it failed to comply with the Commission's order in Avista's 2021 CEIP filing,[389]DiLuciano testifies that the Company's DER Potential Assessment was published on June 17, 2024, and provides the report in Exh. JDD-10t.

252 Finally, DiLuciano responds to Staff's proposal to require two conditions for the annual review process to determine the recovery of distribution provisional plant. First, DiLuciano argues that the financial information and data that Staff requests in Condition 1 are already provided to the Commission as part of the business cases filed in GRCs. Requiring further reporting, he says, would create a burden for the Company. Further, DiLuciano references Staff compliance letters from Avista's 2023 provisional plant review that finds the documentation provided in the filing to be in compliance and sufficient.[390]

253 Regarding Staff's second condition requiring additional analysis in Avista's 2025 IRP, DiLuciano testifies the draft IRP will be filed in September 2024 with a final draft due on January 2, 2025. Therefore, DiLuciano argues that with a rate effective date of December 21, 2024, in this proceeding, the Company does not have adequate time to complete the extensive analysis required for compliance with such a condition.[391]

Avista's Rebuttal of AWEC

254 Company witness Andrews disagrees with AWEC's position and recommendations related to capital projects. First, she identifies a modeling error in RY2 capital adjustment; namely that Mullins fails to adjust Accumulated Deferred Federal Income Taxes (ADFIT) when moving from an AMA basis to an EOP basis, resulting in an overstated reduction in revenue requirement of $859,000 and $96,000 for electric and natural gas, respectively. Andrews contends the capital investments excluded by AWEC contain projects needed to maintain energy reliability for customers.[392]

255 Next, Andrews argues that AWEC's position "upsets the new regulatory paradigm…."[393] Andrews contends that the Legislature and Commission, respectively, acknowledge the

---

[389] DiLuciano, Exh. JDD-3T at 12:13-14. The DER Potential Assessment was published on June 17, 2024, with response testimony due in this case on July 3, 2024. It does not appear this assessment was filed with the Commission in either Docket UE-210628 (2021 CEIP) or the 2022 GRC docket.

[390] DiLuciano, Exh. JDD-3T at 20:24-22:13.

[391] DiLuciano, Exh. JDD-3T at 22:15-3. DiLuciano provides additional testimony as to why incorporating Condition 2 into the 2027 IRP is also inappropriate. *See*, DiLuciano, Exh. JDD-3T at 23:6-25:12.

[392] Andrews, Exh. EMA-6T at 18:11-12.

[393] Andrews, Exh. EMA-6T at 18:18.

need for a more flexible regulatory rate setting process, as evidenced by the passage of ESSB 5295 and the Commission's subsequent Used and Useful Policy Statement. Andrews argues that the statute and policy guidance provides for that flexibility while continuing certain regulatory principles.[394]

256 Andrews also takes issue with Mullins' claim that utilities lack incentive to limit the amount of capital investment and to subsequently ensure they spend to approved budgets. To the contrary, Andrews contends that the Company's capital planning process neither results in funding every request nor provides automatic funding at the level of funding requested. Additionally, Andrews opines that the time to prepare for and complete the adjudication process together with the subsequent period of the proposed MYRP requires estimates months and years in advance. Therefore, AWEC's proposal would penalize a utility by "freezing" funding for specifically identified projects so far in advance given that operational needs change over time.[395]

257 Finally, Andrews claims that the Company experienced earnings erosion despite the rate plan authorized in the 2022 GRC. Andrews references testimony of other Company witnesses to support this statement.[396]

Public Counsel's Cross-Answering Testimony

258 In cross-answering, Public Counsel witness Garrett supports AWEC's position limiting the capital investments allowed for recovery in a MYRP as it better aligns with the *used and useful* standard and provides rate protections to customers. Garrett also references the treatment in Nevada which aligns with AWECs proposal.[397]

AWEC's Cross-Answering Testimony

259 In cross-answering, AWEC witness Mullins opposes Staff's proposal to create separate provisional plant tariffs. AWEC's specific concern is regarding the potential design of the schedules which may negatively impact Schedule 25 (Extra Large General Service) and references a particular Schedule 25i customer that receives a discount under Schedule 25.[398]

---

[394] Andrews, Exh. EMA-6T at 18:18-22:4.

[395] Andrews, Exh. EMA-6T at 23:6-26:2.

[396] Andrews, Exh. EMA-6T at 27:5-15.

[397] M. Garrett, Exh. MEG-9T at 5:1-6:13. While Garrett appears to agree with AWEC, it does not appear that Public Counsel formally adopted those adjustments to Public Counsel's proposed revenue requirement on cross-answering.

[398] Mullins, Exh. BGM-1T at 16:17-17:18.

Decision

260 The Commission declines to adopt AWEC's proposed project-by-project review process and proposal to limit the level of authorized plant to that in service at the time of filing. When CETA was enacted, the legislature amended RCW 80.04.240, mandating the Commission "establish an appropriate process to identify, review, and approve public service company property that becomes used and useful for service in this state after the rate effective date."[399]

261 On January 31, 2020, in establishing a process as mandated by the legislature, the Commission issued a Policy Statement in Docket U-190531, which establishes "a process for the provisional recovery in rates of rate-effective period property, subject to refund, where the property, investment or project in question does not meet the current standards for inclusion in rates prior to rates becoming effective."[400] The Policy Statement was clearly intended to provide flexibility and not be overly prescriptive.[401]

262 We agree with AWEC that Commission policy mandates that rate-effective period investment recovery is subject to and dependent on the request meeting longstanding ratemaking practices and standards.[402] We also recognize and agree with Staff, AWEC, and TEP that the process can and should be improved. However, we do not agree with AWEC that the solution should be to review provisional capital on a project-by-project basis. Rather, we agree with Staff, as supported by TEP and agreed to by Avista, that to allow for additional evaluation, the review process should be extended to six months.

263 Further, while not specifically addressed in post-hearing briefs, we agree with Staff regarding the classification of plant and naming conventions as addressed by Staff witness Erdahl.[403] Avista accepted Staff's position on classification in testimony prior to the evidentiary hearing, but opposed Staff's position that renaming of plant could cause double counting.[404] We do not agree. If during its review process, Staff encounters potential double counting, it would in turn raise concerns for the Commission. The potential risk of double counting outweighs any arguments to the contrary.

---

[399] RCW 80.04.250(3).

[400] Docket No. U-190531, Policy Statement ¶ 20 (Jan. 31, 2020).

[401] *See*, Docket No. U-190531, Policy Statement ¶¶ 30-31 (Jan. 31, 2020)

[402] *See*, Docket No. U-190531, Policy Statement ¶¶ 28-29 (Jan. 31, 2020).

[403] Erdahl, Exh. BAE-1T at 9:1-5, 17-22.

[404] Andrews, Exh. EMA-6T at 11:4-12:12.

264 Staff also requests the Commission require Avista to use a separate tariff for provisional plant filings. The Commission declines to adopt Staff's request at this time. The Commission agrees with Avista that requiring a separate tariff now would add additional complexity and administrative burden to the process. As the Commission has noted, the intent of the Commission's policy following the changes to RCW 80.04.250 are to maintain adherence to longstanding ratemaking principles, while also maintaining flexibility and supporting a streamlined process.[405] Implementing a separate tariff sheet at this time would reduce flexibility and streamlining within the process. However, if review of provisional plant continues to be problematic, the Commission may revisit Staff's proposal.

265 We believe this approach is consistent with the intent of the legislature and Commission policy and that extending the review period will address several the concerns raised by Staff and TEP.

266 TEP raises two additional points: the first is to disallow new business cases from being included in the review, and the second is to enter a final order following conclusion of the review. First, we decline to disallow new business cases at this time. Allowing new business cases is consistent with the Commission's Policy Statement to allow flexibility and further the reduction of regulatory lag. However, the decision is non-precedential on this point and the Commission will continue to monitor the number and cost of new business cases in the future and may disallow their addition in the future if circumstances warrant doing so.

267 Second, we concur with TEP that there is a need for greater formality and transparency in the Provisional Plant review process. Despite our desire to maintain flexibility, and not be overly prescriptive, we provide further clarification on the Commission's expectations for Provisional Plant filings. Specifically, the Commission requires Avista, and will require other companies, to conform to the following when submitting Provision Plant filings:

1) Identify whether a business case is identified in the Clean Energy Implementation Plan (CEIP);
2) Identify whether a business case is required for CETA and/or CCA compliance;
3) Identify each new business case and provide a narrative for business need;
4) Provide information on an annual and cumulative rate-effective period basis;
5) Provide a narrative that explains the filing structure and how worksheets fit together; and

[405] Docket No. U-190531, Policy Statement ¶ 28 (Jan. 31, 2020).

6) Maintain consistent naming conventions.

268 These requirements should allow for greater transparency and clarity for parties reviewing the filing. Additionally, in recognition of TEP's concerns, and our own concerns in this case and following consideration of provisional plant filings at a recent open meeting,406 the Commission will require more formality in the review process. We require Avista and other utilities to present their future provisional plant filings for discussion and consideration at Open Meetings.

269 The Commission's intent in providing this additional guidance and requiring Provisional Plant filings to be presented through the Open Meeting process is to maintain flexibility, further streamline the process, and to adhere to the intent of the changed statutes, but also ensure transparency and clarity, to ensure confidence in the process, and to address the concerns of Staff, TEP, and others in the process. The Commission will continue to monitor this process moving forward and assess whether further changes are needed at a later time.

Decarbonization – Line Extension Allowances, Non-Pipe Alternatives, Customer Reporting, and Planning

270 Avista witness Jason R. Thackston references the Company's 2023 Natural Gas IRP[407] and summarizes the Company's approach to decarbonizing its natural gas system.

> The Company's clean energy future also encompasses natural gas resources, as natural gas is one of the cleanest burning fossil fuels, and plays a key role in reducing carbon emissions, particularly when used directly by customers in their homes rather than electricity generation to meet the same need. The Company's strategy includes diversifying and transitioning from conventional fossil fuel natural gas to RNG, hydrogen, other renewable fuels, and reducing consumption via conservation and energy efficiency. The Company will purchase carbon offsets as necessary to meet the CCA compliance obligations.[408]

271 Both NWEC and the Sierra Club take issue with this approach, and in particular criticize the Company's practices regarding line extension allowances (LEAs), residential gas equipment incentives, and analysis of non-pipe alternatives (NPAs).

---

[406] *See*, Dockets UE-240779 and UG-240780. These dockets were discussed during the regularly scheduled November 7, 2024, Open Meeting, at which time TEP and the Commission expressed concerns over how the provisional plant process had been handled during the compliance period in June and July of 2024, *see also* Docket UE-220053.

[407] *See*, Docket UG-220244.

[408] Thackston, Exh. JRT-1T at 9:2-9.

Line extension Allowances

272 NWEC witness Gehrke testifies that in the 2022 General Rate Case (GRC), the Commission accepted and approved a stipulation that requires Avista to phase out natural gas line extension allowances (LEAs) by 2025. To ensure a glidepath to phasing out LEAs, NWEC recommends that the Commission require Avista to discontinue offering LEAs for Schedules 131, 132, and 146 on January 1, 2025. NWEC also recommends that the Commission require Avista to cease offering service under the Company's Rural Gas Service Connection (Schedule 154).[409]

273 According to NWEC, the 2022 GRC agreement outlined Avista's plan to gradually phase out natural gas LEAs over three years. Under the settlement, for 2023, LEAs would be determined using a net present value method based on a two-year timeframe. In 2024, the calculation would be based on a one-year timeframe. Finally, in 2025, the Company would not offer any allowance for natural gas line extensions.[410] The Coalition continues to support the agreement from the 2022 GRC.[411]

274 NWEC contends that Avista has only partially implemented the agreed-upon changes.[412] On December 14, 2022, the Company requested a revision of Schedule 151. In this tariff revision, the Company implemented the proposed reduction of the LEA for tariff Schedules 101, 102, 111, 112, and 116.[413] For Schedules 131, 132, and 146, the tariff states that Avista will calculate LEAs on a case-by-case basis.[414]

275 Sierra Club witness Dennison also notes that Avista still provides a subsidy for new buildings that rely on gas in the form of its electric LEA, which is available to both all-electric and mixed-fuel new construction projects.[415] Since Avista can still offer LEAs for mixed-fuel buildings, he says, new gas infrastructure may be built that could be considered a stranded asset in the near future. To close this "loophole," Dennison recommends the Commission direct Avista to only offer line extension allowances for

---

[409] Gherke, Exh. WG-1T at 10:14-15.

[410] Gehrke, Exh. WG-1T at 11:3-7.

[411] Gehrke, Exh. WG-1T at 11:9.

[412] Gehrke, Exh. WG-1T at 11:12.

[413] Gehrke, Exh. WG-1T at 11:12-14.

[414] Gehrke, Exh. WG-1T at 11:15-16.

[415] *See e.g.*, Avista Schedule 51, Line Extension, Conversion, and Relocation Schedule: Washington.

new buildings that are fully electrified as this is in alignment with statewide decarbonization goals and mandates.

276 Sierra Club witness Dennison also notes that Avista still provides a subsidy for new buildings that rely on gas in the form of its electric LEA, which is available to both all-electric and mixed-fuel new construction projects.[416] Since Avista can still offer LEAs for mixed-fuel buildings, he says, new gas infrastructure may be built that could be considered a stranded asset in the near future. To close this "loophole," Dennison recommends the Commission direct Avista to only offer line extension allowances for new buildings that are fully electrified as this is in alignment with statewide decarbonization goals and mandates.

277 In its post-hearing brief, Avista reiterates that it does not oppose NWEC's proposal related to the line extension allowances for non-residential customers. However, it opposes Sierra Club's proposal to prohibit electric LEAs for customers installing natural gas or propane. Avista suggests that if such a policy matter were to be considered, that it should not be in this proceeding.[417]

278 AWEC also asks the Commission to reject this proposal. Witness Kaufman suggests that Sierra Club's recommendation may be at odds with RCW 80.28.090[418] and RCW 80.28.100.[419] AWEC says Sierra Club's recommendation may result in "an unreasonable preference for electric-only service under RCW 80.28.090, despite the fact that Avista maintains an obligation to provide natural gas service."[420] Moreover, Kaufman argues that the proposal would be inequitable because only a portion of customers would be eligible for the line-extension allowance, and in some cases customers not eligible for the extension could be double charged.[421]

Gas Equipment Incentives

279 Sierra Club witness Dennison recommends that Avista phase out mid-stream incentives for residential gas appliances like furnaces and water heaters that may prompt builders to

---

[416] *See e.g.*, Avista Schedule 51, Line Extension, Conversion, and Relocation Schedule: Washington.

[417] Avista's Post-Hearing Brief, at ¶ 169.

[418] RCW 80.28.090 (Unreasonable Preference).

[419] RCW 80.28.100 (Rate Discrimination).

[420] Kaufman, LDK-6T at 6:20-7:1.

[421] Kaufman, LDK-6T at 7:20-8:2. AWEC offers a secondary recommendation that if the Commission accepts Sierra Club's recommendation, that the Commission exempt large non-residential customers under Electric Schedule 25 customers from this process.

install new gas infrastructure to serve these appliances.[422] For natural gas equipment appliances, Dennison recommends the Company re-appropriate 20 percent of the budgeted residential gas incentives in its current Biennial Conservation Plan (BCP)[423] to incentives for residential building envelope and electrification readiness measures as well as require the Company to offer information related to electrification for customers who inquire about natural gas rebates or incentives.

280 Avista opposes this proposal. Witness Bonfield states that under RCW 80.28.380 the Company must demonstrate that "the target will result in the acquisition of *all resources identified as available and cost-effective."*[424] He interprets "all to indeed mean all," thereby allowing Avista the ability to cast a wide net when it examines resources and conservation measures required by law. He states that if the Company were to accept Sierra Club's recommendation on this topic, it would be in violation of existing applicable decarbonization laws and rules.[425]

281 Moreover, Bonfield states that accepting this proposal would arbitrarily increase rates for electric customers. He notes that the Company has already dedicated $2 million (on an annual basis) from its CEIP to address electric customers' energy endeavors, many of which include building envelope upgrades to replace natural gas equipment with efficient electric equipment.[426]

282 NWEC also disagrees with Sierra Club's recommendation, noting that the 2024-2025 Biennial Conservation Plans (BCP) were just approved in January 2024.[427] Any substantive changes to these offerings, it says, should be made in the next BCP.

Non-Pipes Alternatives

283 Sierra Club witness Dennison argues that NPAs can decrease the need for expansion of any current gas infrastructure, which he argues represents substantial avoided costs.[428] Dennison says the 2022 GRC Settlement requires Avista to consider NPAs in its gas system distribution planning process in future IRPs, and requires the EEAG to weigh in on

---

[422] Dennison, Exh. JAD-1T at 15:17-20.

[423] *See* Docket UG-230898.

[424] Bonfield, Exh. SJB-5T at 46:8-9 (emphasis in original).

[425] Bonfield, Exh. SJB-5T at 46:20-47:2.

[426] Bonfield, Exh. SJB-5T at 48:8-16.

[427] *See* Docket UG-230898.

[428] Dennison, Exh. JAD-1T at 20:10-12.

how Demand Side Management (DSM) programs can be used as NPAs.[429]

284 Although Avista is required to examine NPAs with the Energy Efficiency Advisory Group (EEAG), in a data request to the Company, Avista confirmed "it has not performed an analysis of non-pipe alternatives in WA."[430] Dennison concludes that Avista failed to evaluate the possibility of NPAs for specific projects and failed to engage with the EEAG in the 2023 IRP process on this very topic. When pressed for more information on the extent of Avista's analysis on potential NPAs, the Company informed Dennison that NPAs are "relatively new and the Company has little experience with NPAs to date."[431] Dennison argues Avista should have some familiarity with analyzing NPAs because the Oregon PUC ordered the Company to essentially do the same thing in its Order acknowledging Avista's 2023 Natural Gas IRP in Oregon.[432]

285 Dennison then recommends that Washington adopt Oregon's NPA framework which is more prescriptive than what the 2022 GRC Settlement Agreement requires, and which he believes addresses many of the concerns Avista raised in previous data responses.[433] He recommends that for the 2025 IRP, the Commission require Avista to perform analyses using this framework on at least five projects (even if they exceed $500,000) to gain experience with NPA analyses.

286 On rebuttal, Avista witness DiLuciano states that the 2022 Settlement agreement does not explicitly require any type of NPA analysis, but rather only to consider NPAs when conducting gas system planning. Therefore, he says, Avista has complied with the settlement agreement and has evaluated NPAs when considering reinforcement alternatives not related to safety, compliance, or road moves that exceed $500,000.[434] He says "[t]his process and methodology was presented to the Company's EEAG at its Fall 2023 meeting. At that time, no advisory group members expressed concern or offered suggestions on altering the proposed methodology."[435]

---

[429] *See* Final Order 10/04, No. UE-220053, UG-220054, Appendix A, at 11-12.

[430] Dennison, Exh. JAD-1T at 24:14-15.

[431] Exh. JAD-9, Avista Response to Sierra Club Data Request SC-017.

[432] Exh, JAD-4, Oregon PUC, Order No. 24-156, No. LC 81 at Appendix A, P. 71.

[433] Dennison, JAD-1T at 28:5-16. The language included in the brackets within the quotation reflect Washington specific thresholds and requirements.

[434] DiLuciano, Exh. JDD-3T at 26:18-23.

[435] DiLuciano, Exh. JDD-3T at 26:20-23.

287 The Company does accept Sierra Club's recommendation to adopt the OPUC framework for NPA analyses but declines to do so in the 2025 IRP. Avista notes that the next IRP is due by April 1, 2025, leaving little time to complete such an analysis. Furthermore, the Company believes conducting these analyses for "practice" is not the best use of Avista's time and resources, which are ultimately paid by customers.[436]

288 Kaufman also addresses Sierra Club's recommendation to adopt the Oregon PUC framework to analyze NPAs. AWEC agrees that Avista should adopt the framework, but disagrees that the Commission should be overly prescriptive based on an entirely different proceeding that unfolded in a different state. AWEC recommends allowing Avista to maintain the ability to exercise discretion when it comes to conducting NPA analyses for Washington customers.[437]

Decarbonization Planning

289 Dennison highlights the settlement stipulations from the 2022 GRC discussed above and asserts that Avista has "continued on a business-as-usual trajectory" and "has not adequately begun making the transformative changes that will be needed to meet its decarbonization obligations…"[438] Dennison asserts this continued lack of attention to CCA obligations is reflected in Avista's 2023 IRP, as the Company indicates it intends to comply with the CCA by primarily relying on "CCA allowance purchases, with some synthetic methane in later years, a very small amount of energy efficiency, and no electrification."[439] Dennison believes that this approach will create significant financial risks for customers, and that Washington will exceed the CCA statewide emissions caps, especially as other utilities pursue similar strategies.[440] Dennison points to the most recent Cascade Natural Gas (CNG) IRP[441] that similarly relies on allowance purchases, and notes that although the Commission has not acknowledged Avista's IRP, it declined to acknowledge CNG's IRP for over-reliance on CCA allowance purchases.

290 To address this alleged deficiency, Dennison recommends the Commission direct Avista to complete a decarbonization plan by March 2027, with the following elements:

---

[436] DiLuciano, Exh. JDD-3T at 30:23-28.

[437] Kaufman, Exh. LDK-6T at 10:2-13.

[438] Dennison, Exh. JAD-7:18-8:2.

[439] Dennison, Exh. JAD-1T at 8:5-7.

[440] Dennison, Exh. JAD-1T at 8:9-12.

[441] *See* Docket UG-220131.

1) Incorporate findings from the Company's Targeted Electrification Pilot,
2) Evaluate a range of decarbonization and CCA compliance measures including evaluation of building electrification as a proactive resource strategy,
3) Address opportunities to coordinate Avista's efficiency and electrification measures with available funds and programs including IRA and Washington's HEAR program,[442]
4) Analyze at least one scenario in which Avista's annual gas system emissions are no greater than its share of the statewide CCA emissions cap, without relying on additional allowances and estimate the percentage reduction in gas system throughput by 2030 and identify strategies that would decrease natural gas rate base by the same percentage by 2030.[443]

291 Dennison further recommends that, in alignment with the 2021 State Energy Strategy, the Commission require Avista to conduct a Targeted Electrification Pilot with targets to engage 5,000 customers through electrification assessments and for Avista to provide at least 1,000 rebates for electrification equipment and include provisions to conduct engagement and outreach to low-income customers or customers within Named Communities.

292 Avista responds that it believes the Preferred Resource Strategy selected in the 2023 Natural Gas IRP is a decarbonization plan, and provides one with the lowest reasonable cost while complying with all known laws, rules, and environmental policies. Because that plan is within the IRP, Avista believes any concerns with the Company's decarbonization efforts should occur within the context of the IRP.

293 AWEC also disagrees and believes Sierra Club relied on an erroneous interpretation of the CCA's requirements and reliance on the OPUC's criticism of Avista in their IRP proceeding. As such, AWEC asserts that Sierra Club 's recommendation essentially renders decarbonization a "planning goal."[444] AWEC says Avista's goal should be to meet CCA requirements in a cost-effective manner.[445] If the Commission mandates a plan, AWEC recommends a decarbonization study similar to that undertaken by Puget Sound Energy to identify cost-effective decarbonization measures.[446]

---

[442] *See* Home Electrification and Appliance Rebates Program.

[443] Dennison, Exh. JAD-1T at 45:11-46:2.

[444] Kaufman, Exh. LDK-6T at 10:20-11:3

[445] Kaufman, Exh. LDK-6T at 12:8-17.

[446] AWEC's Post-Hearing Brief, at ¶ 111.

294 NWEC largely supports Sierra Club's recommendations. With regard to the Targeted Electrification Pilot, it recommends that the Pilot target 40 percent of its customers from low-income or Named Communities, which aligns with the federal Justice40 initiative and is a ,similar in construct to PSE's Targeted Electrification Pilot which has a 30 percent requirement.[447] NWEC also recommends that Avista be required to install a minimum of 25 no-cost, electric-only heat pumps during the pilot period.[448] Alternatively, if the Commission does not accept this recommendation, NWEC recommends the Commission require Avista to work with the EAAG and Conservation Resources Advisory Group (CRAG) to address low-income electrification efforts.[449]

Decision

295 Washington voters approved Initiative Measure No. 2066 in the recent General Election. In pertinent part, the initiative adds limits to the Commission's authority to approve, or approve with conditions, multiyear rate plans. Specifically, section 4 of the initiative amends RCW 80.28.425, adding the following limitations:

> (12) The commission shall not approve, or approve with conditions, a multiyear rate plan that requires or incentivizes a gas company or large combination utility to terminate natural gas service to customers.
>
> (13) The commission shall not approve, or approve with conditions, a multiyear rate plan that authorizes a gas company or large combination utility to require a customer to involuntarily switch fuel use either by restricting access to natural gas service or by implementing planning requirements that would make access to natural gas service cost-prohibitive.[450]

296 While the election occurred and its results were certified following the parties' submission of briefs in this proceeding, the initiative has the force of law, and the Commission must follow the initiative's directives, unless and until the effect of initiative is stayed or reversed by a court of law.

---

[447] Gehrke, Exh. WG-8T at 4:7-12.

[448] Gerhke, Exh. WG-8T at 4:14-16.

[449] Gehrke, Exh. WG-8T at 5:4-12.

[450] Initiative Measure No. 2066, approved Nov. 5, 2024.

297 Sierra Club and NWEC propose a number of programs and changes to Avista's natural gas service both in response to Avista's 2023 Natural Gas IRP and provisions in the 2022 GRC Settlement, including natural gas decarbonization plans, changes to line extension allowances, or LEAs, non-pipe alternatives, or NPAs, and equipment incentives, many of which appear to run counter to the initiative's directives. We address each in turn.

Decarbonization Plan

298 Avista's strategy for natural gas decarbonization to comply with its CCA obligations is set forth in its 2023 Natural Gas IRP. This strategy includes diversifying and transitioning from conventional fossil fuel natural gas to RNG, hydrogen, other renewable fuels, and reducing consumption via conservation and energy efficiency. The Company will purchase carbon offsets as necessary to meet the CCA compliance obligations.[451] The Company's approach to decarbonization to meet its CCA compliance obligations was proposed in its 2023 Natural Gas IRP, and as it is not proposed in this proceeding for approval, we decline to address it.

299 Sierra Club's witness Dennison requests the Commission direct Avista to adopt a Decarbonization Plan, that among other elements, would "identify strategies that would decrease natural gas rate base by the same percentage by 2030," which we interpret to mean the removal of gas assets from its system, and the possible termination of customer usage of natural gas.[452] This element of the proposed plan would appear to be explicitly prohibited by the initiative. Without further briefing or legal analysis of the effect of the initiative on the Commission's authority and how companies may pursue decarbonization of their energy systems to meet CCA and CETA requirements while complying with the provisions of the initiative, we find it inappropriate to adopt Sierra Club's decarbonization proposal.

Line Extension Allowances

300 NWEC proposes the Commission require Avista to discontinue offering LEAs for Schedules 131, 132, and 146 on January 1, 2025, in keeping with the provisions of the 2022 GRC Settlement. NWEC also recommends that the Commission require Avista to no longer offer service under the Company's Rural Gas Service Connection (Schedule 154).[453] Sierra Club supports NWEC's proposals and recommends the Commission direct

---

[451] Thackston, Exh. JRT-1T at 9:2-9.

[452] Dennison, Exh. JAD-1T at 45:11-46:2.

[453] Gherke, Exh. WG-1T at 10:14-15.

Avista to only offer LEAs for new buildings that are fully electrified, and no longer allow Avista to offer LEAs for mixed-fuel new construction projects.[454]

301 While Avista does not oppose NWEC's proposal relating to LEAs for non-residential customers, it opposes Sierra Club's proposal to prohibit electric LEAs for customers installing natural gas or propane. Avista suggests that the Commission should not determine such a policy decision in this proceeding.[455] AWEC is silent on NWEC's proposal but does not support Sierra Club's, arguing that limiting LEAs to electric-only customers to incentivize the curtailment of gas would be inequitable and possibly discriminatory.[456]

302 The elimination of LEAs for non-residential customers was originally agreed to in the 20222 GRC Settlement and neither Avista nor AWEC oppose this treatment. However, both Avista and AWEC object to the limitation of electric LEAs to electric-only customers. This proposal goes beyond what the parties appear to have agreed to in the 2022 GRC Settlement, and appears to be contrary to the prohibition in Initiative 2066 for the Commission to "approve, or approve with conditions, a multiyear rate plan that authorizes a gas company or large combination utility to require a customer to involuntarily switch fuel use either by restricting access to natural gas service or by implementing planning requirements that would make access to natural gas service cost-prohibitive." For these reasons, we reject Sierra Club's proposal.

Gas Equipment Incentives

303 Sierra Club recommends that Avista phase out mid-stream incentives for residential gas appliances like furnaces and water heaters that may prompt builders to install new gas infrastructure to serve these appliances.[457] Specifically, Sierra Club recommends Avista use 20 percent of the budgeted residential gas incentives for natural gas appliances in its current BCP and use this amount for incentives for residential building envelope and electrification readiness measures.[458] Sierra Club also recommends the funds be used for the Company to offer information related to electrification for customers who inquire about natural gas rebates or incentives.

---

[454] *See e.g.*, Avista Schedule 51, Line Extension, Conversion, and Relocation Schedule: Washington.

[455] Avista's Post-Hearing Brief, at ¶ 169.

[456] AWEC's Post-Hearing Brief, at ¶¶ 105-7.

[457] Dennison, Exh. JAD-1T at 15:17-20.

[458] *See* Docket UG-230898.

304 NWEC opposes Sierra Club's recommendation to reappropriate funds for natural gas appliance incentives, noting that the 2024-2025 BCPs were just approved in January 2024, and any substantive changes to these offerings should be made in the next BCP.[459]

305 Avista opposes Sierra Club's proposal, arguing that pursuing the proposal would put the Company in violation of existing applicable decarbonization laws and rules.[460] The Company also argues that adopting the proposal would result in arbitrarily increasing rates for electric customers, and that the Company has already dedicated $2 million (on an annual basis) from its CEIP to address electric customers' energy endeavors.[461]

306 We reject Sierra Club's proposal as contrary to the BCPs that the Commission approved earlier this year. We do not reach the question of whether approving Sierra Club's proposal would be inconsistent with Initiative I-2066.

Non-Pipeline Alternatives

307 Turning to Non-Pipeline Alternatives (NPA), Sierra Club recommends that the Commission adopt the Oregon Public Utility Commission's (OPUC) NPA framework, which is more prescriptive than what is required in the 2022 GRC Settlement.[462] Sierra Club further recommends the Commission require Avista in its 2025 IRP, to perform NPA analyses using the Oregon framework on at least five projects (even if they exceed $500,000) to gain experience with NPA analyses.

308 Avista supports adopting the Oregon NPA analysis, and including NPA analysis in situations where an NPA is not selected, and where the project is unrelated to safety, compliance, or road moves and which exceeds a threshold of $500,000 for individual projects or groups of geographically related projects.[463]

309 The Commission acknowledges Avista's agreement to adopt the OPUC NPA framework, as well as Initiative I-2066.[464] The Commission has a statutory obligation to ensure fair

---

[459] *See* Docket UG-230898.

[460] Bonfield, Exh. SJB-5T at 46:20-47:2.

[461] Bonfield, Exh. SJB-5T at 48:8-16.

[462] Dennison, JAD-1T at 28:5-16. The language included in the brackets within the quotation reflect Washington specific thresholds and requirements.

[463] Avista's Post-Hearing Brief, at ¶ 157.

[464] The implications of the passage of Initiative I-2066 remains uncertain. The initiative is currently being litigated and the parties were not asked to specifically brief I-2066 in this case. Despite this, the Commission expects Avista to evaluate NPAs within the law.

and reasonable rates for customers while promoting energy conservation all while balancing the will of Washington voters. We do not find that applying the Oregon NPA analysis runs counter to the provisions of the initiative that prohibit the Commission from authorizing "a gas company or large combination utility to require a customer to involuntarily switch fuel use either by restricting access to natural gas service or by implementing planning requirements that would make access to natural gas service cost-prohibitive." NPAs are planning tools to assist the utility in making cost-effective decisions and do not mandate fuel switching, restricting access to natural gas, or making gas service cost-prohibitive.

310 As such, the Commission understands the value of NPA analyses, as well as how demand response programs and energy efficiency programs result in conservation and by extension, lower costs for customers through avoided capital expenses. On balance, the Commission approves Avista's adoption of the OPUC framework on NPAs, with the following exceptions:

- Avista must examine the relationship between any NPA and the Climate Commitment Act (CCA), but may not assume that all CCA allowances will be purchased at the ceiling price.
- Avista must provide an explanation of the resulting investment selection (either the NPA or a traditional investment) that compares the costs of both projects, but Avista is not required to rank or score any NPA in its evaluation process.

311 Although the Company indicates it has completed a cursory NPA analysis in Oregon, the Company has not performed any such analysis in Washington. As the Commission foresees NPA analyses becoming more commonplace in the future, it is imperative that Avista gain familiarity with these types of analyses.

312 As such, the Commission orders Avista to conduct two NPA analyses on natural gas distribution projects related to customer growth for any potential projects that exceed $500,000 using the criteria otherwise adopted above. The Commission orders the Company to submit these analyses in a compliance filing for this docket no later than December 31, 2025.

Equity – Low-Income Assistance and Disconnections, Language Access Plan, and Energy Burden Analysis/Reporting

Equity

313 In the final order resolving the Company's 2022 GRC,[465] the Commission approved a Settlement Stipulation to include certain equity provisions and required Avista to demonstrate its progress towards incorporating the four tenets of equity[466] into its capital planning process. The Commission agrees with Avista that the Compliance Filing due December 31, 2024, is the correct venue to evaluate compliance with Settlement Stipulations from the 2022 GRC. Accordingly, as indicated in Avista's direct testimony, we expect the filing to: (1) "identify and prioritize the needs of Named Communities in capital planning;" (2) weigh "the distributional impacts the Company's business decisions and processes"[467] by addressing equity through its Customer Benefit Indicators (CBI),[468] Customer Experience Journey;[469] wildfire equity plan;[470] and (3) interconnect it to existing business policies, practices, and procedures.[471]

*Low-Income Assistance Disconnection*s

314 In 2001 the Commission approved Avista's Low-Income Rate Assistance Program (LIRAP) to collect funding through "electric and natural gas tariff surcharges on Schedule 92 and 192,"[472] disburse funding to low-income households pursuant to WAC 194-40-030,[473] provide financial assistance to households unable to afford their energy bills and avert disconnection of utility services.

315 Avista provided extensive testimony regarding the benefits customers received in response to the implementation of its enhanced customer and bill assistance programs. In October 2023, Avista implemented My Energy Discount (MED), as part of its portfolio of

---

[465] *See* Dockets UE-220053, et. al., Order 10/04, pgs. 24-28 ¶¶ 71-78.

[466] The four tenets of equity are distributional justice, procedural justice, recognition justice, and restorative justice.

[467] Thackston, Exh. JR-1T at 15:1-3.

[468] CBI metrics represent "equity areas identify by Avista's EAG that are most at risk to disproportional outcome" in conjunction with the Company's 2021 CEIP to monitor and track progress towards clean energy goals." Thackston, Exh, JRT-1T at 17:2-10.

[469] The Customer Experience Journey is a cross-functional team of employees that collaborate with customers to design a "human-centered Experience Design methodology" to focus on customer needs from the *outside in* rather the inside out. Thackston, Exh, JRT-1T at 17:12-20.

[470] Thackston, Exh, JRT-1T at 17:22-29. The equity wildfire equity plan will prioritize customer and community input for those living in rural and high-fire risk areas.

[471] Thackston, Exh. JRT-1T at 19:3-6.

[472] Dockets UE-240006 & UG-240007 (*consolidated*), Bonfield, Exh. SJB-1T at 16: 3-5.

[473] "'Low-income' means household incomes that do not exceed the higher of eighty percent of area median income or two hundred percent of federal poverty level, adjusted for household size." WAC 194-40-030.

assistance options under its LIRAP. MED's automatic enrollment mechanism eliminates critical barriers for customers that historically limited participation in providing aid to those in need. With these barriers reduced, Avista maintains that within the first three months of the program, customer saturation in the overall LIRAP increased by 10 percent;[474] and the Company provided more than $3.1 million to 26,306 customers,[475] which resulted in more customers being served in the first three months of MED's rollout than an entire program year.[476]

Decision

316 No party provided response testimony opposing Avista's enhanced customer and bill assistance programs. Thus, the Commission finds that the data Avista presented on MED's impacts over the ten-month period of October 2023 to July 2024 to be persuasive. During this period, Avista distributed approximately $14.9 million dollars in bill credits to approximately 41,110 active participants and the Company's saturation rates for its overall LIRAP programs rose to 29 percent.[477]

Disconnection Policies

317 Regarding Avista's existing disconnection policies, TEP testifies that Avista's use of credit codes as a determinant for service disconnections violates the equity tenets established by the Commission by inordinately burdening marginalized and vulnerable populations, including communities of color, low-income customers, customers without college degrees and more.[478] TEP explains that Avista relies on criteria, such as the number of times a customer has been past-due over the previous 12 months, and the number of months since the customer was last eligible for disconnection, as part of its calculation to determine a customer's credit code. This in turn sets a timeline for a customer's disconnection based on a past-due threshold amount that triggers the collections process.[479] TEP maintains that this approach results in customers with lower credit codes having lower disconnection thresholds and shortened timelines compared to customers with higher credit codes. TEP argues that any credit coding criteria related to a

---

[474] Bonfield, Exh. SJB-1T at 23:20-24:1.

[475] Bonfield, Exh. SJB-1T at 19:11-17.

[476] Bonfield, Exh. SJB-1T at 19:2-6.

[477] Bonfield, Exh. SJB-5T at 7:12-13.

[478] Stokes, Exh. SNS-1T at 3:10-20.

[479] Stokes, Exh. SNS-1T at 9:15-10-7. See also Table 1, Exh. SNS-3, Avista Response to TEP DR 012.

customer's disconnection or arrearage history should be removed.[480] Instead, TEP recommends that the credit coding criteria be based only on two factors: (1) a customer's current arrearage amount; and (2) duration of time in arrears. TEP also recommends that Avista conduct a robust review of its existing credit codes with the (EAAG and Equity Advisory Group (EAG).[481]

318 On rebuttal, Avista rejects TEP's recommendation on the basis that its disconnection policies are sound and use of its credit codes "aim to reduce or eliminate potential disconnections through early intervention and collaborative solutions," which includes connecting customers to various assistance programs, outreach and translation efforts if necessary.[482] Avista highlights the effectiveness of its enhanced assistance programs and notes that 35,000 of the 41,000 customers enrolled in the MED have seen their credit score improve which has reduced both past-due notices and disconnections for customers. Avista further argues that TEP's viewpoint of distributional equity is "inconsistent with the holistic picture of the current conditions faced in those communities," and demonstrates a "fundamental misunderstanding of its credit code scoring methodology. [483] However, because Avista acknowledges that the term "credit code" may imply the use of a credit-scoring methodology, the Company agrees to revise its terminology with the EAAG and EAG to prevent confusion and better align with the approach it is taking "to analyze payment probability on all customer accounts." [484]

Decision regarding Avista's Disconnection Policies

319 As we noted in Dockets UE-220066 and U220067 (Consolidated) Order 32 and Docket UE-210918 Order 18, when there is a clear increase in arrearages overtime and a marginal impact in collecting such arrearages, a phased dunning approach is warranted,[485] but only after customers receive targeted outreach informing them of the Company's "bill assistance, arrearage management, and other programs for which they may be eligible."[486] Accordingly, we reaffirm the effectiveness of the dunning process as in the public interest because it motivates customers to obtain assistance, take prompt action on past-due

---

[480] Stokes, Exh. SNS-1T at 3:10-13.

[481] Stokes, Exh. SNS-1T at 14:11-18.

[482] Bonfield, Exh. SJB-5T at 12:7-8.

[483]Bonfield, Exh. SJB-5T at 11:1-3.

[484] Bonfield, Exh. SJB-5T at 13:22-23 and 15:1.

[485] *WUTC v. Puget Sound Energy*, Dockets UE-220066 and UG-220067 (*Consolidated*) Order 32, Docket UG-210918 Order 18, at (May 16, 2024) at 15 ¶ 49.

[486] *WUTC v. Puget Sound Energy*, Dockets UE-220066 and UG-220067 (*Consolidated*) Order 32, Docket UG-210918 Order 18, at 17 ¶ 56.

balances, and avert service disconnection. For this reason, we reject TEP's proposal to prioritize customers for disconnection based on the current arrearage amount and the duration of current arrears.

320 While the Commission acknowledges Avista's acceptance of TEP's recommendation[487] to review its disconnection policies with EAAG and EAG, we are not ordering Avista to comply with any specific timelines as recommended in TEP's testimony.[488] However, we do require Avista to submit evidence documenting its collaboration with six months of the date of this order.

Low-Income Needs Assessment and Energy Burden Data Analysis

321 In direct testimony, both TEP and NWEC recommend that Avista update and refine its metrics to better understand the needs of its underserved customer base,[489] and conduct a new Low-Income Needs Assessment (LINA) requiring the Company to identify low-income customers by fuel type at the household level.[490] TEP explains this would result in Avista gaining a better understanding of energy burden by fuel type and allow it to tailor its outreach. NWEC also recommends that Avista conduct a new LINA that: (1) updates customer income data; (2) assesses energy burden for newly enrolled LIRAP customers; and (3) provides data for customers with fewer than 12 months of usage data in its Energy Burden Analysis (EBA) to simulate energy burden over time as a function of factors that increase customer bills.[491]

322 To further assess the extent of energy burden within Avista's service territory, TEP provides a "hyper-granular" analysis of un-affordability facing Avista's customers in light of the proposed rate increases in this MYRP. This analysis uses a stratified approach for multiple variables to isolate specific customer needs by breaking down geographic data to the Census Tract level, and then breaking down income levels in each Census Tract for quintiles[492] to identify the scope of affordability and assistance needs for mostly

[487] Bonfield, Exh. SJB-5T at 18:30 - 19:6.

[488] Stokes, Exh. SNS-1T at 15:3-11.

[489] Stokes, Exh SNS-1T at 29:17-21.

[490] Stokes, Exh. SNS-1T at 29:17-21.

[491] Thompson, Exh. CT-1T at 20:6-16.

[492] The Census Bureau rank orders incomes from the highest to lowest in each geographical area. It then divides the rank ordering into five equal parts, each part of which is referred to as a "quintile". A quintile represents 20 percent of population for a given area. It should be noted that quintile ranges can change for each Census Tract. The lowest quintile of income in one Census

homogenous populations within specific Census Tracts. This analysis is then overlaid with the Department of Health Environmental Health Disparities Map[493] to denote Highly Impacted Communities (HIC) and Vulnerable Populations.[494] TEP relies on this data to show that Avista's current rates are unaffordable and that further proposed increases for 2025 and 2026 will only exacerbate unaffordability and increase the energy burden within Avista's service territory.[495] TEP further argues that this ultimately will result in increased disconnections that disproportionately impact customers with the lowest incomes[496] that reside in HICs.[497]

Decision on Low Income Needs Assessment and Energy Burden Data

323 TEP's analysis skillfully articulates the "breadth and depth"[498] of existing un-affordability by segmenting the population by income quintiles and fuel type.[499] While the insights gained from this robust analysis have immense value for the Commission, Avista, and external parties,[500] the evaluation lacks information on the other half of the energy burden equation. Namely, the evaluation does not incorporate any data related to the enhanced energy assistance programs that Avista rolled out in October 2023. For this reason, the Commission rejects TEPs recommendations to require Avista to use the stratification framework for an Energy Burden Analysis and Performance Based Ratemaking (PBR) for 2022 metrics 12, 13, 14, and 15 and 2024 metrics 7, 8, and 9.[501] However, we believe that the insights provided from the stratification framework are invaluable and should be explored with input from Avista, Staff, and other interested parties so that a holistic assessment of the scale of energy burden can be further evaluated in the current Commission-led rulemakings in Docket(s) U-210800 (for arrearage and assistance data) and U-210590 (for PBR metrics).

Tract may be $20,000 on average, whereas in a more affluent Census Tract, the lowest quintile may be $60,000 on average. Colton, Exh RDC-1T at 7-8.

[493] Information by Location | Washington Tracking Network (WTN)

[494] Colton, Exh RDC-1T at 7-8.

[495] Colton, Exh RDC-1T at 10-11.

[496] Colton, Exh. RDC-1T at 8:1-9.

[497] Colton, Exh RDC-1T at 8:20-30.

[498] Colton, Exh. RDC-1T at 12:3.

[499] Colton, Exh. RDC-1T at 52:3-17.

[500] Colton, Exh. RDC-1T at 48.

[501] See Appendix A, Docket Nos. UE-240006 and UG-240007, Commission Ordered Performance Metrics, at 9-10.

324 Further, because Avista agreed in its rebuttal testimony to maintain current reporting requirements for the annual Disconnection Reduction Reports and COVID-19 Arrearage and Assistance reporting in U-210800, and to expand the annual LIRAP reports, we agree that a new LINA and EBA are unnecessary at this time. It is important for the Commission and all interested parties to examine the full effects of Avista's Bill Discount Rate and Arrearage Management Plan, which will not be fully realized until October 2025. Only at that time will we have a comprehensive understanding of the full impacts and benefits these programs have on customers.

325 Accordingly, as set forth in Avista's rebuttal testimony, we expect the revisions in the Company's annual LIRAP reports to include:

1) An assessment of Energy Burden for customers participating in the MED program,[502] and an analysis of the revised program structure that became effective October 1, 2023.[503]

2) Updated saturation rates for low-income customers by fuel type, (beginning in early 2026);[504]

3) Updated reporting metrics that identify arrearage and disconnection demographics,[505] customer participation geography, demographics, data and trends, including impacts to named communities;[506] and

4) An analysis of the revised program structure that became effective October 1, 2023.[507]

326 On balance, we find that the above revisions and expanded reporting are sufficient at this time and would like to acknowledge the on-going work that investor-owned utilities are conducting in coordination with the Department of Commerce as required by RCW

---

[502] Bonfield, Exh. SJB-5T at 26:8-12.

[503] Bonfield, Exh. SJB-5T at 27:28-38.

[504] Bonfield, Exh. SJB-5T at 27:44-28:5

[505] Bonfield, Exh. SJB-5T at 27:11-15.

[506] Bonfield, Exh. SJB-5T at 27:20-24.

[507] Bonfield, Exh. SJB-5T at 27:28-38.

19.405.120 to fully evaluate energy burden and assistance offerings.[508]

327 Additionally, to further refine data specific to investor-owned-utilities, the Commission directs Staff, investor-owned utilities, and other interested parties to collaborate and assess the potential use of the stratification methodology in the rulemakings in Dockets U-210800 and U-210590, and to explore various avenues to promote data accessibility.

328 The Commission also retains the current reporting requirements and cadence for the COVID-19 data in Docket U-210800 moving forward and will require Avista and other regulated energy utilities to continue providing Disconnection Reduction Reports, COVID-19 Data Reports, and PBR metrics until the conclusion of the two rulemakings in Dockets U-210800 and U-210590.

329 While the Commission wishes to promote accessibility, data security is paramount to ensuring trust as more customers use Avista's programs. The Commission acknowledges the value demographic data can have for utilities as they seek to identify and address disparities, inform program design and improvements, and measure the impacts across different groups.[509] Accordingly, the Commission requires Avista to work with the EAAG and EAG to establish a framework to collect and transmit customer demographic data (similar to the demographic data collected in the LIRAP[510]) for those enrolling in Distributed Energy Resource (DER) programs. However, given privacy concerns that impact the collection of demographic data, customer participation will not be required but instead will be optional and only collected after customer consent is provided.

Language Access Plan

330 Next, although TEP and NWEC recommend that Avista create a Language Access Plan (LAP) in coordination with the EAAG and EAG to increase participation in its LIRAP programs,[511] we find that Avista continues to make progress with its Multi-Language Strategy (MLS), that examines the needs of multilingual customers. This is evidenced by Avista's online web platform, which translate account, energy, safety and outage information in Spanish and ongoing efforts the Company is exploring to provide these same services online in other languages and in its mobile application and Interactive Voice Response systems. Avista is also layering its MLS with the Public Participation Plan

---

[508] *See* Energy assistance for low-income households – Washington State Department of Commerce

[509] Thompson, Exh. CT-1T at 16:20-17:5.

[510] Thompson, Exh. CT-1T at 17:8-23.

[511] Stokes, Exh SNS-1T at 37:13-23 and 38:1-5.

(PPP) within the CEIP and is working with the EEAG and EAG to develop and prioritize other language access projects.[512]

331 While we recognize that Avista has not adopted a separate LAP, we believe its MLS achieves the same underlying goals given the on-going collaboration between Avista and relevant advisory groups. As such, we do not find any value in duplicating this work, especially since the effort related to language access is iterative. Therefore, we reject TEP and NWEC's recommendation that Avista develop a separate LAP but expect Avista to continue working towards addressing language access needs and meeting customers where they are.

The Multi-Year Rate Plan

332 Pursuant to RCW 80.28.425, Avista submits an MYRP that would begin with new base rates effective December 2024 (RY1) and December 2025 (RY2). For RY1, the proposed increases reflect an electric base rate relief of $79.3 million or 13.1 percent and natural gas base rate relief of $17.3 million or 13.6 percent effective December 2024. For RY2 of the rate plan, the proposed increases reflect an electric net request of $53.7 million or 11.7 percent and natural gas base rate relief of approximately $4.6 million or 3.2 percent effective December 2025.[1]

Table 1: Proposed Rate Increases for MYRP[2]

Fuel Type	RY1[3]	RY1 Increase	RY2	RY2 Increase
Electric	$79.3 Million	13.1 Percent	$53.7 Million	11.7 Percent
Natural Gas	$17.3 Million	13.6 Percent	$4.6 Million	3.2 Percent
Combined Total	**$96.6 Million**	**26.6 Percent**	**$58.3 Million**	**14.9 Percent**

Avista's Direct Testimony

333 This is the Company's second MYRP proposal since SB 5295 was enacted in 2021. Company witness Vermillion posits that "for the most part" the first MYRP[513] worked as intended with respect to recovery of capital investments, although the Company has not been able to fully recover its authorized rate of return under the MYRP format. Vermillion

[512] Bonfield, Exh. SJB-5T at 33:1-6.

[513] Avista 2022 General Rate Case UE-220053 and UG-220054.

further testifies that although the MYRP construct allows for more timely cost recovery for capital additions, recovery of expenses continues to lag.[514]

334 Witness Vermillion acknowledges the larger increases proposed in RY1 by stating this request represents an attempt to "close the regulatory lag in Year 1 and set a proper base for a MYRP." Avista argues that it is extremely important that the Commission approve a revenue requirement that "gets the first year right." The Company opines that if the revenue requirement for RY1 is insufficient for the recovery of capital investment and/or expenses, even after inclusion of revenues expected in the first year of a rate plan, the utility would underearn in the first year having a "carry-over" effect in every subsequent rate year.[515]

Staff's Response Testimony

335 Staff witness Erdahl recommends the Commission reject Avista's proposed two-year MYRP.[516] Staff notes that RCW 80.28.425(9) requires the Commission to align, to the extent practical, the timing of approval of a MYRP of an electrical company with its CEIP filed pursuant to RCW 19.405.060. Under WAC 480-100-640(1), Avista is required to file its next CEIP by October 1, 2025, and Staff believes approval of this filing as a traditional rate case will allow Avista to develop its next rate case in conjunction with finalization of its CEIP.[517]

336 Staff asserts that MYRPs are intended to eliminate regulatory burden, yet 2024 is the second cycle in a row in which both Avista and Puget Sound Energy have simultaneously filed rate cases. This clustering of rate cases results in additional filings that create unnecessary burdens on the Commission, Staff, and intervenors. As such, Staff recommends denying Avista's proposed MYRP in order to offset the simultaneous rate cases and allow for more time and resources to be dedicated to individual rate cases which is in the public's interest. Further, Staff states that Avista is the natural candidate for moving the filing cycle given that it must file its CEIP in 2025, and PSE will not do so given the recent legislation in ESHB 1589.[518]

AWEC's Response Testimony

---

[514] Vermillion, Exh. DPV-1T at 5:4-7.

[515] Exh. DPV-1T at 24:7-16.

[516] Erdahl, Exh. BAE-1T at 6:22.

[517] Erdahl, Exh. BAE-1T at 7:3-9.

[518] Erdahl, Exh. BAE-1T at 7:19-8:2.

337 Witness Mullins testifies that the MYRP construct may disincentivize the Company to rein in expenses. Mullins explains that:

> "… if a utility has an approved budget in a rate case, it will have an incentive to spend up to that budget to avoid needing to issue a refund to customers in an after-the-fact capital review…setting rates based on budgetary forecasts provides little assurance that those rates are just and reasonable because there is no objective way of determining the reasonableness of a budget. Thus, the utility has an incentive to inflate its budget in a rate case which, if approved, gives it a corresponding incentive to invest more capital than it otherwise would under an [sic] historical test year approach."[519]

338 Mullins substantiates this claim by noting that during the ratemaking process, neither the parties nor the Commission have the opportunity to objectively determine the reasonableness of a utility's capital spending. Mullins explains that in the spending reported in a compliance filing[520] to the 2022 GRC,[521] the actual spending does not match up with the capital forecasts provided by Avista in the beginning of the GRC. Mullins notes that although the initial forecasts and actual expenses are wildly different, Avista still claims these capital expenses were reasonable.

339 Mullins states that "setting utility rates based on budgets is problematic because there is no objective way to assess the reasonableness of a budget . . . ."[522] As such, Mullins recommends the Commission only include capital that is "demonstrated to be used and useful on or before the rate effective date of the respective rate years to be considered in the revenue requirement."[523]

340 AWEC's primary recommendation is to limit the capital investment allowed into rates for each year of the MYRP. However, witness Mullins recommends that approving a single year revenue requirement might be appropriate "given deficiencies in how Avista

---

[519] Mullins, Exh. BGM-1T at 7:17-8:1.

[520] *See* e.g. Docket No. UE-220053 & UG-220054, Avista Compliance Filing (Provisional Capital for 2023), Attachment A, (March 29, 2024) (The absolute error in capital spending was 73.8%, yet Avista claims that it spent more than its forecast, warranting no adjustment to provisional capital included in rates in the 2022 GRC.)

[521] 2022 Avista GRC UE-220053 and UG-220054.

[522] Mullins, Exh. BGM-1T at 9:5-6.

[523] Mullins, Exh. BGM-1T at 9:21-22.

evaluated the removal of Colstrip 1 and 2 from rates."[524] Mullins acknowledges a single year revenue requirement may be more efficient given that the removal of Colstrip from rates is the single greatest factor in this proceeding.[525]

Avista's Rebuttal Testimony

341 Avista witness Christie rejects Staff's recommendation to only accept one year of the two-year rate proposal. Christie states that Staff justifies this recommendation by citing regulatory burden and alignment with the CEIP filing due next year. Christie argues that rejection of the MYRP would result in additional administrative burden requiring another filing to accomplish what the Company is attempting in this filing.[526]

342 Christie acknowledges the burden of simultaneous rate cases from multiple utilities but opines "[w]hile a staggering of major rate filings by utilities would relieve some of the administrative burden on Staff and the parties, it does not override the Commission's ultimate responsibility to provide timely rate relief where warranted."[527] Christie provides further argument in opposition of Staff's recommendation:

- Decreased credit ratings would impact customers through further absorption of lost return on equity of approximately 70 basis points;
- The Company does not have the means to file another rate case immediately following this filing;
- Rejecting the Company's MYRP is contrary to the intention of the MYRP statute, which is to provide certainty to the Company and its customers; and
- There are no meaningful investments or costs of compliance related to the CEIP included in this GRC (other than what was contemplated in the previous CEIP).[528]

AWEC's Cross Answering Testimony

343 AWEC witness Mullins acknowledges Staff's recommendation to reject the second year of the MYRP. While AWEC does not take a position, with witness Mullins noting that the majority of the revenue requirement in RY2 is driven by the removal of Colstrip from rates. AWEC states that if the Commission rejects RY2, it will still need to address the costs related to the removal of Colstrip at some point. Even in light of RCW 80.28.425(9), AWEC does not believe there is any practical benefit to aligning a MYRP with a CEIP and

---

[524] Mullins, Exh. BGM-1T at 13:5-7.

[525] Mullins, Exh. BGM-1T at 13:5-10.

[526] Christie, Exh. KJC-4T at 23:12-14.

[527] Christie, Exh, KJC-4T at 24:7-9.

[528] Christie, Exh. KJC-4T at 25:17-20.

asserts that simultaneous rate cases will likely occur in the future even if the Commission rejects RY2.[529]

Parties' Briefs

Avista's Brief

344 Avista disagrees with the proposals submitted in response to its multiyear rate plan (MYRP). To that point, Avista observes that "what sets this case apart are the dramatic changes in the landscape against which Avista operates" including, among other things, "proposals that would undermine the multiyear rate plan (MYRP) legislation, striking at its very core, i.e., rejection of more than a one year plan (Staff) or disruption of the "portfolio" approach to subsequent "provisional" capital review (AWEC)."[530]

345 The Company disagrees with Staff's argument that there is a burden associated with processing a two-year rate plan. Avista claims that "Staff's proposal to ignore Rate Year 2 (RY2) overlooks the fact that $54.2M of the $69.3M RY2 request on rebuttal is simply removal of Colstrip. The remaining $15M is mostly a continuation of capital and expense items already reviewed in Rate Year 1 (RY1)."[531] Avista goes on to claim a one-year plan would cause Avista to lose 9 to 12 months of additional rate relief that would be covered in RY2, and such a result would be, in effect, the Commission ordering zero rate relief for Rate Year 2.[532]

Staff's Brief

346 Staff reiterates its arguments that: 1) the Commission should deny Avista's MYRP and approve the filing as a traditional one-year rate case so that the Company's subsequent MYRP can align with its CEIP due October 1, 2025, ; and 2) the Commission should deny Avista's MYRP in order to ease the administrative crush on the Commission and interested parties, making for a better ratemaking process.[533] On brief, Staff introduces a third argument for rejecting Avista's MYRP. Specifically, Staff asserts that rejection of the

---

[529] Mullins, Exh. BGM-8T at 15:8-12.

[530] Avista Post-Hearing Brief, at ¶ 2. The issue of the "portfolio" with regard to "provisional" capital review will be addressed elsewhere in this order. However, we note that in AWEC's testimony it also opposed the Company's MYRP. See Mullins, Exh. BGM-1T at 7:17-8:1.

[531] Avista's Post-Hearing Brief, at ¶ 11.

[532] Avista's Post-Hearing Brief, at ¶ 11.

[533] Staff's Post-Hearing Brief, at ¶ 6.

MYRP would allow the Commission to evaluate Avista's next MYRP in light of the equity report it will make in two months.[534]

347 With regard to the equity report, Staff states that "if the Commission approves a two-year rate plan, it will go four years between meaningful looks at equity in Avista's operations in the company's rate cases. Given the Legislature's incorporation of equity into ratemaking[535] and the Commission's directive that equity take center stage in utility operations,[536] the Commission should not accept that kind of a suspension in reviewing Avista's equity practices."[537] Staff concludes that the Commission "should treat this case as a traditional rate filing and review Avista's practices in light of its equity compliance filing in the company's next rate plan filing next year."[538]

AWEC's Brief

348 AWEC continues to contest the Company's MYRP based on the Company forecasting its expenses for its budget in a rate case versus recovering the actual expenses.[539] AWEC continues its argument that the MYRP disincentivizes the Company from reigning in expense, expanding its argument that the process incentivizes Avista to spend up to its capital forecast developed in its internal capital investment process.[540] Although Avista witness Andrews states, "The Company's long-standing practice has been to constrain the level of capital investment each year," AWEC is not convinced.[541] In fact, AWEC argues that the Commission's reliance on Avista's internal capital investment process "has the effect of making the regulated the regulator and bases the reasonableness of the Company's investments on its own internal recommendations."[542] AWEC raises similar concerns about Avista's forecasted budget expense versus actual incurred expense in its discussion of the Company's Miscellaneous O&M expense.[543]

Decision

[534] Staff's Post-Hearing Brief, at ¶ 6.

[535] Staff's Post-Hearing Brief, at ¶18 (*citing*, RCW 19.405.010(6); RCW 80.28.425(1)).

[536] Staff's Post-Hearing Brief, at ¶ 18 (*citing*, Cascade at 19-20 ¶ 59).

[537] Staff's Post-Hearing Brief, at ¶ 18.

[538] Staff's Post-Hearing Brief, at ¶ 18.

[539] AWEC's Post-Hearing Brief, at ¶10; *See also*, Mullins, Exh. BGM-1T at 7:17-8:1.

[540] AWEC's Brief, ¶10.

[541] AWEC's Brief, ¶10 referencing Andrews, EMA-6T at 23:6-7.

[542] AWEC's Brief, ¶10.

[543] AWEC's Brief, ¶¶85-88.

349 In determining whether to approve the Company's MYRP, it is helpful to review the language of RCW 80.28.425, the Multi-Year Rate Plan statute. The pertinent language of RCW 80.28.425(1) provides:

> …[E]very general rate case filing of a gas or electrical company must include a proposal for a multiyear rate plan as provided in this chapter. The commission may, by order after an adjudicative proceeding as provided by chapter 34.05 RCW, approve, approve with conditions, or reject, a multiyear rate plan proposal made by a gas or electrical company or an alternative proposal made by one or more parties, or any combination thereof. The commission's consideration of a proposal for a multiyear rate plan is subject to the same standards applicable to other rate filings made under this title, including the public interest and fair, just, reasonable, and sufficient rates. In determining the public interest, the commission may consider such factors including, but not limited to, environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission.[544]

350 Additionally, and previous to the Multi-Year Rate Plan statute, RCW 80.28.020 conferred broad powers upon the Commission to establish just, reasonable, or sufficient rates for regulated utility companies, when the Commission determines that rates are insufficient to yield a reasonable compensation for the service rendered.[545] RCW 80.01.040(3) empowered the Commission to regulate in the public interest before RCW 80.28.425 further expanded those powers.[546]

351 As was stated previously, Avista filed its MYRP with effective dates of December 2024 for RY1 and December 2025 for RY2 seeking: 1) proposed increases reflecting an electric base rate relief of $79.3 million or 13.1 percent and natural gas base rate relief of $17.3 million or 13.6 percent in RY1; and 2) proposed increases reflecting an electric net request of $53.7 million or 11.7 percent and natural gas base rate relief of approximately $4.6 million or 3.2 percent in RY2.[547]

---

[544] RCW 80.28.425(1).

[545] RCW 80.28.020.

[546] RCW 80.01.040(3).

[547] Vermillion, Exh. DPV-1T at 3:1-10.

352 Staff opposes the Company's MYRP and wants the Commission to approve Avista's filing as a traditional rate case in conjunction with finalization of its CEIP in October 2025.[548] Staff also believes that an Avista MYRP filed in 2025 would relieve and reduce regulatory burden upon the Commission, as well as reduce the burden upon Staff and intervening parties, as Avista and Puget Sound Energy (PSE) have simultaneously filed MYRPs. In short, Staff argues that staggering the MYRPs of Avista and PSE would be in the public interest.[549]

353 AWEC also opposes Avista's MYRP. AWEC argues that approval of Avista's forecasted budget related to its MYRP removes the incentive for the Company to limit expenses, and would encourage the Company to spend up to that approved budget. Moreover, AWEC believes that this would negatively impact ratepayers as rates would be based on forecasted budgets, and that the Company could subject ratepayers to inflated rates, as there is no incentive to control expenses.[550] AWEC opines that during the MYRP process, neither the parties nor the Commission have the opportunity to objectively determine the reasonableness of a utility's capital spending. AWEC adds "setting utility rates based on budgets is problematic because there is no objective way to assess the reasonableness of a budget . . . ."[551]

354 For the above reasons, Staff and AWEC recommend denial of the Company's MYRP, and both recommend treating Avista's filing as a traditional rate case for the Commission to approve only a single year of the Company's proposed rates.

355 Upon review of the evidence and testimony, we find Avista's arguments to be more persuasive. We are reminded that the purpose and intention of the MYRP statute is to provide stability and assurance to the Company *and* the ratepayer. To that point, we are persuaded that adopting Staff's proposal would result in the loss of up to a year of rate relief that is covered in RY2[552] as well as the effect of the removal of Colstrip in rates in RY2.[553]

356 Given that the parties and the Commission have fully litigated this case, restricting rate recovery to the first year would result in a waste of all of our resources, and would likely be considered credit negative by credit rating agencies. Contrary to Staff's and AWEC's

548 Erdahl, Exh. BAE-1T at 7:3-9.

549 Staff's Brief, ¶6; Erdahl, Exh. BAE-1T at 7:19-8:2.

550 Mullins, Exh. BGM-1T at 7:17-8:1.

551 Mullins, Exh. BGM-1T at 9:5-6.

552 Avista's Brief, ¶11.

553 Avista's Brief, ¶11.

assertions, holding a full proceeding and ruling on Avista's current filing and directing the Company to make a subsequent filing in 2025, does not provide the Commission with regulatory relief, but actually compounds regulatory burden with back-to-back Avista rate cases. As such, we do not see alignment with Avista's CEIP as practical in this case, in accordance with RCW 80.28.425(9), given the regulatory burden.

357 We also believe that not only would there be a tremendous regulatory burden placed upon the Commission, but requiring a subsequent filing would also have a negative impact on the Company. Given the time, expense, and resources it would take to file another rate case on the heels of this one may unduly burden the Company financially. Again, we must also consider what the impact may be on the credit rating of the Company if we remove the certainty of the MYRP and instead approve a single year of rates. Ultimately, relieving the Commission and intervening parties of the regulatory burden on one hand may result in adverse impact on the ratepayers in the form of rates on the other hand if they have to absorb lost return on equity.

358 In light of the foregoing, and to ensure just, reasonable, or sufficient rates, we reject Staff's and AWEC's recommendation to deny the Company's MYRP and reject their recommendation to treat Avista's filing as a traditional rate case. We remind the parties that regulating in the public interest is not a one-sided proposition; we must consider the interests of Staff, the intervenors, the Company, and the ratepayers.[554] In this instance we believe that the adverse impact of denying the two-year MYRP on the Company would have also negatively impacted its customers as well. In addition, denying the MYRP would likely negatively impact the Company's financial ability to provide safe and reliable service. Therefore, we conclude that it is in the public interest to leave intact and accept a two-year MYRP for Avista.

Performance Measures and Other Reporting

Direct Testimony – Avista

Performance Metrics

359 The Company proposes to reduce the number of performance measures agreed to in the 2022 GRC Settlement. In that settlement, the Company agreed to report on 92 initial metrics and develop three additional metrics related to reliability.[555] In this proceeding, the Company proposes to edit several metrics to better align with how the data is presented

---

[554] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 288, 88 L. Ed. 333, 345(1944).

[555] Bonfield, Exh. SJB-1T at 2:26 – 3:24.

and recommends eliminating metrics that: do not align with the regulatory goals, outcomes, and principles outlined in the Commission's Interim Policy Statement Addressing Performance Measures and Goals, Targets, Performance Incentives, and Penalty Mechanisms (Interim Policy Statement) in Docket U-210590; are similar to certain financial metrics ordered by the Commission in its 2022 GRC; and those that are reported elsewhere. This results in a total of 48 proposed metrics.[556]

360 Additionally, for the nine Commission-ordered metrics from the 2022 GRC, Avista proposes to adjust the reporting date to February 15 for publicly available data and then May 1 for the remaining date to coincide with the quarterly data.[557]

361 Finally, Avista recommends the Commission not establish any performance incentive mechanisms (PIM) within this proceeding. In the alternative, if the Commission finds a PIM is required by RCW 80.28.452(7) [*sic*], the Company proposes the same customer service PIM from its 2022 GRC.[558]

Recurring Reporting

362 As part of the 2022 GRC Settlement, the Company agreed to provide recommendations regarding the streamlining of existing reporting requirements. Avista proposes to eliminate the following reports:

- WA Distributed Generation Annual Report
- WA Electric and Natural Gas Decoupling Mechanism Report
- Energy & Emissions Intensity Metrics Report
- I-937 Report
- Critical Infrastructure Report
- Essential Utilities Services Contacts Report
- Annual Disconnection Reduction Report
- Monthly Credit & Collections COVID-19 Report
- Quarterly Credit & Collections COVID-19 Report

---

[556] Bonfield, Exh. SJB-1T at 7:13 – 8:10.

[557] Bonfield, Exh. SJB-1T at 11:1-11. The Company was originally required to file twice in February and once in April until confidentiality due to FERC filings was an issue.

[558] Bonfield, Exh. SJB-1T at 11:14-18. The alternative PIM consists of six measures, a $500,000 incentive or penalty given certain performance, and approval for a Deferred Accounting Mechanism to address any incentive or penalty in the Company's next rate proceeding. Bonfield, Exh. SJB-1T at 11-15. We assume the statutory reference is for RCW is 80.28.425(7). No other party proposed establishing a PIM in this proceeding.

363 Witness Bonfield provides rationale for eliminating each report which includes duplicative information available elsewhere, consolidating information within another filing, uncertainty of the value of report, and that certain information can be made available by request.[559]

364 Further, Avista proposes to modify the reporting of the following three reports:

- Energy Recovery Mechanism Review Filing (annual and quarterly report rather than annual and monthly)
- Purchased Gas Adjustment Activity Reporting (quarterly instead of monthly)
- Natural Gas IRP and Workplan (aligning frequency with electric IRP with a progress report due two years after the IRP is filed).[560]

Staff's Response Testimony

365 Staff witness Erdahl recommends the Commission require Avista to maintain three of the metrics that the Company proposes to eliminate as the metrics were ordered by the Commission in the PacifiCorp 2023 GRC in Docket UE-230172.[561] Staff also proposes a new metric related to connection timelines for new service requests.[562] Erdahl argues the new metric is in the public interest to both ensure utility responsiveness during the current housing crisis and to support new state building codes related to Electric Vehicle Charging Infrastructure.[563]

366 Finally, Staff requests the Commission order Avista to continue filing its Critical Infrastructure Report. Erdahl testifies the Company proposed to eliminate this report in Docket U-210151 related to the Commission's Inquiry into Reducing the Administrative Burden, however, Erdahl notes the Commission did not relieve the Company of that filing requirement in that proceeding and should not do so here.[564]

NWEC's Response Testimony

367 As part of its effort to advance equity, NWEC witness Thompson proposes that Avista maintain two performance metrics related to non-pipe alternatives (NPAs). Thompson

---

[559] Bonfield, Exh. SJB-1T at 27:12 – 28:20. See also Bonfield, Exh. SJB-4. Bonfield recognizes that a legislative change may be required related to the I-937 reporting requirement.

[560] Bonfield, Exh. SJB-1T at 28:23 – 29:14.

[561] Erdahl, Exh. BAE-1T at 12:3-16.

[562] Erdahl, Exh. BAE-1T at 13:5-14.

[563] Erdahl, Exh. BAE-1T at 13:17 – 14:11.

[564] Erdahl, Exh. BAE-1T at 12:17 – 13:2.

argues the clean energy targets mandated by CETA and the necessary balance between utility and customer-level resources that more directly benefit Named Communities supports NWEC's position. While NWEC proposes to maintain the metric that separately tracks emissions avoided by NPAs, it is amenable to eliminating this metric conditioned on Avista continuing to report the carbon intensity metric.[565]

368 Additionally, while not formally requesting a new metric, Thompson recommends the Commission require Avista to collect customer demographic data for all current and future DER program offerings like the data collected through its bill discount program. While Thompson provides that a customer may opt out of providing such information, the Company should not require such information to determine program enrollment eligibility. Finally, Thompson recommends Avista maintain its practice of de-identification and data aggregation to protect individual customer demographics.[566]

369 NWEC also responds to Avista witness Bonfield's proposal to eliminate the Annual Disconnection Reduction Report. Thompson does not agree with Bonfield's claim that the information is available in other reports. Rather, Thompson argues the same level of granularity does not exist in the COVID reporting, the CEIP, or PBR metrics and parties would lose useful information regarding the demographics of the disconnections.[567]

TEP's Response Testimony

370 TEP witness Stokes argues that Avista should maintain seven metrics that were proposed for elimination and provides edits for three of those metrics, modifies three metrics retained by Avista, requests a draft metric from the Interim Policy Statement be amended and required for Avista, and proposes one new metric.

371 Witness Colton provides analysis that crosses both equity issues and performance measures related to the affordability metrics, arrears and disconnections, and energy burden. Colton makes several recommendations including: (1) continuing to require certain affordability and energy burden metrics be reported by census tract and zip code; (2) using the stratification methodology proposed for the energy burden assessment for related PBR metrics; and (3) revising the arrears metric to include the accounts and dollars that were paid on time.[568]

---

[565] Thompson, Exh. CT-1T at 14:13 – 16:17.

[566] Thompson, Exh. CT-1T at 16:20 – 18:11.

[567] Thompson, Exh. CT-1T at 19:4-18.

[568] Colton, Exh. RDC-1T at 51:13 – 52:29, 60:28 – 61:16. The impacted metrics include: Metric 12, 13, 14, and 15 for stratification, and Metric 4 related to arrears.

372 Colton argues that requiring both census tract and zip code reporting allows for "cross-tabulation of data."[569] For example, census data may be compared to the American Community Survey, while zip code data may be compared to the Census Bureau's Zip Code Tabulation Areas, providing the ability for more robust analysis.[570] Alternatively, if the Commission retains only census tract data, TEP recommends the Company be required to maintain "crosswalk files" that indicate the allocation of census tracts over zip codes.[571]

Summary of TEP metric recommendations

373 ***Metric for Clarification***
TEP recommends that Avista explicitly include natural gas in its reporting for residential disconnections.[572]

374 ***Interim Policy Statement Metric to Amend and Require for Avista***
TEP recommends the Commission amend its interim metric regarding the average residential bill by including low-income customers as a separate subset for the data reporting. Stokes argues this provides a better level of granularity about rate impacts to specific communities.[573]

375 ***Metrics to Maintain***
TEP disagrees with Avista's proposal to eliminate the Operations and Maintenance (O&M) metric. Stokes argues that this metric provides insight into the utility's financial management and may be helpful in comparing against other utilities' performance.[574]

376 TEP proposes the Commission require Avista to maintain two metrics related to energy burden and modify a third. Relying on Colton's analysis and testimony, Stokes argues that the two metrics that calculate high-energy burden should be maintained,[575] with the

---

[569] Colton, Exh. RDC-1T at 57:17.

[570] Colton, Exh. RDC-1T at 55:9-19, 57:5 – 58:2.

[571] Colton, Exh. RDC-1T at 58:5-7.

[572] Stokes, Exh. SNS-1T at 18:19 – 19:5.

[573] Stokes, Exh. SNS-1T at 18:4-17.

[574] Stokes, Exh. SNS-1T at 25:1 – 26:6. Stokes provides a simple comparison of Avista and PSE data with no conclusions about the trend or underlying cause for the differences.

[575] Stokes, Exh. SNS-1T at 19:7-12. These metrics (originally designation as Metrics 13 and 14) were maintained by Avista on direct (Metrics 7 and 8) and combined into a single metric on rebuttal (Metric 8).

additional requirement of reporting by stratification provided by Colton.[576] Stokes then adopts TEP's proposal in the PBR docket to designate single-fuel energy burden at 2 percent for natural gas and 4 percent for electric.[577] Further, Colton recommends the Commission modify the arrearage metric to include the number of accounts and dollars that were paid on-time allowing interested persons to understand the substantiality of the arrears.[578]

377 Next, TEP addresses three Equitable Service metrics that it proposes to maintain and/or edit. First, witness Stokes recommends the Commission require Avista to continue reporting its metric related to low-income participation in DR, DER, and renewable energy programs. Stokes testifies the limited data available indicates little participation by low-income customers in these programs. However, with that limited data, Stokes testifies that conclusions about trends are not possible and believes this information is important to evaluate performance of these programs as part of the clean energy transition. Further, TEP recommends the Commission edit the language of this metric to replace the participation language with measuring by those directly benefitting from the program.[579]

378 The other two Equitable Service metrics are related to electric vehicle programs. Stokes provides the same rationale from the above metric to maintain the low-income participation in electric vehicle programs metric. Further, Stokes argues the language should be changed from electric vehicle to electric transportation programs as proposed in the PBR docket. Stokes testifies this change better reflects and strengthens the business case for utility investment in these technologies. TEP also proposes to modify this metric to replace the participation language with measuring those directly benefitting from the program.[580] Additionally, TEP argues the metric related to electric vehicle supply equipment be maintained. Stokes testifies this data is necessary to ensure Named Communities have equitable access to electric vehicle ownership and "contextualizes Avista's measurement of electric transportation spending."[581]

379 Finally, TEP proposes the Commission require Avista to maintain the metric related to NPAs and the metric related to incremental spending in Named Communities.[582] Stokes

---

[576] Colton, Exh. RDC-1T at 60:1-4.

[577] Stokes, Exh. SNS-1T at 20:10-20.

[578] Colton, Exh. RDC-1T at 61:1-16.

[579] Stokes, Exh. SNS-1T at 21:12 – 22:9, 24:1-2.

[580] Stokes, Exh. SNS-1T at 22:12 – 24:7.

[581] Stokes, Exh. SNS-1T at 26:9-20.

[582] Stokes, Exh. SNS-1T at 27:8-11.

argues these metrics, "show[ ] whether Avista is equitably deploying financial resources that aid the transition away from gas service," and "measuring overall incremental spending in Named Communities shows whether Avista is making consistent, yearly investment that promote equity in its operations and support underserved customers."[583]

380 ***New Metric***

TEP proposes a new metric to report the net plant in service per customer for electric and natural gas. Stokes argues this metric would provide insight into capital investment trends and an indication of how a utility chooses to replace aging assets.[584]

Recurring Reporting Recommendations

381 TEP opposes Avista's elimination of the decoupling, disconnection, and COVID reports. Additionally, Colton contends that reported data is not easily accessible for the PBR metrics, disconnection and arrearage reports, or the energy burden analysis. Colton argues this information is useful to those outside the usual GRC parties, for example those groups working on affordable housing issues or agencies responsible for distributing federal funds. Therefore, TEP recommends the Commission require Avista to post these data sets and reports to their website rather than providing solely through various dockets with the Commission.[585]

382 Further, Colton makes a general recommendation that the affordability and energy burden related PBR metrics and reports discussed in their testimony be provided at a monthly data level. Colton testifies this granularity is necessary to understand the relationship of the data for the different seasons of the year. However, Colton does not necessarily propose the metric and reports be filed monthly but believes it reasonable to file the monthly data sets at a greater interval such as quarterly, semi-annually, or annually.[586]

383 Responding specifically to the COVID report, Colton contends that Avista witness Bonfield inaccurately represents the COVID information as duplicative of information provided in other reports. Colton testifies the following components are not otherwise available: (1) length of disconnection, number of disconnection notices, number of accounts, but for the moratorium that would have been disconnected; (2) information related to various fees charged in relation to disconnection or reconnection; (3) information about long-term payment arrangements; (4) information on medical payment

---

[583] Stokes, Exh. SNS-1T at 27:14-16.

[584] Stokes, Exh. SNS-1T at 28:3-8.

[585] Colton, Exh. RDC-1T at 28:7 – 29:6.

[586] Colton, Exh. RDC-1T at 55:22 – 56:12.

arrangements; (5) information about customer deposits; (6) number of premises receiving bill assistance; and (7) past due balances by zip code.[587]

384 TEP also proposes three modifications to the COVID report. First, for the arrearage metric, Colton recommends including not only the dollar amount in arrears but also the number and dollar amount that were paid on time.[588] Second, in additional to reporting total arrears and age of the arrears, Colton proposes to require reporting by the number of accounts for both total and age of the arrears. Finally, Colton asserts that the name of the report should be changed to "Arrearage Report" or to "Arrearage and Disconnection Report" noting that the information is no longer only relevant due to the COVID pandemic and resulting economic state of emergency.[589]

385 Addressing the Disconnection Reduction Report, again Colton argues that Avista witness Bonfield incorrectly argues the information is duplicative. While Colton acknowledges one data point (total disconnections for nonpayment) is available through either the PBR metrics or COVID report, the remainder of the reporting requirements per the 2019 GRC settlement in Dockets UE-190334, UG-190335, and UE-190222, are not provided elsewhere.[590] Colton argues eliminating this required data will hinder the Commission and others in evaluating the affordability of Avista rates.[591]

386 Finally, Colton recommends that Avista include the number of disconnections for nonpayment, number of accounts in arrears, and the dollars of the arrears, and provide the data per their energy burden stratification recommendation contained in earlier sections of their testimony.[592]

387 Stokes proposes the Company maintain the Quarterly Decoupling Report arguing not all information contained in this report is available during the annual adjustment filing. The data not available in the annual filing includes the number of new customers excluded from decoupling, separately identifying the electric and gas weather components, and a workpaper that provides the native formula-based calculations supporting the annual adjustment. Alternatively, if the Commission discontinues this report, TEP proposes the

---

[587] Colton, Exh. RDC-1T at 58:10 – 59:18.

[588] This same information was recommended in response to Metric 4 by witness Colton.

[589] Colton, Exh. RDC-1T at 60:28 – 62:3.

[590] Colton, Exh. RDC-1T at 62:8 – 63:10. *See* Table 17 at page 62 for the none required data points in the COVID report.

[591] Colton, Exh. RDC-1T at 63:12-18.

[592] Colton, Exh. RDC-1T at 64:5-8.

Company be required to include the information described above and the docket numbers, both electric and gas, for the annual decoupling reports filed within the past five years.[593]

Avista's Rebuttal Testimony

Performance Metrics

388 On rebuttal, witness Bonfield wholly changes the Company's position on performance metrics. The Company now proposes that the Commission should only require Avista to report on the performance metrics included in its August 2, 2024, Alternative Forms of Regulation Policy Statement for Initial Reported Metrics (Metrics Policy Statement). Further, the Company also adopts the timing for filing PBR metrics (annually with the Commission Basis Report).[594] Avista argues the Commission has now determined the appropriate metrics to evaluate utility performance during a MYRP, and that the annual filing significantly reduces administrative burden. Finally, Avista argues the Metrics Policy Statement renders both its direct case proposal and all other parties' proposals moot, and argues that because those parties also participated in the PBR docket, they had the opportunity for input on utility performance metrics.[595]

389 Avista also responds to NWEC's proposal to collect the demographic data for all existing and future DER programs. Bonfield contends the Company is unable to collect this information for two reasons. First, Bonfield testifies that many of Avista's DER programs are administered in partnership with community partners or at the distributor level, therefore, the Company does not have direct access to such data. If the Commission were to require the collection of this data, Bonfield contends the workload would be placed on those already resource constrained partners. Second, Bonfield argues the data that is available to the Company is distributed across multiple systems with inadequate security to protect customer information when sharing cross-departmentally. Finally, Bonfield asserts requiring this data collection would take time and financial resources to create a platform and require changes to partner processes as well.[596]

Recurring Reporting

---

[593] Stokes, Exh. SNS-1T at 40:20 – 42:4.

[594] Commission Basis Reports (CBA) are required within four months of the end of a utility's fiscal year by WAC 480-100-257. All Washington regulated utilities follow a fiscal calendar year therefore CBA's must be filed no later than May 1 each year.

[595] Bonfield, Exh. SJB-5T at 38:14 – 39:17.

[596] Bonfield, Exh. SJB-5T at 28:10 – 30:13.

390 Bonfield both clarifies and revises the recurring reporting obligation discussed in direct testimony and acknowledges the Company's intent for each report was not entirely clear. Avista clarifies it proposed to eliminate the following reports:

- WA Distributed Generation Annual Report;
- Energy & Emissions Intensity Metrics Report [requires waiver from WAC 480-109-300(1)];
- Critical Infrastructure Report;
- Essential Utility Services Contracts Report [requires waiver from WACs 480-100-268 and 480-90-268];
- Equity Report;
- Monthly Credit & Collections COVID-19 Report; and
- Quarterly Credit & Collections

391 Further, Bonfield clarifies that direct testimony intended to modify the following reports:

- Commission Basis Report [remove wood pole reporting];
- PGA Activity Reporting [changed frequency which requires waiver from WAC 480-90-233(5)];
- MYRP Metrics [changed filing timeline][597]

392 ***Critical Infrastructure Report*** *- Response to Staff*
Avista disagrees with Staff's proposal to maintain the Critical Infrastructure Report, arguing it is unsure of the value of the information as much of the data remains static, and that Staff did not provide testimony establishing the need for the report. Further, simply combining the report with the reliability report as Staff recommends does not alleviate the burden of providing the information. Finally, Bonfield testifies that no action has been taken because of this report, but that the information can be made available upon request.[598]

393 ***Disconnection Reduction Report*** *– Response to NWEC and TEP*
Witness Bonfield agrees with NWEC and TEP, that not all information contained in the Disconnection Reduction Report is duplicative, therefore, Avista agrees to maintain the report until such time as a decision is made in the Commission's Customer Notice and Fees Rulemaking in Docket U-210800. However, Avista does not agree with TEP's recommended additions to the report or applying the stratification analysis. Bonfield

---

[597] Bonfield, Exh. SJB-5T at 40:18 – 41:25. The decoupling report was not contained in this revised list. However, Bonfield provides later testimony explaining that omission when rebutting TEP's response position.

[598] Bonfield, Exh. SJB-5T at 42:10-17.

testifies that the additional information requested in this report is already provided either within the report or other reporting by the Company. Further, Bonfield argues the company has not previously performed the calculations using stratified energy burden and is uncertain of the additional value gained.[599]

394 ***COVID Reporting (monthly and quarterly)*** *– Response to TEP*
The Company also agrees to maintain the COVID Reporting until the Commission makes determinations in rulemaking docket U-210800, as with the Disconnection Report. Again, witness Bonfield does not agree with TEP's recommended modifications to the reports. First, Bonfield questions the value or use gained by adding the number of accounts and dollars that paid on time. However, Bonfield provides the rulemaking docket referenced above is a more appropriate setting to discuss this issue. Second, Bonfield contends the additional information requested (arrears by number of accounts and dollar amounts) is already available in either the COVID Reporting or within the Customer Benefit Indicators of its CEIP. Finally, Avista takes no position on the title of the report but believes the issue of potentially consolidating arrears and disconnection data is also more appropriate in the rulemaking proceeding.[600]

395 ***Decoupling Report*** *– Response to TEP*
Bonfield testifies the Quarterly Decoupling Report was already discontinued by the Commission in Order 01 of Docket U-210151. However, as requested by TEP, the Company will continue to include the information in all future decoupling annual adjustment filings.[601]

NWEC's Cross Answer

396 In cross-answering testimony, Thompson supports many of TEP's recommendations regarding performance measures, including five measures to maintain,[602] six measures to maintain and edit,[603] and includes TEP's proposed metric related to net plant per customer. Thompson argues that many of TEP's recommendations are easy to integrate, directly

[599] Bonfield, Exh. SJB-5T at 42:20 – 43:11.

[600] Bonfield, Exh. SJB-5T at 43:14 – 44:9.

[601] Bonfield, Exh. SJB-5T at 44:12-21.

[602] One of the proposed metrics to maintain was not eliminated by Avista nor a recommendation from TEP to maintain (Metric 1) and another the Company agrees to maintain on rebuttal (Metric 26).

[603] The Company retains but consolidates two of the metrics being proposed to maintain and edit (Metrics 13 and 14).

align with the Commission's Interim Policy Statement, and provide a more robust reporting to better evaluate the deployment of clean energy in Named Communities.[604]

Parties' Briefs

Avista

397 In briefing, Avista proposes to modify two of its reporting metrics related to affordability and energy burden to align with the Commission's recent policy statement on reported performance metrics in Docket U-210590.[605] Avista further recommends that the Commission require the Company to report the metrics contained in the Commission's Initial Reported Performance Metrics contained in its August 2, 2024, policy statement.[606] Avista also argues that performance incentive mechanisms are unnecessary for the purpose of this rate case.[607] Finally, Avista agrees to maintain its Annual Disconnection Reduction and COVID-19 Arrearage reporting, but disagrees with Staff's position that it should maintain its Critical Infrastructure Report.[608]

Staff

398 Staff generally agrees with Avista's proposal to reduce the metrics it reports from 92 to 48 metrics, but it recommends that the Commission require Avista to retain four metrics and add one additional metric.[609] Staff argues that the Commission should require Avista to retain three metrics that the Commission recently required PacifiCorp to report, to facilitate comparison of utility performance, and another metric that is necessary to assess utility security.[610] Staff also requests that the Commission direct Avista to report a new metric related to connection timelines for new services requests for newly constructed dwellings.[611] Staff also urges the Commission to reject Avista's arguments that the Commission should limit reportable metrics to those metrics contained in the recent policy

---

[604] Thompson, Exh. CT-4T at 6:9 – 7:12.

[605] Avista's Post-Hearing Brief, at ¶ 158.

[606] Avista's Post-Hearing Brief, at ¶ 158.

[607] Avista's Post-Hearing Brief, at ¶ 158.

[608] Avista's Post-Hearing Brief, at ¶ 158.

[609] Staff's Post-Hearing Brief, at ¶ 19.

[610] Staff's Post-Hearing Brief, at ¶ 19.

[611] Staff's Post-Hearing Brief, at ¶ 19.

statement on metrics, because the policy statement reflects a minimum, as opposed to a maximum, level of reporting.[612]

TEP

399 In briefing, TEP requests that the Commission order Avista to adopt a metric regarding low-income customer saturation rates by household and fuel type, as well as TEP's proposed affordability and equity metrics.[613]

Sierra Club

400 Sierra Club requests that if the Commission approves a performance incentive mechanism for Avista, that the Commission establish customer engagement targets of 5,000 home electrification assessments and 1,000 electrification rebates over an 18-month period related to Sierra Club's proposed targeted electrification pilot for Avista.[614]

NWEC

401 NWEC supports the inclusion of 51 performance metrics suggested by Avista in the event that the Commission declines to limit required metrics to those metrics contained in the August 2, 2024, Policy Statement.[615] Regarding collection of customer demographic information for current and future DER programs, NWEC agrees with Avista's proposal to raise this issue with the Company's applicable advisory groups.[616] NWEC further notes and appreciates Avista's agreement to maintain its annual customer Disconnection Reduction Report.[617]

402 Turning to Avista's energy burden analysis, NWEC discusses four points. First, NWEC argues that the Commission should require Avista to include updates to customer income and usage data as a basis for reporting saturation rate and other metrics in its annual LIRAP reports.[618] Second, NWEC agrees with Avista's decision to assess energy burden for customers enrolled in the LIRAP MED and include this information in its annual

---

[612] Staff's Post-Hearing Brief, at ¶ 20.

[613] The Energy Project's Post-Hearing Brief, at ¶¶ 39, 58 (*citing*, Stokes, Exh. SNS-10).

[614] Sierra Club's Post-Hearing Brief, at ¶ 41.

[615] NWEC's Post-Hearing Brief, at ¶ 54 (*citing*, Bonfield, Exh. SJB-2; Bonfield, Exh. SJB-6).

[616] NWEC's Post-Hearing Brief, at ¶ 55.

[617] NWEC's Post-Hearing Brief, at ¶ 56.

[618] NWEC's Post-Hearing Brief, at ¶ 57.

LIRAP report.[619] Third, NWEC states that it is reasonable for Avista to include normalized household service data for customers with less than 12 months of usage data as part of its PBR reporting.[620] Lastly, NWEC indicates that Avista's proposal to discuss simulating energy burden over time as a function of factors that increase bills with its Energy Assistance Advisory Group to determine feasibility and value is reasonable.[621]

403 Finally, NWEC voices support for TEP witness Stokes' recommendations regarding Avista's disconnection policy, PBR metric reporting, low-income customer identification, language access, and the Company's quarterly decoupling report and incorporates the arguments made in its Cross-Answering Testimony.[622]

Decision

404 The Commission appreciates the Parties' thoughtful and constructive arguments regarding various proposed changes to the PBR metrics on which Avista will be required to report. As noted in the August 2024 Policy Statement regarding reported metrics, the process of selecting and refining utility metrics is iterative, and the Commission commends the continued efforts of the Parties to both revise existing metrics and propose new metrics for consideration.[623] The Commission fully anticipates that PBR metrics will continue to be reviewed and refined in the coming year and looks forward to additional robust discussion.

405 As a threshold matter, the Commission rejects Avista's invitation to limit reported metrics to only those metrics identified in the Commission's August 2024 Policy Statement. As explained in the Policy Statement, the metrics that were developed in that proceeding were not intended to be a final, comprehensive set of metrics for all utilities,[624] and the Commission fully encouraged parties to suggest new or additional metrics in the context of a multi-year rate plan proceeding.[625] Furthermore, while the Commission remains

---

[619] NWEC's Post-Hearing Brief, at ¶ 57.

[620] NWEC's Post-Hearing Brief, at ¶ 57.

[621] NWEC's Post-Hearing Brief, at ¶ 57.

[622] NWEC's Post-Hearing Brief, at ¶ 58.

[623] *In re Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making*, Docket U-210590, Policy Statement Addressing Initial Reported Performance Metrics, 3 ¶ 10 (Aug. 2, 2024) (Policy Statement Addressing Initial Reported Performance Metrics).

[624] Policy Statement Addressing Initial Reported Performance Metrics, 3 ¶ 10 ("In doing so, we reiterate our view that a comprehensive PBR framework cannot be established with finality at this juncture.").

[625] Policy Statement Addressing Initial Reported Performance Metrics, 5 ¶ 16.

sensitive to redundant reporting requirements, as utilities continue to report various metrics, the reported data may demonstrate that further adjustments and metrics are necessary to adequately and efficiently monitor a utility's operations and progress with state energy policies.[626] Therefore, it is inappropriate to limit reported PBR metrics to those identified in the August 2024 Policy Statement.

406 In reviewing the proposed changes to the reported metrics, the Commission has attempted to balance considerations of efficiency regarding the scope and quantity of data required by the metrics with the need to establish a reasonable baseline of data to evaluate utility performance. The Commission generally agrees with Avista's proposal to eliminate reporting requirements that are duplicative of data already reported elsewhere.[627] The Commission also considered additional modifications to reported metrics to consolidate and simplify the collection of data where possible. Similarly, in evaluating new or modified metrics proposed by the Parties, the Commission reviewed whether the reported data would be helpful to evaluate utility performance and whether the requested data could be found in existing reporting requirements.

407 Having considered all of the Parties' arguments regarding PBR metrics, the Commission determines that it is reasonable to require Avista to report on the metrics contained in the August 2024 Policy Statement, reduce the number of overall metrics reported to avoid duplication, and require the Company to report on several modified or new metrics. Appendix A, attached to this Order, contains a description of the changes to PBR metrics in this proceeding as well as additional reasoning for the decision to require, retain, modify, or remove a particular metric. Finally, the Commission declines to require any performance incentive mechanisms (PIMs) for Avista as part of this rate case and anticipates further discussion of how to best utilize PIMs after additional review and analysis of the baseline data reported by Avista and other regulated utilities in the context of either a future rate case or proceeding in Docket U-210590.

408 As shown in Appendix A, the Commission has reduced the number of PBR metrics on which Avista will be required to report to 33. These metrics consist of 12 metrics that have been refined or proposed during this proceeding and the 21 metrics contained in the Commission's Policy Statement Addressing Initial Reported Performance Metrics, including the metrics established pursuant to RCW 80.28.425(7).[628] In many cases, metrics were removed because the same information can be found in other reporting required by the Commission, such as information reported as part of Customer Benefit

---

[626] Policy Statement Addressing Initial Reported Performance Metrics, 4 ¶ 12.

[627] Bonfield, Exh. SJB-1T at 7:12 – 8:15.

[628] Policy Statement Addressing Initial Reported Performance Metrics, 7 ¶ 22 – 21 ¶ 82.

Indicators, or were already incorporated into other required PBR metrics. The Commission also authorized the removal of metrics where no party opposed removal, as the lack of opposition suggests that the metric provides little value in reviewing Avista's operations. Similarly, the Commission declined to require a metric if the proposed measurement involved too many factors outside Avista's control because the metric would provide limited insight into the effect of Avista's operational decisions.

409 Similar to its review of PBR metrics, the Commission has attempted to balance the need for regular information from Avista to evaluate its performance with the goal of reducing the administrative burden on the Company caused by duplicative or inefficient reporting requirements. To that end, the Commission determines that it is reasonable to eliminate some of Avista's reporting requirements, consolidate duplicative requirements into other existing reporting obligations, and maintain other reporting until such time as the Commission may consider modifications with input from all utilities subject to the reporting. Appendix B, attached to this Order, contains the Commission's disposition of each reporting issue raised in this proceeding and the reasoning for the Commission's determination.

Cost of Capital

Avista's Direct Testimony

410 The Company's proposed capital structure is 51.5 percent debt and 48.5 percent equity, with a proposed cost of debt of 4.99 percent, a proposed 10.40 percent ROE, and a requested overall rate of return (ROR) in this proceeding of 7.61 percent.[629]

Avista Proposed Cost of Capital[630]				
	Amount	Percent	Cost	Component Cost
Total Debt	$2,743,700,000	51.5%	4.99%	2.57%
Common Equity	$2,588,899,805	48.5%	10.40%	5.04%
Total	$5,332,599,805	100%		7.61%

411 Company witness Christie explains that maintaining a 48.5 percent common equity ratio is necessary since Avista is dependent on raising funds in capital markets and a solid financial profile will assist the Company in accessing debt capital markets on reasonable terms.[631] Additionally, Christie contends that a 48.5 percent common equity ratio solidifies

---

[629] Christie, Exh. KJC-1T at 14:8-11.

[630] Christie, Exh. KJC-1T at 14:13-18.

[631] Christie, Exh. KJC-1T at 14:20-23.

Avista's current credit ratings and moves them closer to the long-term goal of having a corporate credit rating of BBB+.[632]

412 Company witness McKenzie also argues that a common equity ratio of 48.5 percent is a reasonable basis on which to calculate the overall rate of return for three primary reasons:

1) Avista's requested capitalization is consistent with the Company's need to support its credit standing and financial flexibility,[633]
2) The proposed common equity ratio is consistent with the range of capitalizations for the proxy utilities and their utility operating subsidiaries,[634] and
3) The requested capitalization reflects the importance of an adequate equity layer to accommodate operating risks and recognize the impact of off-balance sheet commitments, such as purchased power agreements.[635]

413 McKenzie notes that for the 22 firms in the Utility Group, common equity ratios on December 31, 2022, ranged between 33.0 percent and 63.5 percent and average 44.0 percent.[636] McKenzie elaborates that Value Line expects an average common equity ratio for the proxy group of utilities of 44.8 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 27.0 percent to 59.5 percent.[637]

414 McKenzie further notes that the Commission has previously observed that "[i]t is appropriate … to afford more weight to forward considerations than to historic conditions as we determine the appropriate equity ratio to be embedded in prospective rates."[638]

415 Christie testifies that the Company's proposed weighted average cost of equity is in-line with other utilities' authorized weighted average cost of equity, and that its present weighted average cost of equity is at the low end of actual, commission-authorized values.[639] Christie elaborates that if the Commission carries over the existing ROE of 9.4 percent and 48.5 percent equity component, the weighted cost of equity would be 4.56 percent.[640]

---

632 Christie, Exh. KJC-1T at 15:1-3.

633 McKenzie. Exh. AMM-1T at 10:13-16.

634 McKenzie. Exh. AMM-1T at 10:17-18.

635 McKenzie. Exh. AMM-1T at 10:21-23.

636 McKenzie, Exh. AMM-1T at 38:2-4.

637 McKenzie, Exh. AMM-1T at 38:7-9.

638 McKenzie, Exh. AMM-1T at 38:10-12.

639 Christie, Exh. KJC-1T at 15:8-11.

640 Christie, Exh. KJC-1T at 16:1-2.

416 Christie also contends that the proposed 10.40 percent ROE is reasonable to maintain Avista's financial integrity.[641] Witness McKenzie backs up this assertion by stating that four out of five cost of equity methods the Company implemented produced an ROE of 10.4 percent.[642] McKenzie posits that challenges to the Company's credit standing, pressure of funding more than $1.5 billion of capital expenditures over 2024-2026, Avista's reliance on hydroelectricity, the impact of the existing ERM on price volatility exposure to wildfire, and Avista's relatively small size support this conclusion.[643]

417 McKenzie emphasizes that if the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital.[644]Further, McKenzie explains that other things equal, a higher debt ratio and lower common equity ratio, translates into increased financial risk for all investors.[645] McKenzie elaborates that a greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments, which is true for common shareholders as well.[646] Additionally, McKenzie asserts that a more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital under reasonable terms.[647]

418 Finally, McKenzie contends that in order to offset the debt equivalent associated with off-balance sheet obligations, the utility must rebalance its capital structure by increasing its common equity.[648]

419 The Company's requested overall cost of debt is 4.99 percent.[649] The Federal Funds Rate and Avista's short-term borrowing rate has increased about 525 basis points since the beginning of 2022.[650] Christie emphasizes that higher interest rates increase the cost of

---

[641] Christie, Exh. KJC-1T at 16:6-7.

[642] McKenzie, Exh. AMM-1T at 6:19-20.

[643] McKenzie, Exh. AMM-1T at 7:6-28.

[644] McKenzie, Exh. AMM-1T at 37:3-5.

[645] McKenzie, Exh. AMM-1T at 37:12-13.

[646] McKenzie, Exh. AMM-1T at 37:13-18

[647] McKenzie, Exh. AMM-1T at 39:3-5.

[648] McKenzie, Exh. AMM-1T at 40:11-13.

[649] Christie, Exh. KJC-1T at 18:18.

[650] Christie, Exh. KJC-1T at 19:23, 20:1.

borrowing under the Company's $500 million revolving credit facility and are expected to increase the cost of issuing long-term debt over the next couple of years.[651]

420 Christie argues that if the Company were simply trying to grow its rate base to increase earnings, it could fully justify increasing its capital budget to well over $600 million over the next several years, but it is choosing not to, in order to balance investment need with customer affordability.[652]

Public Counsel's Response Testimony

Return On Equity

421 Public Counsel witness D. Garrett testifies that the average results of the three models it used to calculate ROE is 8.5 percent.[653] D. Garrett argues that with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital, which leads to results that are detrimental to ratepayers and the state's economy.[654]

422 D. Garrett argues that McKenzie's Capital Asset Pricing Model (CAPM) cost of equity is overstated due to McKenzie's overestimation of the Equity Risk Premium as well as an unnecessary size adjustment.[655] Additionally, D. Garrett contends that McKenzie conducts an additional unnecessary size adjustment and adds a flotation costs premium.[656] D. Garrett further contends that the Company's Empirical Capital Asset Pricing Model (ECAPM) further inflates that traditional CAPM's results.[657]

423 D. Garrett concedes that competitive firms maximize their value by minimizing their weighted average cost of capital, or WACC, but this is not the case for regulated utilities.[658] Under the regulated rate of return model, a higher WACC results in higher rates, all

[651] Christie, Exh. KJC-1T at 20:2-4.

[652] Christie, Exh. KJC-1T at 34:8-12.

[653] Garrett, Exh. DJG-1T at 4:7-8.

[654] Garrett, Exh. DJG-1T at 7:3-6.

[655] Garrett, Exh. DJG-1T at 38:1-3.

[656] Garrett, Exh. DJG-1T at 38:3-4.

[657] Garrett, Exh. DJG-1T at 43:4-5.

[658] D. Garrett uses the terms "cost of capital" and "weighted average cost of capital, (WACC)," interchangeably throughout their testimony. Garrett, Exh. DJG-1T at 49:6-7.

else held constant.[659] Thus, because there is no incentive for a regulated utility to minimize its WACC, D. Garrett articulates that a Commission must ensure that the regulated utility is operating at the lowest reasonable WACC.[660]

424 D. Garrett testifies that according to the debt ratios recently reported in Value Line for the utility proxy group, the average debt ratio of the proxy group is 55 percent and the average equity ratio is 45 percent.[661] D. Garrett notes that this debt ratio is notably higher than Avista's proposed debt ratio of only 51.5 percent[662] arguing that this means that Avista has a lower level of financial risk relative to the proxy group, a discrepancy that D. Garrett believes can be mathematically accounted for through the Hamada Model.[663]

425 Since Avista's debt ratio is notably lower than that of the proxy group, D. Garrett argues that when Avista is "relevered" to match the proxy group, it results in a lower ROE than if Avista had been operating with a capital structure equal to that of the proxy group. D. Garrett concludes that according to the results of the Hamada model, if the Commission were to adopt the Company's proposed capital structure, its indicated cost of equity estimate (under the CAPM) would be 9.2 percent.[664]

Flotation Costs Adjustment

426 Additionally, D. Garrett disagrees with the Company's position of adding a flotation cost adjustment of .08 percent to its overall modeling results.[665] D. Garrett contends that flotation costs are not actual "out-of-pocket" costs for the Company,[666] the market already accounts for flotation costs,[667] and that it is inappropriate to add any additional basis points to an awarded ROE proposal that is already [668]

AWEC's Response Testimony

---

[659] Garrett, Exh. DJG-1T at 51:1-3.

[660] Garrett, Exh. DJG-1T at 51:7-10.

[661] Garrett, Exh. DJG-1T at 52:14-16.

[662] Garrett, Exh. DJG-1T at 52:16-17.

[663] Garrett, Exh. DJG-1T at 52:17-20.

[664] Garrett, Exh. DJG-1T at 56:2-4.

[665] Garrett, Exh. DJG-1T at 44:3-6.

[666] Garrett, Exh. DJG-1T at 44:11.

[667] Garrett, Exh. DJG-1T at 44:19.

[668] Garrett, Exh. DJG-1T at 45:17-18.

427 AWEC witness Kaufman recommends that the Commission accept Avista's proposed cost of debt of 4.99 percent and capital structure with 48.5 percent equity and 51.5 percent debt,[669] and that Avista's return on equity be reduced from the current authorized amount of 9.4 to 9.25 percent.[670]

428 Kaufman testifies that investors currently expect the U.S. equity market to have total annual returns of 4 to 8 percent.[671] Kaufman asserts that when considering the Company's proposed proxy group of comparable investments, AWEC's cost of capital models support an ROE in the range of 8.3 to 9.3 percent.[672]

429 Kaufman states that the results of their cost of capital models differ from the Company's because AWEC excludes two models that are not consistent with financial theory, and used model inputs that more accurately represent investor expectations.[673] Kaufman urges the Commission give no weight to the Risk Premium or Expected Earnings models, as they believe those models are not grounded in market outcomes or consistent with financial theory.[674]

430 Kaufman states that AWEC would make the following changes to the Company's cost of capital modelling assumptions:

- AWEC assumes short term earnings growth converges to the long run GDP growth rate from five to 25 years in a linear manner, as it argues that it is mathematically implausible for firms to indefinitely grow at a rate greater than the GDP growth rate.[675]
- AWEC assumes that utility stock betas will move towards the industry average over time, rather than a beta of one.[676]
- AWEC excludes weeks with market returns more than three standard deviations from mean weekly returns.[677]

---

[669] Kaufman, Exh. LDK-1CT at 21:3-4.

[670] Kaufman, Exh. LDK-1CT at 21:4-5.

[671] Kaufman, Exh. LDK-1CT at 21:5-8.

[672] Kaufman, Exh. LDK-1CT at 21:8-10.

[673] Kaufman, Exh. LDK-1CT at 23:3-4.

[674] Kaufman, Exh. LDK-1CT at 23:4-7.

[675] Kaufman, Exh. LDK-1CT at 23:10-13.

[676] Kaufman, Exh. LDK-1CT at 23:14-15.

[677] Kaufman, Exh. LDK-1CT at 23:16-17.

- AWEC uses a range for the equity risk premium from 5.0 to 6.9 percent.[678]
- AWEC excludes size premium adjustments from the ECAPM model.[679]

431 Kaufman opines that the ultimate question for the Commission is whether the proposed ROE is fair and reasonable, not whether the models are fair and reasonable.[680] While the justification of models and inputs are important, Kaufman argues that the Commission can also evaluate the ROE independently from the models.[681]

432 Witness Kaufman notes that AWEC's recommendation results in returns that are somewhat higher than investor expectations.[682] However, Kaufman argues that this recommendation is closer to investor expectation than the Company's proposal.[683] Further, Kaufman contends that AWEC's ROE recommendation of 9.25 percent is well above the short- and long-term returns expected for U.S. stocks, and reflects a return needed for an equity investment with greater than average risk.[684]

Discounted Cash Flow (DCF) Model

433 Kaufman asserts that poor credit of specific utilities should not be resolved through return on equity adders beyond that indicated by a market analysis.[685] Kaufman proposes two changes to the Company's Discounted Cash Flow (DCF) model:

- Consider short- and long-term growth forecasts; and
- Lengthen the second stage transition period from five to 20 years.[686]

434 Kaufman argues that the first recommendation reduces estimated cost of equity, while the second increases estimated cost of equity.[687] AWEC contends that net impact is an overall reduction in the estimated cost of equity.[688]

---

[678] Kaufman, Exh. LDK-1CT at 23:18-19.

[679] Kaufman, Exh. LDK-1CT at 24:1-2.

[680] Kaufman, Exh. LDK-1CT at 27:4-6

[681] Kaufman, Exh. LDK-1CT at 27:6-7.

[682] Kaufman, Exh. LDK-1CT at 27:14-15

[683] Kaufman, Exh. LDK-1CT at 27:15-16.

[684] Kaufman, Exh. LDK-1CT at 28:6-8.

[685] Kaufman, Exh. LDK-1CT at 29:6-8.

[686] Kaufman, Exh. LDK-1CT at 29:17-18.

[687] Kaufman, Exh. LDK-1CT at 29:18-19.

[688] Kaufman, Exh. LDK-1CT at 29:20.

Capital Asset Pricing Model

435 Witness Kaufman also proposes two changes to the Company's CAPM:

- Kaufman argues that Avista's betas are biased and grossly misrepresent reasonable forecasts for utility stock betas. Instead, AWEC uses raw betas and betas adjusted to the industry average.[689]
- For its equity risk premium, AWEC uses two alternatives that are less susceptible to bias and more consistent with investor expectations and finance literature.[690]

436 Kaufman states that Avista's equity risk premium is 7.3 percent, while nearly all third-party estimates of the equity risk premium indicate it is between 3.0 and 6.0 percent.[691]

437 Witness Kaufman argues including firms with growth forecasts between -20 and 20 percent is less biased.[692] Kaufman refers to this symmetric filter as the "Corrected Avista Method." AWEC testifies that while the Corrected Avista Method remains theoretically unsound and inconsistent with investor expectations, it offers an improvement over Avista's methodology in its direct case.[693]

438 Kaufman asserts that a forward-looking risk premium can be implied from current market prices and expected cash flows.[694] Kaufman states that the implied equity premium of the trailing 12 months is the best predictor of the actual implied premium,[695] and that the January 2024 trailing 12-month period's implied equity risk premium is 4.6 percent.[696]

439 Kaufman also asserts that Avista's size premium model, instead of a standard CAPM model, is not supported by peer reviewed research.[697] Kaufman continues that, in general, the size premium refers to a highly contested theory that small firms offer a size premium that compensates investors for size related risk in addition to a market premium.[698]

---

[689] Kaufman, Exh. LDK-1CT at 31:17-19.

[690] Kaufman, Exh. LDK-1CT at 32:1-3.

[691] Kaufman, Exh. LDK-1CT at 46:13-14.

[692] Kaufman, Exh. LDK-1CT at 47:3-4.

[693] Kaufman, Exh. LDK-1CT at 47:7-9.

[694] Kaufman, Exh. LDK-1CT at 52:7-8.

[695] Kaufman, Exh. LDK-1CT at 52:9-10.

[696] Kaufman, Exh. LDK-1CT at 52:10-11.

[697] Kaufman, Exh. LDK-1CT at 53:18-20.

[698] Kaufman, Exh. LDK-1CT at 53:22-23.

Kaufman contends that due to a lack of consensus on the existence of a size premium, it is not necessary to adjust Avista's cost of capital for a size premium.[699]

Floating Costs Adjustment

440 Kaufman finds Avista's floating costs unnecessary, and contends that they are a direct result of Avista's decision to manage its equity through dividends and issuances rather than through stock buybacks and retained earnings.[700] Kaufman further argues that while the Company provides evidence of historic flotation costs, it does not show that these costs were historically unrecovered.[701] Further, Kaufman contends that Avista fails to demonstrate that either stock issuances or flotation costs are necessary or expected in the test year.[702]

441 Finally, AWEC witness Kaufman argues that even if its cost of capital range of 8.5 percent to 9.5 percent were increased by Avista's 8 basis point flotation cost adjustment, its recommended cost of equity remains unchanged at 9.25 percent.[703]

Staff's Response Testimony

442 Staff witness Parcell testifies that the Company's proposed 48.5 percent common equity ratio is proper and incorporates this ratio into its own cost of capital analysis.[704] Based on this analysis, Parcell recommends a 9.5 percent ROE for each year of the MYRP, for both electric and natural gas utility operations.[705]

443 Parcell contends that Avista's bond ratings are similar to most electric utilities in the U.S.[706] Staff explains that this is evidenced by the relative Moody's and Standard & Poor's debt ratings, which indicate that the Company's ratings are similar to those of Staff's utility proxy group in developing their ROE recommendations.[707] Additionally, Parcell notes that Moody's and S&P regard Washington's recent legislation (ESSB 5295), in

---

[699] Kaufman, Exh. LDK-1CT at 54:12-13.

[700] Kaufman, Exh. LDK-1CT at 56:5,9-11.

[701] Kaufman, Exh. LDK-1CT at 55:22, 56:1.

[702] Kaufman, Exh. LDK-1CT at 56:2-3.

[703] Kaufman, Exh. LDK-1CT at 56:18-20.

[704] Parcell, Exh. DCP-1T at 4:15-17.

[705] Parcell, Exh. DCP-1T at 6:12-14.

[706] Parcell, Exh. DCP-1T at 19:10.

[707] Parcell, Exh. DCP-1T at 19:10-13.

addition to other favorable regulatory mechanisms, as risk-reducing to the Company.[708] Witness Parcell recommends that the ROE established in this proceeding be set at a level that is no higher than the bottom of the market-determined ROE range for the proxy group, which is 9.5 percent.[709]

444 Parcell examined Avista's historic (2019-2023) capital structure ratios, which indicate that Avista has had a slightly declining equity ratio over the past five years.[710] Parcell notes that the Avista Utilities (Division) capital structure has also declined slightly, with equity ratios (including short-term debt) of about 48 percent or less over the past five years.[711] Parcell further notes that over the past several rate proceedings for Avista, all of the historic equity ratios used to determine cost of capital were less than 48.5 percent.[712]

445 Parcell argues that the capital structure used in Staff's analysis is similar to Avista's recent actual ratios including its 2023 capital structure, and is consistent with the capital structure of other electric and combination electric utilities.[713]

Discounted Cash Flow (DCF) Model

446 Parcell testifies that a range of 8.6 percent to 10.6 percent (9.6 percent mid-point) broadly represents the current DCF-derived ROE for the proxy group.[714] Parcell states that this range includes most of the DCF proxy group rates and exceeds the low and mean/median DCF rates.[715] Parcell recommends a more narrow range of 9.0 percent to 10.0 percent (9.5 percent mid-point), which exceeds the mean/median DCF result, excludes the singular highest DCF result, and includes many of the above-average DCF results.[716]

447 Parcell asserts that Avista uses four sets of DCF calculations collectively to produce DCF ROE results with a range of 9.2 percent to 10.7 percent, three of which are within Parcell's

---

[708] Parcell, Exh. DCP-1T at 24:28-29.

[709] Parcell, Exh. DCP-1T at 25:17-20.

[710] Parcell, Exh. DCP-1T at 28:2,10-11.

[711] Parcell, Exh. DCP-1T at 28:11-13.

[712] Parcell, Exh. DCP-1T at 28:13-16.

[713] Parcell, Exh. DCP-1T at 31:18-19, 32:1.

[714] Parcell, Exh. DCP-1T at 38:1-2.

[715] Parcell, Exh. DCP-1T at 38:2-4.

[716] Parcell, Exh. DCP-1T at 38:6-8.

own DCF results (9.2 percent, 9.7 percent and 9.9 percent).[717] As a result, Parcell opines that its DCF ROE results and the Company's DCF ROE results are similar.[718]

Capital Asset Pricing Model

448 Parcell notes that the CAPM results collectively indicate a ROE of 10.7 percent for the proxy group but proposes the Commission give no weight to the CAPM modeling results in determining Avista's ROE.[719] Parcell highlights that McKenzie's testimony reaches CAPM conclusions of 11.7 percent to 11.8, which greatly exceeds Parcell's testimony.[720] Thus, Parcell finds the Company's CAPM results to be outliers that warrant no weight in determining Avista's ROE.[721]

449 Parcell disagrees with McKenzie's risk premium estimates and the "size premium" employed, as well as the use of ECAPM.[722] Similar to Kaufman, Parcell argues that Avista's 7.3 percent risk premium greatly exceeds the historic levels of risk premiums (4.9 percent to 6.4 percent), and that the Company offers no explanation as to why investors would expect such a dramatic increase.[723]

450 Finally, witness Parcell argues that inclusion of a small-firm adjustment is improper and results in an overstatement of the ROE for the proxy electric utilities.[724] While Parcell acknowledges that it may or may not be true that on an overall market basis, smaller publicly traded firms exhibit more risk than larger firms, it believes that such is not the case for regulated utilities.[725]

Comparable Earnings Analysis

451 Parcell testifies that their Comparable Earnings (CE) analysis indicates that the ROE for the proxy utilities is no more than 9.0 to 9.5 percent (9.25 percent mid-point).[726]

---

[717] Parcell, Exh. DCP-1T at 38:18-19.

[718] Parcell, Exh. DCP-1T at 39:1-2.

[719] Parcell, Exh. DCP-1T at 39:14-15,17-19.

[720] Parcell, Exh. DCP-1T at 44:3-4.

[721] Parcell, Exh. DCP-1T at 44:4-6.

[722] Parcell, Exh. DCP-1T at 44:10-12.

[723] Parcell, Exh. DCP-1T at 45:1-4.

[724] Parcell, Exh. DCP-1T at 45:12-13.

[725] Parcell, Exh. DCP-1T at 45:18-22.

[726] Parcell, Exh. DCP-1T at 51:16-17.

Parcell states that the Company's Expected Earnings (EE) Approach is a form of the comparable earnings methodology.[727] According to Parcell, the Company's tabulation of Value Line's "expected" ROE for the proxy group shows an "Adjusted Return on Common Equity" average of 10.8 percent.[728]

452 Parcell argues that it is inappropriate to focus only on expected ROE without any reference to how such returns are perceived by investors.[729] Further, Parcell notes that the actual 2021, 2022, and 2023 median ROEs are less than the Company's 10.8 percent CE recommendation.[730] Parcell also notes that Staff's projected annual average and median ROEs are all less than Avista's 10.8 percent EE results.[731]

Risk Premium Model

453 Parcell argues that there are two primary problems with Company witness McKenzie's risk premium analyses, which have the effect of overstating the ROE for the proxy companies and Avista as:[732]

- The highest risk premium values over this period occurred in 2011-2022, corresponding to the post-Great Recession period,[733] and
- It is not proper to compare utility authorized ROEs in the 1970's and 1980's with current authorized ROEs.[734]

454 Parcell concludes that the risk premium result for Avista's ROE range is 9.8 percent to 10.8 percent (10.3 percent mid-point).[735]

Flotation Costs Adjustment

---

[727] Parcell, Exh. DCP-1T at 52:12-13.

[728] Parcell, Exh. DCP-1T at 52:16-17.

[729] Parcell, Exh. DCP-1T at 52:21-22.

[730] Parcell, Exh. DCP-1T at 53:10-11.

[731] Parcell, Exh. DCP-1T at 53:12-13.

[732] Parcell, Exh. DCP-1T at 54:14-15.

[733] Parcell, Exh. DCP-1T at 54:16.

[734] Parcell, Exh. DCP-1T at 54:19-20.

[735] Parcell, Exh. DCP-1T at 59:18-19.

455 Similar to other parties, Parcell disagrees with the Company's proposal to add a flotation cost adjustment of .08 percent to the ROE calculation.[736] Parcell notes that flotation costs are known to investors and thus are reflected in the stock prices of companies and therefore any effect of flotation costs is incorporated in DCF ROE model results.[737] Thus, Parcell argues that there is no need to add flotation costs to the results of ROE models.[738] Parcell also notes that the Commission rejected Avista's request to include flotation costs in both the 2017 and 2020 GRCs.[739] Parcell finds that as in those cases, the Company has not demonstrated that it incurred flotation costs in this proceeding.[740]

Walmart's Response Testimony

456 Walmart witness Perry testifies that the Company's proposed ROE of 10.40 percent is excessive.[741] Perry argues that since the Company's most recent GRC was settled through a "black-box" settlement, Avista's current ROE is unclear.[742] Further, Walmart argues that the requested ROE of 10.4 percent exceeds the average reported electric and natural gas ROEs and the 9.4 percent ROE the Commission has authorized since 2021.[743]

457 Further, Perry contends that according to S&P Global data, of the 118 reported electric utility rate case ROEs authorized between 2021 and present the average ROE is 9.5 percent with a median of 9.5 percent.[744] For natural gas the average is 9.58 percent, with a median of 9.59 percent. Perry notes that the Company's requested ROE of 10.4 is significantly above the broader industry trends.[745]

458 Perry notes that the average ROE authorized for vertically integrated electric utilities in 2021 was 9.54 percent; 9.60 percent in 2022; 9.71 percent in 2023, and 9.72 percent thus far in 2024.[746]

---

[736] Parcell, Exh. DCP-1T at 63:15-17.

[737] Parcell, Exh. DCP-1T at 64:1-3.

[738] Parcell, Exh. DCP-1T at 64:3-4.

[739] Parcell, Exh. DCP-1T at 64:7-11.

[740] Parcell, Exh. DCP-1T at 64:11-12.

[741] Perry, Exh. LVP-1T at 8:15-16.

[742] Perry, Exh. LVP-1T at 9:13-16.

[743] Perry, Exh. LVP-1T at 9:20, 10:1, 13:17-18.

[744] Perry, Exh. LVP-1T at 10:21, 11:1-4.

[745] Perry, Exh. LVP-1T at 11:4-6, 15:10-12.

[746] Perry, Exh. LVP-1T at 11:12-15.

459 Perry elaborates that the average ROE authorized for investor-owned gas utilities in 2021 was 9.56 percent; 9.53 percent in 2022; 9.58 percent in 2023. and 9.93 percent thus far in 2024.[747] As such, Perry again argues that the Company's proposed 10.40 percent ROE is counter to broader industry trends.[748]

460 Perry states that if the Commission approved an electric ROE of 9.62 percent for Avista, it would reduce the Company's propose electric revenue requirement increase for RY1 by $11.6 million, or 15.1 percent, inclusive of taxes.[749] For natural gas, Perry states that an authorized ROE of 9.58 percent would reduce the Company's proposed natural gas revenue requirement increase for RY1 by $3.1 million, or 17.9 percent, inclusive of taxes.[750]

Avista's Rebuttal Testimony

461 On rebuttal, Christie maintains the Company's proposed cost of capital: a rate of return of 7.61 percent, a capital structure of 48.5 percent equity and 51.5 percent debt, a 4.99 percent cost of debt, and a 10.4 percent ROE.[751]

462 Christie contends that the ROE recommendations of other parties' COC witnesses ("Other Witnesses") fall well below a fair and reasonable level for the Company's electric and gas operations.[752] Christie argues that the Other Witnesses' analyses are undermined by errors and methodological flaws and fall below accepted benchmarks.[753] Christie asserts that adjusting national authorized ROEs for electric utilities to reflect current capital market conditions, in and of itself, implies an ROE of approximately 10.43 percent.[754]

463 Further, Christie argues that adjusting previous ROEs approved by the Commission to account solely for increases in bond yields implies a current return on equity of 10.43 percent.[755] Further, adjusting the risk premium of 5.01 percent to the averaged Baa utility bond of 5.83 percent as of June 2024 results in an implied return on equity of 10.84

[747] Perry, Exh. LVP-1T at 15:15-17.

[748] Perry, Exh. LVP-1T at 15:17-18.

[749] Perry, Exh. LVP-1T at 12:6-7, 13:1-2.

[750] Perry, Exh. LVP-1T at 16:6-7, 17:1-2.

[751] Christie, Exh.KJC-4T at 18:13-15.

[752] Christie, Exh.KJC-4T at 19:15-17.

[753] Christie, Exh.KJC-4T at 19:17-19.

[754] Christie, Exh.KJC-4T at 19:19-21.

[755] Christie, Exh.KJC-4T at 20:1-2.

percent.[756] Christie notes that the expected returns for the Other Witnesses' own proxy groups fall in the range of approximately 10.0 percent to 10.7 percent.[757] Finally, Christie testifies that the Company's earned ROE has fallen below its authorized ROE in 11 of the past 14 years, in many cases by a substantial margin, especially without the means to address regulatory lag since 2018.[758] Christie argues that these factors further support Avista's 10.40 percent ROE request in this case.[759]

Response to Staff Testimony

464 McKenzie argues that Staff's recommendation contains numerous flaws that lead to a significant downward bias, including:[760]

- Staff's criteria for its proxy group are arbitrary, unnecessarily restrict the size of the group, and undermine the reliability of the analyses;[761]
- Staff's DCF analysis relies on historical data, including growth rates based on dividends and book value; the decision to average individual growth rates together to compute a single DCF estimate for each company; computational shortcomings in the retention growth calculation, and subjectively excluding a 10.6 percent DCF result as an outlier;[762]
- Staff's CAPM analysis relies on historical data when the ROE estimation process is clearly forward-looking; adopting an improper methodology to calculate the historic market risk premium; failure to account for the impact of firm size, and subjectively excluding a 10.7 percent CAPM result as an outlier;[763]
- Staff's CE analysis relies on historical data in a process that is forward-looking; considers market-to-book (M/B), and fails to apply an essential mid-year adjustment factor; and[764]
- Staff's selective exclusion of available data in its risk-premium approach results in subjective bias.[765]

---

[756] Christie, Exh.KJC-4T at 20:11-14.

[757] Christie, Exh.KJC-4T at 20:2-5.

[758] Christie, Exh.KJC-4T at 22:13-15.

[759] Christie, Exh.KJC-4T at 20:14-15.

[760] McKenzie, Exh. AMM-15T at 3:6-7.

[761] McKenzie, Exh. AMM-15T at 3:8-10.

[762] McKenzie, Exh. AMM-15T at 3:11-15.

[763] McKenzie, Exh. AMM-15T at 3:17-22.

[764] McKenzie, Exh. AMM-15T at 3:23-27.

[765] McKenzie, Exh. AMM-15T at 3:28-29.

465 In addition to the perceived modeling flaws, McKenzie provides several other arguments opposing Staff's recommended ROE. First, McKenzie asserts that utility bond yields are now approximately 260 basis points higher than when the Commission authorized Avista's current ROE of 9.40 percent, suggesting that even a gradual move towards a fair ROE requires far more than a 10-basis point increase.[766] Second, witness McKenzie contends the Commission made no specific adjustment to Avista's 9.40 percent ROE on the basis of the Company's MYRP, despite the enactment of ESSB 5295 five months prior.[767]

466 Regarding Staff's DCF model, Avista argues that historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model.[768] The Company explains that to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates.[769] Further, McKenzie contends that Staff simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data.[770] As such, the Company asserts that Staff's DCF analysis included individual growth rates that do not reflect investors' expectations.[771]

467 Responding to Staff's CAPM model, McKenzie opines that Staff analysis is based entirely on historical, not projected, rates of return, significantly understating investors' required rate of return.[772] McKenzie also takes issue with Staff calculating its equity risk premium using the *total* return for Duff & Phelps' (Kroll's) long-term government bond series[773]. As a result, the Company concludes that two of three historical market risk premium (MRP)s and the resulting CAPM cost of equity estimate are all understated.[774] Finally, McKenzie contends that averaging Staff's 7.82 percent MRP with the 7.17 percent long-horizon historical MRP reported by Kroll results in an average of 7.5 percent.[775] Substituting this average MRP into Staff's CAPM study results in an average return on equity of 11.7 percent.[776]

---

[766] McKenzie, Exh. AMM-15T at 32:16-20.

[767] McKenzie, Exh. AMM-15T at 35:9-11.

[768] McKenzie, Exh. AMM-15T at 39:3-4.

[769] McKenzie, Exh. AMM-15T at 39:4-5.

[770] McKenzie, Exh. AMM-15T at 43:6-7.

[771] McKenzie, Exh. AMM-15T at 43:7-9.

[772] McKenzie, Exh. AMM-15T at 46:12-13, 47:5.

[773] McKenzie, Exh. AMM-15T at 51:11-15.

[774] McKenzie, Exh. AMM-15T at 51:15-16.

[775] McKenzie, Exh. AMM-15T at 52:3-5.

[776] McKenzie, Exh. AMM-15T at 52:5-6.

468 McKenzie acknowledges that arguments regarding the implications of a M/B ratio greater than 1.0 in comparative earnings analyses are not uncommon, however, the Company is not aware of a single instance in recent history where a state regulator has relied on M/B ratios as the basis to evaluate a fair ROE.[777] Further, McKenzie emphasizes that the fallacy of relying on M/B ratios in evaluating cost of equity estimates has been explicitly recognized and characterized by FERC as "academic rhetoric."[778]

469 Witness McKenzie contends that Staff subjectively chooses to truncate the data available in its risk premium approach by ignoring all observations prior to 2012.[779] By choosing a truncated period for its risk premium study, McKenzie argues that Staff unnecessarily introduces a subjective bias that undermines the credibility of its analysis.[780]

470 McKenzie notes that the fact that Staff's expected earnings results exceed authorized returns says nothing about the validity of its expected earnings ROE estimate.[781]

471 Finally, McKenzie maintains that flotation costs are legitimate expenses and that unless a discreet adjustment is made to recognize them, they will not be recovered in the rate setting process.[782]

Response to Public Counsel

472 In response to Public Counsel, McKenzie finds Public Counsel's recommendation of an ROE of 8.50 percent extreme, and that the Commission should reject Public Counsel's conclusions and recommendations in their entirety.[783] The Company provides the following reasons to support this conclusion:

- Public Counsel's DCF approach ignores projected earnings growth rates; relies on a "sustainable" growth DCF model that wrongly assumes investors anticipate every firm in the electric utility industry to mimic a long-term growth forecast for GDP; and fails to remove illogical estimates;[784]

[777] McKenzie, Exh. AMM-15T at 67:4-6.

[778] McKenzie, Exh. AMM-15T at 67:6-8.

[779] McKenzie, Exh. AMM-15T at 68:12-13.

[780] McKenzie, Exh. AMM-15T at 67:13-15.

[781] McKenzie, Exh. AMM-15T at 71:10-12.

[782] McKenzie, Exh. AMM-15T at 73:11-12.

[783] McKenzie, Exh. AMM-15T at 4:1-2.

[784] McKenzie, Exh. AMM-15T at 4:4-9.

- Public Counsel's CAPM application uses unreliable, illogical, and undocumented inputs, relies on historical data that is inconsistent with this method's assumptions, and fails to incorporate the size adjustment;[785]
- Public Counsel's suggestion that Avista's capital structure would distinguish the Company's overall investment risk from other electric utilities is incorrect, and the "Hamada" adjustment to its CAPM results is deeply flawed and should be given no weight;[786] and
- Public Counsel's analysis fails to apply the risk premium approach.[787]

473 McKenzie highlights that Public Counsel's recommendation is 130 basis points below the average allowed ROE for other vertically integrated electric utilities in 2023.[788] McKenzie further argues that such an outcome would fall well below the returns available from comparable-risk investments and undermine the Company's financial integrity.[789]

474 McKenzie explains that the practical impact of Public Counsel's approach is that differences in ROE are explained only by differences in dividend yield, which violates basic tenets of securities valuation and the DCF model.[790]

475 McKenzie further argues that the fundamental difference between the Company's CAPM analysis and Public Counsel's is that the Company's looks to the future return expectations, while Public Counsel's "implied equity risk premium" methodology is based on historical data.[791] As a result, McKenzie asserts that Public Counsel's methodology is inconsistent with the assumptions of the CAPM.[792]

476 McKenzie also refutes Public Counsel's contention that Avista's risk premium approach is not market based.[793]

477 Witness McKenzie argues that a fair ROE is not evaluated in a vacuum; it is predicated on analyses for a group of comparable risk utilities, with the relative reliance on equity

---

[785] McKenzie, Exh. AMM-15T at 4:10-12.

[786] McKenzie, Exh. AMM-15T at 4:13-15.

[787] McKenzie, Exh. AMM-15T at 4:16-17.

[788] McKenzie, Exh. AMM-15T at 77:21, 78:1-2.

[789] McKenzie, Exh. AMM-15T at 78:2-4.

[790] McKenzie, Exh. AMM-15T at 90:1-3.

[791] McKenzie, Exh. AMM-15T at 95:4-6.

[792] McKenzie, Exh. AMM-15T at 95:9-10.

[793] McKenzie, Exh. AMM-15T at 102:14, 18-20.

financing being only one factor considered in this overall assessment.[794] As a result, McKenzie contends that there is simply no basis for Public Counsel's proposed CAPM adjustment based only on variations in equity ratios between individual utilities.[795]

Response to AWEC

478 McKenzie testifies that AWEC's recommendation to reduce Avista's ROE from 9.40 percent to 9.25 percent makes no economic sense since investors' required rate of return has increased significantly since the Company's last litigated rate proceeding.[796] Additionally, McKenzie lists the following reasons in support of its position:

- The return benchmarks cited by AWEC provide no meaningful basis to evaluate a fair ROE for Avista;[797]
- There is no support for the assumptions of AWEC's three-stage DCF model;[798]
- AWEC's constant growth DCF application is based on the incorrect notion that investors expect growth for all utilities to converge to a long-term forecast of growth in GDP;[799]
- AWEC's beta-calculations are subjective and results-oriented, which run counter to those published by reputable sources;[800] and
- The two MRPs AWEC used to apply the CAPM either lack any clear foundation or were based on illogical modifications. Additionally, AWEC's CAPM results are downward biased because Kaufman fails to account for the implications of firm size.[801]

479 McKenzie asserts that AWEC's proposal to decrease Avista's ROE when capital costs have demonstrably increased shows that its recommendation is divorced from fundamental financial principles and should be given no weight.[802] McKenzie further argues that

---

[794] McKenzie, Exh. AMM-15T at 107:12-14.

[795] McKenzie, Exh. AMM-15T at 107:14-15, 108:1.

[796] McKenzie, Exh. AMM-15T at 4:20-23.

[797] McKenzie, Exh. AMM-15T at 4:25-26.

[798] McKenzie, Exh. AMM-15T at 5:1-2.

[799] McKenzie, Exh. AMM-15T at 5:3-6.

[800] McKenzie, Exh. AMM-15T at 5:7-10.

[801] McKenzie, Exh. AMM-15T at 5:11-15.

[802] McKenzie, Exh. AMM-15T at 114:7-10.

AWEC's 4.0 to 8.0 percent market return range is meaningless and cannot be used to make the case that its ROE recommendation is conservative.[803]

480 McKenzie also argues that there is no basis for AWEC's assertion that the use of the current five-year betas in the CAPM "overinflates utility cost of capital."[804]

Response to Walmart

481 McKenzie argues that although Walmart does not conduct any analysis or provide an explicit ROE recommendation, it expresses concern over Avista's ROE request based on a comparison with historical allowed ROEs and customer impact consideration.[805] McKenzie contends that comparisons with historical allowed ROEs are overly simplistic and fail to account for the significant increase in long-term capital costs.[806]

482 McKenzie argues that the cost of equity is established in competitive capital markets, and Walmart's suggestion that Avista's ROE might be artificially suppressed to minimize customer impacts ignores the requirements of regulatory standards, and the long-term harm that can result if investor confidence is undermined.[807] Further, McKenzie contends that while Walmart's data on allowed ROEs can be useful in the Commission's deliberations, it is not a substitute for the detailed analyses presented in its direct testimony.[808] Finally, McKenzie refutes Walmart's suggestion that a lower ROE is to customers' benefit.[809] McKenzie argues that while a downward-biased ROE may provide the illusion of "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can work to the disadvantage of customers.[810]

Avista's General Rebuttal of the Other Parties

483 McKenzie argues that the 8.50 percent to 9.50 percent ROE recommendations of the Other Witnesses fall approximately 93 to 193 basis points below national average authorized ROEs, once adjusted for current interest rates.[811] Additionally, McKenize contends that the

---

[803] McKenzie, Exh. AMM-15T at 115:3-4.

[804] McKenzie, Exh. AMM-15T at 121:18-20.

[805] McKenzie, Exh. AMM-15T at 5:18-20.

[806] McKenzie, Exh. AMM-15T at 5:22-24.

[807] McKenzie, Exh. AMM-15T at 5:25-28.

[808] McKenzie, Exh. AMM-15T at 135:5-6.

[809] McKenzie, Exh. AMM-15T at 135:19-20.

[810] McKenzie, Exh. AMM-15T at 135:20, 136:1-2.

[811] McKenzie, Exh. AMM-15T at 6:8-10.

ROE disparity is even more evident when considering that utility bond yields have *increased* approximately 250 basis points since the Commission approved an ROE of 9.40 percent for Avista.[812]

484 McKenzie explains that trends in 30-year Treasury bonds and utility bonds are relevant indicators for evaluating cost of equity.[813] Witness McKenzie states that trends in these bond yields since Avista's last rate proceeding demonstrate a substantial increase in the returns on long-term capital demanded by investors.[814] Additionally, McKenzie notes that key interest rate benchmarks indicate that investors' required return on debt securities has increased an average of 170 basis points from September 2021 to June 2022, and another 99 basis points to June 2024.[815]

485 Thus, McKenzie argues that the cost of capital—both debt and equity—has increased significantly since the Commission authorized the current ROE of 9.40 percent.[816] Further, McKenzie contends that there is no evidence risks associated with increased cost levels for capital projects have been mitigated by any offsetting risk since the Commission entered its final order in the 2022 GRC.[817]

486 Additionally, McKenzie argues that the Other Witnesses do not address the implications of declining utility credit ratings, increased financial pressures, or the heightened risk posed by wildfires in their ROE recommendations. Nor does McKenzie believe their recommendations reflect the significant upward trend in capital costs since Avista's last litigated rate proceedings.[818]

487 McKenzie testifies that the ROE recommendations of Public Counsel and AWEC are unmoored from fundamental principles of finance and violate the basic, common-sense relationship between interest rates and the cost of equity.[819] McKenzie finds it inconceivable that the Company's ROE could have decreased when other capital costs have significantly increased.[820]

---

[812] McKenzie, Exh. AMM-15T at 6:10-12.

[813] McKenzie, Exh. AMM-15T at 7:15-18.

[814] McKenzie, Exh. AMM-15T at 8:12-15.

[815] McKenzie, Exh. AMM-15T at 9:5-6.

[816] McKenzie, Exh. AMM-15T at 14:14-16.

[817] McKenzie, Exh. AMM-15T at 15:7-10.

[818] McKenzie, Exh. AMM-15T at 16:13-16.

[819] McKenzie, Exh. AMM-15T at 17:5-7.

[820] McKenzie, Exh. AMM-15T at 17:4-5.

488 McKenzie states that despite interest rates having increased substantially—which means the cost of equity has climbed—Staff is arguing that Avista's ROE should be increased by just 10 basis points, while Public Counsel and AWEC are arguing for a reduction.[821] McKenzie believes that these outcomes are not credible and would violate accepted principles of finance.[822] Therefore, Company witness McKenzie argues that the Commission should specifically reject the ROE recommendations of Public Counsel and AWEC on this basis.[823]

489 McKenzie also argues that adjusting historical average allowed ROEs from 2020 to Q1 2024 to reflect current capital market conditions results in an implied cost of equity of 10.43 percent, therefore substantiating that the non-Company ROE recommendations are insufficient.[824]

490 Finally, McKenzie reiterates that the average ROEs for the non-utility group reported in direct testimony range from 10.5 percent to 11.0 percent, and average 10.8 percent.[825] McKenzie asserts that a comparison of objective risk indicators shows the non-utility group to be less risky than the utility group or Avista, and thus these ROE results provide a conservative guideline for a fair ROE.[826]

Parties' Briefs

Avista's Brief

491 In its brief, Avista reiterated that Avista's earned ROE has fallen below its authorized ROE in 11 of the past 14 years, in many cases by a substantial margin, especially without the means to otherwise address regulatory lag since 2018, with an attrition adjustment.[827] The

---

[821] McKenzie, Exh. AMM-15T at 20:8-10

[822] McKenzie, Exh. AMM-15T at 20:11.

[823] McKenzie, Exh. AMM-15T at 20:11-13.

[824] McKenzie, Exh. AMM-15T at 24:1-4.

[825] McKenzie, Exh. AMM-15T at 31:7-9.

[826] McKenzie, Exh. AMM-15T at 31:9-11.

[827] Avista's Post-Hearing Brief, at ¶ 30. Moody's noted that "the lag in cash flow recovery and limited revenue increases have pressured Avista's credit metrics particularly during a time when the sector faced material headwinds from higher natural gas prices and other cost pressures." (Moody's Investors Service, Avista Corp., update to credit analysis, Credit Opinion (Aug. 16, 2023)). Similarly, S&P reported the prospect of lowering Avista's ratings over the next 12 to 24 months if financial metrics are pressured by "regulatory lag." (S&P Global Ratings, Avista Corp., Ratings Direct, Ratings Score Snapshot (Dec. 8, 2023)). (Christie, Exh. KJC-4T at 22:17-19).

Company took issue with the other parties' recommendations for Avista's ROE, [828] specifically that the Other Witnesses' ROE recommendations fall below accepted benchmarks.[829]

492 Avista also argues that the Other Witnesses' ROE analyses are undermined by errors and methodological flaws, including, among other things: 1) failure to account for significantly higher capital costs, declining creditworthiness, and rising risk exposures, such as wildfires; 2) errors in the specification of their proxy groups; and 3) unsupported growth rate assumptions in the application of the discounted cash flow ("DCF") model that do not reflect investors' expectations.[830] Avista then details and addresses the particulars of recommendations by each of the Other Witnesses.[831]

Staff's Brief

493 Staff argues that the Company's conclusions are unsupported in McKenzie's testimony and contradictory with his past testimony before this Commission.[832] Staff asserts that the Company's recommendations concerning its ROE are quite simply in direct contrast to the objective facts presented by the parties in this case. Staff concedes that Avista is deserving of a moderate rate increase, as stated above, but argues the wildly inflated numbers McKenzie presented are contrary to both Commission precedent and reasoned policy. [833]

494 Additionally, with regard to bond yields, Staff argues that Avista's testimony is contradictory with current bond trends and primarily the result of McKenzie's continued use of the disfavored CAPM. Staff alleges that the CAPM has been deemphasized by the Commission.[834] Staff claims that witness McKenzie goes beyond just using the CAPM but creates an ECAPM by substituting actual betas with hypothetical ones for the chosen proxy group, skewing an already flawed model.[835] Staff rejects Avista's proposed 10 basis point increase of the Company's ROE using ECAPM.[836]

---

[828] Avista's Post-Hearing Brief, at ¶¶ 31-45.

[829] Avista's Post-Hearing Brief, at ¶ 32.

[830] Avista's Post-Hearing Brief, at ¶ 32.

[831] Avista's Post-Hearing Brief, at ¶¶ 33-45.

[832] Staff's Post-Hearing Brief, at ¶ 38.

[833] Staff's Post-Hearing Brief, at ¶ 40.

[834] Staff's Post-Hearing Brief, at ¶ 41-42 (*citing*, *Wash. Utils. & Transp. Comm'n v. Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 100 (Sept. 27, 2021)).

[835] Staff's Post-Hearing Brief, at ¶ 42 (*referencing*, McKenzie, AMM-1T, at 47:8-9).

[836] Staff's Post-Hearing Brief, at ¶ 45.

495 Next, Staff argues that contrary to Avista's assertions, the Company is actually financially healthy with an improving credit rating.[837] Staff adds that Avista also has no fears of lessened access to capital. As McKenzie testified, Avista's 10.4 percent return on equity is not a requirement to obtain funding.[838] Staff alleges that Avista's capital structure through its last case was 48.5 percent common equity, the same as the proposed structure in this case.[839] Yet, Avista's actual common equity ratio stands at 46.2 percent, well below its current authorized rate.[840] Thus, Staff asserts that "by keeping its true equity lower, it can charge ratepayers at an already inflated hypothetical rate structure of 48.5 percent while pocketing the difference."[841]

496 Staff contends that, contrary to Avista's argument, expansion of infrastructure is immaterial to ROE or cost of capital considerations.[842] Further, Staff argues against the Company's position that "constructive" and "supportive" regulation necessitates a higher ROE, and that constructive regulation is not relevant to this case.[843] Staff also rejects Avista's attrition claim, and claims that the Company has not conducted and presented studies demonstrating such attrition, nor has it shown any particularized reasonings for why that attrition was outside the realm of the Company's control.[844]

497 Staff asserts that the Commission has a history of applying gradualism to ROE in rate cases, including in Avista's own prior cases. Staff asserts that this approach benefits ratepayers and utilities alike, and the Commission should reaffirm its use for ROE considerations.[845]

Flotation Costs

498 Staff asserts that the Commission should reject Avista's flotation adjustment as the Commission has denied this particular type of adjustment in prior litigated cases involving

---

[837] Staff's Post-Hearing Brief, at ¶¶ 45-46.

[838] Staff's Post-Hearing Brief, at ¶ 47 (*referencing*, McKenzie, TR, at 151:7-13).

[839] Staff's Post-Hearing Brief, at ¶ 47.

[840] Staff's Post-Hearing Brief, at ¶ 47 (*referencing*, Parcell, DCP-1T, at 30:16-17).

[841] Staff's Post-Hearing Brief, at ¶ 47.

[842] Staff's Post-Hearing Brief, at ¶ 48.

[843] Staff's Post-Hearing Brief, at ¶ 49.

[844] Staff's Post-Hearing Brief, at ¶ 50.

[845] Staff's Post-Hearing Brief, at ¶ 53.

Avista.[846] Staff argues that flotation costs are a known factor and are therefore already incorporated into investor evaluations of stock by the ROE models used to calculate a company's authorized return.[847] Staff posits that adding flotation costs to rates would be redundant and would in essence ask ratepayers to pay for flotation costs twice, once when the costs were naturally incorporated in rates, and the second time through the Company's proposed added adjustment.[848] Staff also argues that that the Company has not presented a rationale or argument as a basis for the Commission to change its position on flotation costs from prior cases.[849]

Public Counsel's Brief

499 Public Counsel states that the Commission should set a ROE that is limited to Avista's actual cost of capital.[850] In that vein, Public Counsel argues that a more accurate ROE given current economic realities would be 8.5 percent, resulting in an overall ROR of 6.86 percent, as opposed to the Company's proposed 10.4 percent ROE, which would result in an overall ROR of 7.61 percent.[851] Public Counsel adds that there is evidence in this record that Avista's awarded rates have consistently exceeded the rates that are necessary for capital acquisition and higher than are warranted by Avista's business risk.[852] Public Counsel alleges that Avista's claim of under earning and attrition have not interfered with the Company's access to capital or its financial soundness.[853]

500 Public Counsel argues that the Commission should accept its recommendation to lower the Company's ROE from 9.4 percent, and that appropriate range for Avista's ROE is is 8.0 percent to 9.2 percent.[854] Public Counsel believes that lowering Avista's ROE will not affect its financial performance.[855]

---

[846] Staff's Post-Hearing Brief, at ¶ 54; *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-170485 & UG-170486, Order 07/02, at 30 ¶ 75; *Avista*, Dockets UE-200900 & UG-200901, Final Order 08/05, at 38 ¶ 99.

[847] Staff's Post-Hearing Brief, at ¶ 55.

[848] Staff's Post-Hearing Brief, at ¶ 55.

[849] Staff's Post-Hearing Brief, at ¶ 56.

[850] Public Counsel's Post-Hearing Brief, at ¶ 2 and ¶ 79.

[851] Public Counsel's Post-Hearing Brief, at ¶79 (*referencing*, Christie, Exh. KJC-4T at 18:13–15).

[852] Public Counsel's Post-Hearing Brief, at ¶ 86.

[853] Public Counsel's Post-Hearing Brief, at ¶ 87.

[854] Public Counsel's Post-Hearing Brief, at ¶ 89 (*referencing*, Garrett, Exh. DJG-1T at 3 Figure 1).

[855] Public Counsel's Post-Hearing Brief, at ¶ 95.

501 Public Counsel contends that the Commission should discount Avista's modeling because it does not accurately predict or explain investor behavior, and because the Company's witness admits that his modeling and testimony are not useful to the Commission in achieving the goals of *Bluefield* and the Commission's test.[856] Public Counsel then goes on to detail its additional reasons for its position that the Commission should not rely on McKenzie's financial modeling, which allegedly result in bias and overstated growth forecasts.[857]

Flotation Costs

502 Consistent with other party witnesses, Public Counsel argues that the Commission should reject Avista's request for flotation costs. [858] Public Counsel adds that "these costs are not out-of-pocket costs for the Company, and the Commission has no metric by which to determine which party would have negotiated to capture that additional value; i.e. would the stock price have dropped or risen slightly."[859] Public Counsel opines that only competition could fairly make that allocation.[860]

AWEC's Brief

503 AWEC argues that Avista's ROE should be lowered from its current level of 9.4 percent and set at 9.25 percent.[861] AWEC makes a similar argument to Staff that the Commission should give little weight to usage of CAPM and ECAPM, based the Commission's recent skepticism about those models.[862] AWEC also takes issue with Avista's models for Risk Premium and Expected Earnings as AWEC claims that FERC has rejected use of both models.[863] AWEC does not take issue with Avista's DCF model but rather the results of its analysis, which yielded a cost of equity range between 9.2 percent and 11.9 percent, an exceedingly broad range. AWEC believes that this range is too broad.[864] AWEC opines that its DCF results are more accurate as they yield a range between 8.5 percent and 9.2

[856] Public Counsel's Post-Hearing Brief, at ¶ 96 referencing McKenzie, TR. at 151:1–6.

[857] Public Counsel's Post-Hearing Brief, at ¶¶ 82-83, 97-101.

[858] Public Counsel's Post-Hearing Brief, at ¶ 93 referencing Garrett, Exh. DJG-1T at 45:1–4.

[859] Public Counsel's Post-Hearing Brief, at ¶ 93 referencing Garrett, Exh. DJG-1T at 45:5–16.

[860] Public Counsel's Post-Hearing Brief, at ¶ 93.

[861] AWEC's Post-Hearing Brief, at ¶ 13.

[862] AWEC's Post-Hearing Brief, at ¶ 15.

[863] AWEC's Post-Hearing Brief, at ¶ 17.

[864] AWEC's Post-Hearing Brief, at ¶ 18.

percent, which is also in line with Public Counsel and Staff's models. Consequently, AWEC posits that its recommended 9.25 percent is reasonable.[865]

Flotation Costs

504 As with other witnesses, AWEC recommends that the Commission reject Avista's flotation cost adjustment, as it did in Avista's 2020 general rate case.[866] AWEC claims that "while Mr. McKenize attempted to respond to the Commission's criticism of this adjustment in that case by showing Avista's actual flotation costs, Avista fails to show both that it did not recover these flotation costs through its authorized rates and that Avista will incur flotation costs in the test year."[867]

Walmart's Brief

505 Walmart contends that Avista's request for an ROE of 10.40 percent is not just and reasonable.[868] In support of its position, Walmart cites to its testimony in which it alleges that the nationwide average ROE is 9.5 percent,[869] and that the average ROE for vertically integrated utilities authorized from 2021 through the present is 9.62 percent,[870] well below Avista's proposed ROE of 10.40 percent.[871] Walmart believes that increased costs to retailers, in the form of higher energy costs resulting from a high ROE, will result in passing through higher prices to retail consumers.[872] For these reasons, Walmart requests that the Commission deny Avista's proposed ROE of 10.40 percent and set a just and reasonable ROE.[873]

Decision

[865] AWEC's Post-Hearing Brief, at ¶ 19-20.

[866] AWEC's Post-Hearing Brief, at ¶ 14; See also Docket Nos. UE-200900, UG-200901, UE-100894 (*Consolidated*), Order 08-05 ¶ 96 ("2020 GRC Order").

[867] AWEC's Post-Hearing Brief, at ¶ 14.

[868] Walmart's Post-Hearing Brief, at p. 1.

[869] Walmart's Post-Hearing Brief, at p. 2 citing Perry, Ex. LVP-1T at 11:2.

[870] Walmart's Post-Hearing Brief, at p. 2 citing Perry, Ex. LVP-1T at 11:12.

[871] Walmart's Post-Hearing Brief, at p. 2.

[872] Walmart's Post-Hearing Brief, at p. 1.

[873] Walmart's Post-Hearing Brief, at p. 2.

506 In determining cost of capital, the Commission is guided by the longstanding precedent of the *Hope*[874]and *Bluefield*[875] cases. The Commission will analyze service on debt as well as the return to the equity owner, which should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[876] Moreover, "what the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience. There must be a fair return upon the reasonable value of the property at the time it is being used for the public."[877]

507 Based on this guidance of the *Hope* and *Bluefield* cases, in *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, we stated that "a utility's cost of capital has three main components: capital structure, return on equity, and cost of debt. Taking all these factors into account, it is possible to describe the utility's overall rate of return (ROR), also known as the weighted average cost of capital (WACC)."[878]

Cost of Capital (ROE)

508 As was stated previously, Avista proposes a capital structure of 51.5 percent debt and 48.5 percent equity, a proposed cost of debt of 4.99 percent, a proposed 10.40 percent ROE, and a requested overall ROR in this proceeding of 7.61 percent.[879] Avista contends that the proposed 10.40 percent ROE is reasonable to maintain Avista's financial integrity.[880] Avista supports this assertion by stating that four out of five cost of equity methods they implemented produced an ROE of 10.4 percent.[881] Avista also alleges that its earned ROE has fallen below its authorized ROE in 11 of the past 14 years, in many cases by a substantial margin, especially without the means to address regulatory lag since 2018.[882]

---

[874] *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).

[875] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).

[876] *Federal Power Com. v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[877] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. at 690.

[878] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Dockets UE-230172 & UE-210852, Order 08, ¶ 112 (Mar. 19, 2024); See also *Bluefield*, 262 U.S. at 689-90.

[879] Christie, Exh. KJC-1T at 14:8-11.

[880] Christie, Exh. KJC-1T at 16:6-7.

[881] McKenzie, Exh. AMM-1T at 6:19-20.

[882] Christie, Exh.KJC-4T at 22:13-15.

509 In turn, Staff does not contest the Company's capital structure, i.e., equity ratio, nor does Staff contest Avista's cost of debt.[883] However, Staff does contest Avista's proposed ROE. Staff argues that the Company's proposed increase, from 9.4 percent to 10.4 percent, represents a significant departure from recent ROEs the Commission has approved for Avista.[884] Staff further argues that Avista's proposed ROE is not supported by testimony and is inconsistent with Commission policies.[885] An example, among others, Staff provides as inconsistent with the Commission's policies is the Company's use of CAPM and ECAPM to calculate ROE.[886] Staff recommends a 9.5 percent ROE for each year of the MYRP, for both electric and natural gas utility operations, a 10 basis point increase to ROE.[887]

510 Similar to Staff, Public Counsel does not contest the Company's equity ratio, nor does it contest Avista's cost of debt, but does contest Avista's proposed ROE (10.4 percent) and its overall ROR (7.61 percent).[888] Public Counsel argues that a more accurate ROE, given current economic realities would be 8.5 percent, resulting in an overall ROR of 6.86 percent.[889] Public Counsel, like Staff, also takes issue with Avista's financial modeling, and argues that the Commission should continue to lower Avista's ROE to be consistent with the actual cost of capital.[890]

511 AWEC also disagrees with Avista's modeling claiming that the Commission is skeptical of the CAPM and ECAPM models on which Avista relies.[891] AWEC states that of the other forms of modeling Avista uses, discounted cash flow, is one acceptable to the Commission. However, AWEC disputes the inputs Avista uses in its DCF modeling to arrive at the range for its ROE, between 9.2 percent and 11.9 percent.[892] AWEC believes that this range is too broad, and that a range of 8.5 and 9.3 percent from AWEC's DCF

---

[883] Staff's Post-Hearing Brief, at ¶ 32.

[884] Staff's Post-Hearing Brief, at ¶ 33.

[885] Staff's Post-Hearing Brief, at ¶ 41-51.

[886] Staff's Post-Hearing Brief, at ¶ 41-45.

[887] Parcell, Exh. DCP-1T at 6:12-14.

[888] Public Counsel's Post-Hearing Brief, at ¶ 79.

[889] Public Counsel's Post-Hearing Brief, at ¶ 79 referencing Garrett, MEG-3 (schedule 3.10) and MEG-4 (scheduled 4.10).

[890] Public Counsel's Post-Hearing Brief, at ¶¶ 89-101.

[891] AWEC's Post-Hearing Brief, at ¶ 16.

[892] AWEC's Post-Hearing Brief, at ¶ 18.

calculations is more in line with the results from Public Counsel's and Staff's DCF models. AWEC recommends a ROE of 9.25 percent.[893]

512 Walmart opposes Avista's proposed ROE and asserts that the increased cost to retailers like Walmart can put pressure on consumer prices and on the other expenses required by a business to operate, and this can result in passing through higher prices to consumers.[894] Walmart contends that Avista's 10.4 percent ROE is too high compared to the nationwide ROE average of 9.5, and the authorized average ROE for vertically integrated utilities has been 9.62 percent since 2021.[895] Walmart suggests an ROE of 9.62 percent [896] for Avista's electric operation and 9.58 percent for Avista's gas operation.[897]

513 After reviewing the evidence and testimony, we reject Avista's proposed ROE. In its brief, Staff raises the principle of gradualism that this Commission has articulated in prior proceedings. Staff makes a valid point that gradualism protects ratepayers and utilities alike, and that the Commission should reaffirm its use for ROE considerations.[898] We agree. In past proceedings, including those involving Avista, we have relied on this principle. Specifically, the Commission has said, "We must evaluate all cost of capital evidence offered and consider other relevant principles and factors such as the general state of the economy, investment cycles in the industry, and the principle of gradualism to determine, consistent with the public interest, a reasonable range of returns and what specific ROE within that range is appropriate for determining Avista's revenue requirements."[899]

514 Even with economic factors Avista cites, approving an ROE at 10.4 percent, a 100 basis point increase from the Company's current 9.4 percent ROE, is against this principle and we cannot in good conscience and in our statutory duty approve such a steep increase absent extreme circumstances that we do not see here. Doing so certainly would not be in the public interest.

---

[893] AWEC's Post-Hearing Brief, at ¶ 20.

[894] Walmart's Post-Hearing Brief, at p. 1.

[895] Walmart's Post-Hearing Brief, at p. 2.

[896] Perry, Exh. LVP-1T at 12:6-7, 13:1-2.

[897] Perry, Exh. LVP-1T at 16:6-7, 17:1-2.

[898] Staff's Post-Hearing Brief, at ¶53.

[899] *Wash. Utils. & Transp. Comm'n v. Avista Corp*, Dockets UE-200900, UG-200901 & UE-200894, Order 08/05, ¶ 97 (September 27, 2021); *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 & UG-121705 *(Consolidated)*, Order 15, Dockets UE-130137 & UG-130138 *(Consolidated)*, Order 14, Final Order on Remand, 16, ¶ 32 (Jun. 29, 2015) [hereinafter PSE Remand Final Order].

515 However, we also reject the ROEs recommended by Staff, Public Counsel, AWEC, and Walmart. The parties through their witnesses have utilized analytical tools with which we are well-acquainted, including DCF, CAPM, ECAPM, and CE. The models yielded results for ROE ranging from as low as 8 percent calculated by Public Counsel to a high of 11.8 percent calculated by Avista. We observe that the range of results is due to a similar approach to modeling from Avista's rate case in Docket UE-200900 wherein we noted "the wide-ranging results are directly attributable to the experts' selection of proxy groups and reliance on different sources for growth rates, discount rates, and market risk premiums."[900] The difference here at least is that the witnesses' analyses produced a 380-basis point range of possible returns rather than the 450-basis point range from the prior Avista rate case.

516 Despite the range of possible returns, we note that Staff and Walmart offer to raise Avista's ROE slightly higher with Staff at 9.5 percent for gas and electric for RY1 and RY2, and Walmart at 9.62 percent for electric for RY1 and RY2 and 9.58 percent for gas in RY1 and RY2. Public Counsel and AWEC would actually reduce Avista's ROE to 8.5 percent and 9.25 percent, respectively. These proffered ROEs are either too low or do not adjust high enough to address the current conditions facing Avista.

517 While we cannot go as high as the 10.4 percent level for ROE the Company requests, for previously stated reasons, we recognize that upward adjustment is needed to address the challenges the Company faces and to ensure it remains a viable entity able to provide reliable and adequate service to its customers. The challenges of remaining credit worthy and acquiring capital for continued operation are very real. In fact, these challenges go to the heart of the Commission's responsibility, which is to assure confidence in the financial integrity of the utility company, to maintain its credit rating and to attract capital, so that it can continue to provide service for the public convenience.[901]

518 Given this precedent and our adherence to it, we approve raising Avista's ROE to 9.8 percent for electric and gas operations for both RY1 and RY2. We believe doing so serves two purposes. First, we remain consistent with the principles of gradualism and protect the ratepayers from rate shock, which we believe would have been the case if we had approved Avista's ROE at 10.4 percent. Second, approving a higher ROE allows the Company to maintain its credit rating, attract needed capital, and continue to be a viable

---

[900] *Avista Corp*, Dockets UE-200900, UG-200901 & UE-200894, Order 08/05, ¶ 98.

[901] *Federal Power Com. v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. at 690.

utility, providing service to its ratepayers, pursuant to the precedent established in the *Hope* and *Bluefield* cases.

519 In short, the ratemaking process, where agencies similar to the Commission seek to establish just and reasonable rates, involves a balancing of the investor and consumer interests.[902] We believe that approving Avista's ROE at 9.8 percent strikes that balance between investor and consumer interests, and therefore is in the public interest.

520 Given that no party contested Avista's proposed capital structure of 51.5 percent debt and 48.5 percent equity, we approve the Company's proposed capital structure. Similarly, no party contested the Company's proposed cost of debt of 4.99 percent. Based on our decision to increase the Company's ROE to 9.8 percent, Avista's overall rate of return, or ROR, will be 7.32 percent.

Flotation Costs

521 Flotation costs are incurred when a company issues new securities.[903] These costs are incurred by the investors with the sale of these new securities,[904] and include services such as legal, accounting, and printing costs, as well as the fees and discounts paid to compensate brokers for selling the stock to the public.[905] Avista asserts that it should be offered an opportunity to recover flotation costs, which it believes are a legitimate expense incurred to provide equity capital.[906] Avista proposes an 8-basis point increase to its ROE based on flotation costs.[907]

522 Staff, Public Counsel and AWEC all argue for rejection of flotation costs because they are a known factor already incorporated into investor evaluations of stock by the ROE models used to calculate a company's authorized return, and because the Commission has rejected inclusion of flotation costs in ROE in prior proceedings.[908] Staff posits that adding flotation costs to rates would be redundant and would in essence ask ratepayers to pay for

[902] *Federal Power Com. v. Hope Natural Gas Co.,* 320 U.S. at 603.

[903] *Avista Corp.*, Dockets UE-170485 & UG-170486, Order 07/02, at fn. 80.

[904] McKenzie, AMM-1T, at 49:4-11.

[905] McKenzie, AMM-1T, at 49:4-11.

[906] Avista's Post-Hearing Brief, at ¶ 33.

[907] McKenzie, AMM-1T at 54:4-11.

[908] Staff's Post-Hearing Brief, at ¶¶ 55, 56; Public Counsel's Post-Hearing Brief, at ¶ 93; AWEC's Post-Hearing Brief, at ¶ 14.

flotation costs twice, once when the costs were naturally incorporated in rates, and the second time through Avista's proposed added adjustment.[909]

523 Public Counsel adds that "these costs are not out-of-pocket costs for the Company, and the Commission has no metric by which to determine which party would have negotiated to capture that additional value; i.e. would the stock price have dropped or risen slightly."[910] AWEC also recommends that the Commission reject the Company's flotation cost adjustment as it does not provide adequate evidence to support its request.[911]

524 We agree with Staff, Public Counsel, and AWEC, and reject Avista's proposed flotation cost adjustment. In Avista's 2017 rate proceeding the Commission rejected Avista's request for flotation costs, reasoning that "while these costs may be legitimate adjustments made during the underwriting process, the Company had failed to demonstrate the level of flotation costs it had actually incurred during the test year."[912] The Commission reiterated this standard in Avista's 2020 case and rejected Avista's proposed flotation cost adjustment. In that matter, the Commission stated, "we remain unpersuaded in this case that we should include any flotation adjustment without a compelling showing."[913]

525 We remain unpersuaded in this case as well. Avista's witness McKenzie acknowledged the precedent from the 2017 and 2020 rate cases and admitted that our concerns stated in those proceedings were not addressed in this one.[914] Based on the lack of evidentiary support, we have no choice but to reject the Company's proposed flotation adjustment.

Cost of Service, Rate Spread and Rate Design

Avista's Direct Testimony

526 Avista proposes rate increases for residential customers under Schedules 1 & 101 and argues that the Company's fixed costs do not vary with customer usage and are therefore customer allocated costs.[915] Company witness Miller further argues it is important for

---

909 Staff's Post-Hearing Brief, at ¶ 55.

910 Public Counsel's Post-Hearing Brief, at ¶ 93 referencing Garrett, Exh. DJG-1T at 45:5–16.

911 AWEC's Post-Hearing Brief, at ¶ 14.

912 *Avista Corp.*, Dockets UE-170485 & UG-170486, Order 07/02, at ¶76.

913 *Avista Corp*, Dockets UE-200900, UG-200901 & UE-200894, Order 08/05, ¶96.

914 McKenzie, AMM-1T at 53:18-54:21.

915 Miller, Exh. No. JDM-1T at 32:5-11. We note that every reference to Schedule 1 in this section also applies to Schedules 7 and 8 (TOU Pilot).

charges to accurately reflect the actual costs incurred to serve customers.[916]To further detail, Avista proposes increasing the Basic Monthly Charge (BMC) for electric residential customers from $9.00 to $15.00 in Rate Year 1 (RY1) and $20.00 in Rate Year 2 (RY2), and for natural gas residential customers from $9.50 to $15.00 in RY1 and $20.00 in RY2.[917]

527 Avista bases its rate spread recommendation on its proposal for an electric revenue increase of $77.0 million (13.0 percent) in RY1 over current base tariff rates in effect and an increase of $78.1 million (11.7 percent) in RY2, and for natural gas customers proposes a revenue increase of $17.3 million (13.6 percent) in RY1 and $4.5 million (3.2 percent) in RY2.[918]

528 Avista proposes to spread this rate increase through an equal increase of 13.1 percent for the base tariff rates for each electric customer class (except the 12.8 percent increase for Schedule 25) and on the gas side proposes an equal increase of 11.7 percent for all customer classes.[919] Avista justifies this proposal based on the size of the increase and argues a uniform increase will make modest improvements towards more evenly distributed return ratios.[920]

Staff's Response Testimony

529 Staff argues that the Company did not justify including a broader range of costs in its proposed BMC calculation.[921] Citing prior Commission guidance and policies regarding gradualism, Staff recommends a $1.00 increase for residential gas and electric customers to bring the Company's basic charge closer to cost parity without too sharp of an increase to the basic charge.[922]

Public Counsel's Response Testimony

---

[916] Miller, Exh. No. JDM-1T at 32:21-23.

[917] Miller, Exh. No. JDM-1T at 32:5-11.

[918] Miller, Exh. No. JDM-1T at 32:5-11.

[919] Miller, Exh. No. JDM-4 (schedule 25 has a proposed increase of 12.8 percent).

[920] Miller, Exh. No. JDM-1T at 2:8-12.

Parity Ratio: Schedule revenue to cost ratio divided by system's revenue to cost ratio.

Return Ratio: Schedule rate of return divided by overall rate of return.

[921] Hillstead, Exh. No. KMH-1T at 26:8-15.

[922] Hillstead, Exh. No. KMH-1T at 27:14-18.

Basic Charge

530 Public Counsel recommends that the Commission reject the Company's proposed increase in customer charges for both residential electric and natural gas general service. Public Counsel witness Dismukes criticizes the Company for including non-customer related activities into its cost allocation for calculating the basic charge.[923]

531 Public Counsel's calculation for what is necessary to recover customer related costs in the basic charge amounts to $9.93 for electric schedule 1 in RY1 and $11.44 for gas schedule 101 in RY1.[924] Beyond the arguments for using those figures, Dismukes asserts that higher basic charges reduce incentives for customers to conserve. Furthermore, Public Counsel's analysis estimates that low-use electric residential customers would see an increase of 15.57 percent if the Company's proposal were to go into effect compared to the proposed average rate increase for all residential customers of 13.02 percent.[925] For low-use gas customers, the bill increase would be 9.19 percent with the Company's proposal, as opposed to a 6.74 percent average rate increase for all residential customers.[926] Public Counsel highlights the close correlation between having low usage and being low income to support its position.

AWEC's Response Testimony

532 AWEC witness Kaufman begins the discussion of rate spread by referencing Staff's "recent practice of characterizing deviations from rate parity of less than 0.05 as within the margin of error, more than 0.1 as unreasonable, more than 0.2 as excessive, and deviations more than 0.3 as grossly excessive."[927] AWEC argues for rate increases described in Table 4 and 5.

---

[923] Dismukes, Exh. No. DED-1T at 9:13-17.

[924] Dismukes, Exh. No. DED-1T at 9-10.

[925] Dismukes, Exh. No. DED-3.

[926] Dismukes, Exh. No. DED-4.

[927] Kaufman, Exh. No. LDK-1CT at 10:17-11:1.

Table 4: Recommended Electric Rate Change as Percent of Average[928]

Schedule	Parity (AWEC COS)	% of Avg. Change RY1	% of Avg. Change RY2
Residential Service 1	0.85	51	150
General Service 11-12	1.18	125	75
Large Gen. Service 21-22	1.21	150	50
XL Gen. Service 25	1.30	200	25
Pumping Service 31-32	1.06	100	100
Street/Area Lights 41-48	1.08	100	100
Gen. EV 13	0.27	0	200
Large Gen. EV 23	0.14	0	200

Table 5: Recommended Gas Rate Change as Percent of Average[929]

Schedule	Parity (AWEC COS)	% of Avg. Change RY1
Gen. Service 101	0.97	100
Large Gen. Service 111	1.21	50
Interruptible 131	1.34	25
Transport 146	0.74	150

533 Kaufman also notes that the Company's rate spread usually includes Colstrip costs and rate impacts. Kaufman expresses concern that when the Colstrip tracker retires there will be rate impacts that would result in the residential rate schedule moving further below rate parity.[930]

Rate Design- Schedule 25 Special Contracts

534 In addition to its proposals for rate spread, AWEC proposes several changes to the rate design for Schedule 25 that do not affect other rate schedules.[931] These include:

- Increasing demand charges by 50 percent in RY1 and 25 percent in RY2.

[928] Kaufman, Exh. No. LDK-1CT at 12.

[929] Kaufman, Exh. No. LDK-1CT at 12.

[930] Kaufman, Exh. No. LDK-1CT at 13:10-14:2.

[931] Extra Large General Service (electric).

- Increasing the discount for usage greater than 115 kV primary voltage discount from $1.93 to $4.39 ($6.10 if AWEC's recommended COSS allocation is not adopted); and
- Modifying the discount to apply to customers served through substations not owned by the Company.[932]

The Energy Project's Response Testimony

535 TEP recommends the Commission reject Avista's proposal to increase customer charges for residential and commercial electric customers as well as general service gas customers. TEP witness Colton offers an in–depth study related to Avista's rate proposals using a "stratification approach" which is further detailed in his testimony related to equity. In short, Colton suggests that Avista's proposal to increase the BMC will disproportionately impact lower income households who typically have lower average usage levels and therefore would pay proportionally more with a higher basic charge.[933]

NWEC's Response Testimony

536 NWEC witness McCloy recommends the Commission reject Avista's proposal to increase customer charges for residential and commercial electric customers as well as general service gas customers.[934] McCloy argues the purpose of the fixed charge is not to pay the utility's total fixed costs. Instead, McCloy advocates for fixed charges to focus on recovery for customer service, metering, and billing.

537 McCloy further testifies that the Company's proposed use of the customer charge complicates decoupling mechanisms, arguing that any costs can be considered a fixed cost over a long enough period of time. Recovering more revenue from a large basic charge does help decouple revenue from sales, but McCloy argues that this is not a preferred decoupling strategy. McCloy characterizes a high fixed charge as raising the "floor" for utility revenues, without benefiting customers.[935]

538 McCloy also references in testimony an upcoming decision in California related to income-based fixed charges. NWEC encourages future consideration of creative rate

---

[932] Kaufman, Exh. No. LDK-1CT at 16-17.

[933] Colton, Exh. No. RDC-1T at 65:10-15.

[934] McCloy, Exh. No. LM-1T at 3:2.

[935] McCloy, Exh. No. LM-1T at 9:10-15.

design proposals that can bolster low-income affordability, but asserts more evidence is needed for supporting such a novel idea.[936]

539 NWEC witness Gehrke recommends using the generation allocator S01 to allocate costs for Colstrip consistent with Commission rule and deviating from the Settlement regarding Colstrip allocation.[937] Gehrke argues the S01 allocation would better match cost of service principals.[938]

Walmart's Response Testimony

Rate Spread

540 Walmart's witness Perry testifies in support of aligning rates more closely with the cost of service for each rate class.[939]

541 Perry identified that Avista's proposed electric revenue allocation brings each class closer to cost of service but that parity ratios remain too far away from parity. While Perry supports Avista's initial proposed revenue requirement, they assert that with a lower revenue requirement Walmart would support maintaining the initial increase allocated to Schedule 1, equal increases to Schedules 13, 23, and 31/32, and all remaining revenue collected through an equal increase split between schedules 11/12, 21/22, and 25.[940] Walmart supports the Company's rate spread proposal for gas service.[941]

Avista's Rebuttal Testimony

542 On rebuttal, Avista agrees to modify its basic charge proposal to reflect Staff's recommendation of a $1.00 increase to the basic charge for residential customers on both the gas and electric side. Avista asserts that it continues to believe in better aligning fixed costs and basic charges and offers this compromise in the spirit of reducing the number of contested issues.[942]

---

[936] McCloy, Exh. No. LM-1T at 10:1-5.

[937] Gehrke, Exh. No. WG-1T at 9:20-23.

[938] Gehrke, Exh. No. WG-1T at 10:3-8.

[939] Perry, Exh. No. LVP-1T at 18:10-12.

[940] Perry, Exh. No. LVP-1T at 23:1-6.

[941] Perry, Exh. No. LVP-1T at 23:15-18.

[942] Miller, Exh. No. JDK-8T at 13:1-6.

543 Avista does not oppose changes to the rate design of the Electric Extra Large General Service in Schedule 25 but suggests a more modest change. Rather than a 50 percent increase followed by a 25 percent increase in demand charges, Avista suggests a 25 percent increase for RY1 and RY2.[943]

544 Avista insists that the Commission should not consider party positions relitigating a decision from a Full Multiparty Settlement Stipulation.[944] Company witness Miller points out that NWEC offered supplemental testimony supporting the Colstrip Tracker and Schedule 99 as part of the Settlement Agreement in that docket.

NWEC's Cross Answering Testimony

545 NWEC does not support AWEC's proposal to alter the Company's treatment of Colstrip.[945]

Public Counsel's Cross Answering Testimony

546 Public Counsel witness Dismukes argues that the Company overstates the necessity of increasing the BMC and urges the Commission to reject Staff's recommendation to raise residential basic charges by $1.00.

547 According to Public Counsel, Avista recovers "82.4 percent of customer-related costs for electric Residential Service and 51 percent of customer-related costs for natural gas general service customers."[946] Dismukes further argues that decoupling mechanisms already allow the utility to reconcile volumetric rates with changes in volumetric use.[947] Finally, Dismukes reiterates that increases in the BMC impact low-income customers disproportionately.[948]

548 Dismukes opposes AWEC's proposed rate spread.[949] Public Counsel highlights that AWEC did not factor in its proposal the full rate increase the Commission approved in Avista's most recent GRC. Dismukes elaborates that the "AWEC proposal would add

---

[943] Miller, Exh. No. JDK-8T at 15:16-21.

[944] Miller, Exh. No. JDK-8T at 16:16-21.

[945] Gehrke, Exh. No. WG-8T at 11:11-16.

[946] Dismukes, Exh. No. DED-10T at 8:18-20.

[947] Dismukes, Exh. No. DED-10T at 8:20-21.

[948] Dismukes, Exh. No. DED-10T at 9:7-16.

[949] Dismukes, Exh. No. DED-10T at 3.

compounding disproportionate rate increases to low-load factor customers before it is fully known what the relative cost of providing electric service to different customer classes will be going forward."[950] Dismukes recommends the Commission accept the Company's proposal to equally allocate any potential rate change across all customer classes.

549 Public Counsel also opposes AWEC's proposal to include Colstrip costs and revenues into rate spread considerations.[951]

AWEC's Cross Answering Testimony

550 Kaufman notes that NWEC's reallocation of Schedule 99 would lead to Schedule 25 receiving an increase of 15.5 percent rather than 11.7 percent. Kaufman notes that this would be significant because Schedule 25 already is above parity, and a higher-than-average rate increase would grow the gap in parity.[952] AWEC suggests "spreading the combined revenue from base rates and Schedule 99 according to the approved allocation, then subtracting the generation-based allocation of Schedule 99 from the combined revenue to determine the appropriate base rate revenue" as a method to alleviate that concern.[953]

Parties' Briefs

Avista

551 In the Company's post-hearing brief, Avista suggests the Commission does not need to approve either Avista or AWEC's Cost of Service Study in this proceeding, but rather should recognize that both are directionally similar and accurate for setting rates.[954]

552 On electric rate spread, the Company is supportive of AWEC's proposed rate spread for RY1 and RY2. Avista acknowledges that Schedules 11/12, 21/22, and 25 are overpaying while Schedule 1 is underpaying.[955] However, Avista argues the Commission should reject AWEC's positions related to Schedules 13, 23, and 99. Avista also argues for an equal percentage increase for Schedules 13 and 23 consistent with its original filing. Avista

---

[950] Dismukes, Exh. No. DED-10T at 3:13-16.

[951] Dismukes, Exh. No. DED-10T at 7:12.

[952] Kaufman, Exh. No. LDK-6T at 3:10-17.

[953] Kaufman, Exh. No. LDK-6T at 3:21-22.

[954] Avista's Post-Hearing Brief ¶¶ 159-60.

[955] Avista's Post-Hearing Brief ¶ 161.

further maintains that Schedule 99 should not be factored into rate spread because the tariff is separate and distinct, and the allocation was agreed to in a prior settlement.[956]

553 Similarly, for natural gas rate spread, Avista is supportive of AWEC's position because the Cost-of-Service Studies that both the Company and AWEC performed show Schedules 111/112 and 131/132 are overpaying and Schedule 146 is underpaying.[957]

554 Regarding rate design, Avista is supportive of Staff's proposal for $1.00 increases to residential basic minimum charges for both electric and gas customers. Further, the Company supports AWEC's recommendation related to Schedule 25 demand charges, but recommends the Commission approve a 25 percent increase for RY1 and RY2, instead of the 50 percent increase in RY1 AWEC proposes to support full-cost recovery while reducing variability of rate changes to Schedule 25 customers. The Company is also supportive of AWEC's proposed increase to the greater than 115 kV discount from $1.93 to $4.39 for Schedule 25 customers.[958]

555 Finally, Avista argues the Commission should disregard the arguments NWEC put forward regarding Colstrip Schedule 99, on the basis that the allocation is part of a settlement, to which NWEC was a signatory.[959]

Staff

556 Staff reiterates its argument that the Commission should reject Avista's original rate design proposal and adopt the proposed $1.00 increase to basic charges for residential electric and gas customers. Staff argues that after discovery, they could not validate the Company's claims regarding the basic charge and that Staff's proposal matches the principle of setting the basic charge to recover "direct customer costs."[960]

Public Counsel

557 Public Counsel requests the Commission adopt an equal rate spread for electric and gas customers. While Public Counsel concedes it cannot refute Avista's class cost of service

---

[956] Avista's Post-Hearing Brief ¶ 163.

[957] Avista's Post-Hearing Brief ¶ 164.

[958] Avista's Post-Hearing Brief ¶¶ 165-67.

[959] Avista's Post-Hearing Brief ¶ 168.

[960] Staff's Post-Hearing Brief ¶¶ 116-18.

study showing a 0.86 rate parity, they argue that the Commission should "exercise caution and approve an equal allocation."[961]

558 Public Counsel presents four reasons for adopting an equal rate spread. First, an asymmetric rate spread would have outsized impacts on parity and may overshoot its goal. Second, Public Counsel asserts the class cost of service study has not completely captured the impacts of the last rate adjustment because of "pancaking" rate cases. Third, the removal of Colstrip and move towards renewables energy is moving residential ratepayers towards parity as they carry less of Colstrip and more of the costs from renewables. Fourth, residential ratepayers are already troubled by recent increases and potential overcorrections would intensify inequities from rate increases.[962]

559 Regarding rate design, Public Counsel argues the Commission should reject Avista's proposal to increase the basic charge. Public Counsel argues the basic charge should not be increased because Avista overstates costs attributable to customer-related activities, stating 82.4 and 51 percent of costs for electric and gas customers respectively is recovered through existing basic charges. Further, Public Counsel reasons that shifting costs from variable to fixed reduces conservation incentives, and that an increase is not necessary with a decoupling mechanism. Finally, Public Counsel argues that Staff's $1.00 increase should be rejected for the same reasons.[963]

AWEC

560 AWEC argues in its post-hearing brief that the Commission should adopt the rate spread Avista proposes in its Rebuttal Testimony. AWEC opposes Public Counsel's approach for an equal spread of revenue requirement on the basis that Public Counsel did not provide any supporting evidence or perform its own cost of service study and maintains that its suggested approach could in fact exacerbate the existing class parity levels.[964]

561 Additionally, AWEC argues that the Commission should adopt its three recommended changes to Schedule 25, as modified by Avista, which AWEC asserts are unopposed. The changes include (1) increasing demand charges for energy blocks 1 and 2 by 25 percent in RY1 and 25 percent in RY2, (2) increasing the primary voltage discount from $1.93/kW to

---

[961] Public Counsel's Post-Hearing Brief ¶ 128.

[962] Public Counsel's Post-Hearing Brief ¶¶ 129-34.

[963] Public Counsel's Post-Hearing Brief ¶¶ 135-36.

[964] AWEC's Post-Hearing Brief ¶¶ 72-80.

$4.39/kW, and (3) changing language in Schedule 25 to make the primary voltage discount applicable to customers served through third party substations.[965]

NWEC

562 NWEC reiterates its argument to alter Schedule 99 rate spread to the generation allocator S01 as detailed in witness Gehrke's testimony. NWEC argues that it has reevaluated its position, even though it supported the Schedule 99 allocation as part of a settlement.[966] NWEC explains that since the Commission adopted the settlement without conditions, made the settlement part of the Order, it may go back and amend the allocation pursuant to its authority under RCW 80.04.210 and WAC 480-07-875.[967] NWEC argues in favor of its Schedule 99 adjustment by asserting that the reallocation would be consistent with the Commission's cost of service methodology.[968]

563 Finally, NWEC opposes the basic minimum charge increases proposed by both Avista and Staff on the basis that the increase is not mandated by rule, law, or governing principle, exceeds those of other Washington regulated utilities and disproportionately impacts marginalized customers.[969]

Decision

564 The Commission finds Public Counsel's recommended approach to rate spread to be the most reasonable and equitable in this case and therefore rejects the rate spreads put forward by AWEC and Avista. The Commission also agrees with Staff and Avista that a $1.00 increase to the minimum charge for electric and gas customers is supported by the record. The Commission further finds that the three adjustments AWEC proposed for Schedule 25, as modified by Avista, should be adopted. However, AWEC's proposals regarding Schedule 13 and 23 should be rejected, as should the proposals from AWEC and NWEC for modifications to Schedule 99 allocations and calculation in rate spread.

565 Regarding rate spread, the Commission recognizes that some rate classes are not within the range of parity that Staff has recently used to evaluate deviations from rate parity.[970]

---

[965] AWEC's Post-Hearing Brief ¶¶ 82-83 (Oct. 28, 2024).

[966] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, NWEC's Post-Hearing Brief ¶¶ 29-30, 34-35 (NWEC's Post-Hearing Brief).

[967] NWEC's Post-Hearing Brief ¶ 32 (Oct. 28, 2024).

[968] NWEC's Post-Hearing Brief ¶¶ 28, 37.

[969] NWEC's Post-Hearing Brief ¶¶ 39-41.

[970] *See*, Kaufman, Exh. No. LDK-1CT at 10:17-11:1.

While the Commission finds the framework instructive and helpful, it is not mandated that each class falls within a certain range when looking at rate parity ratios, and as highlighted in Public Counsel's arguments, there are a number of factors likely to impact parity ratios over the rate effective period. While we acknowledge that the cost-of-service study does not capture all the increases from Avista's last rate case, as noted in Public Counsel's post-hearing brief, early results show parity improving.[971]

566 We also recognize and agree with Public Counsel that the 2025 removal of Colstrip from rates is likely to impact parity, and adopting a differential allocation in this case may in fact have impacts not fully reflected in the record before us. Because of this, the Commission finds Public Counsel's recommendation for an equal allocation is fair, just, and reasonable, and that Avista's next cost of service study shall account for removal of Colstrip from rates.

567 On rate design, the Commission agrees with Staff, as supported by Avista, that electric and gas basic charges should be increased by $1.00 each. As Avista asserts, and Staff to some degree confirms, Avista's current basic charge does not meet the fixed costs components of the basic charge. Staff calculated the components of the electric basic charge to be $10.93 and the natural gas components to be $18.60, and the $1.00 increase for gas and electric basic service charge will move the charges closer to customer fixed costs.[972]

568 While Public Counsel, NWEC, and TEP do not support an increase to the basic charge due to its disincentive to conserve and other impacts such an increase may have on marginalized customers, the record supports an increase. We agree with Staff that the basic charge is intended to recover "direct customer costs."[973] While NWEC is correct that no law requires an increase, it is within the Commission's discretion to order an increase here. We are further in agreement with Staff, that a $1.00 increase for electric and gas customers, is consistent with the principle of gradualism and is a fair, just, and reasonable increase at this time.

569 AWEC's three adjustments to Schedule 25, as modified by Avista, are unopposed and should be adopted. Those include (1) increasing demand charges for energy blocks 1 and 2 by 25 percent in RY1 and 25 percent in RY2, (2) increasing the primary voltage discount

---

[971] AWEC's Post-Hearing Brief ¶ 131 (*citing*, Dismukes, Exh. DED-10T at 3:19-4:3, 5:1-6; Miller, Tr. Vol. III at 327:16-23).

[972] Hillstead, Exh. KMH-1T at 27:4-28:10.

[973] *PacifiCorp*, Dockets UE-140762, UE-140617, UE-131384 & UE-140094, at 91 ¶ 216.

from $1.93/kW to $4.39/kW, and (3) changing language in Schedule 25 to make the primary voltage discount applicable to customers served through third party substations.

570 Finally, we decline to adopt AWEC's proposal to include Colstrip in rate spread, NWEC's proposal to reallocate Schedule 99, and AWEC's proposals related to Schedules 13 and 23. For the proposals related to Colstrip, we agree with Avista that both AWEC and NWEC were signatories to the original settlement, and that the settlement should not be amended at this time. While we agree with NWEC that the Commission has the authority to order changes to the settlement, we decline to do so now and there is no compelling reason within this record to disturb what is settled. Finally, we agree with Avista and find Schedules 13 and 23 are newly adopted and should have time to mature. Accordingly, an equal percentage of base revenue increase is appropriate, consistent with our approach to rate spread generally, and Avista's original filing.

Return on Purchase Power Agreements

Avista's Direct Testimony

571 Avista witness Kinney testifies that pursuant to RCW 80.28.410(2)(b) the Company has included interest on qualifying PPAs (Chelan, Clearwater III and Columbia Basin Hydro) at the Company's proposed rate of return in this general rate case of 7.61 percent.[974] Kinney testifies that its pro forma adjustment includes interest totaling $2.16 million included for RY1 (2025).[975] This reflects interest to be deferred in 2024 and recovered in 2025 ($0.66 million), and incremental interest in 2025 of $1.5 million.[976] Schultz testifies that the net impact of this adjustment decreases Washington electric net operating income (NOI) by $1,706,000.[977]

572 In RY2 (2026) Kinney states that it included $2.34 million in total PPA interest, resulting in incremental increase of $176,000 above RY1 levels.[978] The net impact of this adjustment decreases Washington electric NOI by $139,000.[979]

---

[974] Kinney, Exh. SJK-1T at 49:13-15.

[975] Kinney, Exh. SJK-1T at 49:15-17.

[976] Kinney, Exh. SJK-1T at 49:17-18.

[977] Schultz, Exh. KJS-1T at 86:20-21.

[978] Kinney, Exh. SJK-1T at 49:18-20.

[979] Schultz, Exh. KJS-1T at 95:16-17.

NWEC's Response Testimony

573 NWEC witness Gehrke recommends that the Commission reject Avista's proposal to provide an incentive for purchased power agreements. Gehrke states that aside from citing RCW 80.28.410(2)(b), Avista does not provide additional rationale for the inclusion of the incentive, one that NWEC argues will cost customers several million dollars over the rate plan.[980]

574 Gehrke does not believe that Washington statute requires the Commission to provide a return on PPAs.[981] RCW 80.28.410(2) states the utility "may…defer for later consideration by the Commission," costs included in subsections (a) and (b) – the latter including a rate of return for PPAs.[982] Gehrke testifies that "[l]ater consideration by the Commission" indicates that the Commission retains its broad discretion to approve or reject a proposal to receive a return on PPAs.[983]

575 Additionally, Gehrke highlights that the Oregon Public Utilities Commission (OPUC) analyzed the premise that an inherent bias exists in utility resource procurement, one that favors utility ownership of generation assets over PPAs due in part to an inability to earn a return on PPAs.[984] Witness Gehrke states that while the OPUC agreed that such a bias exists, it had no evidence as to its size or impact on rates and thus warned about the potential for incentives on PPAs to greatly outweigh the impact of the bias.[985]

576 Gehrke argues that Avista makes no showing that a bias exists, nor does the Company make any attempt to quantify that bias. NWEC further argues that it is possible, even likely, that rewarding Avista with a full rate of return for CETA-compliant PPAs would overcompensate the utility at the expense of customers.[986]

577 NWEC witness Gehrke contends that rather than using utility financing (debt or equity) to fund PPAs, Avista contracts with a third-party power plant owner and pays for the resource over the contract's duration.[987] Gehrke states that regardless of the method used to acquire

---

980 Gehrke, Exh. WG-1T at 2:14-17.

981 Gehrke, Exh. WG-1T at 3:13-14.

982 Gehrke, Exh. WG-1T at 3:14-16.

983 Gehrke, Exh. WG-1T at 3:16-19.

984 Gehrke, Exh. WG-1T at 4:1-5.

985 Gehrke, Exh. WG-1T at 4:8-24, 5:1-2.

986 Gehrke, Exh. WG-1T at 5:5-7.

987 Gehrke, Exh. WG-1T at 5:15-17.

capital for a purchased power agreement project, the contracted price is structured to cover the capital costs associated with the agreement, including a return on investment.[988] Gehrke specifies that these costs are paid for by customers through the power cost rates.[989] Gehrke thus argues that under Avista's proposal customers would be charged for two financing costs, which is not appropriate for cost-based pricing.[990]

578 Gehrke contends that if the Commission concludes that it is inclined to provide the incentive, RCW 80.28.410(2)(b) allows for "a rate of return of no less than the authorized cost of debt and no greater than the authorized rate of return for the electrical company."[991] Gehrke further contends that in order to protect customers and keep CETA compliance costs low, if the Commission decides to authorize a return, it should allow a return for PPAs only equal to the cost of debt.[992]

579 Gehrke argues that since Avista must demonstrate that it acted prudently in order to recover costs associated with the lowest reasonable-cost resource, it is counterintuitive that adding additional costs to a contracted resource via a newly established return would result in a greater acquisition of contracted resources.[993] Gehrke emphasizes that Avista must choose the lowest-cost resource that fits the resource need, which is true with or without a return added for PPAs.[994]

580 In conclusion, Gehrke recommends that the Commission reject Avista's proposal to include a rate of return for PPAs.[995] In the alternative, should the Commission feel compelled to provide an incentive, Gehrke believes that the Commission should set the rate of return for PPAs at the cost of debt for the Company.[996]

---

[988] Gehrke, Exh. WG-1T at 6:1-4.

[989] Gehrke, Exh. WG-1T at 5:17-18.

[990] Gehrke, Exh. WG-1T at 5:18-20.

[991] Gehrke, Exh. WG-1T at 6:13-17.

[992] Gehrke, Exh. WG-1T at 6:17-19.

[993] Gehrke, Exh. WG-1T at 7:6-10.

[994] Gehrke, Exh. WG-1T at 7:10-12.

[995] Gehrke, Exh. WG-1T at 7:15-16.

[996] Gehrke, Exh. WG-1T at 7:16-18.

Staff's Response Testimony

581 Staff witness Hillstead does not agree that the Company should use a ROR of 7.61 percent for calculating the interest in its PPA adjustment.[997] Hillstead argues that the 7.61 percent is a computation based on the Company's proposed capital structure which includes an ROE of 10.4 percent.[998] Hillstead further argues that using a rate of 7.61 percent results in an inflated interest expense and thus a higher revenue requirement.[999]

582 Hillstead testifies that it has concerns with the Company's methodology for this adjustment. The first issue is that pro forma adjustments are to be known and measurable, not assumptions.[1000] The second issue in the Company's use of 7.61 percent, is that this rate of return has not been authorized by the Commission and is solely based on the Company's proposed capital structure.[1001]

583 Hillstead recommends that the interest rate for this adjustment be at Avista's cost of long-term debt, per Staff witness Parcell's capital structure recommendations, which is 4.93 percent.[1002] This is the appropriate rate to use because PPAs are contracts, not capital investments.[1003] In Hillstead's view, the lower end of the range should be used absent adequate justification by the Company for the use of the upper end of the range.[1004] Hillstead contends that the Company has made no such justification for the upper end of the range.[1005]

NWEC's Cross-Answering Testimony

584 Gehrke argues that the Commission is not compelled to grant an incentive on CETA PPA costs and retains broad ratemaking authority.[1006] Additionally, in PSE's GRC, Gehrke

---

[997] Hillstead, Exh. KMH-1T at 17:9-10.

[998] Hillstead, Exh. KMH-1T at 17:10-12.

[999] Hillstead, Exh. KMH-1T at 17:12-13.

[1000] Hillstead, Exh. KMH-1T at 17:17-18.

[1001] Hillstead, Exh. KMH-1T at 17:18-20.

[1002] Hillstead, Exh. KMH-1T at 18:11-14.

[1003] Hillstead, Exh. KMH-1T at 18:14-15.

[1004] Hillstead, Exh. KMH-1T at 18:15-16.

[1005] Hillstead, Exh. KMH-1T at 18:16-17.

[1006] Gehrke, Exh. WG-8T at 10:22 and 11:1-2.

states that The Energy Project is making a similar argument regarding the language of RCW 80.28.410 and that NWEC concurs with this position.[1007]

Avista's Rebuttal Testimony

585 Avista witness Andrews does not agree with NWEC's assertion that a return on PPAs does not "follow traditional cost-based ratemaking."[1008] Andrews argues that rather than being a cost-based item, the return is essentially a performance-based incentive, created by the Legislature, which serves to compensate utilities for securing clean energy PPAs over potentially more expensive self-build options.

586 Andrews testifies that Senate Bill 5116 states, in reference to the transition to clean energy, that the "legislature declares that utilities in the state have an important role to play in this transition, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy."[1009] Andrews argues that the purposeful inclusion of "a rate of return of no less than the authorized cost of debt and no greater than the authorized rate of return of the electrical company…," is such an incentive.[1010]

587 Avista witness Andrews further argues that incentives of any type are meant to drive certain behaviors and that for CETA, an incentive rate of return will help drive adoption of clean energy PPAs and/or remove any bias towards selecting self-build options.[1011]

588 Company witness Andrews argues that the findings of the Oregon Public Utility Commission are not relevant in this instance.[1012] Andrews states that witness Gehrke cites an investigation – from 2010 – where the OPUC found it to be inconclusive as to whether customers were harmed by paying an incentive rate of return as compared to the savings from the mitigation of a self-build bias.[1013] Andrews argues that such a "stale" proceeding in Oregon should not be used to supplant the legislature's intent upon the passage of CETA, that allows for an incentive rate of return.[1014]

[1007] Gehrke, Exh. WG-8T at 11:2-6.

[1008] Andrews, Exh. EMA-6T at 50:5-9.

[1009] Andrews, Exh. EMA-6T at 50:11-14.

[1010] Andrews, Exh. EMA-6T at 50:14-16.

[1011] Andrews, Exh. EMA-6T at 51:1-6.

[1012] Andrews, Exh. EMA-6T at 51:9-10.

[1013] Andrews, Exh. EMA-6T at 51:10-12.

[1014] Andrews, Exh. EMA-6T at 51:18-20.

589 Andrews states that it has filed a 4.99 percent cost of debt, which has been supported (or not opposed) by the parties in this case.[1015] Witness Andrews testifies that Staff witness Hillstead states that the cost of long-term debt is 4.93 percent.[1016] While Andrews concedes that this is correct, it contends that what is contemplated in the law is the "authorized cost of debt", not authorized cost of long-term debt.[1017] As such, Andrews argues that if the Commission were to authorize a return on PPAs at the authorized cost of debt, 4.99 percent would be the appropriate value.[1018]

Parties Briefs

Avista

590 In its post-hearing brief, Avista reiterates its previously stated position, that the Commission should authorize the Company's Pro Forma Power Purchase Agreement Interests Adjustments as proposed (3.23 RY1 and 5.12 RY2).[1019] Avista opposed NWEC's proposal to remove interest; and Staff's proposal to limit interest to the Company's cost of debt.

Staff

591 In opposition, Staff's brief reiterates that the return on CETA-qualifying PPAs should be limited to the Company's authorized cost of debt.[1020] Staff notes that RCW 80.28.410(2)(b) controls, and provides a range between an authorized cost of debt and its authorized rate of return. Staff notes, that this range is difficult to square with NWEC proposal to not allow any return of these costs. Staff's brief concluded by noting how the Commission has broad discretion in determining appropriate deferred costs of capital; and the Company bears the burden of showing proposed rates are fair, just, reasonable and sufficient. Staff avers that Avista has not provided a sufficient showing as to why the high-end of the range would be appropriate here. [1021]

[1015] Andrews, Exh. EMA-6T at 52:11-12.

[1016] Andrews, Exh. EMA-6T at 52:12-13.

[1017] Andrews, Exh. EMA-6T at 52:13-14.

[1018] Andrews, Exh. EMA-6T at 52:14-16.

[1019] Avista's Post-Hearing Brief, at ¶ 113.

[1020] Staff's Post-Hearing Brief, at ¶¶ 106-109.

[1021] Staff's Post-Hearing Brief, at ¶¶ 106-109.

NWEC

592 In its brief, NWEC reiterates its previously stated position that approving a rate of return for PPAs executed for CETA compliance is not legally required of the Commission. NWEC rejects both Staff and Avista's proposals here, because the "burden to demonstrate that an incentive is necessary" has not been met.[1022] NWEC points out that other performance-based ratemaking constructs are being reviewed in an ongoing proceeding, citing to Docket U-210590. NWEC urges the Commission to exercise its discretion to reject this rate of return, because it will increase costs for customers. NWEC emphasizes that an incentive is inappropriate – because Avista is already required to choose the lowest-cost resource that fits the resource needs.

TEP

593 In its brief, TEP proffers that RCW 80.28.410 uses permissive language, such that the Commission has the discretion to determine whether "any" cost recovery is appropriate. TEP goes on to identify three reasons why authorizing a rate of return inappropriate here.[1023] First, TEP contends that capital costs are already included in the PPA contract price, such that customers would be forced to pay twice for capital costs of such projects; TEP describes this as a "phantom cost of capital." [1024] Second, TEP argues that approving a rate of return would raise the cost of contracting for clean energy – which is against the state's clean energy policy. Finally, TEP highlights that Avista bears the burden and has not demonstrated any convincing arguments for this incentive. [1025]

Decision

594 The Commission finds it appropriate to allow a return on Avista's PPA. The plain language of RCW 80.28.410 gives the Commission the discretion to allow such costs to be deferred and is intended to incentivize PPAs, as they often are the lowest cost resource. The PPAs at issue are for resources which need to be procured and these PPAs are the lowest reasonable cost resources available. The statute contemplates returning a range between the cost of debt and the authorized rate of return. *See* RCW 80.28.410(2)(b). This return is meant to incentivize procurement of resources at the lowest reasonable cost to aid the utilities in meeting Washington's long-term decarbonization goals. In reviewing the record, we conclude that Avista did not present a case warranting the authorized rate of return, and as such, we agree with Staff that the lower end of the spectrum, the cost of

[1022] NWEC's Post-Hearing Brief, at ¶¶ 12-27.

[1023] TEP's Post-Hearing Brief, at ¶¶ 27-33.

[1024] TEP's Post-Hearing Brief, at ¶ 59.

[1025] TEP's Post-Hearing Brief, at ¶¶ 32-33.

debt, is appropriate here, and that the appropriate cost of debt is 4.93 as proposed by Staff. We believe that 4.93 percent is the appropriate cost of debt given the statutory intent for utilities to enter long-term PPAs to provide service to their Washington customers, with the expectation that those resources reduce GHG emissions to meet Washington's long-term emissions targets.

Targeted Electrification Pilot

Avista's Direct Testimony

595 Avista witness Thackston describes the Company's strategy for natural gas decarbonization as diversifying and transitioning from conventional fossil fuel natural gas to RNG, hydrogen, other renewable fuels, and reducing consumption via conservation and energy efficiency. Witness Thackston further adds that the Company will also purchase carbon offsets as necessary to meet CCA compliance obligations.[1026]

Sierra Club's Response Testimony

596 Witness Dennison's testimony urges Avista to conduct a robust Targeted Electrification Pilot program to advance electrification.[1027] Dennison specifically identifies (1) non-pipe alternatives (NPAs) analysis, (2) identifying ways to incorporate electrification into its CCA compliance strategy, and (3) opportunities to coordinate electrification efforts with other electrification programs and policies as experiences that would help Avista.

597 Dennison continues to more fully describes each of these benefits:

- NPAs can avoid costs related to replacing, upgrading, or expanding gas system infrastructure; avoid the risk of future stranded assets; reduce gas consumption and emissions.[1028]
- CCA compliance requires reducing GHG emissions, Dennison cites electrification as one of the most "promising, cost-effective strategies for reducing [emissions]."[1029]
- Finally, Dennison claims targeted electrification will help coordinate electrification efforts to make the most of investments. Sierra Club specifically mentions

[1026] Thackston, Exh. JRT-1T at 9:5-9.

[1027] Dennison, Exh. JAD-1T at 31:3-5.

[1028] Dennison, Exh. JAD-1T at 20:13-18.

[1029] Dennison, Exh. JAD-1T at 31:20-23.

incentives, state & federal rebates and tax credits as incentives that would be easier to access.[1030]

598 Dennison also cites PSE's targeted electrification pilot as a success.[1031] Dennison mentions provisions of the PSE settlement agreement that resulted in the creation of the pilot, including directives to PSE to demonstrate material benefits to low-income participants, enroll eligible participants in bill assistance programs, and include appropriate low-income customer protections.[1032]

599 Dennison identified accomplishments of the PSE electrification pilot in testimony including:

- 7,712 home electrification assessments with 30 percent reaching Named Communities.
- 852 heat pump rebates distributed.
- 14 low-income direct install weatherization and electrification projects and identified candidates for small business and multi-family retrofit projects.
- Development of a joint pilot with Seattle City Light aiming to install heat pumps in 20 homes through the Low-Income Weatherization Program.

600 Dennison made four recommendations for a potential pilot program including:[1033]

Customer Engagement targets
Dennison recommends a target of engaging 5,000 customers through home electrification assessments and providing at least 1,000 rebates for electrification equipment between June 2025 and December 2026.

Provisions to engage low-income customers and Named Communities
Dennison suggested that language from ESHB 1589 about the inclusion of low-income electrification programs in large combination utilities' Integrated System Plans (ISPs) could inform similar provisions for Avista. Dennison further adds that target numbers for low-income and Named Communities participation could be beneficial.

[1030] Dennison, Exh. JAD-1T at 32:5-13.

[1031] Dennison, Exh. JAD-1T at 33:5-6.

[1032] Dennison, Exh. JAD-1T at 33:7-16.

[1033] Dennison, Exh. JAD-1T at 34:4-13.

Provisions for public reporting
Dennison recommends a report summarizing the results of the pilot by January of 2027; including information about the number of customers engaged through each measure, the number and types of equipment incentives provided, the Company's cost for providing each measure, and lessons learned.

Provisions to incorporate the Pilot into Avista's decarbonization and CCA compliance strategies
Dennison recommends using the lessons from an electrification pilot to inform a Gas System Decarbonization Plan for the Company. The witness further adds that the costs of the pilot should be treated as CCA compliance costs and shared between gas customers and shareholders, this would be different than how costs for PSE's pilot were treated.

Avista's Rebuttal Testimony

601 The Company does not support the proposal for the Commission to require a targeted electrification pilot. Witness Bonfield claims, "If or when electrification is cost-effective, the Company will pursue it as part of its [Preferred Resource Strategy] PRS".[1034] Witness Bonfield offers that in the Company's 2025 Natural Gas IRP, it plans to refine electrification assumptions to include "an end use model to estimate a customer's decision with equipment at its end of life and new building code requirements."[1035]

NWEC's Cross Answering Testimony

602 NWEC testifies in support of a targeted electrification pilot, citing the "valuable experience in integrating electrification into the CCA compliance strategy."[1036]

603 In response to the Seirra Club's suggestion that "it may be appropriate to set a target for the number of electrification retrofits performed in low-income households and Named Communities through the Pilot. This and other aspects of the Pilot related to low-income and Named Community participation could be informed by input from the Company and other parties," witness Gehrke recommends:[1037]

[1034] Bonfield, Exh. SJB-5T at 56:10-11.

[1035] Bonfield, Exh. SJB-5T at 56:12-14.

[1036] Gehrke, Exh. WG-8T at 2:22-23.

[1037] Gehrke, Exh. WG-8T at 3:8 – 5:13.

- A program target of 40 percent of its customers from low-income or Named Communities.
- A minimum of 25 no-cost, high-efficiency electric-only heat pump installations to low-income and Named Community customers.
- Avista should acquire operational experience in conducting electric-only heat pump installations for its customers.
- If the recommendations above are not adopted, NWEC encourages the Company to consult with its Energy Assistance Advisory Group and Conservation Resources Advisory Group on low-income electrification programming.

AWEC's Cross Answering Testimony

604 AWEC does not mention targeted electrification directly in cross-answering testimony, however, AWEC notes that "[n]o additional direction from the Commission is required to obligate Avista to appropriately plan to meet long-term CCA compliance obligations cost-effectively. While the proposal does not add to Avista's planning burden, prescribing certain decarbonization planning requirements risks biasing the decarbonization plan towards ineffective solutions."[1038]

Parties' Briefs

Avista

605 In briefing, Avista reiterates that it does not support Sierra Club's proposal that the Company be required to perform a targeted electrification pilot.[1039]

Sierra Club

606 Sierra Club requests that the Commission require Avista to conduct a targeted electrification pilot with various specific targets, similar to the Puget Sound Energy electrification pilot following its 2022 general rate case.[1040] Sierra Club states that a targeted electrification program would yield several benefits related to decarbonization, CCA compliance, leveraging additional sources of funding, and synergy with Avista's NPA analyses.[1041]

[1038] Kaufman, Exh. LDK-6T at 12:8-14.

[1039] Avista's Post-Hearing Brief, at ¶ 158.

[1040] Sierra Club's Post-Hearing Brief, at ¶¶ 39-40.

[1041] Sierra Club's Post-Hearing Brief, at ¶ 40.

607 Sierra Club further recommends that if the Commission approves a performance incentive mechanism (PIM) for Avista, that such a mechanism be tied to Avista meeting customer engagement targets related to the targeted electrification pilot.[1042] Sierra Club suggests that its proposed PIM would aid the Commission's evaluation of Avista's efforts to advance state climate policy as reflected in RCW 80.28.425.[1043] Sierra Club also proposes that the targeted electrification pilot be considered as a CCA compliance cost and recovered from Avista's gas customers.[1044] Sierra Club notes that NWEC is supportive of the proposed targeted electrification pilot, as the pilot will aid Avista in meeting CCA emissions goals and advancing equity, and agrees with NWEC's proposals for additional compliance actions regarding the pilot.[1045]

608 Sierra Club disagrees with Avista's proposal to review electrification in the context of its IRP for three reasons. Sierra Club raises concerns with (1) Avista's electrification analysis in its IRP, (2) the delay in waiting for future IRP processes, and (3) the distinct purposes of a pilot project as compared to the IRP process, suggesting that the IRP system-level analysis is ill-suited to identifying smaller scale projects.[1046]

NWEC

609 NWEC is generally supportive of Sierra Club's proposal to require Avista to implement a targeted electrification pilot and, similar to Sierra Club, asserts that such a pilot would assist Avista in meeting its CCA obligations and promote equity in the context of decarbonization.[1047] NWEC recommends that the Commission adopt Sierra Club's proposal, with modified thresholds to require that the program target 40 percent of customers from low-income or Named Communities and a minimum of 25 no-cost high efficiency electric-only heat pump installations to low-income and Named Community customers.[1048] In the alternative, NWEC recommends that the Commission require Avista to consult with its Energy Assistance Advisory Group and Conservation Advisory Group regarding a timeline that would align with other targeted electrification programming.[1049]

[1042] Sierra Club's Post-Hearing Brief, at ¶ 41.

[1043] Sierra Club's Post-Hearing Brief, at ¶ 41.

[1044] Sierra Club's Post-Hearing Brief, at ¶ 42.

[1045] Sierra Club's Post-Hearing Brief, at ¶ 43 (Oct. 28, 2024) (citing Gehrke, Exh. WG-8T at 4:7-16, 5:4-13).

[1046] Sierra Club's Post-Hearing Brief, at ¶ 44.

[1047] NWEC's Post-Hearing Brief, at ¶¶ 43-45.

[1048] NWEC's Post-Hearing Brief, at ¶ 45.

[1049] NWEC's Post-Hearing Brief, at ¶ 45.

Decision

610 The Commission declines to require Avista to implement a targeted electrification program in this proceeding. Although the aims of Sierra Club and NWEC are laudable, the Commission determines that the benefits of future electrification may be adequately addressed as part of the Company's IRP process, as suggested by Avista witness Bonfield.[1050] Furthermore, similar to the decision concerning the request that the Company adopt a decarbonization plan, directing an electrification pilot would appear to be explicitly prohibited by I-2066. The Commission believes that it would be prudent to withhold further consideration of an electrification pilot until a future GRC, where the Commission will have the benefit of full testimony and briefing regarding how the pilot would promote state emissions policy goals in light of I-2066. To the extent that a component of the requested electrification pilot would have required an analysis of non-pipeline alternatives, we do not find that analyses of non-pipeline alternatives are necessarily prohibited by I-2066 in the abstract. Indeed, earlier in this Order, we directed the Company to conduct two NPA analyses on natural gas distribution projects related to customer growth for any potential projects that exceed $500,000.

Wildfire Expense Balancing Account

Avista's Direct Testimony

611 In Avista's 2020 GRC, the Commission approved a two-way Wildfire Expense Balancing Account to track the variability in Avista's wildfire expenses against an established baseline, with deferral of the difference in actual wildfire expenses, up or down, over the 10-Year Wildfire Resiliency Plan.[1051] The authorized wildfire expense baseline was first set at $3.1 million for Washington electric operations, effective October 1, 2021, and updated to $5.1 million in Dockets UE-220053, *et. seq.,* with any deferrals above or below this level to be deferred for later return to or recovery from customers.[1052]

612 In this proceeding, the Company is proposing to increase its annual baseline to $8.3 million for each year of its proposed two-year rate plan.[1053] This is based on projected annual wildfire expenses of $14.9 million is 2025 and $13.8 million in 2026, on a system basis. Washington's share of these expenses, excluding labor, result in the proposed $8.3

[1050] Bonfield, Exh. SJB-5T at 55:22 – 56:16.

[1051] Andrews, Exh. EMA-1T at 17:19 – 18:2.

[1052] Andrews, Exh. EMA-1T at 18:2-5 and 18:16-18.

[1053] Andrews, Exh. EMA-1T at 19:4-6.

million annual baseline amount.[1054] Avista states that the proposed increase in the baseline is primarily caused by its enhanced risk-based vegetation management program, which includes 100 percent risk-tree identification annually, and which has resulted in a "much bigger and more expensive proposition than originally anticipated."[1055]

613 In addition, the Company requests carrying charges on its existing deferred Wildfire balance, any new deferred balances going forward, and while any balances are being amortized.[1056] The Company claims that in its original request for the deferral mechanism it inadvertently proposed "no interest on the unamortized Wildfire deferral balances," however its original intent was to accrue interest as the balances were being amortized and recovered from, or returned to customers.[1057] Avista notes that the Commission approved the balancing account deferral and amortization without carrying charges of any kind.[1058] The Company argues that carrying charges are appropriate due to the large deferral balances it has experienced in recent years, the higher carrying costs it has experienced to cover all its operating costs, as well as its delayed recovery of wildfire costs.[1059] The Company proposes that its carrying charges be based on its actual cost of debt, updated semi-annually on January 1, and July 1 each year, effective December 21, 2024 (Rate Year 1).[1060]

Staff's Response Testimony

614 Staff does not contest Avista's proposed increase to its Wildfire Balancing Account baseline, from $5.1 million to $8.3 million annually.[1061] Staff also does not contest Avista's proposal to accrue interest on its deferred balance, because "the circumstances were outside of the utility's control and the costs were unexpected and significant."[1062] Staff notes, however, that since the balancing account's creation in 2020, it is becoming increasingly difficult for Staff to distinguish between spending that is specific to wildfire

---

[1054] Andrews, Exh. EMA-1T at 19:6-10.

[1055] Andrews, Exh. EMA-1T at 20:13 – 21:11.

[1056] Andrews, Exh. EMA-1T at 24:11-17.

[1057] Andrews, Exh. EMA-1T at 24:2-10.

[1058] Andrews, Exh. EMA-1T at 24:8-10.

[1059] Andrews, Exh. EMA-1T at 24:11-13.

[1060] Andrews, Exh. EMA-1T at 24:16-17.

[1061] Erdahl, Exh. BAE-1T at 26:7-10.

[1062] Erdahl, Exh. BAE-1T at 26:14-16.

risk mitigation and "spending which results in other shared benefits, such as enhanced reliability and reduced storm damage."[1063]

615 Staff offers two proposals for Avista's next GRC: (1) to fold into base rates all wildfire mitigation costs that result in other shared benefits; and (2) "to clearly identify and report learnings from any enhanced grid hardening (i.e., undergrounding) wherever those projects are located on Avista's electric transmission and distribution grid."[1064] Staff identifies costs that it believes would be considered exclusively related to mitigation of wildfire risk and properly contained in a future balancing account, including: weather monitoring and establishment of prescribed system operating parameters; undergrounding of equipment in high-fire risk areas; identification and removal of risk trees (accelerated vegetation management); and the development of public power cutoff protocols and mechanisms.[1065] Staff argues that standard vegetation management and grid hardening benefit not only wildfire resilience, but also system reliability and storm damage mitigation, and would be more properly included in base rates in the future.[1066] Staff further argues for eventual phasing out of the wildfire balancing account completely, stating that, because these practices have been codified and are becoming a typical part of doing business for all electric utilities in the state, a tracker is not necessary for such costs and they should instead become a part of base rates.[1067]

Avista Rebuttal Testimony

616 Avista does not agree with Staff's proposal to discontinue the wildfire expense balancing account.[1068] The Company agrees that these costs are becoming a normal part of its operations but does not agree with Staff's contention that a tracker is no longer necessary and should instead become embedded in base rates in its next GRC.[1069] Avista argues that the use of a balancing account protects both the customers and the Company, as it allows the Company to defer and recover any excess costs over the established baseline, and to refund to customers the difference if the costs are less than the baseline.[1070] Also, Avista argues that the tracker allows the Company to react to any future needs identified in its

[1063] Erdahl, Exh. BAE-1T at 26:19 – 27:5.

[1064] Erdahl, Exh. BAE-1T at 27:14-19.

[1065] Erdahl, Exh. BAE-1T at 28:3-6 and *generally* Howell, Exh. DRH-3.

[1066] Erdahl, Exh. BAE-1T at 28:14-16.

[1067] Erdahl, Exh. BAE-1T at 28:18 – 29:3.

[1068] Andrews, Exh. EMA-6T at 32:18-22.

[1069] Andrews, Exh. EMA-6T at 30:13 – 31:1.

[1070] Andrews, Exh. EMA-6T at 31:2-10.

Wildfire Resiliency Plan, and to pass along any benefits, which "are not easily identified or quantified in real time, let alone estimated into the future in order to in include in the next GRC."[1071] The Company requests that the Commission allow the Wildfire Expense Balancing Account tracker to continue, at least through 2029, over its 10-year Wildfire Resiliency Plan, as previously approved by the Commission in Dockets UE- 200900, *et. al*.[1072]

Parties' Briefs

Avista's Brief

617 Avista requests the Commission approve the Company's electric Wildfire Expense Adjustment 3.24,adjusting the Company's wildfire expense and Wildfire Expense Balancing Account baseline to $8.3 million over the Two-Year Rate Plan, including a carrying charge at the Company's cost of debt on the deferred balances (current and on-going), and during amortization of these deferred balances, as-filed by the Company.[1073] The Company alleges that these adjustments are supported by Staff, and are uncontested by the remaining parties.[1074] In addition, the Company requests the Commission allow the Wildfire Expense Balancing Account "tracker" to continue beyond this GRC, at least through 2029, as this tracker acts as protection for customers and the Company, if costs expected over the life of the Wildfire Plan vary from that included in base rates.[1075]

Staff's Brief

618 Staff takes no issue with adjusting the Wildfire Expense Balancing Account baseline, nor approval of a carrying charge for the account's balances, but also recommends that the Commission order Avista to do two things: (1) move costs not strictly and exclusively related to mitigating wildfire risk out of the balancing account and into base rates; and (2) report on its experience with grid hardening.[1076] Staff notes that Avista seems to agree to report on grid hardening, but rejects moving cost not strictly and exclusively related to mitigating wildfire risk out the wildfire balancing account. Staff takes issue with Avista's position that a tracker would provide dollar-for-dollar recovery or refund for any deviation between actual costs and what is built into rates. But the Commission does not allow for a

[1071] Andrews, Exh. EMA-6T at 32:5-14.

[1072] Andrews, Exh. EMA-6T at 32:18-21.

[1073] Avista's Brief, ¶145.

[1074] Avista's Brief, ¶145; Erdahl, Exh. BAE-1T, at 26:12-16.

[1075] Avista's Brief, ¶145; Andrews, Exh. EMA-6T at 28-32.

[1076] Staff's Brief, ¶112 referencing Erdahl, Exh. BAE-1T at 27:12-19.

tracker for every cost, and it should not, given the incentive distorting effects noted by AWEC witness Mullins.[1077]

619 Staff goes further by recommending that Avista remove non-wildfire-specific costs from the tracker,[1078] and leaving in the tracker costs incurred specifically needed to address wildfire dangers, such as expedited vegetation management or undergrounding facilities in high-risk areas.[1079] Staff suggests that many of the costs Avista is recovering through the tracker are providing shared benefits, such as those incurred generally for reliability, instead providing benefits to address wildfire expenses and costs.[1080]

Decision

620 In Avista's 2020 rate case, we determined that Avista's circumstances concerning wildfires are extraordinary and justified exercising the Commission's discretion to use regulatory tools such as balancing accounts, trackers, or deferrals.[1081] As such, we found that Avista had shown that use of a Wildfire Balancing Account was justified, and we expected that implementation of the account would remove much uncertainty regarding wildfire expenses, both for the Company and for customers.[1082] "Our intent in authorizing the account is to track and review actual wildfire expense, encourage the utility to take actions to address the increasing threat of wildfires to the utility and its customers with the knowledge that prudent expenditures will be recovered and at least a portion will be included in rates currently authorized for recovery, and ensure fairness to Avista's customers by monitoring the incremental wildfire expenses collected from them."[1083]

621 The Commission authorized Avista to initiate the Wildfire Expense Balancing Account in October of 2021 and established a baseline of $3.1 million for the balancing account.[1084] The Commission directed that modifications to the mechanics of the account, such as the application of a new base level of wildfire expense, additional requirements, or performance-based metrics, should be considered in GRCs, in order to monitor wildfire

---

[1077] Staff's Brief, ¶¶113-114 referencing Mullins, Exh. BGM-1T at 64:20-65:1.

[1078] Staff's Brief, ¶¶115 referencing Erdahl, Exh. BAE-1T at 27:14-16.

[1079] Staff's Brief, ¶¶115 referencing Erdahl, Exh. BAE-1T at 28:1-10.

[1080] Staff's Brief, ¶¶ 115.

[1081] *Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 256.

[1082] *Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 257.

[1083] *Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 257.

[1084] *Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 257.

expenses.[1085] In Avista's 2022 rate case, the Commission approved a new baseline for the balancing account of $5.1 million. [1086]

622 None of parties, including Staff, contest the Wildfire Expense Balancing Account baseline being raised to $8.3 million over the Two-Year Rate Plan, nor does any party contest the carrying charge related to the Company's cost of debt on the deferred balances. The only issue is Staff's recommendation to remove non wildfire specific costs from the tracker, such as standard vegetation management and grid hardening, because they benefit not only wildfire resilience, but also system reliability and storm damage mitigation, and would be more properly included in base rates in the future.[1087] Staff does support Avista's inclusion of expedited vegetation and undergrounding facilities in high-risk areas.[1088]

623 The Company argues that the use of a balancing account protects both the customers and the Company, as it allows the Company to defer and recover any excess costs over the established baseline, and to refund to customers the difference if the costs are less than the baseline.[1089] Also, Avista argues that the tracker allows the Company to react to any future needs identified in its Wildfire Resiliency Plan, and to pass along any benefits, which "are not easily identified or quantified in real time, let alone estimated into the future in order to in include in the next GRC."[1090]

624 With regard to the non-wildfire costs that result in shared benefits for reliability that should be removed from the Wildfire Balancing Adjustment, we disagree with Staff and reject their recommendation. As the Company points out, the balancing account in its present form allows Avista to react to any future needs identified in its Wildfire Resiliency Plan. As we have seen with the unpredictable nature of wildfires, what may be non-fire risk area today may turn into a fire-risk area tomorrow. Avista's standard undergrounding and standard vegetation management protects against this very real, possible outcome, given the unpredictability of wildfires. The Commission is hesitant to limit the Company's flexibility in that regard. Therefore, we reject Staff's recommendation to remove standard undergrounding in non-fire risk areas and standard vegetation management from Avista's Wildfire Balancing Adjustment.

[1085] *Avista Corp*, Dockets UE-200900 & UG-200901, Order 08/05, 39 ¶ 258-259.

[1086] *Wash. Utils. & Transp. Comm'n v. Avista Corp,* Dockets UE-220053 & UG-210584, Order 10/04, ¶ 147 (December 12, 2022).

[1087] Erdahl, Exh. BAE-1T at 28:14-16.

[1088] Staff's Brief, ¶115.

[1089] Andrews, Exh. EMA-6T at 31:2-10.

[1090] Andrews, Exh. EMA-6T at 32:5-14.

625 As none of the parties contest the Wildfire Expense Balancing Account baseline being raised to $8.3 million over the Two-Year Rate Plan, we accept Avista's proposed new level for the balancing account's baseline. Furthermore, as none of the parties contest the proposal to recover carrying charges at cost of debt, we accept Avista's proposal in that regard.

Insurance Expense Balancing Account and Pro Forma Insurance Expense

Avista Direct Testimony

626 Avista proposes to continue the use of its insurance expense balancing account, which defers actual insurance expense above or below its approved baseline, for later return to or recovery from customers.[1091] The Company proposes to increase its currently authorized baseline from $8.3 million to $12.8 million (WA Electric) and from $1.7 to $2.3 million (WA Natural Gas) for its proposed two year rate plan.[1092] Avista witness Andrews notes that the Commission's approval of the balancing account was non-precedential per the approved Settlement, and that the Commission conditioned its approval, requiring Avista to "document its action to seek out, negotiate, and attain the best insurance at the lowest costs."[1093] Avista witness Schultz argues that Avista met this condition in its annual insurance expense balancing account filing beginning September 1, 2023.[1094]

627 Andrews argues that the Company continues to experience extraordinary and volatile conditions currently and expects this to continue through its proposed two-year rate plan.[1095] Andrews explains that the Company's proposed baseline increase is based on its Pro Forma Adjustment 3.12, which contains expected increases in insurance premiums for general liability, directors and officers (D&O) liability, property insurance, and other insurance expense.[1096] Andrews states that the Company will update any 2023/2024 estimated amounts used in its proposal later in the proceeding once further actual invoices become available.[1097] Andrews notes that the Company incurred approximately $14.6 million in insurance expense during the test year, approximately $0.9 million below its

[1091] Andrews, Exh. EMA-1T at 24:23 – 25:2 and at 25:16-17.

[1092] Andrews, Exh. EMA-1T at 25:2-5.

[1093] Andrews, Exh. EMA-1T at 25:17 – 27: 20. *See also* Dockets UE-220053, *et. al.,* Order 10/04 ¶¶ 144-146.

[1094] Andrews, Exh. EMA-1T at 27:22-28. *See also* Andrews Exh. EMA-5C.

[1095] Andrews, Exh. EMA-1T at 28:1-7.

[1096] Andrews, Exh. EMA-1T at 28:14-19.

[1097] Andrews, Exh. EMA-1T at 29:8-11.

2023/2024 authorized baseline, but reflecting an increase of 119 percent above 2020 levels.[1098]

628 Also, as with proposal with the Wildfire Expense Balancing Account, Avista proposes to accrue interest at the Company's actual cost of debt on any existing deferred balances, any new deferred balances going forward, and while being amortized.[1099]

Staff Response Testimony

629 Staff witness Erdahl agrees that Avista should be allowed to continue its insurance balancing account, because "there has not been evidence of conditions becoming more stable." Erdahl notes that the balancing account protects the ratepayers and the Company from over or under-collection of insurance expense.[1100] Staff also supports Avista's proposed increase to its baseline, and its request to accrue interest on its deferred balance.[1101]

AWEC's Response Testimony

630 AWEC witness Mullins contests the continuation of the balancing account, arguing that as a matter of policy and in the interest of ratepayer protections, the Commission should limit the number of true-up mechanisms granted to Avista.[1102] Mullins argues that the dollar-for-dollar recovery of such a mechanism removes "the Company's incentive to seek out, negotiate, and attain the best insurance at the lowest costs."[1103] Mullins notes that the insurance expense balancing account was created as part of the Commission's approval of a multi-party settlement in its last rate case, and therefore represents a compromise of the settling parties, subject to the Commission's additional reporting requirements that conditioned its approval.[1104] Mullins states that AWEC and other parties have since gained additional understanding of the administrative burdens that multi-year rate plans impose on the parties, and the additional work required for both Avista and reviewing parties related to these additional reporting requirements.[1105] Mullins argues that this additional

[1098] Andrews, Exh. EMA-1T at 30:3-14.

[1099] Andrews, Exh. EMA-1T at 33:1-18.

[1100] Erdahl, Exh. BAE-1T at 32 5-8.

[1101] Erdahl, Exh. BAE-1T at 32:10 – 33:3.

[1102] Mullins, Exh. BGM-1T at 64:15-20.

[1103] Mullins, Exh. BGM-1T at 64:20 – 65:1.

[1104] Mullins, Exh. BGM-1T at 65:3-6.

[1105] Mullins, Exh. BGM-1T at 65:6-10.

reporting "introduces ambiguity in terms of what actions are available or appropriate upon review of Avista's documentation."[1106] Mullins believes that this additional burden, along with the lack of incentive for Avista to manage its insurance expenses between rate cases, supports discontinuance of the balancing account.[1107]

631 Mullins does not dispute inclusion of Avista's forecasted insurance expense in base rates, and notes "AWEC's opposition is to the use of the single-issue ratemaking to recover these costs."[1108]

Public Counsel's Response Testimony

632 Public Counsel witness M. Garrett disputes the directors and officers portion of Avista's insurance expense proposal, arguing that a 50/50 cost allocation between customers and shareholders is appropriate.[1109] M. Garrett's adjustment would reduce operating expenses by $237,000 (WA Electric) and $75,000 (WA Natural Gas).[1110] M. Garrett argues that D&O liability insurance generally protects the assets of a company's directors and officers from financial impacts of litigation resulting from their actions taken on the corporation's behalf, and also shields shareholders, Board members, and senior leadership from legal action resulting from their decisions.[1111] M. Garrett argues that the costs of a director or officer's negligent acts are not a necessary cost of providing utility service, and because they have a fiduciary duty to put the interests of shareholders first, some of these costs should be borne by shareholders, including D&O liability insurance.[1112]

633 M. Garrett argues that a 50/50 allocation between customers and shareholders, as opposed to the 90/10 allocation proposed by Avista is more appropriate, as both groups benefit from the Company holding D&O liability insurance.[1113] M. Garrett notes that several state regulatory commissions have required equal sharing of these costs, including Arkansas, California, Nevada, New Mexico, Florida, and New York, and that Connecticut previously allowed only 25 percent of these costs in rates.[1114]

[1106] Mullins, Exh. BGM-1T at 65:10-12.

[1107] Mullins, Exh. BGM-1T at 65:12-14.

[1108] Mullins, Exh. BGM-1T at 65:15-19.

[1109] M. Garrett, Exh. MEG-1T at 34:6-7.

[1110] M. Garrett, Exh. MEG-1T at 34:7-12.

[1111] M. Garrett, Exh. MEG-1T at 28:15-18.

[1112] M. Garrett, Exh. MEG-1T at 29:3-7.

[1113] M. Garrett, Exh. MEG-1T at 30:1-12.

[1114] M. Garrett, Exh. MEG-1T at 30:16 – 34:3.

AWEC's Cross Answering Testimony

634 In Cross-Answer testimony directed at Staff, Mullins argues that under the balancing account approach, insurance costs are updated annually on November 1st each year, resulting in more rate volatility and unpredictability for customers.[1115] Mullins also argues that this methodology could create a windfall for Avista, noting that the balancing account is not subject to an earnings test, and should Avista earn at or above its rate of return and also experience a material increase in its insurance costs, it will still be allowed to recover these costs, even when such recovery is not necessary to ensure healthy earnings for the utility.[1116] Mullins argues that under a scenario where the balancing account is removed, the Company still has the ability to file for a deferral to track and recover any excessive insurance costs.[1117] Mullins argues that this approach could be subject to an earnings test, preventing potential windfall, and that any recovery would be granted in conjunction with its next rate case, eliminating AWEC's rate volatility concerns.[1118]

Avista Rebuttal Testimony

635 Regarding Mullins's proposed discontinuation of the insurance expense balancing account, Andrews disagrees with the assertion that the true-up mechanism is single-issue ratemaking, results in additional administrative burden, and removes Avista's incentive to manage its insurance costs.[1119] Noting the findings of the Commission in the final order of the Company's 2022 GRC, and reiterated by Staff in its response testimony, Andrews argues that "the volatility experienced by Avista, and the utility industry, is extraordinary and outside the Company's control."[1120] Andrews argues that tracking mechanisms such as this were created for this very reason, as protection for the Company and customers from extraordinary circumstances and volatility in certain expenses.[1121]

636 Regarding M. Garrett's proposal to split the cost of D&O insurance equally between shareholders and customers, Avista witness Schultz argues that M. Garrett's proposal

[1115] Mullins, Exh. BGM-8T at 20:5-8.

[1116] Mullins, Exh. BGM-8T at 20:11-14.

[1117] Mullins, Exh. BGM-8T at 20:15-19.

[1118] Mullins, Exh. BGM-8T at 20:19-24.

[1119] Andrews, Exh. EMA-6T at 37:3-7.

[1120] Andrews, Exh. EMA-6T at 37:7-10.

[1121] Andrews, Exh. EMA-6T at 37:10-12.

should be rejected.[1122] Schultz argues that M. Garrett's analysis focuses on the findings of seven states, but ignores the other 43 states, and argues that it is *this* Commission's findings that are most relevant to Avista.[1123] Schultz states that the Company has consistently applied the reduction of 10 percent for D&O insurance since ordered by the Commission in Avista's 2009 rate case.[1124] Schultz argues that Avista's Board of Directors is focused primarily on utility operations, and that based on the actual time the Board dedicates to the utility, "a 90%/10% sharing of these fees is conservative."[1125]

Parties' Briefs

Avista's Brief

637 Avista states that the Commission should approve the Company's electric and natural gas Insurance Expense Adjustments 3.12, updating the Company's insurance expense and its proposed Insurance Expense Balancing Account baselines, over the Two-Year Rate Plan, to $12.8 million for electric, and $2.3 million for natural gas, as filed by the Company.[1126] The Company requests approval of the Pro Forma Insurance Expense as well as the approval of the D&O Insurance expense sharing at its current level of 90percent/10 percent, as opposed to the 50/50 proposed by Public Counsel.[1127] Avista seeks the inclusion of a carrying charge at the Company's cost of debt on the deferred balances (current and on-going), and during amortization of these deferred balances, was supported by Staff, and uncontested by the other parties.[1128]

Staff's Brief

638 In its brief, Staff supports approval of: 1) the continuation of Avista's insurance balancing account;[1129] 2) an increase to its baseline;[1130] and 3) a carrying charge on the current

[1122] Schultz, Exh. KJS-5T at 54:2-6.

[1123] Schultz, Exh. KJS-5T at 54:10-12.

[1124] Schultz, Exh. KJS-5T at 54:12 – 55:3.

[1125] Schultz, Exh. KJS-5T at 55:4-6.

[1126] Avista's Brief, ¶146.

[1127] Avista's Brief, ¶146 referencing M. Garrett, Exh. MEG-1T, at 34:4-12.

[1128] Avista's Brief, ¶146 referencing M. Garrett, Exh. MEG-1T, at 32:18 – 33:3.

[1129] Andrews, Exh. EMA-1T at 24:20-25:5.

[1130] Andrews, Exh. EMA-1T at 24:20-25:5. Avista specifically seeks to increase the baseline from $8.271 million to $12.795 million for electric operations and from $1.746 million to $2.247 for natural gas operations.

deferred balance and any future deferrals.[1131] Staff notes that AWEC opposes the Insurance Expense Balancing Account as a single-issue ratemaking mechanism. Staff does not agree with AWEC's position and points out that the insurance market has been volatile for companies. Staff opines that the Commission's reporting requirements will allow the parties to verify that Avista is taking all efforts toto minimize its insurance costs. [1132] Staff asserts that the Commission should allow Avista to continue the account, adjust the baseline, approve the carrying charge, and continue in effect the reporting requirements for the account.[1133]

Public Counsel's Brief

639 Public Counsel reiterates that they favor a 50 percent or less rather than a 90 percent allocation of insurance expenses.[1134]

AWEC's Brief

640 AWEC rejects Avista's proposal to continue the Insurance Expense Balancing Account because it believes that balancing accounts constitute single-issue ratemaking and allows Avista dollar-for-dollar recovery of insurance expense.[1135] AWEC cites to Commission precedent for the premise that "single-issue ratemaking is generally disfavored as it allows for specific ratemaking treatment for a single or small subset of costs, regardless of whether other costs have gone up or down during the same period, and "risks over-earning by the company and over-paying by the customers."[1136] AWEC opines that Avista forecast the insurance expense within the confines of the MYRP, instead of truing up the expense through the balancing account.[1137]

Decision

641 In Avista's 2022 rate case, and as part of settlement, the parties agreed to the establishment of a non-precedential Insurance Balancing Account. The Commission approved the

---

[1131] Staff's Brief, ¶110 referencing Andrews, Exh. EMA-1T at 33:12-18.

[1132] Staff's Brief, ¶111 referencing Erdahl, Exh. BAE-1T at 30:10-32:1.

[1133] Staff's Brief, ¶111; Andrews, Exh. EMA-6T at 37:13-38:6 (agreeing to continue reporting on measures Avista has taken to minimize insurance costs).

[1134] Public Counsel's Brief, ¶106.

[1135] AWEC's Brief, ¶104.

[1136] AWEC's Brief, ¶104 citing *In re Avista Corporation*, Docket UG-060518, Order 04 at 11 (Feb. 1, 2007).

[1137] AWEC's Brief, ¶104.

settlement and the Insurance Balancing Account.[1138] In that case, Public Counsel opposed the establishment of the Insurance Balancing Account on the grounds that generally, authorizing a pass-through guaranteeing a company recovery of its costs in a certain area removes the business incentive for the company to control those costs.[1139] However, in the present case, it is AWEC that seeks discontinuance of the Insurance Balancing Account,[1140] raising the same arguments that Public Counsel raised in Avista's 2022 rate case.[1141]

642 In Avista's 2022 rate case we found that Avista had demonstrated unprecedented increases and volatility in its insurance costs, and that the insurance expense increases in recent years are "extraordinary" and "volatile" and caused an under-recovery of approximately $5.3 million in 2022.[1142] Moreover, we held that Avista demonstrated that it had taken and is taking appropriate steps to try to control these costs, but had shown unprecedented recent increases in insurance that were largely out of its control. These increases had 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.[1143] Further, we agreed that these costs had increased due to factors outside the Company's control and despite the Company's best efforts under its Wildfire Resiliency Plan.[1144]

643 Based on the evidence and testimony, we reject AWEC's recommendation to discontinue and accept Avista's proposal to continue the Insurance Balancing Account. Similar to the circumstances in 2022, we again see a volatile insurance market due to the increase of recent natural disasters, including the persistent presence of wildfires. We note that Avista witness Andrews stated in her testimony that "the volatility experienced by Avista, and the utility industry, is extraordinary and outside the Company's control."[1145] In addition, we note Staff witness Erdahl's testimony that, "there has not been evidence of conditions

---

[1138] *Avista,* Dockets UE-220053, *et. al.,* Order 10/04 ⁋140.

[1139] *Avista,* Dockets UE-220053, *et. al.,* Order 10/04 ⁋140; See also Mullins, Exh. BGM-1T at 64:20-65:1.

[1140] Mullins, Exh. BGM-1T at 64:15-20.

[1141] Mullins, Exh. BGM-1T at 65:15-19.

[1142] *Avista,* Dockets UE-220053, *et. al.,* Order 10/04 ⁋141; Andrews, Exh. EMA-1T at 66:16-19 and Exh. EMA-7T 28:5-11.

[1143] *Avista,* Dockets UE-220053, *et. al.,* Order 10/04 ⁋141; See also Andrews, EMA-1T at 64:2-74:19; Brandkamp, Exh. REB-1CT at 3:22-8:12.

[1144] *Avista,* Dockets UE-220053, *et. al.,* Order 10/04 ⁋141; See also Andrews, EMA-1T at 64:2-74:19; Brandkamp, Exh. REB-1CT at 3:22-8:12.

[1145] Andrews, Exh. EMA-6T at 37:7-10.

becoming more stable," and that the balancing account protects the ratepayers and the Company from over or under-collection of insurance expense.[1146] Therefore, because of the continued volatility of market conditions beyond Avista's control the Insurance Balancing Account shall continue.

644 We turn to the baseline for the Company's Insurance Balancing Account. Avista proposes adjusting the Insurance Expense Balancing Account baselines, over the Two-Year Rate Plan, to $12.8 million for electric, and $2.3 million for natural gas, as filed by the Company.[1147] No other parties contest Avista's proposed adjustments. Additionally, given the current market and environment, increasing the Insurance Expense Balancing Account baselines is appropriate. Therefore, we approve increasing Insurance Expense Balancing Account baselines to $12.8 million for electric, and $2.3 million for natural gas.

645 Next, Avista has proposed to recover carrying charges at its cost of debt. No Party contests Avista's proposal. We grant Avista's proposal to recover its carrying charges at its cost of debt.

Association Dues

Public Counsel's Response Testimony

646 While not addressed in Avista's direct testimony, Public Counsel witness M. Garrett proposes full disallowance of Avista's industry association dues paid to the American Gas Association (AGA) and the Edison Electric Institute (EEI), which would reduce the as-filed revenue requirement by approximately $140,000 for AGA dues and $252,000 for EEI dues.[1148] M. Garrett argues that Avista has not adequately demonstrated that its "request for recovery of these dues relates to customer interests rather than lobbying and broader industry advocacy efforts."[1149]

647 M. Garrett maintains that in recent years, regulatory commissions and legislators nationwide are raising concerns of utilities inappropriately passing along costs of political activities and "industry self-promotion to captive customers,"[1150] since a significant

[1146] Erdahl, Exh. BAE-1T at 32 5-8. In Order 10/04 ¶144, the Commission established that overcollection or undercollection would be subject to rebate or surcharge.

[1147] Avista's Brief, ¶146.

[1148] M. Garrett, Exh. MEG-1T at 24:12-17. *See also* Exh. MEG-3 Sch. 3.8 and Exh. MEG-4 Sch. 4.8.

[1149] M. Garrett, Exh. MEG-1T at 24:10-13.

[1150] M. Garrett, Exh. MEG-1T at 15:16-18.

portion of the industry association dues relate to payments for lobbying efforts and political activities.[1151] M. Garrett argues that given there is significant overlap between the services these associations provide for the public interest and those which advocate for their members' private interests, these expenses should be removed until "a clear distinction between these services" can be made.[1152] M. Garrett also refers to IRS regulations that require these associations to report amounts spent on lobbying activity, but argues that the narrow definition for "lobbying" is not sufficient to determine how much of EEI's and AGA's efforts are "more appropriately described as advocating for its members' private interests to federal, state, and local officials and policymakers."[1153]

648 Additionally, in light of growing concerns, M. Garett highlights that FERC recently opened a Notice of Inquiry (NOI) to examine this issue, and he cites to a recent appellate court decision holding that "*indirect* influence expenses (*e.g.,* industry associations that provide public policy advocacy services on behalf of dues-paying members) should be recorded [below the line]."[1154] M. Garett also cites to state public utility commissions in Kentucky, Minnesota, California, and Avista's recent rate case in Oregon, where industry association dues were disallowed, in full or in part.[1155] M. Garret also cites to legislation enacted in Colorado, Connecticut, New York, and Maine, as instructive to prohibit utilities from recovering expenses for trade or industry association dues from retail customers.[1156]

Sierra Club's Cross Answering Testimony

649 In its Cross-Answer testimony, Sierra Club witness Dennison supports Public Counsel's proposed 100 percent removal of industry association dues, noting agreement with the arguments put forth by Garrett above.[1157] Dennison also highlights that Sierra Club led a coalition of 17 organizations that called for Avista to end its membership with the AGA on the basis of AGA's opposition to policymakers misleading the public by failing to disclose their financial backers. Specifically, in a letter to Avista, the AGA in relevant part stated it "opposed local, state, and federal building decarbonization policies, deployed tactics and experts that were previously used by big tobacco companies to cast doubt about the health

---

[1151] M. Garrett, Exh. MEG-1T at 16:1-2.

[1152] M. Garrett, Exh. MEG-1T at 16:6-13.

[1153] M. Garrett, Exh. MEG-1T at 17:19 – 18:4.

[1154] M. Garrett, Exh. MEG-1T at 19:10 – 20:4.

[1155] M. Garrett, Exh. MEG-1T at 21:11 – 22:2.

[1156] M. Garrett, Exh. MEG-1T at 23:13-17.

[1157] Dennison, Exh. JAD-12T at 9:5-6.

harms of burning gas indoors, and mislead policymakers and the public by failing to disclose its financial support for these efforts."[1158]

Avista's Rebuttal Testimony

650 Avista witness Schultz asserts that all costs associated with political activities and lobbying efforts paid to the EEI and AGA are booked "below-the-line" and charged directly to shareholders, and that all other costs related to membership are directly related to utility operations, and therefore properly recoverable from ratepayers.[1159] Schultz argues that EEI and AGA provide "public policy leadership, critical industry data, market opportunities, strategic business intelligence, and one-of-a-kind conferences and forums, among other things."[1160] Schultz also asserts that "Washington ratepayers benefit from Avista's involvement in these organizations because they provide an opportunity for Company's employees: (1) to stay abreast of critical electric and natural gas industry issues issue specific to utilities: (2) to access to volumes of information on industry data; and (3) to foster networking opportunities within those industries."[1161]

651 Schultz provides some specific examples of how Avista and its customers benefit from Avista's membership in EEI and AGA, including its participation in EEI's Reliability Technical Committee (RTC), EEI's Reliability Executive Advisory Committee (REAC), EEI's Spare Transformer Equipment Program (STEP), AGA's Peer Review, AGA's Technical Committees and Technical Discussion Groups, and AGA's Field Operations Committee.[1162] Schultz cites to a specific example of a customer benefit received through its membership. Namely AGA deployed its National Mutual Aid Program during the Williams Pipeline dig-in that occurred in November 2023, which allowed Avista to quickly restore services to its 36,000 natural gas customers after the pipeline was damaged.[1163] Through this program, Schultz states, AGA helped coordinate over 300 mutual aid workers from eight natural gas utilities across six states, which enabled Avista to restore service to customers in less than a week.[1164]

[1158] Dennison, Exh. JAD-12T at 8:1-7.

[1159] Schultz, Exh. KJS-5T at 59:6-12.

[1160] Schultz, Exh. KJS-5T at 59:15-17.

[1161] Schultz, Exh. KJS-5T at 59:17-21.

[1162] Schultz, Exh. KJS-5T at 60:1 – 61:24.

[1163] Schultz, Exh. KJS-5T at 61:27-33.

[1164] Schultz, Exh. KJS-5T at 61:34 – 62:3.

652 Finally, Schultz disputes M. Garrett's statement that in Avista's recent general rate proceeding in Oregon, the commission disallowed industry association dues. The Oregon case was an all-party settlement, whereby as part of the "give-and-take," Avista agreed to remove these costs for settlement purposes.[1165] As such, Schultz explains that the disallowance and approval of a settlement agreement "are two very different things and should give the Commission pause"[1166] in reviewing the arguments put forward by M. Garrett and the Sierra Club. For these reasons, Schultz concludes that Avista's industry association membership dues are prudently incurred and that Public Counsel's proposed removal of such costs from revenue requirement should be rejected.[1167]

Decision - Association Dues

653 While the Commission acknowledges that an overlap can exist between the services associations provide for the public interest and those which advocate for their members' private interests in lobbying, absent any evidence in the record that demonstrate the dues Avista pays go directly toward private interest and lobbying, we find this argument speculative. More importantly, Avista identified a direct nexus to the benefits its customers received through its membership in these groups, including deployment of AGA's National Mutal Aid Program during the Williams Pipeline incident, which enabled the Company to coordinate over 300 mutual aid workers from eight natural gas utilities across six states to restore service to customers in less than a week. Additionally, because it is unclear to what degree it is Avista's responsibility to perform an audit for each association's costs and services, and because FERC's NOI into this issue is pending, we reject Public Counsel and Sierra Club's proposal to disallow Avista's industry association dues paid to AGA and EEI.

Investor Relations Expense

Public Counsel's Response Testimony

654 Public Counsel witness M. Garrett proposes an adjustment to Avista's investor relations expense, arguing that a 50/50 split of these costs between shareholders and ratepayers is appropriate.[1168] M. Garrett's adjustment would result in a revenue requirement reduction of $201,000 (WA Electric) and $60,000 (WA Natural Gas).[1169]

[1165] Schultz, Exh. KJS-5T at 62:5-13.

[1166] Schultz, Exh. KJS-5T at 62:13-16.

[1167] Schultz, Exh. KJS-5T at 62:18-19.

[1168] M. Garrett, Exh. MEG-1T at 36:7-9.

[1169] M. Garrett, Exh. MEG-1T at 36:9-12.

655 M. Garrett argues that "shareholders and customers both benefit when the Company incurs expenses to disseminate information about Avista's current and future earnings and investments to the larger investment community in a timely manner," noting that customers benefit when the Company can access capital at a lower price, and shareholders benefit through higher share prices.[1170] Based on this, M. Garrett believes a 50/50 split is appropriate.[1171]

Avista's Rebuttal Testimony

656 Avista witness Schultz offers on rebuttal that the effect of a 90/10 adjustment would be a reduction in revenue requirement of approximately $40,000 (WA Electric) and $12,000 (WA Natural Gas).[1172]

657 Schultz argues that the proposal to split these costs 50/50 is "completely unreasonable."[1173] As an investor-owned utility, Schultz argues, Avista raises approximately half of its funds used to serve its customers through equity markets, and as a result is required to meet certain rules and requirements that set forth how Avista operates, including "the development and issuance of quarterly and annual financial reports, which is facilitated by investor relations."[1174] Schultz explains that Avista's investors, who are its owners, provide the funds necessary to operate its business for the benefit of its customers and that its investor relations team facilitates its compliance with Securities and Exchange Commission (SEC) requirements, financial reporting, and communication with the investment community.[1175]

658 Schultz also argues that Public Counsel's proposed 50/50 split is arbitrary and unsupported by evidence.[1176] Schultz notes that, unlike when Avista had significant non-utility operations in the past which may justified a lower percentage sharing, Avista is now comprised almost entirely of utility operations, with only a small set of passive investments under Avista Capital.[1177]

[1170] M. Garrett, Exh. MEG-1T at 36:3-7.

[1171] M. Garrett, Exh. MEG-1T at 36:7-9.

[1172] Schultz, Exh. KJS-5T at 35:9-12.

[1173] Schultz, Exh. KJS-5T at 49:6-9.

[1174] Schultz, Exh. KJS-5T at 49:9-14.

[1175] Schultz, Exh. KJS-5T at 49:16 – 50:4.

[1176] Schultz, Exh. KJS-5T at 50:12-14.

[1177] Schultz, Exh. KJS-5T at 50:15-19.

659 However, Schultz does believe that after review of the arguments made by M. Garrett, some degree of adjustment is appropriate, and Avista offers a 90/10 split, which is consistent with Avista's rationale for having 90 percent of the costs associated with its Board of Directors allocated to utility customers.[1178] Schultz states that "given a small portion of the overall Company is related to non-utility activities, it is reasonable to assert that a portion should be recognized as non-utility."[1179]

Decision – Investor Relations

660 The Commission finds that Avista's revised offer provided on rebuttal of a 90/10 split is a reasonable middle-ground as opposed to the 50/50 split proposed by Public Counsel. The Company's proposal is also consistent with the 90/10 allocation of Avista's Directors' and Officers' liability insurance policy.

Working Capital

AWEC's Response Testimony

661 AWEC Witness Mullins argues that Avista inappropriately includes interest-bearing accounts within its Working Capital. Mullins testifies that although the Company claims to deduct the interest associated with the two specific accounts in question, Avista errs in its calculation of the net interest and is unable to track the interest specific to electric and natural gas operations. He argues, too, that the historical period will not accurately reflect the expected interest earned during the rate plan as interest is not earned based on an average balance and is subject to changing condition in the commodities market.[1180] Further, Mullins testifies the Company's working capital model contained hardcoded balances and therefore AWEC was unable to duplicate Avista's calculation. However, Mullins estimates the impacts of AWEC's recommendation would reduce the revenue requirement by approximately $2.5 million for electric and $311,000 for natural gas.

Avista's Rebuttal Testimony

662 Company witness Andrews refutes AWEC's proposed adjustment to Working Capital testifying that Avista used the methodology for excluding interest-bearing portions of accounts used for commodity trades in its 2019 GRC in consolidated dockets UE-190334,

---

[1178] Schultz, Exh. KJS-5T at 50:5-8.

[1179] Schultz, Exh. KJS-5T at 50:9-10.

[1180] Mullins, Exh. BGM-1T at 26:3 – 28:2, 29:6-22.

UG-190335, UE-190222. Andrews argues this methodology was proposed by Commission Staff and approved by the Commission.[1181]

663 Additionally, Andrews rejects AWEC's contention that the Company is unable to accurately identify the interest-bearing portion of the two accounts nor unable to identify the impacts to electric and natural gas operations independently. Witness Andrews references Company witness Schultz's calculations of the Working Capital adjustment (1.03 ISWC Adjustment) that specifically identify that 92 percent of the accounts are non-interest-bearing and identifies specific dollar amounts for the electric and natural gas share of the interest-bearing portion of the accounts.[1182]

664 Further, Andrews disagrees with AWEC's position that historical account balances are not an indicator of future balances. While Andrews agrees that the events that occurred in winter 2022 were extraordinary, the collateral balances have not returned to pre-2022 levels. With continued changing market conditions, which have resulted in more market transactions over the past five years, collateral balance baselines are anticipated to remain elevated. Therefore, Andrews contends that margin rates have also not returned to pre-2022 levels. Finally, Andrews argues the Company appropriately uses historical balances in its Working Capital adjustment as it not feasible to project the hundreds of balance sheet accounts that flow into this adjustment. Andrews states that allowing a party to "cherry pick" accounts to reduce working capital is inappropriate; while some accounts may decline from historical balances, others may just as likely increase.[1183]

665 Finally, witness Andrews provides testimony that generally supports the inclusion of working capital as a mechanism to mitigate regulatory lag. Andrews claims otherwise the Company would be required to incur a greater lost return beyond what it has already absorbed.[1184]

Parties' Briefs

Avista

666 Avista argues that the Commission should approve its Investor Supplied Working Capital (ISWC) Restating Adjustment 1.03 and reject AWEC's proposal to remove the Wells and Mizuho account balances from the adjustment. Avista states that it complied with the

---

[1181] Andrews, Exh. EMA-6T at 45:3-15.

[1182] Andrews, Exh. EMA-6T at 46:15 – 47:5.

[1183] Andrews, Exh. EMA-6T at 47:9 – 48:8.

[1184] Andrews, Exh. EMA-6T at 49:3-19.

methodology that the Commission approved in Dockets UE-190334, UG-190335, and UE-190222 by removing the minimal interest-bearing portion of these accounts such that they represent expected ISWC balances during the effective period of the multi-year rate plan.[1185] The Company further notes that it has experienced a lost return of over $6.3 million in 2023 due to increased ISWC balances as a result of increased power supply margin account balances, resulting in substantial regulatory lag.[1186]

AWEC

667 AWEC recommends that the Commission adopt an adjustment to reflect the removal of Avista's Wells and Mizuho interest-bearing accounts. AWEC states that while the method Avista used in this proceeding is consistent with the method used in Dockets UE-190334, UG-190335, and UE-190222, the Commission did not expressly adopt that methodology in its order.[1187] AWEC argues that Avista's methodology is inappropriate for two reasons. First, AWEC contends that because there are factors that influence the accounts' earned interest beyond the account balances, it is inappropriate to conclude that a portion of the balances do not earn interest.[1188] Second, AWEC contends that the two accounts' performance during the historical period are not representative of anticipated performance during the rate effective period of the rate plan.[1189]

668 AWEC further disagrees with Avista's assertion that AWEC's proposed adjustment is selectively interpreting accounts and maintains that its recommendation is grounded in RCW 80.28.425(3)(b)'s requirement to determine the fair value of property during the rate effective period of the rate plan.[1190] AWEC assert that Avista's adjustment fails to properly forecast the balances of the Wells and Mizuho accounts in the rate effective period because Avista did not adjust its historical data to account for the influence of unusual

[1185] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, Avista's Post-Hearing Brief ¶ 112 (Oct. 28, 2024).

[1186] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, Avista's Post-Hearing Brief ¶ 112 (Oct. 28, 2024).

[1187] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 95 (Oct. 28, 2024).

[1188] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 96 (Oct. 28, 2024).

[1189] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 96 (Oct. 28, 2024).

[1190] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 97 (Oct. 28, 2024).

market prices during the winter of 2022-2023.[1191] AWEC contends that Avista's power supply forecasts demonstrate that the conditions that caused high prices during the winter of 2022-2023 are unlikely to reoccur during the rate effective period of the rate plan.[1192] Instead, AWEC maintains that margin prices will be effectively zero based on the data from 2020 to 2021, and consequently Avista's recommended approach does not comply with RCW 80.28.425(3)(b).[1193] Finally, AWEC argues that regulatory lag does not provide a justification for adopting Avista's proposed treatment of its Wells and Mizuho accounts because regulatory lag is within the control of the Company.[1194]

Decision

669 The Commission rejects AWEC's proposed revision to Avista's working capital Restating Adjustment 1.03. As an initial matter, the Commission disagrees with AWEC's assertion that the methodology used by Avista for its working capital adjustment is not precedential. As AWEC acknowledges in its briefing, the methodology used by Avista in this case is the same methodology used in Dockets UE-190334, UG-190335, and UE-190222.[1195] While the methodology was not explicitly discussed in the order, it was in fact used during the case and incorporated into the final outcome, and the Company has used that methodology in all of its subsequent rate cases.[1196] Consequently, it was deemed fair, just, reasonable, and sufficient by the Commission and AWEC's arguments to the contrary are unpersuasive.

670 In its brief, AWEC argues that the Commission should reject Avista's methodology in part because the extraordinary prices that occurred during the winter of 2022-2023 are not representative of how the working capital accounts will perform during the rate effective period.[1197] However, it is clear from Avista's testimony that it considered several factors other than just the winter 2022-2023 prices, including elevated power and gas prices

---

[1191] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 97 (Oct. 28, 2024).

[1192] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 97 (Oct. 28, 2024).

[1193] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 97 (Oct. 28, 2024).

[1194] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 98 (Oct. 28, 2024).

[1195] Id., at ¶ 95.

[1196] Andrews, Exh. EMA-6T at 45:6-15.

[1197] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 96 (Oct. 28, 2024).

relative to past years, greater price volatility, and the impacts of significant market events.[1198] The Commission further shares Avista's concerns that attempting to forecast an adjustment to its ISWC is not reasonably feasible, given that it consists of hundreds of balance sheets.[1199]

671 Although AWEC argues that its adjustment method is more reasonable because it forecasts the likely performance of the accounts during the rate effective period, there does not appear to be supporting analysis for AWEC's forecast beyond a citation to witness Mullins' testimony.[1200] In turn, witness Mullins states in testimony "[a]s can be seen, in the winter of 2022-2023, the margin balances were extraordinary, whereas in the past they hovered close to zero."[1201] Contrary to AWEC's assertions, this observation, standing on its own, does not support the conclusion that the margin balances will in fact be close to zero during the rate effective period. Furthermore, even assuming that AWEC's forecast was accurate, it is not appropriate to adjust some, but not all, of the accounts in Avista's ISWC, because the limited adjustments will not reasonably reflect the performance of the entire ISWC during the rate-effective period.

672 Finally, the Commission disagrees with AWEC's assertion that its proposed methodology is the only methodology that complies with RCW 80.28.425(3)(b). The Commission notes that pursuant to RCW 80.28.425(3)(d), "[i]n ascertaining and determining the fair value of property of a gas or electrical company pursuant to (b) of this subsection . . . the commission may use any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." This statute affords the Commission broad discretion regarding an appropriate methodology, provided that the method is "reasonably calculated" to arrive at rates that are fair, just, reasonable, and sufficient. Consequently, the Commission has discretion to authorize a methodology that considers historical performance, even in the absence of a forecast. The Commission has done so in the past on this issue and determines that it is reasonable to do so again based on the record developed in this proceeding. The Commission accepts Avista's proposed Restating Adjustment 1.03.

[1198] Andrews, Exh. EMA-6T at 47:9 – 48:2.

[1199] Andrews, Exh. EMA-6T at 48:13 - 20.

[1200] *WUTC v. Avista Corp.*, Dockets UE-240006 & UG-240007, AWEC's Post-Hearing Brief ¶ 97, fn. 242, 247 (Oct. 28, 2024) (citing Mullins, Exh. BGM-1T at 28:12-13).

[1201] Mullins, Exh. BGM-1T at 28:12-13.

FIT/DFIT/ITC Adjustment

673 We note that Avista filed a petition in Dockets UE-200896 and UG-200896, requesting the Commission authorize a change to its accounting for federal income tax expense for certain plants and defer the associated change in tax expense (Tax Customer Credit) on October 30, 2020, the same date it filed its 2020 GRC in Dockets UE-200900 and UG-200901.

674 In its order granting the petition, the Commission authorized Avista to change its accounting method for plant related to IDD#5 mixed service costs (inventory costs) and for meters from normalization to flow-through treatment. Additionally, Order 01 authorized the deferral for the associated change in tax expense. The Commission found the proposed accounting treatment had no immediate impact on rates, and that the treatment of unprotected ADFIT and EDIT (including the Tax Customer Credit) would be addressed within the context of the 2020 GRC.

675 The 2020 GRC resulted in a partial multiparty settlement, however, the Tax Customer Credit remained contested. In its final order, the Commission ordered that Avista begin returning the benefit to customers as of the rate effective date over a two-year period through separate tariff schedules. However, as the balance of the Tax Customer Credit would not reach zero at the end of that two-year period, the Commission temporarily ordered a new 10-year amortization schedule for that remaining balance subject to reexamination in the subsequent GRC.

676 On December 12, 2022, the Commission issued its final order in that subsequent GRC which resulted in a full multiparty settlement.[1202] The settling parties agreed the Residual Tax Customer Credit be returned to customers using the same tariff schedules created in the 2020 GRC over a two-year period beginning with the rate effective date of the 2022 GRC. At that time, the residual amounts were $27.6 million for electric and $12.5 million for natural gas.[1203]

[1202] Public Counsel opposed certain aspects of the settlement, but the Residual Tax Customer Credit was not one of those issues.

[1203] *WUTC v. Avista*, Dockets UE-220053, UG-220054, and UE-210854 *(consolidated)*, Order 10/04 ¶¶ 58-61 (Dec. 12, 2022). The settlement provided no additional information regarding continued tax deferrals or further residual credits, nor did it discuss how or when to discontinue those deferrals and associated tariff schedules and subsequently including any remaining balances into rate base.

AWEC Response Testimony

677 In this proceeding, AWEC proposes the Commission now require Avista to fully transition to flow-through accounting rather than continuing the deferral process.[1204] Mullins argues these benefits are no more uncertain than any other tax provision. Therefore, Mullins contends this is the appropriate proceeding to discontinue the deferrals, and on a going-forward basis, include the benefits as a reduction to rate base. Mullins proposes a one-time offset to RY2 for electric to mitigate the rate increase associated with the Colstrip retirement. For natural gas, Mullins recommends the amount be amortized over the two-year rate plan. However, AWEC recognizes residual balances will remain in that account and recommends maintaining the tariff schedules to refund that ending balance to customers.[1205]

678 Additionally, Mullins takes issue with the Company including a carrying charge at its full cost of capital on the residual balances. Mullins argues that the Commission never authorized such treatment. AWEC recommends eliminating the carrying charge, which in combination with the full transition in tax treatment, results in a reduction in revenue requirement of approximately $5.7 million for electric and $5.4 million for natural gas.[1206]

Avista's Rebuttal Testimony

679 Witness Andrews disagrees with AWEC's recommendations, testifies that witness Mullins erred in his recalculation of the tax benefit amount owed to customers, and argues that the Commission through approval of the two preceding rate cases accepted the Company's appropriate inclusion of the carrying charge.

680 First, Andrews reasons the Commission's approval of the deferral treatment ensures customers receive dollar-for-dollar actual tax benefits and keeps the Company whole.[1207] Next, Andrews testifies that if the Commission were to decide to end the deferrals in December 2024, that the end-of-period balances would result in a debit balance (due from customers) of $0.5 million for electric and a credit balance of $2.4 million for natural gas, and require an adjustment to the test period liability balances to reflect the revised ADFIT

[1204] Mullins, Exh. BGM-1T at 36:6-19.

[1205] Mullins, Exh. BGM-1T at 37:7-38:3, 39:14-18.

[1206] Mullins, Exh. BGM-1T at 38:10-11, 39:2-3, 39:5-10.

[1207] Andrews, Exh. EMA-6T at 57:14-19, 71:16-72:1.

level resulting in an increase in rate base of $30.1 million and $11.6 million for electric and natural gas, respectively and by extension the revenue requirement.[1208]

681 Addressing the carrying charge, Andrews contends the customers have received the benefit of lower rate base over the course of the deferral and subsequent amortizations. If the Company did not include the full cost of capital, Avista would be "penalized" for the return on that understated rate base in the amount of $9.7 million.[1209] Further, Andrews argues the treatment, including the return, were presented in its workpapers in both the 2020 and 2022 GRC proceedings. Andrews submits that no party contested those calculations during either rate case and subsequently, the Commission approved that treatment through its final orders in those proceedings.[1210]

682 Finally, while Avista proposes to continue the current deferred accounting treatment, Andrews offers that if the Commission prefers to end the Customer Tax Credit deferred accounting that it allows the Company to do so in the next GRC. Andrews argues this will allow the Company to fully account for this change.[1211]

Parties' Briefs

AWEC

683 In its brief, AWEC notes that "the remaining balances due to customers, at least based on Avista's calculation, will decline effectively to zero by December 31, 2024."[1212] AWEC agrees with Avista's calculation of associated accumulated deferred income taxes. However, AWEC opposes the perpetual deferral of the annual impacts of the flow-through accounting.[1213] Instead, AWEC recommends to the Commission that the associated flow-through benefits be considered in base rate revenue requirement, which AWEC contends would be consistent with the accounting application approved by the Commission in Dockets UE-200895/UG-20089. [1214] AWEC challenges Avista's characterization of its

---

[1208] Andrews, Exh. EMA-6T at 58:13. Andrews notes correcting AWECs balances results in an increase to Mullins revenue requirement by $2.8 million and $1.1 million for electric and natural gas, respectively. Andrews, Exh. EMA-6T at 58:13-15.

[1209] Andrews, Exh. EMA-6T at 67:6-10, 68:6-8, 70:6-12.

[1210] Andrews, Exh. EMA-6T at 72:9-73:10.

[1211] Andrews, Exh. EMA-6T at 60:7-12.

[1212] *WUTC v. Avista Corp.*, Dockets 240006 & 240007, AWEC's Post-Hearing Brief ¶ 59 (Oct. 28, 2024).

[1213] AWEC's Post-Hearing Brief, at ¶ 60.

[1214] AWEC's Post-Hearing Brief, at ¶ 61.

accounting application. [1215] Further, AWEC notes how this process did not result in benefits to ratepayers in 2024.[1216]

Avista

684 In its brief, Avista reiterates its opposition to AWEC's proposal that Avista transition fully to flow-through accounting of its 2025 estimated tax deductions associated with IDD#5 and meter expenditures.[1217] Avista emphasizes that the process is to the benefit of customers, citing to the $3.4 million saved over 2022 and 2023.[1218] At bottom, Avista contends that the current "accounting for these tax credits has kept customers whole – returning no more, no less owed them."[1219]

Decision

685 We acknowledge AWEC's point that extending these deferrals in perpetuity would be inappropriate. However, we are not persuaded that a change is necessary at this time. Therefore, we reject AWEC's proposal to immediately end the deferral and eliminate the carrying charge. Instead, we accept Avista's alternative proposal to end the deferral in Avista's 2026 general rate case.

Electric and Natural Gas Adjustments (3.03) Pro Forma EDIT Reverse South Georgia Method (RSGM) Expense

686 Briefly, we turn to the issue Avista presented related to the Electric and Natural Gas Adjustments (3.03) Pro Forma EDIT RSGM Expense. The Company's proposed adjustment revises the Company's test year Excess Deferred Income Tax (EDIT) expense levels for a change in its method of accounting for the reversal of long-term tax benefits from the Average Rate Assumption Model (ARAM) to the RSGM. Andrews provides supporting documentation in Exh. EMA-4 to justify the accounting change. The exhibit contains an internal memo that recognizes an inadvertent error related to cost of removal that was not properly accounted for as required by the IRS. This adjustment increases the RY1 electric and natural gas revenue requirement by $122,000 and $181,000,

---

[1215] AWEC's Post-Hearing Brief, at ¶ 62.

[1216] AWEC's Post-Hearing Brief, at ¶ 64.

[1217] Avista's Post-Hearing Brief, at ¶ 115.

[1218] Avista's Post-Hearing Brief, at ¶ 116.

[1219] Avista's Post-Hearing Brief, at ¶ 117.

respectively; with an incremental increase of approximately $1 million for electric in RY2 associated with removing Colstrip EDIT from base rates on January 1, 2026.[1220]

Decision

687 We note that no party has contested this adjustment. However, as the reversal of protected EDIT was addressed in the Company's 2017 GRC and the Commission specifically ordered the use of ARAM, the Commission addresses the change in accounting methodology for the record in this proceeding. Furthermore, the Tax Cut and Jobs Act (TCJA) of 2017 required that protected EDIT be returned due to the change in corporate tax rate.[1221] While ARAM is the most common methodology, when certain information is not known (e.g., the age of assets) then the RSGM may be utilized to avoid violating the normalization rules and passing back EDIT more rapidly or to a greater extent than under the ARAM.

688 The Commission has reviewed Avista's testimony and supporting documentation filed in this proceeding and is satisfied that the Company is required by law to change the method of accounting. Additionally, changing the methodology in this proceeding avoids a violation of the Safe Harbor provision that allows a Company to change its methodology at its next available opportunity. Accordingly, the Commission accepts the Company's change in accounting methodology.

Misc. Restating Non-Utility/Non-Recurring Expenses

AWEC's Response Testimony

689 Witness Mullins recommends the Commission remove two cost items as non-recurring: (1) wildfire litigation, and (2) patent and patent application costs. Mullins rationale is simply that wildfire litigation is not an ongoing expense, and that the Company has a history of developing venture corporations, and therefore, customers should not bear the burden of those costs.[1222]

[1220] Andrews, Exh. EMA-1T at 14:15-15:7.

[1221] Tax Cuts and Jobs Act (TCJA, P.L. 115-97).

[1222] Mullins, Exh. BGM-1T at 34:3-12.

Avista Rebuttal Testimony

690 Company witness Schultz responds to AWEC's recommendations regarding the non-utility/non-recurring restating adjustment.[1223] First, Schultz testifies that the Company does not include any patent-related costs that are non-utility or related to a subsidiary. To the contrary, Schultz argues that Avista pursues innovation and protects those pursuits through patents providing several project examples such as the Company's Digital Exchange Platform, real time optimization of Avista hydro facilities, an invention to facilitate load disaggregation, and enhanced outage management and electric operations.[1224]

691 Second, witness Schultz argues that the Company must maintain some level of legal expense for a variety of categories, with wildfire litigation being a continuing expense and normal course of business given the nature of those cases. Schultz provides four examples of wildfire litigation that occurred in the historical period and are expected to continue through the rate plan period.[1225] Further, Schultz contends it is in the best interest of the Company and its customers that Avista "defend its interests and pursue those rights…."[1226]

Parties' Briefs

Avista

692 In its briefing, Avista rejects AWEC's characterization of legal and wildfire litigation costs as "non-recurring." [1227] Avista explains that in the normal course of business, the company becomes involved in "various claims, controversies, disputes and other contingent matters, including wildfire litigation." In fact, Avista contends that it "has been conservative and understated legal expenses in this case." [1228] In support of this, Avista explains that the requested legal expenses are lower than the level actually experienced in 2023.

[1223] The Company did make a correction to this adjustment to exclude a single invoice as non-utility. This correction lowered the revenue requirement by $2,000 for electric and $1,000 for natural gas. Schultz, Exh. KJS-5T at 25:10-17.

[1224] Schultz, Exh. KJS-5T at 36:14-21.

[1225] Schultz, Exh. KJS-5T at 37:25-38:7.

[1226] Schultz, Exh. KJS-5T at 38:10.

[1227] Avista's Post-Hearing Brief, at ¶ 98.

[1228] Avista's Post-Hearing Brief, at fn. 130.

AWEC

693 In its briefing, AWEC continues to recommend that the Commission adjust Avista's revenue requirement to remove non-recurring legal expenses incurred in the test period.[1229] AWEC argues that the Company's list of incidents amount to "Specific, discrete cases that will most certainly conclude."[1230] AWEC rejects the normalization of such costs and requests that they be excluded from rates. AWEC goes on to state that the patents do not provide a benefit to ratepayers, and thus litigation expense to protect them do not "meet the used and useful standard."[1231] In support of this, AWEC proffers that a competing utility's infringement of Avista's patent does not harm ratepayers.

Decision – Litigation Costs

694 We reject AWEC's proposed adjustment to remove wildfire and patent litigation expenses as non-recurring. Litigation costs generally are part of the cost of doing business. However, we note that costs may become unreasonable, at which point such costs would be excluded from rates.

Miscellaneous Pro Forma Adjustments – Non-Executive Labor, Employee Benefits, and Incentive Pay Pro Forma Labor, Non-Executive Adjustments

Avista's Direct Testimony

695 Avista Pro Forma Adjustment 3.05 proposes increases in base pay for non-executive Union and non-Union employees.[1232] This base pay reflects a portion of Avista employees' total compensation package, which also includes pay-at-risk incentives (see Pro Forma Incentives Adjustment 3.08), which aim to "provide competitive compensation in the marketplace."[1233] Avista witness Schultz states that base pay levels are determined through consultation with third-party firms that compare Avista's compensation levels with other organizations in the utility industry, and other industries regionally and nationally.[1234]

[1229] AWEC's Post-Hearing Brief, at ¶ 100.

[1230] AWEC's Post-Hearing Brief, at ¶ 101.

[1231] AWEC's Post-Hearing Brief, at ¶102.

[1232] Schultz, Exh. KJS-1T at 56:3 and 57:5-7.

[1233] Schultz, Exh. KJS-1T at 56:3-6.

[1234] Schultz, Exh. KJS-1T at 56:9-11.

Based on these surveys, salary recommendations are presented to the independent Compensation Committee of the Board of Directors, for consideration and approval.[1235]

696 Specifically, Avista's non-executive non-Union base pay adjustment annualizes the impact of the actual pay increases effective March of 2023, and include expected increases for March 2024,[1236] and a final increase for non-Union employees that its Board will approve in the first quarter of 2024."[1237] Avista also included an estimated prorated March 2025 increase for total labor expense levels in RY1.[1238]

697 For Union employees, Avista proposes an increase to annualize the effect of the 3.5 percent increase that occurred in 2023, and notes that the Company is currently negotiating 2024 merit increases, which it expects will be finalized during the pendency of the case.[1239] In lieu of final amounts which will be available upon ratification of its Union contract, Avista proposes that its estimated merit increases for 2024 and 2025, be consistent for its non-Union employees.[1240]

698 The effect of this adjustment is an expense increase, resulting in a decrease in Net Operating Income (NOI) of approximately $5.2 million (WA Electric) and $1.4 million (WA Natural Gas).[1241]

699 Avista's related adjustment for RY2, Pro Forma Adjustment 5.02, reflects incremental increases in Union and non-Union wages and salaries for 2026,[1242] the Company's adjustment annualizes its estimated 2025 wage increases and includes the prorated salary increases expected in March 2026 for both Union and non-Union employees.[1243] The effect of this adjustment would in turn result in a decrease in NOI of approximately $2.1 million (WA Electric) and $0.6 million (WA Natural Gas).[1244]

[1235] Schultz, Exh. KJS-1T at 56:20 – 57: 3.

[1236] Schultz, Exh. KJS-1T at 57:8-9.

[1237] Schultz, Exh. KJS-1T at 57:8-13.

[1238] Schultz, Exh. KJS-1T at 57:13-15.

[1239] Schultz, Exh. KJS-1T at 57:16-21.

[1240] Schultz, Exh. KJS-1T at 57: 19-20.

[1241] Schultz, Exh. KJS-1T at 58:1-3.

[1242] Schultz, Exh. KJS-1T at 92:3-6.

[1243] Schultz, Exh. KJS-1T at 92:6-9.

[1244] Schultz, Exh. KJS-1T at 92:9-10.

Staff's Response Testimony

700 Staff contests Avista Pro Forma Adjustment 3.05, on the basis that Avista's adjustment uses estimated wage increases for its Union and non-Union employees for 2024 and 2025, which are not known and measurable.[1245] Staff witness Hillstead contends that the amounts used in Avista's pro forma adjustment for non-Union employees differ slightly from the wage increases approved by Avista's Board of Directors for March 1, 2024 and March 1, 2025, which were approved after Avista's initial filing.[1246] Accordingly, Staff proposes a pro forma adjustment reflecting the actual approved non-Union wage increases for 2024 and 2025.[1247]

701 Regarding base pay increases for Union employees, Hillstead notes that the Union increases for 2024 and 2025 cannot be quantified, as the contract has not yet been ratified.[1248] Pending finalization of the contract, Staff proposes removal of Avista's proposed Union pay increases for 2024 and 2025, but states that they would support inclusion of these amounts should those costs become known and measurable on rebuttal.[1249]

702 In total, Staff's proposed adjustment would result in a revenue requirement reduction of approximately $1.85 million (Combined WA Electric and WA Natural Gas) in RY1.[1250]

Avista's Rebuttal Testimony

703 On rebuttal, Schultz explains that Avista came to agreement with the Union and ratified the contract on July 31, 2024, granting a 5 percent merit increase effective March 2024, which will be retroactively paid, and a 5 percent increase effective March of 2025.[1251] Avista initially estimated and based its pro forma adjustment on a 4 percent merit increase for both 2024 and 2025,[1252] and then updated the adjustment, which resulted in an expense

[1245] Hillstead, Exh. KMH-1T at 11:10-18.

[1246] Hillstead, Exh. KMH-1T at 12:2-6. *See also* Hillstead, Exh. KMH-6C.

[1247] Hillstead, Exh. KMH-1T at 12:7-8.

[1248] Hillstead, Exh. KMH-1T at 12:9-11.

[1249] Hillstead, Exh. KMH-1T at 12:14-17.

[1250] Hillstead, Exh. KMH-1T at 10:1 (Table 3 – Impact of Contested Adjustments on NOI and Revenue Requirement).

[1251] Shultz, Exh. KJS-5T at 40:15 – 41:6.

[1252] Shultz, Exh. KJS-5T at 41:9-10.

increase from the Union employee portion of its initial proposal of $417,000 (WA Electric) and $126,000 (WA Natural Gas).[1253]

704 Regarding the non-Union portion of its pro forma adjustment, Schultz notes that Staff has accepted and incorporated the Board approved pay increase in its adjustment, which results in a reduction in expense of approximately $338,000 (WA Electric) and $89,000 (WA Natural Gas) when compared to the non-Union portion of Avista's initial proposal.

705 Schultz notes Staff's silence on its RY2 Pro Forma Adjustment (5.02), as Staff does not support a multi-year rate plan (MYRP).[1254] The Company has included in this adjustment, a 3 percent merit increase for 2026 for both Union and non-Union employees, which represents the minimum increase approved by the Board for its non-represented employees.[1255] The Company argues that it is appropriate to apply this increase to its Union employees as well, as "the bargaining unit typically will not accept a merit increase less than that of non-Union employees," and notes that over the past five years, Union merit increases have exceeded the Board approved minimums.[1256] When compared to Avista's as-filed adjustment, Avista's revised proposal would increase its RY1 expense slightly, by $80,000 (WA Electric) and by $37,000 (WA Natural Gas), and would reduce expense in RY2 by $541,000 (WA Electric) and by $147,000 (WA Natural Gas).[1257]

Decision - Pro Forma Labor and Non-Executive Adjustments

706 We accept Avista's Pro Forma Adjustments 3.05 and 5.02, as revised on rebuttal. Avista's revised adjustments appropriately reflect the Union wage increase that became effective July 31, 2024, which granted a 5 percent merit increase effective March 2024, and a 5 percent increase effective March of 2025. Avista's revised adjustments also incorporate a reduction from its initial proposal to its non-Union wage increase, which was approved by the Board after the Company's initial filing. For RY2 the Company's adjustment includes a 3 percent merit increase for both Union and non-Union employees, based on the Board approved minimum. Staff indicated its support for the use of the Board approved minimum in RY2 during the evidentiary hearing.[1258]

[1253] Shultz, Exh. KJS-5T at 41:13-17.

[1254] Shultz, Exh. KJS-5T at 40:1-2.

[1255] Shultz, Exh. KJS-5T at 42:13-14.

[1256] Shultz, Exh. KJS-5T at 42:12 – 43:8.

[1257] Shultz, Exh. KJS-5T at 40:3-9.

[1258] TR at 408:10 – 409:2.

Pro Forma Employee Benefits

Avista's Direct Testimony

707 Avista proposes Pro Forma Adjustment 3.07 which adjusts its test year retirement plan expenses and medical insurance expenses for active and retired employees to the amounts expected in RY1.[1259] Avista calculates its adjustment based on estimates determined annually by Willis Towers Watson, an independent actuarial company which deals with Avista's retirement plan, and by Mercer, which deals with its medical plans.[1260]

708 Regarding the retirement portion of its adjustment, the Company included only its test year level of actual pension expense but plans to update its adjustment to reflect a prorated amount for RY1 based on an updated actuarial report expected in first quarter of 2024.[1261] Avista witness Schultz notes that the Company has made changes to its overall retirement plan, and proposes an increase consistent with its proposed labor increases prorated for the rate effective period, resulting in an increase in 401(k) expense of $749,000 (Total System).[1262]

709 Schultz notes that Avista has closed its defined benefit pension plan to all non-Union employees as of January 1, 2024, and for Union employees effective January 1, 2024, and a defined contribution 401(k) plan replaced the defined benefit pension plan for employees hired after these cutoff dates.[1263]

710 Schultz also discusses Avista's pension settlement and related amortization, which is a component of its adjustment, and was authorized for a 12-year amortization beginning January 1, 2023, as approved in Avista's last rate case.[1264] Schultz notes that the test year contained six months of this amortization, and Avista proposes to annualize this amount within its pro forma adjustment.[1265]

[1259] Shultz, Exh. KJS-5T at 59:3-6.

[1260] Shultz, Exh. KJS-5T at 59:6-8.

[1261] Shultz, Exh. KJS-5T at 60:15-19.

[1262] Shultz, Exh. KJS-5T at 61:2-5.

[1263] Shultz, Exh. KJS-5T at 61: 9-18.

[1264] Shultz, Exh. KJS-5T at 62: 13-20.

[1265] Shultz, Exh. KJS-5T at 62: 20 – 63: 1.

711 Regarding the medical benefits contained in its adjustment, Avista similarly plans to update its adjustment based on updates from its consultant that it expects to receive in the first quarter of 2024 and will adjust its medical expense once received.[1266]

712 Pro Forma Adjustment 5.03 represents the RY2 portion of Avista's employee benefits expense adjustment.[1267]

AWEC's Response Testimony

713 AWEC disputes Avista's pro forma employee benefits adjustment, and proposes its own adjustment based on an updated actuarial report received in response to a data request.[1268] AWEC witness Mullins argues that the pension and other post-employment benefit costs were materially lower in the updated actuarial report than the values Avista used for its pro forma adjustment.[1269] AWEC argues that Avista did not properly include the full reduction to its benefits expense calculation, as provided through the updated actuarial report, and instead relied on test period expense levels.[1270]

714 AWEC's proposed adjustment would result in a combined reduction in expense of approximately $1.6 million in RY1 and $0.4 million in RY2.[1271]

Public Counsel's Cross-Answer Testimony

715 In cross-answer testimony directed at AWEC witness Mullins, Public Counsel witness M. Garrett adopts Mullins' proposed adjustment.[1272] M. Garrett agrees with Mullins rationale, arguing that "the Company did not include the full reduction in its pension expense on an on-going basis" as reflected in the results of the updated actuarial report.[1273]

[1266] Shultz, Exh. KJS-5T at 64: 4-10.

[1267] Shultz, Exh. KJS-5T at 92: 11-14.

[1268] Mullins, Exh. BGM-1T at 21: 2-3.

[1269] Mullins, Exh. BGM-1T at 21: 6-7.

[1270] Mullins, Exh. BGM-1T at 21: 9-19.

[1271] *See* Mullins, Exh. BGM-1T at 22: 5 (Table 4). Sum of WA Electric and WA Natural Gas impacts.

[1272] M. Garrett, Exh. MEG-9T at 2: 8-10.

[1273] M. Garrett, Exh. MEG-9T at 3: 2-11.

Avista – Rebuttal Testimony

716 Schultz argues that AWEC's adjustment omitted an update to health insurance, post-retirement medical expense, 401(k) expense, as well as the pension amortization expense originally included in the Company's adjustment.[1274] Avista also notes a discrepancy in Mullin's testimony, in which Mullins states that both pension and post-retirement medical expenses were updated per the updated actuary reports, when in fact, Mullins only updated pension expense.[1275] Avista argues that Mullins appears to have chosen only to include the one update that reduced expense, ignoring other components that increased expense.[1276]

717 Schultz argues that Avista has accurately reflected the full effect of the pension settlement and amortization, as well as the updated actuarial report's findings in its adjustment, which has been updated on rebuttal.[1277] Schultz also notes that Mullins has accepted Avista's RY2 adjustment (Pro Forma Adjustment 5.03).[1278] Schultz urges the Commission to reject AWEC's proposal and adopt Avista's revised adjustment, the expense impact of which is shown below:[1279]

Table No. 17 – PF Employee Benefits Expense – As Filed versus Rebuttal

Pro Forma Employee Benefits Expense - As-Filed vs. Rebuttal (Adjs. PF 3.07 & PF 5.03)						
	As-Filed		Rebuttal		Variance	
	RY1 2025	RY2 2026	RY1 2025	RY2 2026	RY1 2025	RY2 2026
WA Electric	$ 131,936	$ 463,696	$ 299,016	$ 164,105	$ 167,080	$ (299,591)
WA Natural Gas	$ 41,764	$ 146,782	$ 94,653	$ 51,947	$ 52,889	$ (94,835)
Total	$ 173,700	$ 610,478	$ 393,669	$ 216,052	$ 219,969	$ (394,426)

Decision

718 We accept Avista's Pro Forma Pension Adjustment 3.07, which the Company revised on rebuttal and AWEC agreed to in briefing. The Commission agrees with Avista that AWEC's originally proposed adjustment improperly excluded updates to health insurance, post-retirement medical expenses, and 401(k) expenses and pension amortization expense

[1274] Schultz, Exh. KJS-5T at 47: 2-5.

[1275] Schultz, Exh. KJS-5T at 47: 9-12.

[1276] Schultz, Exh. KJS-5T at 48: 13-16.

[1277] Schultz, Exh. KJS-5T at 48: 10-11 and 18-19.

[1278] Schultz, Exh. KJS-5T at 48: 21 – 49:2.

[1279] Schultz, Exh. KJS-5T at 29: 10-18 (Table No. 17).

originally included in the Company's adjustment.[1280] Additionally, we accept the updated employee pension and medical insurance expenses based on the updated actuarial reports Avista provided on rebuttal.

Pro Forma Incentives

Avista's Direct Testimony

719 In its Pro Forma Incentive Adjustment 3.08, the Company proposes to deviate from its traditional six-year average methodology, and instead proposes an adjustment based on forecasted incentive payouts, which would result in an expense increase of $1.2 million (WA Electric) and $0.4 million (WA Natural Gas).[1281] Avista witness Schultz argues that the six-year average of actual incentive expense "is simply not representative of the level of incentive expense the Company is forecasted to incur in RY1 (and carrying into RY2)."[1282]

720 Schultz explains that the Company's incentive program, which consists of the non-executive short-term incentive plan (STIP) and the executive STIP, "provide incentives and focus employees on stated goals, while recognizing and rewarding employees for their contributions toward achieving those goals."[1283] The Company has included 100 percent of its non-executive STIP costs and approximately 40 percent of its executive STIP costs (excluding metrics related to earnings per share and non-regulated activity targets).[1284]

Staff's Response Testimony

721 Staff contests Avista's proposed pro forma adjustment to incentive expenses, arguing that the proposed methodology deviates from the previously established six-year average methodology and the Commission's established standard for pro forma adjustments.[1285] Staff witness Hillstead argues that Avista's proposal assumes that the forecasted incentive pay is certain, when it cannot be due to the nature of incentive pay, and can therefore only be known and measurable in retrospect.[1286] Hillstead references Avista's 2017 GRC in

---

[1280] Schultz, Exh. KJS-5T at 47:2-5.

[1281] Schultz, Exh. KJS-1T at 65: 1-13.

[1282] Schultz, Exh. KJS-1T at 65: 6-8.

[1283] Schultz, Exh. KJS-1T at 65:22 – 66: 4.

[1284] Schultz, Exh. KJS-1T at 67: 4-6.

[1285] Hillstead, Exh. KMH-1T at 13: 11-18.

[1286] Hillstead, Exh. KMH-1T at 14: 2-6.

which the Company proposed a similar adjustment using budgeted projections.[1287] Hillstead notes that Staff contested this adjustment and proposed using a six-year average of actual incentive payouts as the methodology for its adjustment, which the Company ultimately accepted.[1288]

722 In this case, Staff analyzed the Company's actual incentive distributions between 2017 and 2022, the six years that comprise the six-year average, and found large variations between targeted and actual payouts.[1289] Hillstead states that the Company may be correct in its speculation that incentive payments will be significantly higher than its current six-year average, but argues that the Company will have the opportunity to include these actual payouts as part of the six-year methodology in a future GRC.[1290]

723 Staff recommends full disallowance of Avista's proposed pro forma adjustment and to maintain the level of incentive expenses at the six-year average, as reflected in Avista's Restating Adjustment 2.13.[1291] Staff's proposed disallowance would result in an approximate $1.2 million reduction in total revenue requirement.[1292]

Avista's Rebuttal Testimony

724 Schultz argues that Avista's pro forma incentive adjustment meets the standard of a pro forma adjustment and believes it is appropriate to increase incentive expense beyond the normal six-year average methodology, arguing that its adjustment is more representative of what the Company expects to incur in RY1 and RY2.[1293] Schultz argues that incentive expense is based on a percentage of each individual's salary, and that as these salaries increase each year, incentive expense naturally increases with it.[1294] Schultz notes Staff's acceptance of Avista's pro forma non-executive non-Union labor increases through 2025, and that Staff considers them to be known and measurable, and which are a larger increase than the "conservative levels" the Company is proposing with this adjustment.[1295]

[1287] Hillstead, Exh. KMH-1T at 14: 7-9.

[1288] Hillstead, Exh. KMH-1T at 14: 9-13.

[1289] Hillstead, Exh. KMH-1T at 14: 14-17.

[1290] Hillstead, Exh. KMH-1T at 15: 1-4.

[1291] Hillstead, Exh. KMH-1T at 14: 19-21.

[1292] Hillstead, Exh. KMH-1T at 10:1 (Table 3 – Impact of Contested Adjustments on NOI and Revenue Requirement).

[1293] Schultz, Exh. KJS-5T at 52: 2-8.

[1294] Schultz, Exh. KJS-5T at 52: 11-13.

[1295] Schultz, Exh. KJS-5T at 52: 13-16.

725 Schultz argues that the six-year average methodology understated the amounts "from the get-go, since labor will increase through RY1 and RY2."[1296] Schultz notes that Avista's six-year average payout percentage from 2017-2022 is 95 percent for non-officer and 98% for officers, and that if the Company were to apply these payout percentages to its planned labor increases in 2025 and 2026, the result would be much higher than the "reasonable and conservative" adjustment it proposes here, which is based solely on its expected 2024 incentive payouts.[1297] Schultz argues that it "simply cannot leave a combined $1.6 million of incentive expense unaccounted for and create yet more regulatory lag."[1298] Schultz states that Avisa's incentive compensation is a critical component of its total compensation philosophy necessary to recruit and retain qualified employees, and as such, "customers should have this benefit reflected in their retail rates."[1299]

Decision

726 We agree with Staff on his issue. While Avista's proposed adjustment is based on contracts tied to specific incentives in 2024, Staff correctly points out that the contracts in the record have not been performed. Accordingly, there is no guarantee that those incentive amounts will be paid.[1300]

727 The 2024 expected incentive payments remain pending employee performance on contracts, and thus the amounts remain unknown and unmeasurable. As we have said throughout this order, *pro forma* adjustments generally must meet the known and measurable standard, and not be based on speculation, estimates, or forecasts. The incentive adjustment proposed by Avista is based on estimates and forecasts, and therefore does not meet the known and measurable standard. Avista must continue to use the six-year rolling average methodology with no escalation factor for the incentive adjustment, consistent with the historic known and measurable methodology.

[1296] Schultz, Exh. KJS-5T at 52: 18 – 53: 1.

[1297] Schultz, Exh. KJS-5T at 53: 1-8.

[1298] Schultz, Exh. KJS-5T at 53: 12-13.

[1299] Schultz, Exh. KJS-5T at 53: 13-16.

[1300] *See*, Staff's Post-Hearing Brief, at ¶¶ 104-05.

Miscellaneous Issues

Electric Property Rent

728 AWEC witness Mullins recommends that the Commission adopt a higher level of rent from Electric Property for Avista for RY1, based on revenue growth trends observed in Avista's FERC Account 454 and increased pole costs.[1301] Mullins recommends the Commission increase rent from Electric Property by $2.1 million in RY1. Mullins recommends an increase of $0.2 million in RY2, a rate of growth that is equal to the expected growth in distribution plant. [1302] Public Counsel witness M. Garrett adopts and supports Mullin's adjustment to rents from electric property. [1303]

729 Andrews agrees with Mullins' proposal to include a higher level of rent from Electric Property but does not agree with the magnitude of change AWEC proposed. On rebuttal, Avista includes an additional $0.6 million of electric revenue requirement for RY1 and $0.2 million for RY2.[1304]

730 Andrews disagrees with the rationale Mullins used to calculate the increase in rent from Electric Property in RY1,[1305] and instead uses updated data from a completed audit to project revenue growth for calendar year 2024 to arrive at the $0.6 million increase in Rent from Electric Property in RY1.[1306] Andrews states that Avista adopts the 5.6% growth rate proposed by Mullins for RY2 and calculates an increase of $0.2 million in Rent from Electric Property for RY2. [1307]

731 In briefing, Avista disagrees with AWEC's adjustment proposed in its response testimony, arguing that AWEC's adjustment is based on an atypical, one-time back-billing of joint users for unauthorized attachments.[1308] Avista recommends that the Commission approve the Company's proposed Pro Forma Adjustments AWEC1 (RY1) and AWEC2 (RY2), which have been updated to include more recent data regarding pole attachments,[1309] and

---

[1301] Mullins, Exh. BGM-1T at 23:4 – 25:3.

[1302] Mullins, Exh. BGM-1T at 25:4 – 26:1.

[1303] M. Garrett, Exh. MEG-9T at 2:5-11, 4:11-14.

[1304] Andrews, Exh. EMA-6T at 53:5-11.

[1305] Andrews, Exh. EMA-6T at 53:16 – 54:20.

[1306] Andrews, Exh. EMA-6T at 55:1-56:4.

[1307] Andrews, Exh. EMA-6T at 56:5-10.

[1308] Avista's Post-Hearing Brief, at ¶ 114 (citing Mullins, Exh. BGM-1T at 24:9 – 26:1).

[1309] Andrews, Exh. EMA-6T at 53:18 – 55:19.

to reflect incremental joint use revenue from other utilities.[1310] The effect of these adjustments is to increase other electric revenue by $600,000 in RY1 and $200,000 in RY2.[1311]

Decision

732 While Public Counsel continues in brief to urge the Commission to adjust Avista's revenues to reflect AWEC's electric property rental concerns,[1312] AWEC changes its position. After reviewing Avista's rebuttal testimony, AWEC agrees with the revised electric property rental revenue to $600,000 in RY1 and $200,000 in RY2.[1313] Given this resolution of the issue, the Commission accepts the adjustment Avista proposes on rebuttal and to which AWEC agrees, resulting in increases to other electric revenue by $600,000 in RY1 and $200,000 in RY2.[1314] The additional analysis provided on rebuttal to support its revised adjustment is appropriate. The analysis is based on updated, more recent data regarding pole attachments.[1315] Avista also removes one-time back-billing costs from the calculation of revenues related to electric property rents because those costs are unlikely to reoccur during the rate effective period.[1316] Finally, with respect to the anticipated growth rate for RY2, the Commission notes that Avista has adopted Mullins' proposed growth rate proposed.[1317]

Coyote Springs

733 On rebuttal, Avista revised its proposal related to overhaul expenses for Coyote Springs 2. The Company's original request for the recovery of expenses of the Coyote Springs 2 (CS2) overhaul in direct testimony,[1318] required every 32,000 fired-hours, was uncontested by intervening parties.[1319] After the Company filed direct testimony, the Company determined the actual run hours of CS2 have been greater than anticipated and may require the maintenance overhaul to occur in 2025 instead of 2026. To account for this

---

[1310] Avista's Post-Hearing Brief, at ¶ 114.

[1311] Avista's Post-Hearing Brief, at ¶ 114.

[1312] Public Counsel's Post-Hearing Brief, at ¶ 102.

[1313] AWEC's Post-Hearing Brief, at ¶ 94 (citing Andrews, Exh. EMA-6T at 7:4-15).

[1314] Andrews, Exh. EMA-6T at 7:4-15; AWEC's Post-Hearing Brief, at ¶ 94 (Oct. 28, 2024).

[1315] Andrews, Exh. EMA-6T at 53:18 – 55:19.

[1316] Andrews, Exh. EMA-6T at 56:1-4.

[1317] Andrews, Exh. EMA-6T at 56:5-10.

[1318] Andrews, Exh. EMA-6T at 47:7 – 53:35.

[1319] Andrews, Exh. EMA-6T at 74:8 – 75:8.

change, the Company requests that the Commission approve the deferral of Washington's share of the actual costs of the overhaul when the overhaul occurs, regardless of if it occurs in 2025 or 2026. The Company is not requesting any other changes to its proposed amortization expense in RY2.[1320]

734 Specifically, Avista requests that the Commission defer the actual Washington share of Coyote Springs 2 major maintenance, with a carrying charge of actual cost of debt on both the deferred balance and during a four-year amortization period. [1321] Avista states that the maintenance will be required in either 2025 or 2026 depending on the usage of Coyote Springs 2 and its proposed amortization period will last from July 2026 to June 2030.[1322] The Commission accepts Avista's uncontested adjustment related to Coyote Springs 2.

Directors' Fees

735 Avista requests a 90/10 split of directors' total compensation between ratepayers and shareholders,[1323] while AWEC and Public Counsel argue that it should be a 50/50 split of cash compensation with a full disallowance of stock compensation.

736 AWEC witness Mullins recommends the Commission allow Avista to recover only 50 percent of directors' fees from ratepayers, and that no stock compensation provided to directors be included in the revenue requirement.[1324] He cites the Commission practice of allowing a 50 percent recovery of directors' fees established in Avista's 2015 general rate case, in Docket UE-150204.[1325] Similarly, Public Counsel witness M. Garrett recommends that the Commission allow Avista to recover 50 percent of directors' fees from ratepayers, and that no stock compensation provided to directors be included in the revenue requirement.[1326] M. Garrett argues that the directors' compensation should come from value that they add through maximizing Avista's long-term earnings, as they represent shareholders and not ratepayers.[1327]

[1320] Andrews, Exh. EMA-6T at 75:9 – 76:16.

[1321] Avista's Post-Hearing Brief, at ¶ 121.

[1322] Avista's Post-Hearing Brief, at ¶ 121.

[1323] *WUTC v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-240006 & UG-240007 (*consolidated*), filed Revisions to Tariff WN U-28 (Electric) and Tariff WN U-29 (Natural Gas) (Jan. 18, 2024).

[1324] Mullins, Exh. BGM-1T at 32:12-17.

[1325] Mullins, Exh. BGM-1T at 31:3-13.

[1326] M. Garrett, Exh. MEG-1T at 27:8-14.

[1327] M. Garrett, Exh. MEG-1T at 27:14 – 28:6.

737 In rebuttal and on brief, Avista rejects the recommendation from AWEC and Public Counsel. Avista argues that the Company's structure has changed significantly since the Commission established a 50/50 split between shareholders and customers as part of the general rate case in Dockets UE-090134 & UG-090135, and that the Company has divested from other interests and is now comprised almost entirely of utility operations.[1328] Schultz also argues that the complex regulatory environment in which the Company operates further justifies increased recovery of directors' fees from ratepayers.[1329]

738 Schultz also claims that the Commission has never excluded director stock compensation specifically from rates. Schultz explains that the overall compensation given to directors is a mix of cash and stock subject to the preference of each director, and that the overall value of the compensation is recorded to FERC Account 930.2.[1330]

739 On briefing, AWEC argues that Avista's request to recover 90 percent of its directors' fees from ratepayers is contrary to the Commission's precedent of splitting the recovery equally between ratepayers and shareholders.[1331] AWEC maintains that an equal division of directors' fees between ratepayers and shareholders is appropriate because directors prioritize the interests of shareholders in the event of a conflict between shareholders' and ratepayers' interests.[1332] AWEC further notes that in Avista's 2009 general rate case, the Commission determined that the Board of Directors provided services that benefited ratepayers to the same extent as it benefited shareholders without relying on the time directors spent on utility activities rather than non-utility activities.[1333] Additionally, AWEC contends that even acknowledging that utility operations have become more complex over time, Avista has not demonstrated that the skills necessary for complex operations provide additional benefits to ratepayers relative to shareholders.[1334] As such, AWEC recommends that the Commission continue to allocate director cash compensation equally between ratepayers and shareholders.

740 As to director stock compensation, AWEC requests that the Commission disallow the portion of directors' fees associated with stock compensation because the purpose of stock

---

[1328] Avista's Post-Hearing Brief, at ¶ 107, fn. 148.

[1329] Schultz, Exh. KJS-5T at 55:10 – 58:3.

[1330] Schultz, Exh. KJS-5T at 58:4-17.

[1331] AWEC's Post-Hearing Brief, at ¶ 89.

[1332] AWEC's Post-Hearing Brief, at ¶ 89.

[1333] AWEC's Post-Hearing Brief, at ¶ 90.

[1334] AWEC's Post-Hearing Brief, at ¶ 90.

compensation is to align directors' interests with those of shareholders.[1335] Furthermore, AWEC contends that providing stock compensation to directors results in a dilution of shareholder equity, which is not a cost that is includable in a revenue requirement calculation and should be excluded from the revenue requirement.[1336]

741 Public Counsel argues that the Commission should only allow Avista to recover 50 percent of the cash compensation of its Avista's Board of Directors from ratepayers and to wholly preclude recovery of the Board of Directors' stock-based compensation.[1337] Public Counsel maintains that investor-owned utility directors and officers are biased toward their shareholders' interests, as these executives owe a fiduciary duty to their shareholders, but not toward ratepayers.[1338] Public Counsel suggests that, as a result of the tension between maximizing shareholder value and maintain low rates, as well the high level of Avista's executive compensation relative to publicly-owned utility executives, it is reasonable for ratepayers and shareholders to each bear 50 percent of the cost associated with director-level compensation.[1339] Public Counsel further contends that because the primary value of Avista's Board of Directors is to the shareholders, a focus on shareholder value is inappropriate in the context of regulated monopoly, and that the Board of Directors must prioritize maximizing public value.[1340]

742 Turning to Avista's D&O liability insurance, Public Counsel states that while such insurance is useful in attracting and retaining effective management personnel, other jurisdictions have authorized an equal division of insurance related expenses between ratepayers and shareholders.[1341] Public Counsel maintains that the main beneficiary of these insurance policies are shareholders and losses to the ratepayer are not compensable, as payments from these policies only go to Avista, and that the benefits of attracting qualified managers are ancillary to this benefit.[1342] Consequently, Public Counsel argues that the Commission should only allow Avista to recover 50 percent of its D&O liability insurance costs from ratepayers.

[1335] AWEC's Post-Hearing Brief, at ¶ 91.

[1336] AWEC's Post-Hearing Brief, at ¶ 92.

[1337] Public Counsel's Post-Hearing Brief, at ¶ 104.

[1338] Public Counsel's Post-Hearing Brief, at ¶ 105.

[1339] Public Counsel's Post-Hearing Brief, at ¶ 105.

[1340] Public Counsel's Post-Hearing Brief, at ¶ 105.

[1341] Public Counsel's Post-Hearing Brief, at ¶ 106.

[1342] Public Counsel's Post-Hearing Brief, at ¶ 106.

Decision

743 The Commission authorizes Avista to recover 90 percent of its D&O liability insurance for recovery through rates. Inclusion of this amount is consistent with Commission precedent established in Avista's 2009 general rate case and is a reasonable component of executive benefits intended to attract and retain qualified officers and directors.[1343] While both AWEC and Public Counsel note that other state regulators have allocated D&O liability insurance equally between shareholders and ratepayers or required ratepayers to bear less of the costs than shareholders, the Commission addressed this issue in Avista's 2009 GRC.[1344] As in that proceeding, those decisions offer limited insight into how to allocate insurance costs in the context of this proceeding, and only represent a small subset of other state regulatory jurisdictions.[1345] Furthermore, the Commission disagrees with Public Counsel's assertion that D&O insurance provides no benefit to ratepayers, as the insurance will shield ratepayers from financial harm in the event of shareholder litigation against Avista's Board of Directors. Consequently, the Commission is not persuaded that it should alter its precedent with respect to the allocation of D&O liability insurance in this case.

744 Turning to the issue of directors' fees, and the Commission rejects Avista's proposal to increase the recovery of directors' fees from ratepayers from 50 percent to 90 percent. According to Avista, the directors' allocation of time on utility vs. non-utility activities demonstrate that the directors' activities predominantly benefit ratepayers, such that it is appropriate for ratepayers to bear a larger proportion of directors' fees.[1346] However, the allocation of director time to utility functions does not necessarily imply that the function is for the benefit of ratepayers, because a director's fiduciary duties to shareholders may result in a director taking utility action that is to the benefit of shareholders, but not ratepayers. As such, the Commission does not find that the allocation of director time and the complexity of utility operation support changing Commission precedent with respect to the allocation of directors' fees. Absent further evidence and argument as to why the Commission should modify its precedent, the Commission will continue to allow 50 percent of directors' fees to be recovered from ratepayers.[1347]

[1343] *WUTC v. Avista Corp.*, Dockets UE-090134, UG-090135, & UG-060518, Order 10, 56-57 ¶ 137 (Dec. 22, 2009).

[1344] *WUTC v. Avista Corp.*, Dockets UE-090134, UG-090135, & UG-060518, Order 10, 56 ¶ 136 (Dec. 22, 2009).

[1345] *WUTC v. Avista Corp.*, Dockets UE-090134, UG-090135, & UG-060518, Order 10, 56 ¶ 136 (Dec. 22, 2009).

[1346] Avista's Post-Hearing Brief, at ¶ 109.

[1347] *WUTC v. Avista Corp.*, Dockets UE-150204 & UG-150205, Order 5, 76 ¶ 220 (Jan. 6, 2016).

745 The Commission also rejects Public Counsel and AWEC's request to exclude stock compensation from the recovery of directors' fees from ratepayers. Assuming without deciding that stock compensation is solely intended to incentivize directors to prioritize the interests of shareholders over ratepayers, this consideration alone does not demonstrate that stock compensation provides no benefit to ratepayers because, as witness Mullins points out, shareholder interests may overlap with ratepayer interests.[1348] In these circumstances, director activities can be characterized as providing a benefit to ratepayers. Furthermore, as Avista points out, the Commission has not previously excluded stock compensation from director compensation in past rate cases and stock compensation is recorded as a utility expense.[1349] Consequently, the Commission declines to entirely preclude the recovery of stock compensation to directors from ratepayers based on the record in this case.

Labor - Executive (3.06 Pro Forma Labor Exec)

746 Public Counsel witness M. Garrett recommends that ratepayers should be responsible for test year salaries of Avista's executives, but that shareholders should pay for the proposed payroll escalations contained in Avista's pro forma adjustment. M. Garrett's recommendation reduces electric O&M expense by $60,000, and the gas O&M expense by $19,000.[1350]

747 M. Garrett justifies this position by stating that investor-owned utility (IOU) executive salaries are higher than those at consumer-owned utilities (COU) and cooperative utilities, claiming that this difference shows that increased executive salaries are not necessary costs to provide utility service. M. Garrett also suggests that the Commission open an investigatory docket to examine differences in compensation between IOUs, COUs, and cooperative utilities, and require Avista to provide COU and cooperative compensation data in its next GRC.[1351]

748 On rebuttal, Schultz testifies that its Pro Forma Labor Executive adjustment has been updated to remove retired officers and reflect the current estimated breakdown of utility and non-utility responsibilities, 96 percent to ratepayers and 4 percent to shareholders, as well as to include the Board of Director approved labor increases.[1352] On rebuttal, the

---

[1348] Mullins, Exh. BGM-1T at 31:16-20.

[1349] Schultz, Exh. KJS-5T at 6-11.

[1350] M. Garrett, Exh. MEG-1T at 9:12-22, M. Garrett, Exh. MEG-4.

[1351] M. Garrett, Exh. MEG-1T at 7:6 – 9:11.

[1352] Schultz, Exh. KJS-5T at 28:6-15.

overall increase of the revenue requirement proposed by Avista above test period levels for RY1 is $115,000 for electric and $37,000 for natural gas.[1353]

749 In response to Public Counsel's criticisms of Avista's pay structure, Schultz argues that a significant portion of executive compensation is linked with goals related to specific items of corporate performance that will likely produce shareholder value, and it is that compensation that is charged to shareholders. Schultz claims that the appropriate amount of compensation for utility activity is charged to ratepayers. Avista rejects Public Counsel's recommendations to remove increased pro-forma executive compensation and for the Commission to require a study comparing executive compensation between IOUs, COUs, and cooperative utilities.

750 Both Avista and Public Counsel continue their arguments on brief. Avista disagrees with Public Counsel's request to decrease director compensation based on the difference between compensation between IOU executives and publicly-owned utility executives.[1354] Avista argues that executive compensation is based on the particular responsibilities of each officer, and divided into utility and non-utility activities.[1355] Avista maintains that an executive compensation survey is unnecessary because Avista completed a compensation survey in Dockets UE-110876 & UG-110877.[1356] Avista further argues that its proposed increases to executive compensation in this case are reasonable relative to similarly sized investor-owned utilities and notes that M. Garrett appears to agree with this assessment.[1357]

751 Public Counsel requests that the Commission require Avista's shareholders pay for the proposed adjustments related to director compensation, resulting in a $60,000 decrease to electric revenue and a $19,000 decrease to gas revenue.[1358] Public Counsel argues that the differences in compensation between publicly-owned utility executives and IOU executives is due to the fact that IOU executives owe dual fiduciary duties to both shareholders and utility customers.[1359] Public Counsel asserts that the difference in pay between investor-owned and publicly-owned executives provides a reasonable estimate of

---

[1353] Schultz, Exh. KJS-5T at 28:23-27.

[1354] Avista's Post-Hearing Brief, at ¶¶ 101-02.

[1355] Avista's Post-Hearing Brief, at ¶ 101 (See also, Schultz, Exh. KJS-5T at 44:7-14).

[1356] Avista's Post-Hearing Brief, at ¶ 101, fn. 139.

[1357] Avista's Post-Hearing Brief, at ¶ 102 (see also, M. Garrett, Exh. MEG-1T at 7:8-9).

[1358] Public Counsel's Post-Hearing Brief, at ¶ 103.

[1359] Public Counsel's Post-Hearing Brief, at ¶ 103. Based on arguments presented in further briefing, we understand Public Counsel to mean that Avista' executives do not have fiduciary duties to their ratepayers.

the additional value that IOU executives provide to shareholders, and consequently that Avista's shareholders should bear those costs.[1360] Public Counsel further recommends that the Commission order Avista to conduct an executive salary survey, including compensation data from both publicly-owned and investor-owned utilities.[1361]

Decision

752 We reject Public Counsel's proposed revisions to Adjustment 3.06 and decline to order Avista to perform a compensation survey. As Avista explains, its updated adjustment only includes the portion of executive activity attributable to utility functions (as opposed to non-utility/shareholder functions) and excludes retired officers.[1362] Furthermore, we agree with Avista that IOU executive compensation is not directly comparable to publicly-owned utility executive compensation due to the different responsibilities and relatively greater complexity involved operating an IOU.[1363] Additionally, that Avista's executive compensation appears reasonable relative to other IOU executives supports the conclusion that Avista's proposed executive compensation adjustment is appropriate.[1364] Finally, given that Avista previously performed a compensation survey in Dockets UE-110876 and UG-110877, the Commission declines Public Counsel's request to require an additional compensation survey.

Decoupling

753 Avista witness Anderson proposes to extend the Company's electric and natural gas decoupling mechanisms, without modifications, through calendar year 2026, citing benefits experienced by customers and the Company to date and a lack of adverse impacts.[1365]

754 No party opposes Avista's request. Though the Company requests that the extension continues through 2026,[1366] Staff supports extending decoupling until Avista's next rate case or until the Commission comes to a decision in Docket U-210590. Staff witness Erdahl explains that the Commission is currently evaluating the merits of decoupling

---

[1360] Public Counsel's Post-Hearing Brief, at ¶ 103.

[1361] Public Counsel's Post-Hearing Brief, at ¶ 103.

[1362] Schultz, Exh. KJS-5T at 28:7-15, 44:10-14.

[1363] Schultz, Exh. KJS-5T at 46:7-15.

[1364] M. Garrett, Exh. MEG-1T at 7:8-9.

[1365] Anderson, Exh. JCA-1T 15:22 – 25:2.

[1366] Anderson, Exh. JCA-1T 15:24 – 16:1.

mechanisms, and that deciding the matter here would be premature.[1367] AWEC also supports Avista's proposal to continue its revenue decoupling mechanisms during the multi-year rate plan.[1368]

755 Similarly, NWEC supports Avista's proposal to continue the revenue decoupling mechanisms for the term of the MYRP. Witness McCloy clarifies that the transitions of performance-based ratemaking and electrification may warrant a discussion to modernize the mechanism.[1369]

756 While TEP does not comment on Avista's proposal to extend its decoupling mechanism through 2025, Stokes does comment on Avista's proposal to discontinue its Quarterly Decoupling Report. If the Commission allows the Company to discontinue its Quarterly Decoupling Reports, it recommends that the relevant information from those reports should be included in all future annual adjustment filings.[1370] NWEC supports TEPs request, stating that all Quarterly Decoupling Report information should be included in a consolidated, accessible manner in future decoupling rate adjustment filings.[1371]

757 On rebuttal, witness Bonfield accepts witness Stokes' recommendation, stating that "the Company will make sure all information from the quarterly reports is included in all future annual adjustment filings."[1372] Avista requests that the Commission approve the Company's request to extend its current electric and natural gas decoupling mechanisms through the multi-year rate plan until the end December 31, 2026 as uncontested by the Parties.[1373]

Decision

758 The Commission accepts Avista's proposal to continue its decoupling mechanism during its MYRP. The Commission anticipates that further discussion of whether to remove or modify the mechanisms will occur during Avista's next general rate case or in the context of Docket U-210590.

[1367] Erdahl, Exh. BAE-1T 33:12 – 34:2

[1368] AWEC's Post-Hearing Brief, at ¶ 59.

[1369] McCloy, Exh. LM-1T 14:4 – 15:2

[1370] Stokes, Exh. SNS-1T 40:17 – 42:4

[1371] Thompson, Exh. CT-4T 11:18 – 12:11.

[1372] Bonfield, Exh. SJB-5T 44:10-21

[1373] Avista's Post-Hearing Brief, at ¶ 124.

Pro Forma Miscellaneous O&M Adjustment

Avista's Direct Testimony

759 This adjustment reflects escalated increases in certain Company operations and maintenance (O&M) and administrative and general (A&G) expenses, from the historical test year ending June 30, 2023, through RY1, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies.[1374] The Company applied an annual escalation rate of 6.3 percent for electric and 4.57 percent for natural gas operations by FERC account to certain O&M and A&G annual test period balances as of June 30, 2023, through December 2025 (or 2.5 years).[1375]

760 This adjustment increases RY1 Washington expenses by $8,876,000 for electric and $1,634,000 for natural gas and decreases RY1 Washington NOI by $7,012,000 for electric and $1,291,000 for natural gas.[1376]

761 For RY2, Avista proposes Pro Forma Miscellaneous O&M Expense to reflect escalated increases in certain Company O&M and A&G expenses, to reflect incremental expenses in RY2, beyond RY1 levels, effective December 2025, through December 2026, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies.[1377] The Company applied the same escalation growth rate used in RY1 of 6.3 percent for electric and 4.57 percent for natural gas operations to escalate RY2 amounts above RY1 levels.[1378]

762 This adjustment increases RY2 Washington expenses by $3,550,000 for electric and $653,000 for natural gas and decreases RY2 Washington NOI by $2,805,000 for electric and $516,000 for natural gas.[1379]

AWEC's Response Testimony

763 AWEC contends that Avista's proposal to apply annual escalation factors of 6.30 percent for electric services and 4.57 percent for gas services to the Historical Period non-labor

---

[1374] Schultz, Exh. KJS-1T at 72:1-4.

[1375] Schultz, Exh. KJS-1T at 72:4-7.

[1376] Schultz, Exh. KJS-1T at 72:15-17.

[1377] Andrews, Exh. AMM-1T at 12:4-8.

[1378] Andrews, Exh. AMM-1T at 12:8-11.

[1379] Andrews, Exh. AMM-1T at 12:11-13.

O&M results is concerning as the escalation percentages are well above expected inflation over the rate plan period.[1380]

764 AWEC argues that the trend Avista used was based on total O&M expense, excluding power supply costs, not on non-labor O&M expense.[1381] AWEC argues that the percentages that Avista calculated are not representative of an escalation factor that reasonably can be applied to non-labor O&M expense.[1382]

765 AWEC witness Mullins asserts that Avista's operating expenses for electric services actually declined by 2.39 percent in 2023 and natural gas non-labor O&M expense declined by 3.3 percent.[1383] Given these reductions and AWEC's experience in the 2022 GRC, Mullins questions the veracity of what Mullins describes as aggressive non-labor O&M escalation assumptions included in Avista's filing.[1384]

766 AWEC recommends including no rate escalation in RY 1, and a modest inflationary escalator for RY 2. The inflationary adjustment AWEC recommends for RY 2 is 2.3 percent, which represents the mid-point Personal Consumption Expenditures inflation forecast of the Federal Reserve, Federal Open Market Committee.[1385]

Public Counsel's Response Testimony

767 Public Counsel witness M. Garrett states that Avista's annual escalation rates substantially overstate current inflation expectations through 2026.[1386] Instead, M. Garrett calculated an annual rate of 2.5 percent as a more reasonable inflation expectation through 2026 for the Company's electric and gas operations.[1387]

768 According to Public Counsel, adjusting the electric utility's O&M escalation rate to 2.5 percent reduces the revenue requirement by $5.624 million for RY1 and by an additional $2.249 million for RY2.[1388] Public Counsel also testifies that the adjustments to reduce the

---

[1380] Mullins, Exh. BGM-1T at 15:10-12.

[1381] Mullins, Exh. BGM-1T at 16:2-3.

[1382] Mullins, Exh. BGM-1T at 16:5-7.

[1383] Mullins, Exh. BGM-1T at 19:5-6.

[1384] Mullins, Exh. BGM-1T at 19:6-9.

[1385] Mullins, Exh. BGM-1T at 19:17-20.

[1386] M. Garrett, Exh. MEG-1T at 11:4-5.

[1387] M. Garrett, Exh. MEG-1T at 12:3-4.

[1388] M. Garrett, Exh. MEG-1T at 14:28-29 and at 15:1-2.

gas utility's O&M escalation rate to 2.5 percent reduce the revenue requirement $778 thousand for RY1 and an additional $170 thousand for RY2.[1389]

Staff's Response Testimony

769 Staff contends that Avista's adjustment does not meet the Commission's standard of a pro forma adjustment because the escalated increase is not known nor is it measurable. In addition, the changes in the adjusted O&M expenses had significant fluctuations between 2018 and 2023.[1390]

770 Because the Company failed to provide evidence that the O&M expenses will escalate at the level proposed in the rate year, Staff recommends including only the incremental known and measurable 2023 O&M expenses not already included in the Company's test year, and to disallow any escalation component.[1391]

Avista's Rebuttal Testimony

771 The Company modified its Pro Forma Miscellaneous O&M Adjustments 3.14 and 5.06, in response to Public Counsel data request, PC-DR-297. This modification was intended to reflect actual known changes in expense through end of 12 months ending in December 2023 (12ME December 2023), above the test period expense, which ended in June 2023 (12ME 6.2023). The Company also revised its annual historical O&M growth average to include 2023 results (2019-2023), resulting in escalation growth rates of 4.57 percent for electric and 4.28 percent for natural gas, above the actual results for the twelve-month test year ending December 2023 (12ME 12.2023).[1392]

772 Witness Andrews further states that updating Avista's actual results to reflect known and measurable increases in the specific O&M and A&G expenses as of 12ME 12.2023 produces an increase in actual electric O&M /A&G expense of $5.9 million above test period levels, and shows a reduction in actual natural gas O&M / A&G expense of $468,000.[1393]

773 Avista explains that if it were simply to support revised values for these expenses at 12ME 12.2023, for electric operations, Avista's electric pro forma Adjustment 3.14 would drop

---

[1389] M. Garrett, Exh. MEG-1T at 15:5-7.

[1390] Hillstead, Exh. KMH-1T at 16:7-10.

[1391] Hillstead, Exh. KMH-1T at 16:13-16.

[1392] Andrews, Exh. EMA-6T at 39:10-15.

[1393] Andrews, Exh. EMA-6T at 39:16-19.

by $3.0 million, from a level of $8.9 million to $5.9 million. For natural gas, Avista's pro forma Adjustment 3.14 would drop by $2.1 million, from an increase of $1.6 million to a decrease of $0.5 million.[1394]

774 Additionally, the Company states that it now supports Public Counsel's proposed inflationary rate of 2.5 percent annually through 2026.[1395]

775 With respect to Pro Forma Adjustments 3.14 and 5.06, Avista argues that the Commission should approve its revised escalation adjustments from its rebuttal testimony that incorporate both updated expenses from the 2023 test period and a 2.5 percent growth rate as proposed by Public Counsel witness M. Garrett in RY 1 and RY 2.[1396] The result of these changes on rebuttal to Avista's electric and natural gas revenue requirement in RY1, is an increase of $143,000 for electric, and a reduction of $1.5 million for natural gas.[1397] For RY2, these changes reduce the Company's electric and natural gas revenue requirements by $2.1 million for electric and $323,000 for natural gas.[1398]

Decision

776 The Commission authorizes a 2.5 percent escalation adjustment for Avista's Pro Forma Adjustments 3.14 (RY1) and 5.06 (RY2), as originally proposed by Public Counsel witness M. Garrett.[1399]

777 Pursuant to Commission rule and precedent, a pro forma adjustment gives effect for the test period to all known and measurable changes that are not offset by other factors.[1400] Under this standard, an event that causes a change to revenue, expenses, or rate base must be "known" to have occurred during or after the historical 12 months of actual results of operations.[1401] The "known" component of the standard requires that the effect of the event will be in place during the rate effective period.[1402] Furthermore, the amount of the change must be "measurable," which traditionally has meant that the amount cannot be an

---

[1394] Andrews, Exh. EMA-6T at 40:5-7.

[1395] Andrews, Exh. EMA-6T at 43:16-17.

[1396] Avista's Post-Hearing Brief, at ¶ 111.

[1397] Andrews, Exh. EMA-6T at 44:13-15.

[1398] Andrews, Exh. EMA-6T at 44:15-16.

[1399] M. Garrett, Exh. MEG-1T at 11:12 – 13:6.

[1400] WAC 480-07-510(3)(c)(ii).

[1401] *WUTC v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 45 (Dec. 22, 2009).

[1402] *WUTC v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 45 (Dec. 22, 2009).

estimate, projection, a product of a budget forecast, or some similar exercise of judgment, even informed judgment, concerning future revenue, expense, or rate base.[1403] There are, however, exceptions to this general rule, for example in the context of attrition adjustments and power cost modeling forecasts.[1404] Finally, pro forma adjustments must be matched with offsetting factors, factors that diminish the impact of the known and measurable event, so as to avoid overstating or understating the known and measurable change.[1405]

778 Avista witness Andrews testified that the purpose of the escalation adjustment was to react to the anticipated effect of inflation during the rate effective period of the rate plan.[1406] No Party in this proceeding contends that inflation will not impact Avista's O&M expenses during the rate effective period. Therefore, it is fair to conclude that the effect of inflation on Avista's O&M expenses is "known."

779 Turning to the "measurable" prong of the analysis, the Commission determines that although Avista's proposed adjustment is based on a projected forecast of the effect of inflation, this adjustment, similar to power cost modelling forecasts, falls within the exception to the usual precision required of pro forma adjustments. While the Commission agrees that it is inappropriate to base this adjustment on Avista's own historical data on this record, it is reasonable to rely on the inflation data published by the Federal Reserve, in addition to other governmental sources, to forecast the likely effect of inflation during the rate effective period.[1407] Reliance on this data strikes the appropriate balance between allowing Avista to insulate itself from the anticipated effect of inflation and encouraging Avista to control costs to the benefit of ratepayers. As such, the forecast of inflation data is "measurable" within the exception to the Commission's general pro forma standard and supports an adjustment of 2.5 percent for both RY1 and RY 2 of Avista's multi-year rate plan.

780 Finally, the Commission is satisfied that Avista considered offsetting factors related to its updated test year ending in December 2023. Avista witness Schultz's testimony contains

---

[1403] *WUTC v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 45 (Dec. 22, 2009).

[1404] *WUTC v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 49 (Dec. 22, 2009) (power cost modeling); *WUTC v. Avista Corp.,* Dockets UE-120436 & UG-120437, and UE-110876 & UG-110877, Order 09/14, 26-28 ¶¶ 70-73 (Dec. 26, 2012) (attrition adjustment).

[1405] *WUTC v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 46 (Dec. 22, 2009).

[1406] Andrews, Exh. EMA-1T at 13:8-14; Andrews, Exh. EMA-6T at 42:17 – 43:5.

[1407] M. Garrett, Exh. MEG-1T at 11:1 – 13:6. See also, M. Garrett, Exh. MEG-1T at 13:2-3, fn. 8 (noting that a 2.5 percent inflation rate is consistent with numerous publicly available sources, including Office of Management and Budget, Congressional Budget Office, Federal Reserve's Open Market Committee, and several Federal Reserve Banks).

information reflecting both electric and natural gas offsets for the Company's position on rebuttal, including direct O&M offsets.[1408] Although Public Counsel asserts in briefing that Avista did not properly consider offsetting factors related to its updated test year proposed on rebuttal, they do not direct the Commission's attention to any specific deficiencies or omissions in Avista's rebuttal analysis. Therefore, the Commission finds that Avista's analysis properly incorporates consideration of offsetting factors.

781 In reaching this outcome, the Commission is mindful of RCW 80.28.425(3)(c), which provides that the Commission "shall ascertain and determine the revenues and operating expenses for rate-making purposes of any gas or electrical company for each rate year of the multi-year rate plan." RCW 80.28.425(3)(d) further states in "projecting the revenues and operating expenses of a gas or electrical company pursuant to (c) of this section, the commission may use any formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." Based on this authority, and the pro forma adjustment analysis described above, the Commission determines that it has the discretion to authorize an inflation escalator adjustment to the miscellaneous expenses contained in Avista's Adjustments 3.14 and 5.06. On the record developed in this proceeding, the Commission chooses to exercise this discretion to approve a 2.5 percent escalation increase to the expenses in Adjustments 3.14 (RY1) and 5.06 (RY2). The Commission further orders Avista to provide the workpapers demonstrating its full calculations of offsetting factors related its updated test year and adjustments as part of a compliance filing in this docket.

FINDINGS OF FACT

782 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:

783 (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.

784 (2) Avista is a "public service company," an "electrical company," and a "gas company" as those terms are defined in RCW 80.04.010 and used in Title

[1408] Schultz, Exh. KJS-5T at 17:1 – 18:15; 31:10 – 32:2.

80 RCW. Avista provides electric and natural gas utility service to customers in Washington.

785 (3) Avista's currently effective rates were determined by the Commission's Final Order approving a full multiparty settlement in *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-220053, UG-220054 & UE-210854 *(Consolidated)*, Order 08/05 (Dec. 12, 2022).

786 (4) In May of 2020, Avista issued its Wildfire Resiliency Plan. On October 30, 2020, Avista filed with the Commission revisions to its currently effective Tariffs WN U-28, Electric Service, and WN U-29, Natural Gas Service, and also filed its Petition with the Commission to request accounting and ratemaking treatment of costs associated with its Wildfire Resiliency Plan.

787 (5) Avista requests an increase in its annual electric revenue requirement of approximately $28.5 million (5.38 percent), and an increase to its annual natural gas revenue requirement of approximately $10.7 million (10.14 percent).

788 (6) On September 30, 2024, through October 1, 2024, the Commission held an Evidentiary Hearing before Administrative Law Judges James E. Brown II and Connor A. Thompson, who presided along with the Commissioners.

789 (7) The Commission finds it would be premature to conduct prudency reviews of CCA costs and compliance on an annual basis.

790 (8) During Avista's annual submission of updates to its CCA tracker tariff, the Company shall submit and present information pertaining to where CCA costs are being included in decision making to include, but not be limited to IRPs, CEIPs, dispatch, power purchase, carbon market transactions, and capital projects.

791 (9) CCA allowance prices and costs in dispatch, market purchases, and market sales, and the Commission's policy surrounding their inclusion in NPE, should be addressed in Docket U-230161 so that policy and implementation is consistent for all regulated utilities, and each impacted utility has an opportunity to comment on the issue.

792 (10) The Commission finds that the modeling errors should be addressed by the parties before the Commission adjusts the dead and sharing bands under the ERM.

793 (11) The Commission finds that the modeling errors should be addressed by the parties, and that the forecast error adjustment is not just, reasonable, or sufficient at this time.

794 (12) Because Avista no longer collects GHG revenues in the WEIM since the CCA's implementation, we find that AWEC's adjustment should be rejected.

795 (13) Avista uses an approved methodology to calculate non-energy WEIM benefits and therefore we reject the adjustments proposed by AWEC and supported by Staff for including additional non-energy benefits.

796 (14) The Commission finds that because the CAISO estimate does not account for the opportunity cost of leaving the bilateral market, it should not be used to calculate WEIM benefits for Avista at this time as the evidence suggests its adoption would likely result in an overestimation of benefits not likely to be realized.

797 (15) The Commission finds that the Colstrip transmission assets should remain in rates at this time.

798 (16) The Commission finds that each of AWEC's proposals related to Colstrip as it relates to the ERM and NPE should be rejected.

799 (17) The Commission finds that the adjustment for COB proposed by AWEC to account for COB margins was agreed to during the evidentiary hearing and should be made.

800 (18) The provisional plant review process should continue to be assessed on a portfolio rather than project-by-project basis.

801 (19) To allow for additional evaluation of provisional capital filings, the review process should be extended to six months.

802 (20) Classification of plant and naming conventions should remain consistent throughout the provisional capital review and general rate case process.

803 (21) A separate provisional plant tariff is not necessary at this time.

804 (22) Allowing new business cases is consistent with the Commission's Policy Statement to allow flexibility and further the reduction of regulatory lag.

805 (23) The Commission finds Public Counsel's recommendation for an equal allocation is fair, just, and reasonable, and that Avista's next cost study shall account for removal of Colstrip from rates.

806 (24) Avista provided insufficient evidence to support its request to include its proposed flotation cost adjustment in its calculation for return on equity.

807 (25) Avista's proposed flotation cost adjustment should be rejected from its calculation for return on equity.

808 (26) The Commission finds that a $1.00 increase to the minimum charge for electric and gas customers is supported by the record.

809 (27) AWEC's proposals regarding Schedule 13 and 23 should be rejected, and an equal percentage of base revenue increase is appropriate, consistent with our approach to rate spread generally and Avista's original filing.

810 (28) AWEC's three adjustments, as modified by Avista, to Schedule 25 are unopposed and should be adopted. Those include (1) increasing demand charges for energy blocks 1 and 2 by 25 percent in RY1 and 25 percent in RY2, (2) increasing the primary voltage discount from $1.93/kW to $4.39/kW, and (3) changing language in Schedule 25 to make the primary voltage discount applicable to customers served through third party substations.

811 (29) Sierra Club's proposal to require a decarbonization plan is inappropriate given the subsequent passage of Initiative 2066.

812 (30) Sierra Club and NWEC's proposals relating to line extension allowances are inappropriate given the subsequent passage of Initiative 2066.

813 (31) In light of the record evidence, the Commissions adopts the Non-Pipeline Alternatives framework used by the Oregon Public Utilities Commission, with some modification as an appropriate balance. The first modification we deem appropriate is that Avista must examine the relationship between any NPA and the Climate Commitment Act and should not assume that all CCA allowances will be purchased at the ceiling price. Second, Avista is required to provide an explanation of the resulting investment selection (either the NPA or a traditional investment) that compares the costs of both projects, but Avista is not required to rank or score any NPA in its evaluation process. Avista must conduct at least two NPA analyses on natural gas distribution projects related to customer growth for any potential projects that exceed $500,000, using the criteria described above.

814 (32) In October of 2020, Avista filed with the Commission in Docket UE-200894 a petition for an accounting order authorizing the accounting and ratemaking treatment of the costs associated with the Company's Wildfire Resiliency Plan.

815 (33) The record evidence demonstrates that Avista continues to face increased wildfire threats, risks, costs, and other circumstances.

816 (34) The record evidence demonstrates that Avista has been taking incremental wildfire actions above normal activities, and that the circumstances it faces are extraordinary.

817 (35) The record evidence demonstrates that the base level of Avista's wildfire expense of its Wildfire Balancing Account should be adjusted to $8.3 million and applied across Avista's two-year rate plan.

818 (36) AWEC failed to demonstrate that removal of standard undergrounding in non-fire risk areas and standard vegetation management is appropriate.

819 (37) The record evidence demonstrates that Avista's proposal to recover carrying charges related to the Wildfire at its cost of debt is appropriate.

820 (38) The record evidence demonstrates that increasing Avista's Insurance Expense Balancing Account baselines to $12.8 million for electric and $2.3 million for natural gas is appropriate.

821 (39) D&O insurance benefits both customers and shareholders as part of the compensation package necessary to attract and retain qualified directors and officers and allocating 90 percent to customers and 10 percent to shareholders is appropriate.

822 (40) The performance measures outlined in Appendix A and their related reporting requirements are fair, just, and 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.

823 (41) The modified recurring reporting requirements outlined in Appendix B are fair, just, and reasonable, consistent with applicable law, in the public interest, and will provide necessary information to continue evaluating Avista's operations.

824 (42) The evidence supports Avista's proposed capital structure of 51.5 percent debt and 48.5 percent equity as reasonable and resulting in fair, just, reasonable, and sufficient rates.

825 (43) The evidence supports Avista's proposed return on equity of 9.8 percent as reasonable and resulting in fair, just, reasonable, and sufficient rates.

826 (44) The evidence supports Avista's proposed overall rate of return of 7.32 percent as reasonable and resulting in fair, just, reasonable, and sufficient rates.

827 (45) Staff's proposed rate of return of 9.5 percent is unreasonably low and not supported by persuasive cost of capital modeling.

828 (46) Public Counsel's proposed rate of return of 8.5 percent is unreasonably low and not supported by persuasive cost of capital modeling.

829 (47) AWEC's proposed rate of return of 9.25 percent is unreasonably low and not supported by persuasive cost of capital modeling.

830 (48) Walmart's proposed rate of return of 9.62 percent for electricity and 9.58 percent for gas are unreasonably low and not supported by persuasive cost of capital modeling.

831 (49) Avista provided insufficient evidence to support its request to include its proposed flotation cost adjustment in its calculation for return on equity.

832 (50) Avista's proposed flotation cost adjustment should be rejected from its calculation for return on equity.

833 (51) The Commission finds it appropriate to allow a return on Avista's Power Purchase Agreements. The Commission further finds that the appropriate rate is the company's cost of debt.

834 (52) The record evidence is insufficient to demonstrate that Avista should be required to engage in a targeted electrification pilot as proposed by Sierra Club.

835 (53) The record evidence is insufficient to demonstrate that AWEC's proposed adjustment to Avista's Working Capital Restating Adjustment (ISWC Adjustment 1.03) will result in rates that are fair, just, reasonable, and sufficient.

836 (54) The record evidence demonstrates that Avista's proposed Working Capital Restating Adjustment (ISWC Adjustment 1.03) is based on a methodology previously approved by the Commission and is reasonably calculated to result in rates that are fair, just, reasonable, and sufficient.

837 (55) AWEC's proposal to adjust Avista's wildfire and patent litigation costs as non-recurring is not appropriate in light of the record evidence.

838 (56) AWEC's proposal to modify Avista's accounting of deferred tax credits balances is inappropriate in light of the record evidence.

839 (57) The record evidence demonstrates that Avista's proposed adjustment to electric property rent as revised on rebuttal is reasonable and appropriate.

840 (58) Avista's proposal to defer the actual Washington share of Coyote Springs 2 major maintenance is uncontested and supported by the record.

841 (59) The record evidence does not support AWEC and Public Counsel's proposal to exclude 50 percent of Avista's Directors' and Officers' liability insurance. Because Directors' and Officers' liability insurance benefits both customers and shareholders as part of the compensation package necessary to attract and retain qualified directors and officers, allocating 90 percent to customers and 10 percent to shareholders is appropriate.

842 (60) The record evidence does not support Avista's proposal to increase the ratepayer share of directors' fees from 50 to 90 percent. Avista has not demonstrated that the Commission should alter its precedent of allocating directors' fees equally between ratepayers and shareholders, as established in Avista's 2009 GRC.

843 (61) The record evidence does not support AWEC and Public Counsel's proposal to wholly exclude stock compensation from Avista's directors' fees.

844 (62) The record evidence supports including 50 percent of Avista's directors' fees in rates, consistent with the Commission's precedent established in Avista's 2009 GRC.

845 (63) The record evidence does not support Public Counsel's proposal to adjust Avista's executive compensation. Public Counsel has not demonstrated based on the evidence in this case that the publicly-owned utility executive compensation is directly comparable to investor-owned utility executive compensation.

846 (64) Public Counsel has not demonstrated that requiring Avista to conduct an executive compensation survey including data from publicly-owned utility executives is reasonable or appropriate based on the evidence in this case. Public Counsel has not demonstrated based on the evidence in this case that the publicly-owned utility executive compensation is directly comparable to investor-owned utility executive compensation and Avista has previously performed an executive compensation survey in Dockets UE-110876 and UG-110877.

847 (65) The incentive adjustment 3.08 shall utilize the six-year rolling average methodology with no escalation factor, consistent with historic known and measurable methodology.

848 (66) Avista's proposal to continue its revenue decoupling mechanisms during the multi-year rate plan is uncontested and adequately supported by the record.

849 (67) The record evidence demonstrates that Avista's proposed 2.5 percent escalation adjustment for Pro Forma Adjustments 3.14 and 5.06 is intended to respond to the known effect of inflation during the rate effective period, that inflation is measurable in a similar manner to other adjustments such as Avista's power cost modeling, and that Avista has incorporated offsetting factors into its proposed adjustment.

850 (68) The Commission finds that it is reasonable to require Avista to file its workpapers supporting its pro forma adjustments regarding its updated test year ending in December 2023, as part of a compliance filing within 45 days of this Order.

851 (69) Based on the evidence in the record and the Commission's denial of the forecast error adjustment, the Commission authorizes a Washington Total Power Supply Base of $34,116,983 for rate year 1, and $85,733,975 for rate year 2.

CONCLUSIONS OF LAW

852 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:

853 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

854 (2) Avista is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction

855 (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.

856 (4) Avista's existing rates for electric and natural gas service are neither fair, just, reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

857 (5) Avista shall submit and present information pertaining to where CCA costs are being included in decision making to include, but not limited to Integrated Resource Plans (IRPs), Clean Energy Implementation Plans (CEIPs), dispatch, power purchase, carbon market transactions, and capital projects. This annual report will be addressed and acknowledged through the Open Meeting process and will help the Commission assess a utility's progress and decision making leading up to the Commission's prudency determination at the conclusion of the compliance period

858 (6) CCA allowance prices and costs in dispatch, market purchases, and market sales, and the Commission's policy surrounding their inclusion in NPE, should be addressed in Docket U-230161 affording opportunity to comment from all regulated utilities.

859 (7) The Commission denies Avista's and Staff's proposals to modify the ERM at this time.

860 (8) The Commission denies Avista's forecast error adjustment as it fails to meet the known and measurable standard.

861 (9) Avista shall convene a workshop series with interested parties to address modeling inputs, power supply modeling methodology, use of AURORA, and a changing energy landscape. These conversations should include discussions regarding inclusion of CCA costs and addressing the forecast error as well as other issues raised by the parties in this proceeding.

862 (10) The EIM benefits calculation methodology proposed by Avista, resulting in $6.6 million in benefits is just and reasonable.

863 (11) Avista's transmission assets are used and useful and the Company has provided evidence and testimony showing that they will remain so.

864 (12) There is insufficient evidence supporting the need for an update to the Colstrip mark-to-market valuation and the Commission does not find that the benefits would outweigh the costs of an additional rate proceeding to update that valuation.

865 (13) Consistent with the Commission's Used and Useful Policy, the provisional plant review process should continue to be conducted on a portfolio basis, with a six-month review period, with consistent classification of plant and naming conventions, and shall not be tracked through a separate tariff at this time.

866 (14) In spite of our desire to maintain flexibility, and not be overly prescriptive, we wish to provide further clarification on the Commission's expectations for provisional plant filings. Specifically, Avista must conform to the following:

1) Identify if a business case is identified in the Clean Energy Implementation Plan (CEIP);
2) Identify if a business case is required for CETA and/or Climate Commitment Act (CCA) compliance;
3) Identify each new business case and provide a narrative for business need;
4) Provide information on an annual and cumulative rate-effective period basis;
5) Provide a narrative that explains the filing structure and how worksheets fit together; and
6) Maintain consistent naming conventions.

867 (15) The Commission finds Public Counsel's recommendation for an equal allocation is fair, just, and reasonable, and that Avista's next cost of service study shall account for removal of Colstrip in rates.

868 (16) Avista proposed a multi-year rate plan as required by RCW 80.28.425.

869 (17) The Commission should approve Avista's filing as a multi-year rate plan and not as a traditional rate case filing.

870 (18) The Commission should authorize and require Avista to make a compliance filing in these consolidated dockets to recover in prospective rates its revenue deficiency of $11.882 for rate year 1 and an incremental $68.9 million in rate year 2, for electric operations before offsetting Colstrip factors, and an increase of $14.2

million in rate year 1 and an incremental $4.0 million for rate year 2, for natural gas operations as provided in Appendix C (electric) and Appendix D (natural gas).

871 (19) A $1.00 increase to the minimum charge for electric and gas customers is supported by the record and is just, reasonable, and sufficient.

872 (20) Avista must revise Schedule 25 to include (1) increasing demand charges for energy blocks 1 and 2 by 25 percent in RY1 and 25 percent in RY2, (2) increasing the primary voltage discount from $1.93/kW to $4.39/kW, and (3) changing language in Schedule 25 to make the primary voltage discount applicable to customers served through third party substations.

873 (21) For the proposals related to reallocating Colstrip and including Colstrip in rate spread calculations, we agree with Avista that both AWEC and NWEC were signatories to the original settlement, and that settlement should not be amended at this time.

874 (22) The Commission should authorize a capital structure of 48.5 percent equity and 51.5 percent debt, a cost of debt of 4.99 percent, and an ROE of 9.8 percent, resulting in a ROR of 7.32 percent.

875 (23) The flotation costs incurred by the Company's investors are not expenses the ratepayers shall bear.

876 (24) In the recent election, voters approved Initiative Measure No. 2066, which in pertinent part states:

> (12) The commission shall not approve, or approve with conditions, a multiyear rate plan that requires or incentivizes a gas company or large combination utility to terminate natural gas service to customers.
> (13) The commission shall not approve, or approve with conditions, a multiyear rate plan that authorizes a gas company or large combination utility to require a customer to involuntarily switch fuel use either by restricting access to natural gas service or by implementing planning requirements that would make access to natural gas service cost-prohibitive.

877 (25) The Commission should adopt the non-pipeline alternatives framework described in paragraph 809, as fair, just, reasonable, sufficient and in the public interest.

878 (26) While the consideration of equity pursuant to RCW 80.20.425(1) is distinct from the legal requirements pertaining to low-income customer programs, the

Commission's equity analysis naturally focuses on low-income customer programs, among other broader social, economic, and environmental impacts related to utility rates, services, and practices.

879 (27) Avista has demonstrated sufficient evidence of its continued dedication to promoting equitable outcomes by agreeing to: (1) retain the reporting requirements in accordance with U-210800; (2) collaborate with EAAG and EAG on its disconnection policies and its multilingual MLS strategy; and (3) obtain customer demographic information for DER on an optional basis. The Commission therefore rejects TEP's recommendations that Avista:

1) Prioritize customers for disconnection based on only current arrearage amount and duration of current arrears;
2) Develop a separate LAP in coordination with EAG and EAAG;
3) Provide a new LINA/EBA and report data in its disconnection reduction report using the stratification framework.
4) Publish its stratification and data reporting on its website.

880 (28) 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.

881 (29) 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.[1409]

882 (30) The Commission should adopt the performance measures outlined in Appendix A 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.

883 (31) Avista should be authorized and required to make an annual compliance filing to report the performance measures outlined in Appendix A for each year of the MYRP (beginning January 1 and ending December 31 of each year) as an appendix or appendices to its annual Commission Basis Reports.[1410]

[1409] See RCW 80.28.425(7).

[1410] *In re Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making*, Docket U-210590, Policy Statement Addressing Initial Reported Performance Metrics, 3-4 ¶ 11 (Aug. 2, 2024).

884 (32) Avista should be authorized and required to make recurring reporting filings consistent with the Commissions modifications outlined in Appendix B.

885 (33) The plain language of RCW 80.28.410 gives the Commission discretion to allow a return on power purchase agreements costs to be deferred.

886 (34) Sierra Club's proposal to require Avista to engage in a targeted electrification pilot should be rejected.

887 (35) AWEC's proposal to remove Avista's interest-bearing Wells and Mizuho accounts from Avista's cash working capital should be rejected.

888 (36) The Commission should authorize Avista's Working Capital Restating Adjustment (ISWC Adjustment 1.03) as reasonably calculated to result in rates that are fair, just, reasonable, and sufficient.

889 (37) Avista's litigation costs related to wildfire and patent litigation are fair, just, reasonable and in the public interest.

890 (38) Avista's accounting of deferred tax credit balances is fair, just, reasonable, and in the public interest.

891 (39) The Commission should authorize Avista's proposed adjustment to electric property rent as revised on rebuttal.

892 (40) The Commission should authorize and order Avista's proposed deferral regarding Coyote Springs 2 major maintenance costs.

893 (41) Avista's Wildfire Balancing Account should be authorized with a baseline of wildfire expense of $8.3 million, over Avista's two-year rate plan.

894 (42) Avista's proposal to recover carrying charges on the Wildfire Balancing Account at its cost of debt should be approved by the Commission.

895 (43) Avista's Insurance Expense Balancing Account should be authorized with baselines of $12.8 million for electric, and $2.3 million for natural gas.

896 (44) Public Counsel and AWEC's proposal to exclude 50 percent of Directors' and Officers' liability insurance should be rejected.

897 (45) Avista's proposal to require increase ratepayers' share of directors' fees from 50 to 90 percent should be rejected.

898 (46) Public Counsel and AWEC's proposal to exclude stock compensation from Avista's directors' fees should be rejected.

899 (47) The Commission should authorize Avista to recover 50 percent of its directors' fees in rates.

900 (48) The non-executive labor incentive adjustment proposed by Avista, is based on estimates and forecasts, and therefore does not meet the known and measurable standard.

901 (49) Public Counsel's proposal to adjust Avista's executive compensation based on comparisons to publicly-owned utility executive compensation should be rejected.

902 (50) Public Counsel's request to require Avista to conduct an executive compensation survey including data from publicly-owned utility executives should be rejected.

903 (51) Avista's proposal to continue its revenue decoupling mechanism during the multi-year rate plan should be accepted.

904 (52) The Commission should authorize Avista's proposed 2.5 percent escalation adjustment for Pro Forma Adjustments 3.14 and 5.06.

905 (53) Avista should be authorized and required to make a compliance filing within 45 days of this Order to provide the workpapers supporting its pro forma adjustments regarding its updated test year ending in December 2023.

906 (54) 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.

907 (55) The Commission should retain jurisdiction over the subject matter and the Parties to effectuate the terms of this Order.

908 (56) Based on the evidence in the record and the Commission's denial of the forecast error adjustment, the Commission authorizes a Washington Total Power Supply Base of $34,116,983 for rate year 1, and $85,733,975 for rate year 2.

ORDER

THE COMMISSION ORDERS:

909 (1) The proposed tariff revisions Avista Corporation, d/b/a Avista Utilities, filed in these dockets on January 18, 2024, and suspended by prior Commission order, are rejected.

910 (2) Avista Corporation, d/b/a Avista Utilities, is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order.

911 (3) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

912 (4) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective December 23, 2024.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

David W. Danner

DAVID W. DANNER, Chairman

Ann E. Rendahl

ANN E. RENDAHL, Commissioner

Milt H Doumit

MILT DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.