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April 20, 2018

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
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RE: Docket No. UG 344 – In the Matter of
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL,
Request for a General Rate Revision.

Attached are the following exhibits in UG 344 Staff Opening Testimony:

Exhibit 100 - 106 Gardner:
Exh 100 page 35 and Exh 106 (excel) are confidential

Exhibit 200 - 212 Muldoon:
Exh 208 is confidential

Exhibit 300 - 308 Fox:
Exh 300 pages 24-25, 29 & 35 are confidential
Exh 305 (excel) is confidential
Exh 309 pages 3-4, 59-61 are confidential

Exhibit 400 - 407 Anderson:
Exh 400 page 14 is confidential

Exhibit 500 - 08 Boyle

Exhibit 600 - 604 Gibbens
Exh 602 and 603 (excel)

Exhibit 700 - 715 Kaufman
Exh 700 pages 54-57, 61-62 are confidential
Exh 703, Exh 709, Exh 710 and Exh 714 are confidential

Exhibit 800 - 801 Moore

Exhibit 900 - 902 Rossow
Exh 902 (excel) is confidential

Exhibit 1000 -1003 Zarate

Exhibit 1100 -1102 Peng

Exhibit 1200 -1203 Compton

A certificate of service, service list, CDs (confidential and non-confidential) are included with this filing.

/s/ Kay Barnes

Kay Barnes
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CERTIFICATE OF SERVICE

UG 344

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 20th day of April, 2018 at Salem, Oregon

Kay Barnes

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CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

April 20, 2018

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

A. My name is Marianne Gardner. I am a senior revenue requirement analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding the Northwest Natural Gas Company (Northwest Natural, NWN, or Company) request for a general rate revision, docketed as Docket No. UG 344. As such, I verify NWN's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement after incorporating Staff's proposed adjustments to NWN's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, and my analysis and recommendations.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket UG 344 is submitting separate testimony. In Part 1 of my testimony, I introduce the Staff witnesses and their respective assignments, and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 101	Witness Qualification Statement
Exhibit 102	NWN Responses to Staff Data Requests
Exhibit 103	Escalation – Excerpts from Consumer Price Index – All Urban Consumers for the U.S., published by OEA (released November 16, 2016) and (released February 16, 2018)
Exhibit 104	FERC Notice
Exhibit 105	Staff Outstanding Data Requests to NWN
Exhibit 106	NWN Responses to NWIGU Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

PART 1. REVENUE REQUIREMENT

Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.

A. I have provided a listing of rate topics in Table A.

Table A.

NW Natural **STAFF ISSUE SUMMARY** **Twelve Months Ended October 31, 2019** **($000)**							
Incremental Revenue Requirement							
			NWN supplemental filing	NW Natural/1202/1 at 1, col f.			**37,816**
Opening Testimony Exhibit No.	**Staff Witness**	**Issue No.**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
100	Gardner	1	Uncollectibles (Included in 700-6)				
100	Gardner	2	Interest Synch. (placeholder)				
100	Gardner	4	Other Taxes - Franchise Fee Rate				(2)
100	Gardner	4	Other Taxes - Franchise Fees		(36)		(37)
100	Gardner	4	Other Taxes - ODOE		(48)		(50)
100	Gardner	4	Property taxes (subject to true-up)		(1,104)		(1,135)
100	Gardner	5	Amortization (subject to true-up)				
100	Gardner	6	Customer Deposits			(576)	(52)
100	Gardner	7	Misc. A&G		(4,101)		(4,218)
100	Gardner	8	Salary, Wages & Incentives		(8,525)	(1,607)	(8,914)
100	Gardner	9	Income Tax Rate - TCJA (included in NWN supplemental filing)				
100	Gardner	9	ADIT & EDIT - TCJA (placeholder)				
100	Gardner	10	Escalation (placeholder)				
200	Muldoon	1	Rate of Return - Capital Structure				(8,560)
200	Muldoon	2	Equity Floatation		(1,198)		(1,233)
300	Fox	1-7	Plant adjustments			(191,146)	(17,265)
400	Anderson	1	Advertising Expense		(400)		(412)
400	Anderson	2	Promotions & Concessions		(4,302)		(4,425)

Opening Testimony Exhibit No.	Staff Witness	Issue No.	Proposed Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect
400	Anderson	3	Misc. Revenues	513	15		(512)
500	Boyle	1	Fee-Free Bankcard		(671)		(690)
600	Gibbens	1	D&O Insurance		(250)		(257)
600	Gibbens	3	Medical Insurance		(487)		(501)
700	Kaufman	1-4	Plant & associated depr			(34,348)	(3,102)
700	Kaufman	5	Affiliated Interests & Allocations		(5,541)		(5,699)
700	Kaufman	6	Revenue	2,329	69		(2,324)
800	Moore	1	Gas Storage & Fuel Stock		(122)		(126)
800	Moore	3	Plant Maintenance		(93)		(96)
800	Moore	3	Distribution O&M		(2,148)		(2,210)
800	Moore	5	Customer Accounts Expense		(357)		(367)
900	Rossow	1	Memberships, Dues, Donations		(452)		(464)
1000	Zarate	1	Meals, Entertainment & Travel		(1,349)		(1,387)
1100	Peng	1	Depr. Exp. & Accum. Depr. (subject to true-up)				
1200	Compton	**	LRIC/Marginal Cost Study				
Total Staff-Proposed Adjustments (Base Rates):				2,842	(31,100)	(227,676)	(64,038)
Staff-Calculated Revenue Requirements Change (Base Rates):							(26,222)

** No adjustment to revenue requirement.

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PART 2. SPECIFIC ISSUES

Q. What areas of NWN's filing are you primarily responsible for reviewing?

A. I reviewed the portions of the filing related to uncollectible expense, interest synchronization, working capital allowance, taxes other than income, depreciation and amortization, aid in advance of construction (CIAC), customer deposits, leasehold improvements, administrative and general expenses, workforce levels, wages and salaries, incentives, income taxes, and escalation. In order to gain additional insight, I reviewed the Company's responses to Staff's standard Data Requests (DRs), issued approximately 30 additional DRs, and reviewed the Company's responses.

ISSUE 1. UNCOLLECTIBLES

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense, the Company's filed proposal, and Staff's analysis of the issue.

A. For purposes of determining a utility's revenue requirement, "uncollectible" expense is the charge to expense or cost of service when a customer defaults on a payment. The amount of uncollectible expense included in a utility's revenue requirement is "revenue sensitive," meaning it depends on the amount of forecasted revenues. Accordingly, the amount of uncollectible expense included in revenue requirement is a function of the test year revenue and an "uncollectible rate."

It is a long-standing policy of the Commission Staff to determine the uncollectible rate by averaging the net-write offs (the uncollectible amounts that were actually written off the books) for the three years preceding the test year by the average of the revenues (e.g., general revenues) for those same preceding years. The uncollectible rate that is derived from this three-year average methodology is used to determine the test year uncollectible expense for a utility's revenue requirement.[1] However, Commission Staff also examines

[1] *See, e.g.*, *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3 (January 21, 2014); and *In the Matter of Avista Corporation*, UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average); and *In the Matter of Cascade Natural Gas Corporation*, UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

other evidence to determine whether this approach results in a reasonable forecasted test year result.

Q. Please provide a summary of the Company's filed proposal and Staff's analysis of the issue.

A. The Company's proposal is based on the three-year average methodology described above. The Company's witness, Mr. McVay, testifies, "[t]he adjustment or Uncollectible Accrual for Gas Sales reflects the difference between the Base Year expense and the Test Year expense derived by taking the three-year historical average of write-offs as a percent of total revenues times Test Year sales revenue."[2] As shown in the Company's Exhibit 205, the Company utilized 2015, 2016, and 2017 based on an October 1 through September 30 time period.

To analyze the Company's proposed expense, Staff requested the actual calendar data for 2015, 2016, and 2017. Staff then trended the actual three year rolling average for each of the aforementioned years against the Company's proposed test year weighted average uncollectible rate of 0.114 percent [3] to ensure the 0114 percent was reasonable compared to the prior years.

Q. What is Staff's recommendation?

A. Based on Staff's analysis, Staff finds the Company's uncollectible rate for the test year reasonable. Since it is a revenue sensitive rate, I will have an

[2] NW Natural/200, McVay/13 at 15-20.

[3] NW Natural/200, McVay/1 at 15.

adjustment to the test year uncollectible expense dependent on other Staff proposed changes in test year revenues.

ISSUE 2. INTEREST SYNCHRONIZATION

Q. Please provide a summary of the Commission's historical treatment of interest synchronization, the Company's filed proposal, and Staff's analysis of the issue.

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes in the regulated utility's cost of capital as initially filed in a general rate case. Accordingly, the interest synchronization adjustment depends on Staff Witness Matt Muldoon's proposed adjustments to cost of capital (CoC) in this docket. Mr. Muldoon has recommended in his testimony an adjustment to the Company's filed cost of capital, of which the weighted cost of debt is a component. Because interest expense on long-term debt is tax deductible, Mr. Muldoon's proposed cost of long-term debt impacts income tax expense for ratemaking purposes.

The cost of long-term debt proposed in NWN's direct testimony is 5.233 percent.[4] Staff, as supported by Mr. Muldoon's testimony, concurs with the Company's proposed 5.233 percent cost of debt and a weighted cost of long-term debt of 2.617 percent.[5]

Q. What is Staff's recommendation?

A. As the revenue requirement summary witness, I synchronize the interest expense for the income tax calculation to reflect a weighted cost of debt of

[4] NW Natural/300, Burkhartsmeyer/6 at 14.

[5] Staff/200, Muldoon/52.

2.617 percent. Based on the Company's test year rate base of $1,214,895[6] and weighted cost of long-term debt of 2.617,[7] Staff's does not propose an adjustment at this time. This recommendation may change depending on other parties' opening testimony and other Staff recommendations regarding net rate base.

The interest amount is calculated on the test year as follows:

+ Net Rate Base

X Staff's Recommended (or Authorized) Weighted Cost of Debt

= Allowable Interest Deduction

\- Company's Reported Interest Deduction

=Interest Coordination Adjustment

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[6] NW Natural/202, McVay/1 at 26, col. e.

[7] NW Natural/208, McVay/1 at 1.

ISSUE 3. WORKING CAPITAL

Q. **Please provide a summary of the Company's filed proposal for working capital.**

A. The Company did not discuss working capital in its testimony. However, in its test year, the Company included two components of working capital; gas and material and supplies (M&S) inventories of $35.373 million and $10.399 million, respectively. The Company did not include any prepayments.[8]

Q. Please explain the Commission's historical treatment of working capital?

A. For ratemaking purposes, the components of working capital are generally rate base items identified as fuel inventory, M&S inventory, prepayments, and cash working capital. The Commission typically authorizes utilities to include an allowance for material and supplies in rate base, which has included FERC Account Nos. 154, Plant Material and Operating Supplies; 163, Store Expense Undistributed; 164.2, Liquefied Natural Gas Stored, and 165, Prepayments – Gas Storage.[9] The Commission's long-standing policy has typically been to disallow gas companies a separate amount for cash working capital. The Commission allows electric companies to include cash working capital in rate base if it is calculated based on a current lead-lag study. In Avista's four most recent rate cases, UG 246, UG 284, UG 288 and UG 325, Staff stipulated to allowing Avista to include rate base materials and supplies in inventory costs

[8] Staff /102, Company response to SDR No. 84.

[9] *See, e.g., In re California-Pacific Utilities Company,* UF 3275, Order No. 77-394, (1977 WL 438034); *In re Cascade Natural Gas Corporation,* UF 3094 Order No. 74-898 (1974 WL 391913).

but excluded cash working capital. The Commission adopted those stipulations.[10]

Q. What is Staff's recommendation?

A. Staff's recommendation is to allow NWN to include fuel and M&S inventories in the test year rate base.

[10] *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3; *In the Matter of Avista Corporation*, UG 284, Order No. 15-109 at 3 (April 9, 2015); *In the Matter of Avista Corporation*, UG 288, Order No. 16-076 at App. A, page 3 (February 29, 2016); *In the Matter of Avista Corporation*, UG 325, Order No. 17-344 at 3 (September 13, 2017).

ISSUE 4. TAXES OTHER THAN INCOME

Q. Please provide a summary of the Commission's historical treatment of taxes other than income, the Company's filed proposal, and Staff's analysis of the issue.

A. The category "taxes other than income" (Other Taxes) typically includes franchise fees, the regulatory fee imposed by the OPUC, property taxes, payroll taxes and other miscellaneous taxes or fees, e.g. Oregon Dept. of Energy (ODOE) fee, incurred by the energy utility. Payroll taxes are included as a component of the wages and salaries issue, which is discussed in a subsequent section of this testimony.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for ratemaking purposes on the condition these costs do not exceed 3.0 percent of gross revenues for a gas utility.[11] For simplicity, these costs are referred to collectively as franchise fees. The OPUC fee and ODOE fee are also included in operating expenses for ratemaking purposes. In rate cases, franchise fees, and the OPUC fee are a function of the fee rate multiplied by gross revenues and are called revenue sensitive costs. Additionally, these revenue sensitive fees are included in the conversion factor in determining the revenue requirement.

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[11] See OAR 860-022-0040(1). Fees that exceed three percent must be charged to the customers within the jurisdiction assessing the fee. (OAR 860-022-0040(6).

Property taxes related to property that is not yet used and useful may not be included in customer rates of a gas utility.[12] Hence, these property taxes are excluded from the test year operating expenses. Property taxes related to property that is used and useful are included in test year operating expense and are usually forecasted for ratemaking purposes based on historical property tax information.

Franchise Fees

Q. What is the Commission's historical treatment of franchise fees in a general rate case?

A. The revenue requirement for franchise fees is revenue sensitive. Accordingly, Staff determines a franchise fee rate based on a ratio of annual fees and revenues. Historically, Staff has accepted a franchise fee rate based on a three-year average rate. However, Staff has reviewed other evidence such as a historical trend to determine the reasonableness of the proposed franchise rate and the resulting franchise fees.

Q. Would you please explain the Company's proposal for franchise fees?

A. Yes. The franchise fees included in the test year are $15,219,120. According to the Company's testimony, "franchise fees were derived by applying the effective rate of 2.37 percent to gross sales and transportation revenue and miscellaneous franchise revenues to provide a forecast for total franchise fees for both the base year and test year."[13]

[12] See ORS 757.355(1).
[13] NW Natural/200, McVay/16 at 21-22, 17 at 1-2.

Since the Company did not provide evidence to show how the "effective rate" was determined or support the rate in testimony or its workpapers, Staff issued DR Nos. 388 and 389 requesting the underlying calculation and historical actuals for franchise fees and related revenues.[14] According to the Company's response to DR No. 388, the 2.37 percent was used for the 2017 Purchased Gas Cost Adjustment filing and was based on actual franchise fees from July 1, 2016 through June 30, 2017. In the Company's response, the Company provided the historical data for each of the calendar years 2015, 2016, and 2017. The average rate for the three years is 2.364 percent.

Q. What is Staff's recommendation regarding the franchise fee rate the Company proposes?

A. Staff proposes the franchise fee rate be calculated based on a three-year average of the last the three years of actual data. This results in 2.364 percent versus the Company's 2.37 percent.[15] The 2.364 percent will be used in the test year conversion factor for the revenue requirement. Also, Staff will apply this percent to Staff's adjusted test year revenues to calculate the amount of franchises fees in O&M expense.

<u>OPUC Regulatory Fee</u>

Q. Would you please explain the Company's proposal for the OPUC fee?

[14] Staff/102, NW Natural Responses to Staff DR Nos. 383-389.

[15] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 4 Franchise Fees MG.xlsx.

A. The Company has proposed a rate of 0.300 percent applied to test year gross revenues of $642,156,962.[16]

Q. Does Staff find the 0.300 percent rate reasonable?

A. Yes. According to Order No.18-073, the most recent OPUC order setting the annual fee rate, the rate is set at 0.300 percent; the maximum rate the Commission is allowed to assess utilities.[17] Since this rate is applied to gross revenues, the amount of fees recommended by Staff will be a function of the amount of gross revenues recommended by Staff in subsequent opening testimony.

ODOE Fee

Q. Would you please explain the Company's proposal for the ODOE fee?

A. The Company states in testimony, "the fee was calculated by first calculating an average effective rate for the two-year period of 2015 and 2016, and then applying the average effective rate to total operating revenue." This results in a proposed rate of 0.127 percent and ODOE test year fees of $818,134.

Q. Does Staff recommend a change in the Company's proposed rate of 0.127 percent rate?

A. Yes. Staff's proposes the rate be calculated on a three-year average of the last the three years of actual data. This results in 0.1198 percent versus the Company's 0.1274 percent. Based on the $630.088 million test year revenues, this results in a reduction of ($48) thousand in ODOE fees ($630.088 x

[16] NW Natural/200, McVay/17 at 8-10.
[17] See ORS 756.310(3).

((.1198% - 0.1274%)).[18] Since the ODOE fee is not considered a revenue sensitive rate, there is no change to the conversion factor.

Property Taxes

Q. Would you please explain the Company's proposal for Property Taxes?

A. The Company includes $22.382 million in the test year for property taxes. As shown in the Company's Exhibit 209, the Company derived expense for property taxes by developing a two-year average rate based on the ratio of taxes paid in 2016 and 2017 to net plant at December 31 of the prior year. The average rate calculated was applied to December 31, 2017 net plant balance and forecasted net plant for 2018.

Q. What is Staff's recommendation regarding the property taxes?

A. Staff's proposes to use a three-year average to develop the property tax rate. For opening testimony, Staff proposes to use Staff witness John Fox's adjusted total plant less the test year accumulated depreciation as proposed by Staff witness Ming Peng. Based on these parameters, Staff proposes $21.278 million of property tax for the test year, a ($1.104) million reduction.[19] For the final revenue requirement in this case, Staff recommends truing up property tax to the final level of test year net plant determined by the Commission.

Summary of Other Taxes

Q. What is Staff's recommendation regarding the revenue sensitive rates the Company proposes?

[18] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 4 ODOE Fees MG.xlsx.

[19] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 4 Property Taxes MG.xlsx.

A. Staff's concurs with the 0.300 percent OPUC rate in the conversion factor but proposes 2.364 percent for the franchise fee rate.

Q. What is Staff's recommendation regarding the expense the Company proposes in its test year?

A. Since both the franchise fees and OPUC fee are revenue sensitive and thus are a function of revenues, Staff will propose an adjustment based on other Staff proposals regarding test year revenues. With regard to the ODOE fee, Staff proposes $754.546 thousand in fees; a reduction of ($48) thousand. Finally for property taxes, Staff recommends a reduction of ($1.104) million to be trued up based on the final net plant determined in this case.

ISSUE 5. DEPRECIATION AND AMORTIZATION

Q. Please provide a summary of the Company's filed proposal.

A. Staff witness Ms. Peng, reviewed the Company's filed amortization and depreciation. In her testimony, she thoroughly defines depreciation and amortization, sets forth the Company's initial proposal, and describes her analysis. In the process of her analysis, Ms. Peng identified a few errors in the Company's initial filing.[20] In its March 30, 2018, supplemental filing, the Company updated its filing for these depreciation and amortization errors and for federal tax reform that passed after its initial filing.[21]

Q. Does Staff propose any additional adjustments to amortization or depreciation?

A. Staff does not propose any additional adjustments at this time. However, as the revenue requirement summary witness, I recommend that the test year amortization and depreciation expense, the related reserves, and the final revenue requirement be updated to correspond with the final level of gross plant and intangible assets determined by the Commission.

[20] Staff/1100, Peng/6-7.
[21] NW Natural/200, McVay/4-5.

ISSUE 6. OTHER RATE BASE

Q. Please explain what rate base items are included in this issue.

A. I reviewed the following rate base line items: aid in advance of construction (CIAC), customer deposits, and leasehold improvements.

Q. Please provide a summary of the Company's proposal for CIAC, customer deposits, and leasehold improvements.

A. With regards to CIAC, the Company has reduced the test year rate base by $3.476 million.[22] According to the Company's testimony, CIAC "represents the amounts of customer-provided contributions toward construction costs. The Test Year Balance is calculated using the September 30, 2017 actual balance plus trended amounts based on historic balances for the remaining months."[23] The Company utilized a simple regression model with one X variable to estimate the trend for the test year. The Company included monthly historical ending balances from January 2014 through September 2017 to estimate the monthly balances through October 2019. The Company's analysis can be found in the electronic workpapers filed with its initial application.[24]

Similar to its treatment of CIAC, the Company reduced the test year rate base for customer deposits by $3.849 million.[25] According to the Company's testimony, customer deposits "represent amounts that customers are required

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[22] NW Natural/202, McVay/1 at 21-22 col. (g).

[23] NW Natural/200, McVay/22 at 19-21 and 23 at 1-2.

[24] UG 344 NWN Initial Applications – Work papers\Non-Confidential Work papers\Other Rate Base and Cushion Gas.xlsx\tab "Cust Contrib".

[25] NW Natural/202, McVay/1 at 21-22 col. (g).

to provide to comply with credit requirements under our tariff."[26] As it did in the CIAC test period calculation, the Company again utilized a one X factor regression model to estimate the trend for the test year using monthly historical balances from January 2014 through September 2017. This data was used to forecast 2018 and the 2019 test year. In the case of customer deposits, the deposits are recorded on a Total Company basis, so the Company applied an allocation factor to estimate the Oregon-Allocated amount. The Company's analysis can be found in the electronic workpapers filed with its initial application.[27]

Regarding leasehold improvements, the Company's witness testifies, "[t]he Test Year forecast for this element was obtained by taking the existing principal balances net of amortization through September 2017 and continuing the consistent month amortizations, with an assumption of no new improvements through 2019. The result of the forecast was an amount for this category of zero."[28]

Q. What is the Commission's historical treatment of CIAC, customer deposits, and leasehold improvements in a general rate case?

A. CIAC and customer deposits are treated as a reduction to the test year rate base. There is not a prescribed methodology for estimating the amounts that should be included in the test year. Leasehold improvements are treated

[26] NW Natural/200, McVay/23 at 3-5.

[27] UG 344 NWN Initial Applications – Work papers\Non-Confidential Work papers\Other Rate Base and Cushion Gas.xlsx\tab "Deposits".

[28] NW Natural/200, McVay/23 at 21-22 and 24 at 1-4.

similarly to plant in rate base. To be included in rate base, leasehold improvements must be prudent as well as used and useful as of the date new rates become effective.

Q. Please describe Staff's analysis of the Company's proposal for CIAC and customer deposits.

A. The Company failed to provide the statistical methodology behind its regression model. Additionally, it omitted any assumptions or the theoretical basis for its choice of models. The model appears to be simple; utilizing one X variable. In order to determine whether the Company's result was reasonable, Staff did a simple trend of the data for the years 2010 through 2017. In Staff's opinion, both methods should return approximately the same test year balance.

Staff requested the historical data for the years 2010 through 2017 in Staff DR Nos. 343 and 344.[29] Staff then averaged the beginning and ending balances of each year to create an average yearly balance for each year. Using the averages as data points, Staff estimated the 2018 and 2019 test year based on the trend line.[30] Staff similarly trended the customer deposit data. Based on Staff's trend analysis, Staff calculated a test year average ending credit balance of ($3.400) million and ($4.425) million for CIAC and customer deposits, respectively.[31]

Q. Based on Staff's analysis, what is Staff's recommendation?

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[29] Staff/102, NW Natural Responses to Staff DR Nos. 343 and 344.

[30] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 6 CIAC MG.xlsx.

[31] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 6 Customer Deposits MG.xlsx.

A. Staff has no adjustment to the Company's proposed CIAC test year amount of ($3.476) million. Staff does propose to increase the Company's customer deposit test year balance of ($3.849) million to ($4.425) million. This results in a decrease to rate base of ($576) thousand.

Q. Does Staff recommend any adjustment regarding leasehold improvements?

A. No.

ISSUE 7. ADMINISTRATIVE AND GENERAL EXPENSE

Q. Please describe the expense at issue.

A. The expense at issue is recorded in FERC accounts categorized as administrative and general (A&G), specifically FERC account Nos. 921-935.[32] My testimony for this issue is limited to non-labor expenses charged to account Nos. 921 (office supplies and expenses), 928 (regulatory commission expenses), 930.2 (misc. general expenses), and 931 (rents). Other Staff reviewed the remaining accounts. Additionally, other Staff reviewed certain cost categories within these A&G accounts that are commonly adjusted in a general rate case. These include advertising, promotions, memberships, dues, donations, meals, entertainment, gifts, airfare, lodging, travel, and awards. Their conclusions and recommendations regarding their analyses can be found in their testimony.

Q. What is the Company's proposal related to FERC accounts included in your testimony?

A. The Company did not specifically address A&G expenses at the FERC account level in testimony. The Company discussed Operations and Maintenance (O&M) non-payroll of which A&G is a subcategory. The non-labor amounts were provided in its response to Staff SDR No. 58. The test year amounts for account numbers 921, 928, 930, and 931 are as follows:

FERC Account No.	FERC Account Desc.	Test Year
921	Office Staffing & Expense	$18,719,849

[32] NW Natural/206, McVay/4 at 70-82, col. (b).

928	Regulatory Commission Expense	$103,741
930.2	Misc. General Expense	$2,918,587
931	Rents	$4,477,457
TOTAL		$22,083,056

Q. Please describe in general the adjustments the Company proposed for non-payroll O&M costs and its explanation or rationale for the increase in costs from the base year?

A. The Company escalated general non-payroll O&M costs at January 1, 2018 to the test year using the Portland-Salem Consumer Price Index. However, some items were adjusted for other specific growth rates.[33] The Company discussed that good cost management has resulted in a reasonable growth rate in O&M costs. As an example, the Company compared the O&M growth on a per customer basis internally on a year over year basis from 2013 through the test year.[34] Additionally, the Company charted its O&M expense per customer against other peer utilities.[35]

Q. Did the Company provide a detailed explanation or workpaper that quantified its escalation adjustment?

A. No. The Company did not provide the escalation adjustment at a FERC account or cost category level or even in total. Neither did the Company provide the underlying data for its charts that support its assertion, “that the

[33] NW Natural/600, Moncayo/8 at 17-21 and 9 at 1-16.
[34] NW Natural/600, Moncayo/14.
[35] NW Natural/600, Moncayo/15.

utility is managing its O&M levels to stabilize rates as much as possible for customers."[36]

Q. Has the Company demonstrated to Staff that the test year O&M cost levels are appropriate and just and reasonable for the customer?

A. No. The Company needs to provide the supporting evidence and calculations for its charts and escalation adjustment to allow Staff to fully review and validate its test year proposal. Staff has issued data requests to the Company to elicit information and to explore this issue more fully but the Company's response may not be received in time to be incorporated in Staff's opening testimony.[37]

Q. Please summarize Staff's policy for escalation.

A. It is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. ("All Urban CPI") as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation of expenses. The All Urban CPI measures price changes in a fixed market basket of goods and services in 200 categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers.[38] The most recent release of the All Urban CPI was the March 2018 report, released February 16, 2018. According to Appendix A of this report, the percentage change for CPI for 2015 to 2016, 2016 to 2017, 2017 to 2018, and 2018 to

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[36] NW Natural/600, Moncayo/14 at 5-7.

[37] Staff/102, NW Natural Responses to Staff DR Nos. 401-402.

[38] *In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, UE 116, Order 01-787 at 40 n10 (September 7, 2001); *In the Matter of Northwest Natural*, UG 132, Order No. 99-697 at 43 (November 12, 1999).

2019 is 1.3 percent, 2.1 percent, 1.7 percent, and 1.9 percent, respectively.[39] Since it has been more than six years since NWN has been in for a general rate case, Staff also relied on the December 2016 report, released November 16, 2016. According to Appendix A of the December 2016 report, the percentage change for CPI for 2013 to 2014, and 2014 to 2015 is 1.6 percent and 0.1 percent, respectively.

Q. Please describe Staff's analysis of the Company's proposal?

A. Staff reviewed the trend in these accounts for the historical years 2010 through 2017 and the Company's proposed test year. Staff selected 2013 as the base year for adjustment rather than 2010 because the economy was still recovering from the United States Great Recession. Staff then inflated the 2013 actuals with the year over year change in CPI for the account numbers listed above. Additionally, Staff considered the growth in number of customers from 2013 through the test year and escalated each account by the change in CPI and customer growth rate.[40], [41] For FERC accounts 930 (misc. general expenses) and 931(rents), Staff excluded customer growth from the calculation because, in Staff's opinion, there is not a correlation between customer growth and these expenses. Also, Staff excluded the test year expense for regulatory commission expense as no historical actuals existed for that account in the

[39] Staff/402, Gardner/8.
[40] Staff /102, NW Natural Responses to SDR No. 110.
[41] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 7 A&G MG.xlsx.

data provided by the Company in response to Staff SDR No. 58 and Staff SDR No. 183.[42]

Q. Based on Staff's analysis, what is Staff's recommendation?

FERC Account No.	FERC Account Desc.	Company Test Year	Staff Proposed Adjustment
921	Office Staffing & Expense	$18,719,849	($3,700,943)
928	Regulatory Commission Expense	$103,741	($103,742)
930	Misc. General Expense	$2,918,587	($218,092)
931	Rents	$4,477,457	($78,314)
TOTAL		$22,083,056	($4,101,091)

A. Staff's recommendation is to decrease the test year A&G non-labor expense for the above listed FERC accounts by ($4,101,091).[43]

[42] Ibid.
[43] Ibid.

ISSUE 8. WAGES, SALARIES, INCENTIVES AND FULL-TIME EQUIVALENTS

Q. Please provide a summary of the Commission's historical treatment of wages, salaries, incentives, and overtime expense.

A. The Commission typically uses Staff's three-year wage and salary model (W&S Model) to estimate expenses for non-union wages and salaries.[44] As a starting point, Staffs model uses the utility's actual average wage and salary levels as they existed three years prior to the test year. From there, Staff applies the annual changes to the All Urban CPI[10] to adjust wages and salaries for each of the three subsequent years to establish a forecast of test-year wage and salary levels. If the utility's projected wage and salary level is within ten percent of Staffs projection, the difference between projections is shared between customers and shareholders. Outside the ten-percent band, shareholders keep all of the benefit or pay all the cost.

The W&S Model incorporates actual market-based data by using the All Urban CPI index to adjust historic wages and salaries.[45] Notably, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey.[46]

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[44] See e.g., *In the Matter of PacifiCorp*, UE 116, Order No. 01-787 at 40 (September 7, 2001).

[45] Order 01-787 at 40; *In the Matter of Northwest Natural*, UG 132, Order No. 99-697 at 43 (November 12, 1999). See also *In the Matter of PGE*, UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, UE 88, Order No. 95-322 at10 (March 29, 1995).

[46] Order 01-787 at 40; *In the Matter of Northwest Natural*, UG 132, Order No. 99-697 at 43 (November 12, 1999). See also *In the Matter of PGE*, UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, UE 88, Order No. 95-322 at10 (March 29, 1995).

The Commission has concluded that adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year, and provides an incentive to companies to minimize labor costs.[47] Further, sharing the difference between the two payroll projections equally between ratepayers and shareholders also allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[48]

Rather than using All-Urban CPI for union wages, the Commission typically ties test year union payroll to negotiated wage increases as set forth in the union contract.[49]

For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on increased earnings.[50] It is also Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders), and to disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[51]

Q. Please summarize NWN's proposal for wages, salaries, incentives and overtime expense in this case.

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[47] Order 01-787 at 40.

[48] Order No. 95-322 at 10.

[49] See Order No. 99-697 at 43.

[50] See Order No. 99-033 at 62, *In the Matter of the Application of US West*, UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

[51] See Order 99-697 at 44-45; Order 99-033 at 62.

A. On a Total Company basis, the 2019 test year includes approximately $98.587 million in wages and salaries (base pay)[52],[53] $11.744 million in incentive compensation,[54],[55] and $4.013 million in overtime.[56] The Oregon allocated test year labor expense is 90.3 percent of the Total Company labor expense.[57] As the Company explains in testimony, the Company subscribes to survey data to benchmark and aligns both its base pay and incentives to the market median for a competitive total compensation package.[58]

Q. How do the Company's adjustments to salaries, wages and incentives differ from those Staff typically makes in a general rate case?

A. Staff explains the differences by each component of Staff's W&S Model below.

Escalation

Q. Please explain the Company's proposal regarding the escalation of base payroll.

A. As explained in its testimony, for non-union employees NWN escalated base pay for the calendar year 2017 by 4.00 percent for 2018 and then by 4.25 percent to arrive at the test year base pay. These increases include a merit

[52] NW Natural/700, Doolittle/5 at Table 1.

[53] Staff/102, NW Natural Responses to Staff DR No. 125, DR 125 CONF Supp Attachment 2 –OM Model.xlsx, tab, O&M FTE Salary & Wages, and tab, Capital FTE Salary & Wages.

[54] NW Natural/700, Doolittle/15 at Table 3.

[55] Staff/102, NW Natural Responses to Staff DR No. 125, DR 125 CONF Supp Attachment 2 –OM Model.xlsx, tab, O&M Payroll OH, and tab, Capital Payroll OH.

[56] Staff/102, NW Natural Responses to Staff DR No. 125, DR 125 CONF Supp Attachment 2 –OM Model.xlsx, tab, Overtime & Other Comp.

[57] Staff/102, NW Natural Responses to Staff SDR No 93.

[58] NW Natural/700, Doolittle/4-5.

increase of 3.25 percent for 2018 and a 3.50 percent merit increase for 2019. The additional 0.75 percent is for promotions and equity adjustments.[59]

Staff, consistent with Staff's W&S Model, escalated the wages and salaries from the 2016 historical base year to a projected 2018-2019 test year using the All-Urban CPI. For union employees, Staff's escalation is based on the last contracted rate increase of three percent as provided by the Company in its response to Staff DR No. 94. Staff then determined the difference between its projection of test year amounts and the Company's and applied the sharing percentages.

As noted above, if Staff's projection is less than the Company's test year amount, the sharing test allows the Company to share 50/50 the lesser of the difference between the Company's filed proposal and Staff's calculated projection or a 10 percent band around Staff's calculated projection.[60] In this case, the difference between the Company's filed proposal and Staff's calculated projection was the lesser amount. NWN's wage and salary projection exceeds Staff's projection by $812.237 thousand. Staff multiplied this difference by 50 percent for sharing. Staff then applied the 90.3 Oregon-allocation percentage to derive the adjustment for the Oregon jurisdictional test year.

Q. What is Staff's recommendation regarding the escalation of salaries and wages to include in the 2019 test year?

[59] NW Natural/700, Doolittle/5 at 11-16 and 6 at 1-4.

[60] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 8 W&S model CONF MG, tab 100-8.1 PUC 3-year W&S.

A. Staff recommends reducing the base year salaries and wages by ($812.237) thousand allocated as ($542.574) thousand O&M expense and ($269.663) thousand capital. Also related to this are small adjustments for payroll taxes and depreciation of ($45.034) and ($41.578), respectively.[61]

FTEs

Q. Please provide the background for this issue.

A. NWN's 2019 test year includes 1117 FTE[62] on an Oregon-allocated basis and 1,144 FTE on a Total System basis,[63] which is defined as utility and non-utility operations. This is an increase of 48 FTEs from 2009 through 2017. On an Oregon-allocated basis, this translates to approximately 43.3 FTE; an approximate 4.2 percent increase in the workforce over ten years (including the test year).

Q. Did the Company explain the increase in FTE from 2009 through 2017 in its testimony?

A. No. However, Staff asked the Company to provide the business case for the year over year increase in employees from 2009 through 2017. According to the data provided by the Company, on a Total System basis, FTE dropped by 97 FTE from 2009 to 2010. The Company explained this was due to slow customer growth and efficiency gains like the automation of meter reading. From 2010 through 2017, FTE grew by 145 FTE for a net

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[61] See Staff electronic workpaper, NWN UG 344 Exh 100 Issue 8 W&S model CONF MG, tab 100-8 Misc Labor.

[62] NW Natural/700, Doolittle/5 at 10.

[63] Staff/102, NW Natural Response to Staff DR 326.

gain of 48 FTE. The reasons provided by the Company include increased customer growth, improved emergency response, implementation of a Project Management Office, addition of employees for increasing regulatory and safety requirements, construction, field operations, and training.[64]

Q. Please describe Staff's analysis of the Company's increase in FTE.

A. Staff compared the ratio of customers to FTE in the test year to the ratios in years from 2009 through 2017. Excluding 2009, Staff found that the number of customers per FTE averaged around 660 customers per FTE. The projection for the test year is approximately 661 customers per FTE based on Staff's estimation. Staff also looked at the year over year percentage change in the number of customers. For 2010 through 2012, the growth was flat at around 1 percent. After 2012, customer growth has increased. From 2012 through 2017, the number of customers grew by approximately 44,000 or six percent on a Total Company basis.[65]

Q. What is Staff's recommendation regarding the number of FTE proposed for the test year?

A. Based on Staff's analysis and the Company's response to Staff DR No. 326, Staff does not recommend an adjustment to the Company's proposed number of test year FTE. However, Staff notes that the Company's O&M model for the test year includes incremental pay on a system basis for 10

[64] Staff/102, NW Natural Response to Staff DR No. 326.
[65] See Staff electronic workpaper, UG 344 NWN Issue 8 W&S model CONF MG, tab DR 125.

FTE whose position descriptions are "unidentified positions."[66] It is unclear whether these employees were hired by the end of 2017 and it is not clear what these FTE are for. The expense associated with these 10 FTEs is [Begin Confidential] [redacted] [End Confidential]

Incentives

Q. Please explain the Company's proposal regarding the inclusion of incentive pay in its Oregon jurisdictional test year?

A. As a component of its total compensation package, the Company includes incentives. The Company states, "[w]e determine and provide a competitive total compensation package for the employees that we need to hire and retain."[67] "Total compensation refers to the combination of base pay, merit-based incentive payments (or "pay-at-risk"), medical benefits, and retirement benefits."[68] To ensure the Company's pay is competitive it conducts market research and purchases survey data to ensure its compensation package aligns with peer companies.[69]

The Company offers a "Goals Incentive Program" to its non-bargaining, non-officer employees. This program is based on the employee's performance and provides awards proportional to the employee's achievement of

[66] Staff/102, NW Natural Responses to Staff DR No. 125, DR 125 CONF Supp Attachment 2 –OM Model.xlsx, tab, O&M TY FERC Allocation Summary.

[67] NW Natural/700, Doolittle/2 at 13-15.

[68] NW Natural/700, 17-18.

[69] NW Natural/700, Doolittle/4 at 1-9.

performance goals. It offers a "Key Goals Program" to its bargaining employees. This program has two components. One component is based on operational goals. The operating goals lie within the control of the employee and involve metrics such as improved reliability and customer service. The other is based on the Company's financial performance. Since the Company does not anticipate it will meet the financial targets in the test year, the financial performance portion was excluded. Lastly, the Company's officers' incentive plans include both short-term and long-term incentive plans. These short-term plans are based 70 percent on the Company's performance and 30 percent on the individual officer's performance. The long-term incentive programs are comprised of Restricted Stock Units (RSUs) and performance shares.[70]

Q. Did Staff review incentives as a component of total compensation?

A. Yes. Staff reviewed the median pay analysis the Company provided in its responses to Staff's data requests as well as the data included with its filed testimony. The Company's pay analysis included base pay and incentive pay. Staff finds that both base pay and incentives for the non-bargaining employees and bargaining employees appear to be appropriate as compared to the peer data.

Q. What is Staff's position regarding the level of incentives included in the test year?

A. As Staff mentioned earlier in its testimony, Commission policy traditionally disallows 100 percent of officers' incentives and a portion of non-officer

[70] NW Natural/700, Doolittle/7-9.

employee incentives. Non-officer incentives are disallowed at 50 percent if they are based on non-financial metrics and 75 percent if the incentives are based on financial performance measures. The Commission's policy appropriately matches costs and benefits as officers' incentives hinge on meeting shareholders' financial expectations. The policy as it relates to non-officers is more flexible and recognizes that both customers and shareholders benefit from high-achieving employees whose daily jobs impact both customers' quality of service and the Company's bottom line.

Q. Does the Company object in testimony to the Commission's incentive policy?

A. Yes. The Company believes the Commission should modify its policy and allow the test year proposed incentives, which are $11.744 million on a system basis. Alternatively, the Company suggests the Commission address the issue outside of a rate case in an investigation or other forum.[71]

Q. Please summarize Company's perspective regarding the Commission's incentive policy?

A. The following is the Company's perspective and may not accurately state the Commission's stance on the issue.

1) The Commission policy is historically grounded in a belief that incentive pay results in total compensation above the median.[72]

[71] NW Natural/700, Doolittle/16 at 1-13.
[72] NW Natural/700, Doolittle/11 at 1-4.

This does not reflect NW Natural's current methodology of setting compensation nor is it a current industry practice.[73]

2) The Commission believes, "…because pay-at-risk is in some instances provided to employees only when certain financial metrics are met, shareholders also benefit from pay-at-risk. Thus, they have required shareholders to bear some of the costs or in the case of officers, the full cost."[74] The Company goes on to argue that shareholders may benefit from incentives when certain goals are achieved especially those goals that emphasize cost efficiencies that promote safe and reliable service at reasonable costs. Conversely, good financial metrics enable a Company to raise capital at favorable rates benefitting customers through the rate of return in the revenue requirement. [75]

3) The Commission's policy negatively impacts NWN because payroll costs represents two-thirds of O&M costs and the application of the policy could result in a $7 million disallowance of prudent incentive costs. The Company has considered eliminating its pay-at-risk program for non-officers and increasing base pay. However, the Company rejected this alternative because it would not be a good compensation practice.

[73] NW Natural/700, Doolittle/11-18.

[74] NW Natural/700, Doolittle/11 at 4-8.

[75] NW Natural/700, Doolittle/11 at 9-12 and 12 at 1-4.

4) The Company believes Commission Staff is seeking to expand the Commission's incentive policy to those incentives capitalized in rate base. The Company contends this is an unjustified extension of the Commission's expense side adjustment of incentives.[76]

Q. What is Staff's response to the Company's arguments opposing the Commission's incentive policy?

A. The Company is correct that Commission's policy disallowing portions of incentives for rate-making purposes is well documented in past orders and Staff practice. Staff addresses the Company's arguments below:

1) The Company's interpretation that the Commission (in the distant past) disallowed incentives because incentives result in pay that is over the median is incorrect. As noted in the Commission's disposition in Order 97-171, whether compensation as a whole is reasonable is measured against the market and is a distinct issue from whether customers should pay for incentives in rates.

> The record shows that USWC's base salaries before bonuses are within a reasonable range, as is USWC's compensation including bonuses. Because its compensation is reasonable compared to the market, USWC concludes that its expense for management and executive bonuses is reasonable. USWC conflates two separate issues. The level of overall compensation is reasonable compared to the market. That does not determine whether it is reasonable to ask ratepayers to fund bonuses with the declared goals of USWC's incentive plans.[77]

[76] NW Natural/700, Doolittle/14 at 12-21 and 15 at 1-6.

[77] *In the Matter of the Application of U S WEST Communications, Inc., for an Increase in Revenues*, UT 125, Order No. 97-171.

2) The fact that incentives could benefit both shareholders and customers is not at odds with Commission policy. That is evident in the sharing methodology the Commission policy sets forth. Rather it is the metrics, goals, and targets the plan is based upon that give rise to the disallowance.

In Docket No. UT 125, Staff asserted that bonuses paid by US West Communications (USWC) under certain plans were based on achieving financial, business, and corporate goals. The USWC plans in question included the following metrics (1) Earnings before Interest Taxes, Depreciation, and Amortization (EBITDA); (2) USWC Net Income; and (3) Business Unit Results & Strategic Measures, Customer Service, Customer Loyalty, increase in USWC stock price, and stock dividend growth. Staff proposed to disallow all of the bonuses associated with these plans. In the disposition of this issue, the Commission stated as follows in Order 97-171:

> We note that our disallowance is not based on the manner in which compensation is administered but on the purpose for which the bonuses are awarded. We also note that this conclusion does not prevent USWC from paying bonuses; it merely dictates that bonuses be paid from funds that would go to shareholders, not from funds provided by ratepayers. Therefore, we do not believe that the resolution of this issue places USWC at a competitive disadvantage.* * * If in a future rate case USWC submits employee incentive plans with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement.[78]

The sharing principle is also upheld by the Commission in Order 99-033:

> Staff also proposed an adjustment of $1,273,200 to the Officer Incentive Plan. PGE claims that this adjustment is inconsistent with past Commission practice (in UE 88, for

[78] Ibid.

> example), where the Commission allowed inclusion in revenue requirement of the 25 percent portion of the Officer Incentive Plan applicable to non-officers. Staff now accepts the allowance of a portion of the plan covering non-officer employees and asks that the Commission approve the following principle for incentive pay:
>
> One-half of Our Teamworks expense, all of the Officers portion of the Officer Incentive Plan and seventy-five percent of the non-officer portion of the OIP pay should be excluded from utility rates, consistent with past Commission practice.
>
> **12. Commission Disposition**
>
> The Commission adopts Staff's principle as set out above.[79]

3) The Commission does not dictate an appropriate compensation policy for any of the regulated companies. Rather, the Commission allows in rates those costs that result in just and reasonable rates for customers. The Commission's disallowance of certain incentive plans reflects the fact that customers and shareholders benefit in different proportions to the plan. Since the Commission applies the same policy across all of the regulated companies under its regulatory authority, it does not set them at a competitive disadvantage from each other. Also, NWN's decision to retain its incentive plans rather than eliminating the plans and raising base pay indicates to Staff that the Company is better off even though some of the incentive costs are disallowed in rates.

4) Disallowing a portion of incentives included in the historical base year rate base is not an extension of the Commission incentive policy. Staff's Wage &

[79] *In the Matter of the Application of Portland General Electric Company for Approval of the Customer Choice Plan,* UE 102, Order No. 99-033.

Salary Model does allocate its proposed adjustment between O&M and capital based on the O&M/Capital allocation percentage provided by the Company.[80]

In a recent Portland General Electric (PGE) rate case, Staff discovered that in between rate cases, PGE was continuing to capitalize officer incentives and other non-officer performance-based incentives in rate base. Staff asserted that not only should the disallowed incentives capitalized in plant for the test year be removed but the historical base year should be reduced for the disallowed incentives PGE had continued to capitalize in plant. Therefore, Staff proposed to adjust the test year rate base for performance related incentives included in the plant balance.[81]

Q. What is Staff's recommendation regarding the amount of incentives in the test year?

A. After application of the sharing test, Staff recommends a reduction in NWN's test year incentives of ($7.587) million, allocated between O&M and capital costs as ($6.249) million and ($1.337) million, respectively.[82] Additionally, Staff anticipates adjusting plant in rate base for performance related incentives capitalized in the historical base year. Staff has outstanding DRs regarding the plans' target metrics and the capitalization of incentives contrary to the Commission's policy. The Company's responses to these DRs will not be

[80] Staff/102, NW Natural Responses to Staff DR No. 93.

[81] UE 283 Stipulating Parties/200, Gardner-Higgins-Jenks-Macfarlane-Mullins/6 (settling issue related to capitalization of incentives).

[82] See Staff electronic workpaper, UG 344 NWN Issue 8 W&S model CONF MG, tab 100-8.

received in time to incorporate into opening testimony.[83,84] Therefore, Staff reserves the right to modify this adjustment based on further discovery.

[83] Staff/102, NW Natural's Responses to Staff DR Nos. 407, 408, and 409.
[84] Staff Exhibit 105, Staff DR No. 413.

ISSUE 9. STATE INCOME TAX, FEDERAL INCOME TAX AND ACCUMULATED DEFERRED INCOME TAX

Q. Please summarize the applicable requirements for ratemaking treatment of federal income tax (FIT), state income tax (SIT) and accumulated deferred income tax (ADIT).

A. Consistent with Internal Revenue Code (IRC) Sections 168(f)(2) and 168(i)(9) (Normalization Rules for Public Utilities) and ORS 757.269(1), public utilities are required to normalize federal income taxes for revenue requirement purposes. Normalization of federal income taxes means that a regulated public utility that uses accelerated depreciation for tax purposes must record in rate base a related deferral of taxes that arises from the difference between book depreciation and tax depreciation. According to IRC Sec. 168(i)(9)(A):

> In order to use normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—
>
> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and
>
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a

> reserve to reflect the deferral of taxes resulting from such difference.

Also, ORS 757.269 (1) states "[s]ubject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operation of the utility." According to subsection (3):

> During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes a part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon: (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest.

Q. Please summarize NWN's proposed SIT, FIT and ADIT requested in this case.

A. In the Company's initial application, the Company proposed marginal tax rates for FIT and SIT of 35 percent and 7.6 percent, respectively,[85] and proposed ADIT of ($435.940) million in rate base.[86] As NWN noted in its opening testimony, "[a]t the time the rate case was finalized for printing, federal tax reform appeared imminent but had not been finalized."[87] The

[85] NW Natural/200, McVay/14 at 16-22.
[86] NW Natural/202, McVay/1 at 25, col. (g).
[87] NW Natural/202, McVay/15 at 20-21.

Company stated it would file supplemental filings to reflect the impact of new tax rules.[88] The federal tax reform legislation, the Tax Cuts and Jobs Act of 2017(TCJA), was signed into law on December 22, 2017. As promised, NWN filed supplemental testimony on March 20, 2018.

Q. Would Staff please provide the main impact of the Tax Act in general on regulated public energy utilities?

A. Yes. The three major impacts for regulated public energy utilities are:

1) The change in the corporate tax rate lowers the tax expense included in cost of service.
2) The change in the tax rate requires the recalculation of the ADIT balance, which may give rise to Excess Deferred Income Tax (EDIT).
3) The elimination of bonus depreciation after September 27, 2017.

The largest component requiring remeasurement of ADIT balances in rate base for public utilities is accelerated depreciation on plant for tax purposes versus straight-line for book purposes. As a result of the tax rate change, a portion of the taxes collected by utilities from customers in rates is no longer due to the federal government in a future period. Since accelerated depreciation is subject to normalization rules, the TCJA mandates certain methodologies for the timing of the return or flow-through of the excess deferred income taxes (EDIT) to customers. The TCJA has eliminated or restructured other tax deductions that will also affect the ADIT balance. However, while these deductions may give rise to EDIT, they are not subject to

[88] NW Natural/202, McVay/15 at 21-22 and 16 at 2.

normalization rules and are not subject to the TCJA methodologies for flowing the excess tax back to customers.

Q. What has NWN proposed in its supplemental testimony regarding income tax expense?

A. NWN's test year federal tax expense went down from $19.287 million to $11.024 million. The main driver was the correction of the federal marginal tax rate for its 2019 test year from 35 percent to 21 percent as mandated by the TCJA. NWN also attributed the decrease to the loss of two permanent tax deductions; meals and entertainment and transportation deductions. Since the change in permanent tax deductions was only $762 thousand ($6.727 million[89] less $5.965 million[90]), permanent tax deductions appear to have a much smaller impact.

Q. To what did NWN attribute the change in ADIT?

A. NWN had forecasted the Company would elect bonus depreciation when estimating its test year ADIT. However, the TCJA eliminated bonus depreciation for utilities as described above.

Q. Did NWN discuss the EDIT that was created by the change in marginal tax rate?

A. NWN did not discuss it, which Staff found very curious especially as it would be a violation of normalization to fail to return to customers the EDIT that would

[89] NW Natural/207, McVay/1.

[90] NW Natural/201, McVay/1.

arise from the over-collection of tax from customers for the deferred taxes created due to accelerated depreciation on plant assets.

Q. Please explain the actions Staff has taken on behalf of customers for the over-collection of taxes due to the TCJA?

A. On December 29, 2017, Staff filed separate applications to defer changes in each energy utility's federal tax obligations resulting from H.R.1 – Tax Cuts and Jobs Act. In NWN's case, this application is docketed as UM 1924, Staff's Application to Defer Changes in NW Natural's Tax Obligation. Additionally, each energy utility filed its own deferral application. The deferral application NWN filed is docketed as UM 1919. Subsequent to the deferral filings, Staff and the utilities participated in a joint workshop to discuss the TCJA impacts. Due to the workshop and other informal discussions with individual utilities, Staff has extended the date for comments in its deferral dockets to April 30, 2018.

Staff continues to research the implications and issues surrounding the TCJA in other jurisdictions. As additional background, Staff has included as Exhibit 104 FERC's notice of inquiry, "Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission Jurisdictional Rates".[91] The notice's summary includes discussion of the impact of the TCJA on entities that fall directly under the FERC's oversight but the notice also points to those areas that are common to the public utilities as well. The notice highlights concerns

[91] https://www.federalregister.gov/documents/2018/03/21/2018-05670/inquiry-regarding-the-effect-of-the-tax-cuts-and-jobs-act-on-commission-jurisdictional-rates, accessed 4/2/2018.

covering some of the complex issues the TCJA has posed especially those involving the remeasurement of ADIT and returning EDIT to customers. The notice states FERC is soliciting comments from interested parties until May 21, 2018.

Q. Please describe Staff's analysis of the Company's proposal in UG 344.

A. Staff agrees that the federal tax rate for cost of service should be reduced from the 35 percent the Company initially filed to 21 percent for the test year. The Company did not discuss the revaluation of its ADIT for the tax rate change nor mention any EDIT in testimony. In an informal conversation with the Company and other parties, the Company did disclose that the Oregon-allocated test year rate base does not include the effects of the remeasured ADIT. The Company also disclosed it has calculated the EDIT, but it too is not included in rate base.

Staff has a number of outstanding data requests regarding the impact of the TCJA on the Oregon-allocated test year.[92] Also Staff notes that NWIGU has a number of outstanding data requests surrounding this issue.[93] Therefore, Staff is reserving any recommendation regarding the proper level of ADIT in the test year rate base or regarding the creation of a regulatory liability to accumulate EDIT that should be returned to customers pending further investigation of this issue in the rate case and the deferral docket.

[92] Staff/105, Staff DR Nos. 410 - 412.

[93] Staff Exhibit 106, NW Natural Responses to NWIGU DR Nos. 9, 10, 37, and 38.

ISSUE 10. ESCALATION

Q. Please summarize the Company's rate making treatment for escalating non-labor O&M expenses.

A. As mentioned in Staff's earlier testimony in Issue 7. Administrative and General, the Company escalated general non-payroll O&M costs as of January 1, 2018 to the test year using the Portland-Salem Consumer Price Index. However, some items were adjusted for other specific growth rates.[94]

Q. Please explain the other growth rates the Company utilized, the expense accounts to which the Company applied these specific rates, and the Company's rationale behind using each type of escalator.

A. As explained in Staff's Issue 7 testimony, the Company did not provide an explanation in testimony or in its filed workpapers.

Q. Did Staff issue any data requests inquiring further regarding the Company's escalation?

A. Yes. Staff issued DR Nos. 401 and 402. The Company responded to these DRs on April 9, 2018.[95] Staff did not have enough time to review the Company's responses prior to completing opening testimony.

Q. Does Staff have a recommendation regarding the Company's escalation?

A. Staff recommends using the All-Urban CPI to escalate O&M expense based on Commission's policy. However, to insure there is no double counting of Staff's adjustments to the test year O&M, Staff needs additional time to review the

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[94] NW Natural/600, Moncayo/8 at 17-21 and 9 at 1-16.

[95] Staff/102, NW Natural's Responses to Staff DR Nos. 401 and 402.

Company's responses, and the impact of other Staff opening testimony adjustments to the Company's test year O&M expense. Therefore, Staff reserves the right to recommend an adjustment amount until Staff's review of the Company's escalation is completed.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UE 294, UG 284, UG 287, UG 288, and UG 305.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2017

Standard Data Request Response

Request No. 84: Provide a schedule showing the ending balance for the most recent historical base year (per book) and the estimated balances for each month of the projected test year for materials and supplies inventories that the utility is proposing to include in its rate base.

Response: Please see enclosed excel file "GRC 18 SDR 84 **Attachment 1- Materials and Supplies.xlsx**". The balances the Company proposes to include in rate base represent a trended result of Materials and Supplies balances based on actual amounts from January 2014 through September 2017.

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Rates & Regulatory Affairs
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2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 383

383. Referring to NW Natural/209, McVay/1, and workpaper 200 wp1 Revenue Requirements model.xlsx, Exhibit 209 tab, please explain whether any tax abatements, tax refunds, tax credits have been considered in the calculation of the property tax expense and related rate. If not, please explain and include any offsetting credits to property tax expense and recalculate the proposed property tax rate.

Response:

Local jurisdictions within the State of Oregon provide a 3% discount on property tax billings if they are paid in full on or before November 15^{th} of each year. NW Natural submits payment in full on or before November 15^{th} of each year in order to obtain this discount. This discount is included within the property tax expense figures used to calculate the proposed property tax rate. There are no other Oregon utility related tax abatements, tax refunds or tax credits, related to property taxes.

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Request No.: UG 344 OPUC DR 384

384. Referring to NW Natural/209, McVay/1, please update the property tax portion of the Excel workpaper 200 wp1 Revenue Requirements model.xlsx, Exhibit 209 tab, and include the 2015 actuals, with any credits to property tax expense, and calculate the 2015 effective rate.

Response:

Please see UG 344 OPUC DR 384 Attachment 1 for the additional 2015 data.

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Data Request Response

Request No.: UG 344 OPUC DR 385

385. Please provide a detail narrative explanation regarding the properties for which NW Natural is assessed property taxes, the taxing jurisdiction, and how NW Natural allocates property taxes to the Oregon regulated gas jurisdiction.

Response:

NW Natural's utility operations are subject to property taxation under the 'central assessment' approach. Under central assessment, property tax valuations are not determined by county assessors based on the perceived value of the actual real and personal property held by the business. Rather, a value for the utility operations as a whole is determined by a state level appraiser.

The state level appraiser generally uses a three part appraisal that encompasses asset value, income value, and sales value, to arrive at an overall value of the utility operations. The overall value determined by the state level appraiser is then apportioned to that state appraiser's respective state using an apportionment formula that is generally a weighted average formula that considers factors such as original cost of tangible assets, operating revenues, operating income and sales volumes both within and without the particular state. As a result, the final assessed value for a particular state, does not necessarily bear a direct and specific relationship to the property in that state, but is rather the assessed value that a state has determined is properly allocable to that state.

The state level apportioned value is then further allocated by the state level appraiser to each property tax code jurisdiction in the state in which the utility holds property. The primary method of allocation to these individual tax code areas is the percent of pipe miles located in the tax code area relative to all pipe miles in the state.

Each county in the state receives a report from the state level appraiser which itemizes the value that has been apportioned to each tax code area in the respective county. The county then prepares individual property tax bills for each tax code area that reflect the value apportioned to the area multiplied by the property tax rates that are in effect for that area. These property tax bills are then sent to the utility by each county whereby they are reconciled to the total apportioned value determined by the state and then processed for payment.

Oregon

Oregon’s state level appraisers operate as a division of the Oregon Department of Revenue. The Oregon central assessment appraisal encompasses the operations and assets of the core natural gas utility, interstate storage and KB Pipeline. Only the property taxes imposed by Oregon counties on the core natural gas utility operations and assets are included in Oregon ratemaking. No allocation of property taxes imposed by jurisdictions outside of Oregon is applied to Oregon for ratemaking purposes or otherwise.

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Data Request Response

Request No.: UG 344 OPUC DR 386

386. Please provide in an Excel worksheet, the following information for the years 2012 through 2018, inclusive, for each jurisdiction that levies taxes that NW Natural has included in property tax expense in its filed Oregon Results of Operations Report and its UG 344 forecasted Oregon-Allocated test year, this request is ongoing for 2017:

	2018 Budget	2017	…	2012
Assessed Property Value (Oregon)				
Property Value following appeal				
Net Book Value of Property				
Property taxes accrued				
Property taxes actually paid				
Actual Tax Rate				
Assessed Property Value (Jurisdiction Name)				
Property Value following appeal				
Net Book Value of Property				
Property taxes accrued				
Montana property taxes actually paid				
Actual Tax Rate				
Total Oregon-Allocated Property Value Total Oregon-Allocated Property Value following appeal				
Oregon-Allocated Net Book Value of Property				
Oregon-Allocated property taxes accrued Oregon-Allocated property taxes actually paid				
Oregon-allocated Tax Rate				

Response:

Please see Excel file, "**UG 344 OPUC DR 386 Attachment 1.xlsx**"

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Rates & Regulatory Affairs
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Request No.: UG 344 OPUC DR 387

387. Please provide the total property tax budgeted and total property tax booked for the years 2012 through 2018, inclusive, on an Oregon-Allocated basis. Please explain any year to year variance greater than 10 percent.

Response:

Please see Excel file, “**UG 344 OPUC DR 387 Attachment 1.xlsx**”

OREGON DEPARTMENT OF ENERGY
625 MARION STREET NE
SALEM, OR 97301-3737
PHONE: (503) 378-3268
OREGON TOLL FREE 1-800-221-8035 x368
FEDERAL ID NO: 93-0643773

INVOICE NUMBER	INVOICE DATE	PAYMENT DUE
AR190080	**08/30/17**	**10/04/17**

NORTHWEST NATURAL GAS
ATTN: DAVID H ANDERSON/BRODY WILSON/KAREN STEINBERG
220 NW SECOND AVENUE
PORTLAND, OR. 97209

DESCRIPTION	CHARGES
Energy Resource Supplier Assessment - State Fiscal Year 2017-2018 Calendar year 2016	810,501.00
	Amount Due
	$ 810,501.00

For questions concerning this invoice, call (503) 378-3268.
Please return the remittance copy or include the invoice number on your check stub.

ORS469.421 (11) (B), REQUIRES A PENALTY FEE OF 2% PER MONTH TO BE ASSESSED ON ALL PAST DUE BALANCES

CUSTOMER COPY

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 388

388. Referring to NW Natural/200, McVay/1 and Excel workpaper 200 wp1 Revenue Requirements model.xlsx, Exhibit 209 tab, please provide:

a. The calculation and/or basis for the proposed 2.37 percent Franchise Fee rate for the Oregon-Allocated test year.

b. In an Excel worksheet, on an Oregon-Allocated basis, the actual franchise fee expense for each of the years 2015, 2016, and 2017, inclusive, the related revenues, and the calculation of the franchise fee rate for each of the years 2015 and 2017. In the response, please provide the supporting information for each jurisdiction e.g. municipality etc.

c. The calculation and/or basis for the proposed Oregon Department of Energy (ODOE) rate of .127 percent.

d. In an Excel worksheet, on an Oregon-Allocated basis, the actual ODOE expense for each of the years 2015, 2016, and 2017, the related revenues, and the calculation of the ODOE rate for each of the years 2015 and 2017.

e. The most recent invoice from the ODOE for tax assessment.

Response:

a. See UG 344 OPUC DR 388 Attachment 1 which was prepared and used for the 2017 Purchased Gas Cost Adjustment filing.

b. See UG 344 OPUC DR 388 Attachment 2 – “Franchise Taxes 2015-17,” tab “Tax Rate” for the actual tax expenses and related revenues for the calendar years 2015 through 2017. The other tabs in the file contain greater detail on the taxes by jurisdiction by year.

c. The calculation of the ODOE rate of .127% is shown on the “Exhibit 209 – Other Taxes” tab of submitted workpaper “200 wp1 – Revenue Requirements Model” on rows 59 through 62.

d. See UG 344 OPUC DR 388 Attachment 3 - Annual ODOE Rate Calculations.

e. See UG 344 OPUC DR 388 Attachment 4 - 2017 ODOE Invoice.

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 389

389. Please explain whether applying the Franchise tax rate, ODOE tax rate, and the OPUC tax rate to Oregon total gross revenue is consistent with the actual assessment of these taxes. In other words, are all of these taxes actually assessed on total gross revenues? If not, for each tax type, please explain what revenues the taxing authority actually taxes and provide the proper Oregon-Allocated test year amount for each tax type.

Response:

Yes, applying the Franchise tax rate, ODOE tax rate, and the OPUC tax rate to Oregon total gross revenue is consistent with the actual assessment of those taxes.

The only tax that represents a static rate applied to the gross revenues is the OPUC fee, where the amount is actually a millage rate of 0.3% times the gross revenues.

The franchise tax application in the rate case reflects the franchise taxes recorded for a period in relation to the gross revenues for the period. Franchise taxes are assessed on billed amounts in each franchise area (with different rates for each franchise area) of the Company's service area, so there is no one rate that is applied to revenues on a state-wide basis. In this way, franchise taxes are assessed on subsets of the overall gross operating revenue for the company. The aggregate level of actual franchise taxes as compared to actual overall gross revenues does serve as a predictable basis for the expected franchise taxes related to an expected level of gross revenue. The methodology that relates franchise taxes to revenues has been used and accepted in past ratemaking filings as a component of the revenue sensitive gross-up factor. The rate case included the most recent established indicated franchise tax rate (from the 2017 Purchased Gas Cost Adjustment filing) to apply to gross operating revenue in the case to determine an estimate of the franchise tax.

The ODOE tax rate is developed each year based on the funding requirements of the department divided by the gross operating revenue for utilities in Oregon. The company's assessment is calculated by the resulting rate times NW Natural's gross revenue. So depending on the funding requirement and depending on NW Natural's share of statewide gross operating revenue, the amount can vary. The rate case included a two-year average of the indicated rate to apply to gross operating revenue in the case to determine an estimate of the ODOE tax.

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 343

343. Aid in Advance Construction (CIAC): Referring to UG 344/NW Natural/200, McVay/22 at 17-21 and /23 at 1-2, on a Total Company and an Oregon-Allocated basis:

a. Please provide the ending balance for Aid in Advance of Construction (CIAC) for the years 2010 through 2016;

b. Please provide, for the calendar year 2017,:

i.. The actual ending balance for each month through September and forecasted base year amount for the last three months;

ii. The actual ending balances for October, November, and December when that information is available;

iii. A detailed list of the subsidiary account ledger (e.g. customer accounts) that total the December 2017 year-end balance; and,

c. Please explain the reconciliation process of matching the detailed subsidiary account ledger to the total CIAC recorded in the December 2017 ending balance. Please provide a list of reconciling items and explain how each was resolved. If the December 2017 balance was not reconciled, please explain why not and provide the details for the last time the CIAC account was reconciled.

Response:

a. Please see attached file "UG 344 OPUC DR 343 Attachment 1 CIAC History" at rows 85-172 for 2010 through 2016 information. Contributions are accounted for in the GL on a state specific basis, and column R of that file has the total Oregon amount by month.

b. i. Please see attached file "UG 344 OPUC DR 343 Attachment 1CIAC History" at rows 42-50 for 2017 actual data (column R) and rows 51-53 for estimated data (column X). This information is also provided in "200 wp8 – Other Rate Base and Cushion Gas" file on tab "Cust Contrib."

   ii. Please see file "UG 344 OPUC DR 343 Attachment 1 CIAC History" at rows 182-184.

   iii. Please see file "UG 344 OPUC DR 343 Attachment 2 IS+Customer+Contributions" for reconciliation through December 2017.

c. The "subsidiary ledger" (CIS) provides a direct feed to SAP. The reconciliation consists of ensuring that monthly changes indicated by CIS are reflected in the General Ledger.

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 344

344. Customer Deposits: Referring to UG 344/NW Natural/200, McVay/23 at 3-5, on a Total Company and an Oregon-Allocated basis:

a. Please provide the ending balance for Customer Deposits for the years 2010 through 2016;

b. Please provide, for the calendar year 2017,:

i. The actual ending balance for each month through September and forecasted base year amount for the last three months;

ii. The actual 2017 ending balances for October, November, and December when that information is available;

iii. A detailed list of the subsidiary account ledger (e.g. customer accounts) that total the December 2017 year-end balance; and,

c. Please explain the reconciliation process of matching the detailed subsidiary account ledger to the total Customer Deposits recorded in the December 2017 ending balance. Please provide a list of reconciling items and explain how each was resolved. If the December 2017 balance was not reconciled, please explain why not and provide the details for the last time the Customer Deposits account was reconciled.

Response:

a. Please see attached file “UG 344 OPUC DR 344 Attachment 1 Deposits History” at rows 110-196 for 2010 through 2016 information. Deposits are accounted for in the GL on a system basis, and are allocated using an allocation factor based on detailed state-specific recent historic actual data.

b. i. Please see attached file “UG 344 OPUC DR 344 Attachment 1 Deposits History” at rows 41-52 for 2017 actual and estimated data. This information is also provided in “200 wp8 – Other Rate Base and Cushion Gas” file on tab “Deposits.”

ii. Please see file “UG 344 OPUC DR 344 Attachment 1 Deposits History” at rows 206-208.

iii. Please see file “UG 344 OPUC DR 344 Attachment 2 - Deposits - December 31, 2017.”

c. The “subsidiary ledger” (CIS) provides a direct feed to SAP. The reconciliation consists of ensuring that monthly changes indicated by CIS are reflected in the General Ledger. The reconciliation includes the combination of 3 different report runs from CIS, one of which is account based, and the other 2 are aggregated sums without account detail prior to the most recent financial period.

Rates & Regulatory Affairs
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Request No.: UG 344 OPUC DR 326

326. Referring to the Company's response, UG 344 OPUC DR 092 Attachment 1 rev 2017
11 28.xlsx,:
a. Please supplement the response and include the data for each calendar year 2009 through 2014.
b. Please explain the business case for each year over year increase or decrease in actual FTE by employee category for each calendar year 2009 through 2017 as well as the forecasted increase from 2017 actual FTE count to the test year count.
c. Please provide the actual Oregon-Allocated percent for each of the calendar years 2009 through 2017.

Response:

a. Please see attachment: UG 344 OPUC DR 326 Attachment 1.

b. The Utility added 48 FTEs over the period from 2009 to 2017. The 48 FTE increase reflects additional personnel in key areas to support our core mission of providing safe, reliable natural gas service to customers. To that end, we have added FTEs in the following areas:

- safety compliance and training to handle additional PHMSA regulations and create a more robust emergency response training program;
- field service personnel to meet customers' desire to have four-hour service windows (this was previously approved in the 2012 Oregon rate case);
- project management office to ensure rigor and proper prioritization for our capital investments and other significant Utility projects; and
- specialized information technology personnel to address cybersecurity risks and ensure our Utility infrastructure is safe from virtual attacks.

NW Natural has also added various FTEs in other categories during this time as business needs change and demands increase, but offers the above as an explanation of the main categories of change.

We take a long-term view of our business, investing in both our infrastructure and our employees; therefore, we carefully monitor business needs and trends prior to adding personnel, and also seek to take advantage of opportunities to realize efficiencies through technology. Below are the high-level drivers for changes in FTE levels from 2009 to 2017.

2009 - 2010
The number of Utility employees declined as we continued to experience slower customer growth and realized efficiencies in our processes and workforce. One example of this was the automation of meter reading.

2010 – 2011
The increase in the number of Utility employees is a result of filling a wide variety of open positions, caused by staffing reductions in the prior year.

2011 – 2012
The number of Utility employees increased as we hired additional service technicians, trainers and supervisor for service appointment windows, thus improving emergency response. We began implementing the Project Management Office. The majority of these hires occurred in the last quarter of 2012 so the total impact was not felt until 2013.

2012 – 2013
We began increasing the level of coverage in Gas Control and continued building the Project Management Office. Various other departments added 1 FTE.
Also see comments in 2011 – 2012 above.

2013 – 2014
Employee levels were stable.

2014 – 2015
Employee levels were stable.

2015 – 2016
Utility employees were added in various departments to keep up with customer growth and increasing regulatory and safety requirements.

2016 – 2017
Added Utility employees in construction, field operations, training and other business units.

2018 – 2019 Test Year
At the end of 2017 our FTE count reached 1,141. We expect staffing levels to remain relatively stable through the end of the test year.

c. Because the information provided applies to all employees, the “Payroll” factor is the most applicable allocation factor to use. The Oregon percentages for that allocation factor for 2009 through 2017 were 89.75%, 89.4%, 89.62%, 89.65%, 89.33%, 89.33%, 90.38%, 90.03%, and 89.51%, respectively.

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2017

Standard Data Request Response

Request No. 93: For the test year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages:

O&M	66.8%
Capital	33.2%

Oregon Test Year labor expense represents 90.3% of Total Company labor expense.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 414

414. Please provide the workpapers supporting the industrial customer forecast in “200 wp2 - Rate Case Margin Model.xlsx” sheet “from Industrial file.”

Response:

NW Natural separately provided this information to Staff as confidential, under the protective order in this proceeding, because it contains customer-specific information and is sensitive. NW Natural requests that other parties contact NW Natural if they determine they need to see this information.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 402

402. Referring to NW Natural/600, Moncayo/6 at 1-16, and Staff's above DR, please provide the payroll adjustments by FERC account, cost element, and adjustment type on an Oregon-allocated basis with a narrative explanation for each type of adjustment.

Response:

Detailed calculations of payroll escalation and payroll OH rate changes can be found in UG 344 OPUC DR 125 Supplemental Attachment 2 – OM Model. Specifically, the tabs below are applicable to the payroll calculations

Name of Tab	Description of Tab
Global Assumptions	Location for assumptions used throughout the model
Current FTE Count	Represents NWN current FTE count as of 9/30/17
Incremental FTE Count	Adjusted FTE Count represents adjustments to be made to the current FTE counts through the test year
Total FTE Count	Summarizes Current, Incremental and Total FTE counts by Grade and By Group. Total count is in row 148.
Current FTE Allocation	Allocates Current FTE counts to order type by using work allocation mix percentages
Incremental FTE Allocation	Allocated Incremental FTE counts to order type based on projected work mix. This tab includes projected FTE attrition and additions.
Total FTE Allocation	Combines Current and Incremental FTEs by order type
Current FTE Salary	Calculates monthly salary & wages for current FTEs including pay increases
Incremental FTE Salary	Calculates monthly salary & wages for incremental FTEs including pay increases; also allocates by order type
Total FTE Salary & Wages	Summarizes Current and Incremental FTE salary and wages; also calculates Payroll OH amount
O&M FTE Salary & Wages	Allocates the current FTE Salary & Wages to O&M by using work mix %, and adds that to Incremental FTE O&M salary & wages
Capital FTE Salary & Wages	Allocates the current FTE Salary & Wages to Capital by using work mix %, and adds that to Incremental FTE Capital salary & wages
Non-Utility FTE Salary & Wages	Allocates the current FTE Salary & Wages to Non-Utility by using work mix %, and adds that to Incremental FTE Non-Utility salary & wages
Overtime & Other Comp	Calculates forecasted amount of overtime and other comp for current and incremental BU and hourly NBU employees and allocates it to O&M/Capital
O&M Payroll OH	Allocates the O&M Payroll OH into detail

Capital Payroll OH	Allocates the Capital Payroll OH into detail
Non-Utility Payroll OH	Allocates the Non-Utility Payroll OH into detail
Total Payroll OH	Sum's Payroll OH detail for O&M, Capital & Non-Utility
Payroll Allocation	Calculates what the payroll allocation is in the test year by taking the current FTE payroll allocation and add the incremental allocation $'s
O&M TY FERC Allocation Summary	Shows total payroll is allocated to FERC accounts based on the rolling 12 mo. FERC payroll allocation percent. Also, this is where Oregon allocation of expenses takes place.

Attached as UG 344 OPUC DR 402 Attachment 1 is a summary table that shows payroll for 9 months of actuals in the base year, the 3 months base year forecast adjustment, the adjustment to the test year and the test year total by FERC account.

NW Natural®

Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 407

407. Referring to NW Natural/700, Doolittle/5, UG 344 OPUC DR 326 Attachment 1.xlsx, and NW/Natural/202, McVay/1 col (e), please explain by employee type/category why the Test Year base wages and FTE in testimony do not agree with the Test Year base wages provided in the Company's response to Staff DR 326. In the response, please provide the correct numbers that are included in NW/Natural/202, McVay/1 col (e) in the same format as in the response to DR 326. Additionally, please provide the most recent headcount for payroll purposes broken down by employee category. Please provide the count by full-time, part-time, and temporary employees.

Please use Staff's accompanying spreadsheet to organize the data requested in Staff DR Nos. 407 and 408.

Response:

See attached file "UG 344 OPUC DR 407 Attachment 1".

On the tab "Wages and FTE," note that the Staff-provided spreadsheet showed **12/31/2018** data in cells d-12 through d-16. Corresponding **Test Year 10/31/2019** data was added in column F.

The Test Year base wages and FTE provided in Testimony do not agree with the Test Year base wages provided in the Company's response to Staff DR 326 because the data in Testimony is for **utility only**, while the data in DR 326 is for Total Company including non-utility.

The testimony numbers from NW Natural/700, Doolittle/5 were used in the development of NW Natural/202, McVay/1 col (e).

Note that corrections were made to the Staff-provided spreadsheet, which had an incorrect formula in cell C-17.

Also note that amounts provided are total wages, including O&M, Capital, and Other components.

Issue 8 - Wages, salaries, incentives, and FTE

See tab “Headcount” for information as of April 4, 2018.

NW Natural®

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Request No.: UG 344 OPUC DR 408

408. Referring to NW Natural/700, Doolittle/15, UG 344 OPUC DR 326 Attachment 1.xlsx, and NW/Natural/202, McVay/1 col (e), please explain by employee type/category why the Test Year incentives provided in testimony do not agree with the Test Year incentives provided in the Company's response to Staff DR 326. In the response, please provide the correct numbers that are included in NW/Natural/202, McVay/1 col (e) in the same format as in the response to DR 326.

Please use Staff's accompanying spreadsheet to organize the data requested in Staff DR Nos. 407 and 408.

Response:

See attached file "UG 344 OPUC DR 408 Attachment 1."

Note that the Staff-provided spreadsheet showed **12/31/2018** data in cells d3 through d7. Corresponding **Test Year 10/31/2019** data was added in column F.

The Test Year incentives provided in Testimony do not agree with the Test Year incentives provided in the Company's response to Staff DR 326 because the data in Testimony includes **Bonuses, RSU, and LTIP** and is for **utility only**, while the data in DR 326 is for Total Company includes only **Bonuses** and is for **both utility and non-utility**.

The Test Year incentives provided in NW Natural/700, Doolittle/15 were used in the development of NWNatural/202, McVay/1.

Note that amounts provided are total wages, including O&M and Capital components.

Overall, exclusive of the RSU and LTIP, the Testimony Bonus amounts are 96.8% of the DR 326 Bonus amounts, consistent with the FTE and Base Wages percentages in DR 407.

iv. See NW Natural/700/Doolittle; Page 2/Section II. NW Natural's Approach to Compensating Employees and Page 6/Section IV. Pay at Risk.

v. See "UG 344 OPUC DR 409 Attachment 1" for first part of response. Second part of response; see NW Natural/700/Doolittle; Page 2/Section II. NW Natural's Approach to Compensating Employees and Page 6/Section IV. Pay at Risk.

vi. See "UG 344 OPUC DR 409 Attachment 1" for first part of response. Second part of response; the financial profit sharing portion of the Key Goals Program for union employees was excluded from rate recovery. The amounts above target incentive awards for all plans are excluded from rate recovery as well.

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Request No.: UG 344 OPUC DR 409

409. Referring to NW Natural/700, Doolittle/8-18, NW/Natural/202, McVay/1 col (e), and UG 344 DR 326 Attachment 1.xlsx.

a. Please explain if the terms incentive plans and pay-at-risk plans are synonymous for the purposes of the Company's testimony and its filed revenue requirement. If not, please explain the difference in treatment.

b. Please list each incentive plan and for each plan please (for Staff purposes incentive plans are monetary.):

i. Provide the total incentives forecasted for the test year on a Total Company and Oregon-allocated basis, the amount of incentives included in the filed proposed test year, and the amount excluded from the filed proposed test year.

ii. Provide the percentage of the incentive that is awarded based on financial performance measurements, and the type of financial measure or metric, e.g. earnings per share, revenues, and net income.

iii. Provide the percentage of the incentive that is awarded based on non-financial based metrics, and the type of non-financial measure or metric, e.g. safety metric, customer satisfaction. Also, explain if this incentive is paid independently of whether targets such as revenues goals, net income goals are achieved.

iv. Explain how the plan benefits customers and/or shareholders.

v. For each plan, if an amount was included in recovery in rate case, please provide the amount and justify its inclusion.

vi. For each plan, if an amount was excluded from recovery in the rate case, please provide the amount and justify it inclusion.

In the response, please provide a detailed narrative or point to the Company's testimony, and data responses. Additionally, the illustrative table inserted below has been included to organize the information requested.

Response:

a. The terms incentive plans and pay-at-risk are in fact synonymous for the purposes of the Company's testimony and its filed revenue requirement.

b. See attached file named "UG 344 OPUC DR 409 Attachment 1" and below

   i. - iii. Included in "UG 344 OPUC DR 409 Attachment 1."

While the overall Testimony NBU Salaried + Hourly Bonus amounts are 96.7% of the DR 326 amounts, the Testimony Bonus amounts for each separate NBU group were: NBU Salaried at 96.0% and NBU Hourly at 140.5%. This discrepancy is because the Testimony numbers included an allocation of total NBU Salaried + Hourly bonus amounts based on each group's percentage of base wages: Salaried at 97.5% and Hourly at 2.5%. However, because the Salaried group has a higher average grade, and therefore a higher average bonus target percentage, this method has overstated the Hourly Bonus amount, and understated the NBU Salaried Bonus amount, by approximately $45k.

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Request No.: UG 344 OPUC DR 304

304. Referring to The Tax Cuts and Jobs Act of 2017 (Tax Act), please provide a detailed narrative explaining how implementation of the Act impacts the Company's Test Year on a Total Company (Utility and Non-Utility consolidated) basis, Total Regulated Company basis, and Oregon-Allocated basis. Additionally,:

a. Please update the Company's UG 344 workpaper, 200 wp1 – Revenue Requirements Model.xlsx for the Oregon-Allocated impact and provide a reference page or highlight the cells that have been modified.

b. Please supplement SDR No. 114 for the 2017 tax return. This request is ongoing.

c. Please update SDR Nos. 115, 116, 117 and 118 for the Test year based on the Act. Please include the Total Company (Utility and Non-Utility), Total Regulated Company, and the Oregon-Allocated basis.

In the response, please list all assumptions made in forecasting the impact of the Tax Act.

Response:

a. At the February 28th tax workshop with Staff and other interested parties, it was agreed that the utilities would provide detailed information about how the utilities would propose to treat the impacts of tax reform in a further update in that forum, and that the parties would reconvene to determine next steps for implementing the ratemaking associated with the impacts of tax reform. As those issues are resolved, NW Natural will be better able to update this data request, and it is our hope that we can resolve any outstanding issues and respond to this data request by the end of March 2018.

b. Consistent with our annual filing schedule, the 2017 tax return will not be completed and filed until October 2018.

c. The updated SDRs referenced will be available at the same time that an update can be completed per 304a above.

April 6 Supplemental Response:

The Company supplemented its rate case with testimony on the impact of tax reform on March 20, 2018, including changes to revenue requirement due to lower tax expense, and a decrease in deferred income tax due to the loss of bonus depreciation starting September 2017.

The company originally anticipated that the deferral application process would include discussions that would clarify the treatment of excess deferred taxes included in rate base. The company has viewed the deferral application process, including any uniformity with the treatment for all regulated companies, as the venue that would resolve the excess deferred taxes treatment. At the time of the supplemental testimony, the more detailed issues had still not been discussed or clarified, but the company also considered the excess deferred tax amortization and refund to be a deferral issue that could be processed outside of the rate case. As a result, if an ongoing deferral process were used to determine how the excess deferred taxes should benefit customers, then the general rate case revenue requirement could be left intact at its full value. This approach assumes that the agreed treatment would be to keep the remeasurement amount in rate base. The revenue requirement was therefore not adjusted for any change to the deferred taxes as a result of remeasurement.

The company files this supplemental response to explain that it does have a proposed method to deal with the amortization of the deferred liability account that it plans to put forward in the deferral application process. The method would be to credit to a deferred liability account with the amount that is amortized each year, net of the cost of service on the amount. The reduction of the refund amount for the cost of service reflects that the amount is removed from rate base, and that rate base has increased as a result of its removal.

There are subsets of the remeasurement amount that are not required by the tax reform law to be amortized over time, and that could potentially be credited to customers more quickly, but those amounts are still uncertain. The Company has not presumed the treatment of those amounts, and has always intended that the treatment reflect the agreement of the parties on the timing of credits. If an agreement were reached that resulted in an expedited return of those amounts, and thus an expedited reduction in the deferred tax/excess deferred component of rate base, then the Company would propose that an appropriate adjustment to rate base be made in the rate case.

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Request No.: UG 344 OPUC DR 401

401. Referring to NW Natural/600, Moncayo/7 at 18-21 and 8 at 1-5, and please provide the underlying calculations that support the Company's non-payroll O&M adjustments from September 2017 actuals to the Oregon-Allocated test year by FERC account and cost element if applicable. Please:

a. Provide in an Excel workbook/spreadsheet by FERC account and cost element if applicable.

b. Clearly segregate each adjustment with a separate column for each type of adjustment.

c. Please provide a detailed narrative explanation for each adjustment type referring to any testimony, DR responses, and workpapers.

Please format similarly to the table illustrated below except add more adjustment columns as needed and cross-reference to explanatory footnote:

Line No.	a	b	c	d	e	f	g	h	i		j
1	FERC Acct. No.	FERC Acct. Desc.	Cost Element Code	Cost Element Name	9/30/2017 Actuals	Adj.	Notes	12/31/2017 Base Year	Adj.	Notes	Test Year 10/31/2019
2	813	Wells Exp.	501400	Materials	$8,910.46	$2,971.15	a.	$11,880.61	$516.37	A.	$12,397.83
Notes/Assumptions											
a..	Assumed 1/4 of 9/30/2017 Actuals (formula should be in cell f2, h2, and j2 etc.)										
A.	Assumed Portland-Salem, OR-WA CPI, Urban Consumers, State of Oregon, Oregon Economic and Revenue Forecast, Sept. 2017, Volume XXXVII, No. 3, Release Date: August 23, 2017 (Escalate chg. 2017-2018 plus 10/12 of 2018-2019 chg.) = $11,880.61*(1+2.3%)*(1+(10/12*2.4%)=$12,397.83 (formula should be in cells)										

Response:

Attached is a summary table by FERC account showing the adjustment amounts with a narrative that describes how the adjustments were calculated. Detailed calculations of non-payroll escalation can be found in UG 344 OPUC DR 125 Supp Attachment 2 – OM Model, on the Non-Payroll Forecast tab of the excel model. The expenses in the model were calculated not on an annual basis but instead on a monthly basis and the test year and base year totals were a summation of their respective twelve months. As a result of monthly timing of expenses throughout the base year, some expenses in the attached table will have grown more than 4.35%[1] from the base year to the test year, and some expenses will have grown less than that rate, but in total the expenses are in line with that increase.

[1] 4.35%=(1+2.3%)(1+(10/12*2.4%))-1 The CPI rate for general non-payroll expense in 2018 is 2.3%, and the CPI rate used for 2019 was 2.4%. 10/12 would represent the test year ending on October 2019.*

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

April 20, 2018

Dec 2016 - Other Economic Indicators

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,982.3	16,397.2	16,628.7	16,989.0	17,366.2	17,748.2	18,116.7	18,509.8	18,941.1	19,367.2	19,780.7	20,178.4
% Ch	2.4	2.6	1.4	2.2	2.2	2.2	2.1	2.2	2.3	2.2	2.1	2.0
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	108.8	110.0	111.6	114.1	116.6	119.1	121.5	124.0	126.5	129.1	131.8	134.5
% Ch	1.8	1.1	1.4	2.3	2.2	2.1	2.1	2.0	2.0	2.1	2.1	2.1
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	109.2	109.5	110.7	112.7	114.8	117.3	119.7	122.2	124.7	127.4	130.0	132.8
% Ch	1.5	0.3	1.1	1.8	1.9	2.2	2.1	2.1	2.1	2.1	2.1	2.1
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	241.2	244.2	248.3	254.0	260.3	266.8	273.2	279.7	286.4	293.2	300.4	307.6
% Ch	2.4	1.2	1.7	2.3	2.5	2.5	2.4	2.4	2.4	2.4	2.5	2.4
U.S.	236.7	237.0	240.0	245.9	251.9	258.5	264.9	271.3	277.9	285.0	292.0	299.1
% Ch	1.6	0.1	1.3	2.5	2.4	2.6	2.5	2.4	2.4	2.5	2.4	2.5
Oregon Average Wage												
Rate (Thous $)	48.9	50.7	52.6	54.7	56.9	59.3	61.9	64.4	67.0	69.6	72.2	74.9
% Ch	3.2	3.8	3.6	4.1	4.0	4.2	4.3	4.1	4.1	3.9	3.8	3.7
U.S. Average Wage												
Wage Rate (Thous $)	53.8	55.4	56.5	58.6	61.1	63.4	65.9	68.5	71.2	74.0	76.8	79.8
% Ch	3.1	2.9	2.0	3.8	4.1	3.9	3.8	4.0	4.0	3.9	3.8	3.8
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	306.2	333.8	374.1	413.1	442.4	464.0	484.7	503.2	521.3	540.5	558.4	574.7
% Ch	7.9	9.0	12.1	10.4	7.1	4.9	4.5	3.8	3.6	3.7	3.3	2.9
FHFA National Housing Price Index												
1991 Q1=100	209.5	221.3	233.1	243.8	251.9	258.0	264.5	270.9	277.9	286.8	296.3	306.4
% Ch	5.4	5.6	5.4	4.6	3.3	2.4	2.5	2.4	2.6	3.2	3.3	3.4
Housing Starts												
Oregon (Thous)	15.6	16.0	19.1	21.4	22.9	23.1	23.8	24.2	24.2	24.0	23.5	23.2
% Ch	9.2	2.6	20.0	11.6	7.3	1.0	2.9	1.5	0.2	(0.8)	(2.1)	(1.4)
U.S. (Millions)	1.0	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.5
% Ch	7.8	10.7	4.7	3.2	8.5	6.9	4.6	3.1	1.0	0.4	(0.3)	(0.9)
Other Indicators												
Unemployment Rate (%)												
Oregon	6.8	5.8	5.1	5.3	5.3	5.4	5.4	5.4	5.5	5.5	5.5	5.5
Point Change	(1.0)	(1.1)	(0.7)	0.3	(0.0)	0.0	0.1	0.0	0.0	(0.0)	0.0	0.0
U.S.	6.2	5.3	4.9	4.8	4.6	4.6	4.7	4.8	4.8	4.6	4.6	4.5
Point Change	(1.2)	(0.9)	(0.4)	(0.1)	(0.2)	(0.0)	0.1	0.1	(0.0)	(0.1)	(0.1)	(0.1)
Industrial Production Index												
U.S, 2002 = 100	104.9	105.2	104.2	105.4	108.5	111.1	113.6	115.7	118.0	120.0	121.7	123.2
% Ch	2.9	0.3	(1.0)	1.1	2.9	2.4	2.2	1.9	2.0	1.7	1.4	1.3
Prime Rate (Percent)	3.3	3.3	3.5	3.8	4.5	5.4	5.8	5.8	5.8	5.8	5.8	5.8
% Ch	0.0	0.3	7.6	8.9	17.0	21.0	6.4	0.0	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	3.97	4.02	4.08	4.15	4.20	4.26	4.31	4.36	4.41	4.46	4.51	4.55
% Ch	1.1	1.3	1.5	1.5	1.4	1.3	1.3	1.2	1.1	1.1	1.0	1.0
U.S.	319.5	322.0	324.5	327.1	329.8	332.4	335.0	337.6	340.2	342.8	345.3	347.8
% Ch	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7
Timber Harvest (Mil Bd Ft)												
Oregon	4,125.6	3,788.1	4,180.7	4,748.3	4,776.7	4,811.4	4,812.7	4,813.7	4,832.1	4,817.2	4,809.9	3,833.5
% Ch	(1.8)	(8.2)	10.4	13.6	0.6	0.7	0.0	0.0	0.4	(0.3)	(0.2)	(20.3)

TABLE A.4

Mar 2018 - Other Economic Indicators

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	16,716.2	17,091.6	17,546.7	17,995.1	18,363.4	18,698.3	19,066.3	19,435.8	19,806.1	20,169.7	20,534.2	20,902.9
% Ch	1.5	2.2	2.7	2.6	2.0	1.8	2.0	1.9	1.9	1.8	1.8	1.8
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	111.4	113.4	115.7	118.3	121.1	123.9	126.6	129.5	132.4	135.3	138.3	141.3
% Ch	1.3	1.8	2.0	2.3	2.4	2.3	2.2	2.2	2.2	2.2	2.2	2.2
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	110.8	112.6	114.2	116.2	118.7	121.2	123.7	126.4	129.1	131.8	134.6	137.4
% Ch	1.2	1.7	1.4	1.7	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CPI, Urban Consumers,												
1982-84=100												
West Region, Urban Size A	254.3	262.0	267.6	273.5	281.9	289.8	297.3	305.2	313.5	321.9	330.6	339.5
% Ch	2.2	3.0	2.1	2.2	3.1	2.8	2.6	2.6	2.7	2.7	2.7	2.7
U.S.	240.0	245.1	249.2	254.1	261.3	268.1	274.5	281.2	288.1	295.3	302.6	310.2
% Ch	1.3	2.1	1.7	1.9	2.8	2.6	2.4	2.4	2.5	2.5	2.5	2.5
Oregon Average Wage												
Rate (Thous $)	51.9	53.0	55.2	57.4	59.7	62.1	64.7	67.3	70.1	73.1	76.2	79.5
% Ch	2.3	2.1	4.2	4.1	4.0	4.0	4.0	4.1	4.3	4.2	4.3	4.3
U.S. Average Wage												
Wage Rate (Thous $)	56.0	56.9	58.5	60.8	63.3	65.9	68.5	71.3	74.3	77.4	80.7	84.1
% Ch	1.1	1.6	2.8	3.9	4.1	4.1	3.9	4.0	4.2	4.2	4.2	4.3
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	368.1	399.6	428.3	451.6	471.2	489.3	508.3	530.2	552.3	574.3	597.5	621.2
% Ch	11.4	8.5	7.2	5.4	4.3	3.8	3.9	4.3	4.2	4.0	4.0	4.0
FHFA National Housing Price Index												
1991 Q1=100	232.8	247.9	260.7	269.2	278.2	287.5	296.3	306.5	317.7	329.3	341.5	354.4
% Ch	6.1	6.5	5.2	3.3	3.3	3.4	3.1	3.4	3.6	3.7	3.7	3.8
Housing Starts												
Oregon (Thous)	19.1	19.0	20.5	22.1	23.7	24.6	24.8	24.7	24.3	24.0	24.1	24.4
% Ch	19.8	(0.3)	8.1	7.7	7.2	3.7	1.1	(0.4)	(1.9)	(1.2)	0.6	1.0
U.S. (Millions)	1.2	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5
% Ch	6.3	2.9	6.4	8.7	3.4	1.6	1.6	0.3	0.6	(0.5)	(0.5)	(0.6)
Other Indicators												
Unemployment Rate (%)												
Oregon	4.9	4.0	4.4	4.5	4.7	4.8	4.9	5.0	5.1	5.1	5.1	5.1
Point Change	(0.7)	(0.9)	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
U.S.	4.9	4.4	3.9	3.7	3.8	4.1	4.3	4.4	4.5	4.6	4.7	4.7
Point Change	(0.4)	(0.5)	(0.5)	(0.2)	0.1	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Industrial Production Index												
U.S, 2002 = 100	103.1	105.0	108.5	111.8	114.2	116.3	118.7	121.1	123.4	125.6	127.8	130.0
% Ch	(1.2)	1.9	3.3	3.0	2.2	1.8	2.1	2.1	1.9	1.8	1.8	1.7
Prime Rate (Percent)	3.5	4.1	4.9	5.6	6.1	6.5	6.5	6.4	6.1	6.0	5.9	5.7
% Ch	7.7	16.7	19.5	14.2	10.0	5.7	0.0	(2.1)	(3.9)	(1.8)	(2.3)	(1.9)
Population (Millions)												
Oregon	4.09	4.15	4.21	4.27	4.33	4.38	4.44	4.49	4.54	4.59	4.64	4.68
% Ch	1.5	1.6	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0
U.S.	323.7	325.9	328.5	331.1	333.8	336.4	339.0	341.5	344.1	346.6	349.1	351.5
% Ch	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Timber Harvest (Mil Bd Ft)												
Oregon	3,888.3	3,978.2	4,028.1	4,077.1	4,121.7	4,170.0	4,227.4	4,174.1	4,170.1	4,217.3	4,211.2	4,207.9
% Ch	2.6	2.3	1.3	1.2	1.1	1.2	1.4	(1.3)	(0.1)	1.1	(0.1)	(0.1)

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff/104
Gardner/1

Dated: March 15, 2018.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2018–05678 Filed 3–20–18; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP17–363–006.
Applicants: Eastern Shore Natural Gas Company.
Description: Compliance filing Settlement Compliance Filing to be effective 4/1/2018.
Filed Date: 3/1/18.
Accession Number: 20180301–5260.
Comments Due: 5 p.m. ET 3/13/18.

Docket Numbers: RP18–558–000.
Applicants: Midcontinent Express Pipeline LLC.
Description: Compliance filing 2018 Annual Penalty Revenne Crediting Report.
Filed Date: 3/13/18.
Accession Number: 20180313–5064.
Comments Due: 5 p.m. ET 3/26/18.

Docket Numbers: RP18–560–000.
Applicants: Texas Eastern Transmission, LP.
Description: § 4(d) Rate Filing: Negotiated Rates—Colonial Energy K911486 eff 4–1–2018 to be effective 4/1/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5003.
Comments Due: 5 p.m. ET 3/27/18.

The filings are accessible in the Commission's eLibrary system by clicking on the links or qnerying the docket nnmber.

Any person desiring to intervene or protest in any of the above proceedings mnst file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, bnt intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing reqnirements, interventions, protests, service, and qualifying facilities filings can be fonnd at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: March 15, 2018.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2018–05673 Filed 3–20–18; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Institution of Section 206 Proceeding and Refund Effective Date

	Docket No.
AEP Appalachian Transmission Company, Inc	EL18–62–000
AEP Indiana Michigan Transmission Company, Inc	
AEP Kentucky Transmission Company, Inc	
AEP Ohio Transmission Company, Inc	
AEP West Virginia Transmission Company, Inc	
AEP Oklahoma Transmission Company, Inc	EL18–63–000
AEP Southwestern Transmission Company, Inc	
Baltimore Gas and Electric Company	EL18–64–000
Black Hills Power, Inc	EL18–65–000
Citizens Sunrise Transmission LLC	EL18–66–000
San Diego Gas & Electric Company	EL18–67–000
Transource Maryland, LLC	EL18–68–000
Transource Pennsylvania, LLC	EL18–69–000
Transource West Virginia, LLC	EL18–70–000
UNS Electric, Inc	EL18–71–000, (not consolidated)

On March 15, 2018, the Commission issued an order in Docket Nos. EL18–62–000, EL18–63–000, EL18–64–000, EL18–65–000, EL18–66–000, EL18–67–000, EL18–68–000, EL18–69–000, EL18–70–000, and EL18–71–000 pursuant to section 206 of the Federal Power Act (FPA), 16 U.S.C. 824e (2012), instituting an investigation into the jnstness and reasonableness of each of the above-captioned public utilities' transmission formnla rates nnder its open access transmission tariff or transmission owner tariff on file with the Commission. *AEP Appalachian Transmission Company, Inc., et al.,* 162 FERC 61,225 (2018).

The refund effective date in Docket Nos. EL18–62–000, EL18–63–000, EL18–64–000, EL18–65–000, EL18–66–000, EL18–67–000, EL18–68–000, EL18–69–000, EL18–70–000, and EL18–71–000, established pursuant to section 206(b) of the FPA, will be the date of publication of this notice in the **Federal Register**.

Any interested person desiring to be heard in Docket Nos. EL18–62–000, EL18–63–000, EL18–64–000, EL18–65–000, EL18–66–000, EL18–67–000, EL18–68–000, EL18–69–000, EL18–70–000, and EL18–71–000 must file a notice of intervention or motion to intervene, as appropriate, with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rule 214 of the Commission's Rules of Practice and Procedure, 18 CFR 385.214, within 21 days of the date of issuance of the order.

Dated: March 15, 2018.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2018–05674 Filed 3–20–18; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM18–12–000]

Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission-Jurisdictional Rates

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of inqniry.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is seeking comment on the effect of the Tax Cuts and Jobs Act of 2017 on Commission-jnrisdictional rates. Of particular interest is whether, and if so how, the Commission shonld address changes relating to accnmulated deferred income taxes and bonus depreciation.

DATES: Comments are dne May 21, 2018.

ADDRESSES: Comments, identified by docket number, may be filed electronically at *http://www.ferc.gov* in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. The Comment Procednres section of this docnment contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:
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Kristen Fleet (Technical Information (Electric)), Office of Energy Market Regulation, 888 First Street NE, Washington, DC 20426, (202) 502–8063, *Kristen.Fleet@ferc.gov*
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SUPPLEMENTARY INFORMATION:

1. In this Notice of Inquiry (NOI), the Commission seeks comment on the effect of the Tax Cuts and Jobs Act of 2017 (Tax Cnts and Jobs Act) on Commission-jurisdictional rates. Of particular interest is whether, and if so how, the Commission should address changes relating to accumulated deferred income taxes (ADIT) and bonus depreciation.

I. Background

A. Tax Cuts and Jobs Act

2. On December 22, 2017, the President signed into law the Tax Cnts and Jobs Act,[1] which provides a number of changes to the federal tax system.[2] One of the significant changes with widespread effects on Commission-jurisdictional rates is the reduction of the federal corporate income tax rate from a maximum 35 percent to a flat 21 percent rate, effective January 1, 2018.[3] Because of the reduced federal corporate income tax rate, the current balance of ADIT, that is, the dollar amounts of taxes that public utilities, interstate natural gas pipelines, and oil pipelines collected from customers in anticipation of paying the Internal Revenue Service (IRS), does not accurately reflect the current income tax liability. Additionally, the Tax Cuts and Jobs Act prohibits the use of bonus depreciation for assets acquired in the trade or business of the furnishing or sale of electrical energy or transportation of natural gas by pipeline.

B. Requests for Commission Action

3. In light of the Tax Cuts and Jobs Act, the Commission received letters from several entities requesting that the Commission act to ensure that the economic benefits related to the reduction in the federal corporate income tax rate are passed throngh to customers.[4] These entities request, among other things, that the Commissiou investigate the continned jnstness and reasonableness of applicable Commission-jnrisdictional rates and explore ways to adjust the transmission or transportation revenne requirements of Commission-jurisdictional entities to prevent customers from overpaying for service.

C. Commission's Actions

4. Because the Tax Cuts and Jobs Act, among other things, rednces the federal corporate income tax rate from a maximnm 35 percent to a flat 21 percent rate, beginning January 1, 2018, all public utilities, interstate natural gas pipelines, and oil pipelines subject to the federal corporate income tax will compnte income taxes owed to the IRS based on a 21 percent tax rate. Most Commission-jurisdictional electric transmission aud some non-transmission rates, most interstate natural gas transportation rates, and some oil pipeline rates (and Form No. 6, page 700)[5] are based on cost of service, which comprises all expenses incurred, including income taxes, plus a reasonable retnrn on capital.[6] Wheu the tax expense decreases, so does the cost of service. The Commission must ensure that the rates, terms, and conditions of jurisdictional services under the Federal Power Act (FPA),[7] the Natural Gas Act (NGA),[8] and the Interstate Commerce Act[9] are jnst, reasonable, and not unduly discriminatory or preferential.

5. Because the federal corporate income tax rate has been reduced to 21 percent, the electric transmission rates of entities with stated rates or formula rates with fixed line items for the income tax rate will not accurately reflect their cost of service. Similarly, the transportation rates of interstate natural gas pipelines will not accurately reflect their cost of service.

6. As such, in order to provide more immediate relief to customers of public utilities, pursuant to section 206 of the FPA,[10] the Commission is concurrently issuing orders to show cause directing certain entities to propose revisions to the transmission rates in their open access transmission tariffs or transmission owner tariffs to reflect the change in the federal corporate income tax rate, or show cause why they should not be required to do so.[11]

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[1] Tax Cuts and Jobs Act, Public Law 115–97, 131 Stat. 2054 (2017).

[2] The Commission has previously addressed a major change in the tax law when Congress passed the Tax Reform Act of 1986. *See Rate Changes Related to the Federal Corporate Income Tax Rate for Public Utilities,* Order No. 475, FERC Stats. & Regs. ¶ 30,752, *order on reh'g,* 41 FERC ¶ 61,029 (1987).

[3] Section 13001 of the Tax Cuts and Jobs Act.

[4] These ontities include State Advocates (States, state agencies, and state consumer advocates), Organization of PJM States, Inc., Organization of MISO States, American Public Gas Association, Process Gas Consumers Group, Natural Gas Supply Association, Natural Gas Indicated Shippers, Liquids Shippers Group, Oklahoma Attorney General, Gordon Gooch (*pro se* consumer), Advanced Energy Buyers Group, National Association of State Energy Officials, Tbe R-Street Institute, Office of the Ohio Consumers' Counsel, and the Governor of Delaware. The Interstate Natural Gas Association of America, Edison Electric Institute and the Industrial Energy Consumers of America also sent letters to the Commission in reference to the effects of the Tax Cuts and Jobs Act.

[5] Most oil pipeline rates are indexed. However, these indexed rates can be challenged on a cost-of-service basis and oil pipelinos can also file to set their rates on a cost-of-service basis. When this document refers to cost-of-service ratemaking for oil pipelines, it also refers to the reporting practicos oil pipelines use in the cost-of-service summary on Form No. 6, page 700.

[6] *Pub. Sys.* v. *FERC,* 709 F.2d 73, 75 (DC Cir. 1983).

[7] 16 U.S.C. 824d–e.

[8] 15 U.S.C. 717–717w (2012).

[9] 49 app. U.S.C. 1 *et seq* (1988).

[10] 16 U.S.C. 824e.

[11] *AEP Appalachian Transmission Company, Inc.,* 162 FERC ¶ 61,225 (2018); *Alcoa Power Generating Inc.—Long Sault Division,* 162 FERC ¶ 61,224 (2018).

7. The Commission also is concurrently issuing a Notice of Proposed Rulemaking (NOPR) [12] regarding natural gas pipelines. In the NOPR, the Commission proposes to require interstate natural gas pipelines to make an informational filing with the Commission regarding the effect on their revenue requirements of the (a) Tax Cuts and Jobs Act and (b) the Revised Policy Statement on Treatment of Income Taxes.[13] The Revised Policy Statement establishes a policy that master limited partnerships (MLP) are not permitted to recover an income tax allowance in their cost of service. The NOPR proposes to collect financial information to evaluate the impact of the Tax Cuts and Jobs Act and the Revised Policy Statement on interstate natural gas pipelines' revenue requirement, and to permit such pipelines to voluntarily file rate reductions to reflect the decrease in the federal corporate income tax pursuant to the Tax Cuts and Jobs Act or the elimination of the MLP tax allowance, explain why no action is needed, or take no action other than filing the informational filing.

8. Unlike public utilities and interstate natural gas pipelines, the majority of oil pipelines set their rates using indexing, not cost-of-service ratemaking using an oil pipeline's particular costs. Under indexing, oil pipelines may adjust their rates annually, so long as those rates remain at or below the applicable ceiling levels. The ceiling levels change every July 1 based on an index that tracks industry-wide cost changes.[14] Under currently effective requirements governing the schedule for indexing changes, the index will be re-assessed in 2020 based upon industry-wide oil pipeline cost changes between 2014 and 2019.[15] While the Commission is not taking similar industry-wide action regarding oil pipeline rates, when oil pipelines file Form No. 6, page 700, they must report an income tax allowance and cost of service consistent with the Revised Policy Statement [16] and the Tax Cuts and Jobs Act.

II. Request for Comments

A. Accumulated Deferred Income Taxes

9. ADIT balances are accumulated on the regulated books and records of public utilities, interstate natural gas pipelines, and oil pipelines based on the requirements of the Uniform System of Accounts. ADIT arises from differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes.

10. There are numerous items that are treated differently for IRS purposes and regulatory accounting and ratemaking purposes, the most familiar of which is depreciation expense. The following example uses depreciation expense to illustrate the accumulation of ADIT balances.

11. Under Commission ratemaking policies, income taxes included in rates are determined based on the return on net rate base, with the accumulated depreciation offset to rate base calculated using straight-line depreciation.[17] However, in calculating the amount of income taxes due to the IRS, public utilities, interstate natural gas pipelines, and oil pipelines generally are able to take advantage of accelerated depreciation. Accelerated depreciation usually lowers income taxes payable during the early years of an asset's life followed by corresponding increases in income taxes payable during the later years of an asset's life. This means that a public utility's, interstate natural gas pipeline's, and oil pipeline's income taxes payable to the IRS during any period differ from its income tax allowance for ratemaking purposes during the same period. The difference between the income taxes based on straight-line depreciation and the actual income taxes paid by a public utility and interstate natural gas pipeline generally are reflected in the Uniform System of Accounts, Account 282 (Accumulated Deferred Income Taxes—Other Property) [18] and for oil pipelines in the Uniform System of Accounts, Account 64 (Accumulated Deferred Income Tax Liabilities).[19]

12. Generally, ADIT liabilities are reductions to rate base, while ADIT assets may be additions to rate base, depending on the nature of the items that gave rise to the ADIT asset. In the example above, because the resulting ADIT effectively provides the public utility, interstate natural gas pipeline, and oil pipeline with cost-free capital, the Commission subtracts the ADIT from the rate base of the public utility, interstate natural gas pipeline, and oil pipeline, thereby reducing customer charges. This method of passing the benefits from accelerated depreciation on to customers throughout the asset's life is referred to as tax normalization.[20]

13. As a result of the Tax Cuts and Jobs Act reducing the federal corporate income tax rate from 35 percent to 21 percent, a portion of an ADIT liability that was collected from customers will no longer be due from public utilities, interstate natural gas pipelines, and oil pipelines to the IRS and is considered excess ADIT, which must be returned to customers in a cost-of-service ratemaking context. The Commission expects that a similar effect would be reflected in the cost-of-service summary in oil pipeline Form No. 6, page 700. For public utilities, interstate natural gas pipelines, and oil pipelines that have an ADIT asset, the Tax Cuts and Jobs Act will result in a reduction to the ADIT asset, and public utilities, interstate natural gas pipelines, and oil pipelines may seek to reflect in rates a portion of such reductions. Public utilities, interstate natural gas pipelines, and oil pipelines are required to adjust their ADIT assets and ADIT liabilities for the effect of the change in tax rates in the period that the change is enacted.[21] That is, public utilities and interstate natural gas pipelines are required to re-measure their ADIT balances at the 21 percent rate and record a regulatory asset (Account 182.3) associated with deficient ADIT that is probable of future rate recovery and/or a regulatory liability (Account 254) associated with excess ADIT that is probable of future refund to customers.[22] For oil pipelines, the relevant accounts are Account 44 (Other Deferred Charges) and Account 63 (Other Noncurrent Liabilities), respectively.

1. Effect on Rate Base

14. As a result of the federal corporate income tax rate change, public utilities, interstate natural gas pipelines, and oil pipelines will re-measure their ADIT

[12] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, 162 FERC ¶ 61,226 (2018).

[13] *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (2018) (Revised Policy Statement).

[14] 18 CFR 342.3 (2017). Currently, the index level is based upon the Producer's Price Index for Finished Goods plus 1.23.

[15] *See, e.g., Five-Year Review of the Oil Pipeline Index*, 153 FERC ¶ 61,312 (2015), *aff'd, Assoc. of Oil Pipe Lines* v. *FERC*, 876 F.3d 336 (DC Cir. 2017).

[16] *See* Revised Policy Statement, 162 FERC ¶ 61,227.

[17] *See, e.g., Pub. Serv. Co. of Colo.*, 155 FERC ¶ 61,028, at P 2 (2016); *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,254 (2014), *order on compliance*, 154 FERC ¶ 61,126, at P 2 (2016).

[18] *See* 18 CFR parts 101 and 201.

[19] *See id.* part 352.

[20] *See Midcontinent Indep. Sys. Operator, Inc.*, 157 FERC ¶ 61,250, at P 2 (2016).

[21] *See* 18 CFR 35.24 and 154.305; *see also Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254 (1981), *order on reh'g*, Order No. 144–A, FERC Stats. & Regs. ¶ 30,340 (1982).

[22] *See* Accounting for Income Taxes, Docket No. AI93–5–000, at 8 (1993).

liabilities and assets, and establish regulatory liabilities and assets, as appropriate. Public utilities' stated and formula rates and interstate natural gas pipelines' stated rates may not include comparable provisions allowing rate base to be reduced for regnlatory liabilities and increased for regulatory assets. Similar issues may affect individual oil pipeline cost-of-service rate proceedings or the summary cost of service filed by oil pipelines on Form No. 6, page 700. Therefore, the Commission seeks comment on how to ensure that rate base continues to be treated in a manner similar to that prior to the Tax Cuts and Jobs Act (*i.e.*, how to preserve rate base neutrality), nntil excess and deficient ADIT have been fully settled in a just and reasonable manner.

15. The Commission seeks comment on whether, and if so how, public utilities, interstate natural gas pipelines, and oil pipelines shonld make adjustments so that rate base may be appropriately adjusted by excess ADIT and deficient ADIT. Commenters should address whether pnblic utilities with formula rates could add a line item to their adjustments to rate base such that rate base would be decreased by any excess ADIT placed in Acconnt 254 and increased by any deficient ADIT placed in Acconnt 182.3. With regard to stated rates, commenters shonld address whether, and if so how, public utilities and interstate natural gas pipelines conld make adjustments to ensure that regulatory liabilities and regulatory assets are treated comparably to the ADIT liability and asset accounts. Oil pipelines should discnss how these issues pertain to Form No. 6, page 700 reporting practices and, as relevant, to cost-of-service ratemaking.

16. Given that the Tax Cuts and Jobs Act took effect on January 1, 2018, there may be a lag in implementing any adjnstments to rate base to reflect excess and deficient ADIT. The Commission believes that it may be appropriate for public ntilities and interstate natural gas pipelines to include interest on excess and deficient ADIT, for the time period from Jannary 1, 2018 until any adjnstments to rate base are implemented, and seeks comment on this topic.

2. Flow-Back or Recovery of Plant-Based ADIT

17. Under the Tax Cuts and Jobs Act, pnblic utilities and interstate natural gas pipelines may flow back the excess ADIT associated with utility plant assets (excess plant-based ADIT) no more rapidly than over the life of the underlying assets.[23] Specifically, pnblic utilities and interstate natural gas pipelines are generally not permitted, in compnting costs of service for ratemaking purposes and reflecting operating results in their regulated books of account, to flow-back excess plant-based ADIT more rapidly or greater than the reductions permitted by the Average Rate Assumption Method, which requires amortization of the excess tax reserve over the remaining regulatory lives of the property that gave rise to the ADIT. Alternatively, if the books and records of public utilities and interstate pipelines do not contain the vintage data necessary to apply the Average Rate Assnmption Method, they are required to use an alternative method, *e.g.*, the Reverse South Georgia Method,[24] to flow back excess plant-based ADIT over the remaining regulatory life of the property.[25] The Commission seeks comment on how the Average Rate Assumption Method, and alternatively, the Reverse South Georgia Method or Sonth Georgia Method, as appropriate, will be implemented and used to adjust the tax allowance or expense included in cost-of-service rates to reflect the amortization of excess and deficient plant-based ADIT.

18. While the Commission's nnderstanding is that the Internal Revenue Code does not apply the same standard to oil pipelines,[26] the amortization of excess plant-based ADIT also may affect oil pipeline cost-of-service ratemaking. Accordingly, the Commission also seeks comment on this issue as to oil pipelines.

3. Flow-Back or Recovery of Non-Plant Based ADIT

19. Because the normalization requirement under the Tax Cuts and Jobs Act applies only to plant-based ADIT, the Commission seeks comment on how qnickly excess or deficient non-plant based ADIT shonld be flowed back to or recovered from customers. Specifically, commenters shonld address whether a regulatory asset or regulatory liability recorded by a public utility or interstate natural gas pipeline associated with non-plant based excess or deficient ADIT should be amortized over a shorter (*e.g.*, five-year) period. Oil pipeline commenters shonld also address how qnickly any excess non-plant based ADIT shonld be flowed back in the data reported on Form No. 6, page 700 and in any cost-of-service proceeding as the issue arises.

4. Assets Sold or Retired After December 31, 2017

20. Under the Commission's accounting reqnirements, when assets are sold or retired, the original cost and accumulated depreciation of those assets are removed from the books of a pnblic utility, interstate natural gas pipeline, or oil pipeline. Additionally, any associated ADIT is concurrently removed from a public utility's, interstate natural gas pipeline's, or oil pipeline's books because any previously deferred tax effects related to the assets are now triggered as part of the computation of gains or losses associated with the sale or retirement (*i.e.*, the deferred taxes are now payable to the IRS). The excess ADIT resnlting from the tax rate change of the Tax Cuts and Jobs Act is also removed from the books. The Commission seeks comment on whether, and if so how, it should address excess ADIT that is removed from the books of pnblic ntilities, oil pipelines and interstate natural gas pipelines after December 31, 2017, as a result of assets being sold or retired.

5. Amortization of Excess and Deficient ADIT

21. Commenters should address how pnblic utilities with stated or formula rates and interstate natural gas pipelines with stated rates should adjust their income tax allowance snch that the allowance wonld be decreased or increased by the amortization of excess and deficient ADIT. Likewise, commenters shonld address for oil pipelines how these issnes shonld be applied in cost-of-service ratemaking and in the cost-of-service summary on Form No. 6, page 700.

22. The Commission also seeks comment on whether a pnblic ntility or interstate natural gas pipeline should record the amortization by recording a rednction to the regulatory asset or regulatory liability acconnt and recording an offsetting entry to Account 407.3 (Regulatory Debits) or Acconnt 407.4 (Regulatory Credits). For oil pipelines, the Commission seeks comment whether this information shonld be recorded in Account 665

[23] Section 1561(d) of the Tax Cuts and Jobs Act.

[24] Under the South Georgia method, a calculation is taken of the differenca between the amount actually in the deferred account and the amount that would have boen in the account had normalization continuonsly been followed. Any deficiency is collected from ratepayers (*i.e.*, South Gaorgia Method), and any excess is returned to ratepayers (*i.e.*, Reverse South Georgia Method), over the remaining depreciable life of the plant that causad tho difference. *Memphis Light, Gas and Water Div. v. FERC*, 707 F.2d 565, 569 (DC Cir. 1983).

[25] Section 1561(d) of the Tax Cuts and Johs Act.

[26] *See id.*; 26 U.S.C. 168(i)(9) & (10) (not including oil pipelines among the list of public utilities subject to the normalization requirement and the prohibition against flowing through to ratepayers accelerated depreciation in cost-of-service rates).

(Unusual or Infrequent Items (Debit)) or Account 645 (Unusual or Infrequent Items (Credit)).

6. Supporting Worksheets

23. The Commission seeks comment on whether it should require public utilities, interstate natural gas pipelines, and oil pipelines to provide to the Commission, on a one-time basis, additional information, such as supporting worksheets, to show the computation of excess or deficient ADIT and the corresponding flow-back of excess ADIT to customers or recovery of deficient ADIT from customers. Commenters should address what types of information public utilities, interstate natural gas pipelines, and oil pipelines already record for ADIT-related accounting and whether balances and amortization of regulatory liability and asset accounts, computation of excess and deficient ADIT, delineation between plant assets and non-plant assets, and a description of the allocation method used to determine the transmission-related portion of excess or deficient ADIT would be appropriate to include in a supporting worksheet.

7. Treatment of ADIT for Partnerships

24. In the Revised Policy Statement, the Commission determined that MLPs will no longer be permitted to recover an income tax allowance. Following the *United Airlines* decision,[27] the Commission concluded that MLP investors' tax costs were already reflected in the return on equity, and thus, permitting an income tax allowance for MLPs would lead to a double recovery of such tax costs. The Commission also stated that other pass-through entities would need to address the double recovery concern.

25. The Commission seeks comment on the effect of the elimination of the income tax allowance for MLPs on ADIT. Likewise, the Commission seeks comment regarding the treatment of ADIT to the extent the income tax allowance is eliminated for other non-MLP pass-through entities. For such MLPs and pass-through entities, commenters should address whether previously accumulated sums in ADIT should be eliminated altogether from cost of service or whether those previously accumulated sums should be placed in a regulatory liability account and returned to ratepayers. Commenters should address specifically how their approach would be applied in the MLP's or other pass-through entity's cost of service.

[27] *United Airlines, Inc.* v. *FERC*, 827 F.3d 122 (2016).

B. Bonus Depreciation

26. Generally, bonus depreciation is a tax incentive given to companies to encourage certain types of investment. Bonus depreciation allows companies to deduct a percentage of the cost of a qualified property in the year the property is placed into service, in addition to other depreciation deductions. That is, a company that purchases a qualified business property and places it into service within a taxable year can take a first year deduction in addition to any depreciation deduction available.

27. The Tax Cuts and Jobs Act increases the 50 percent bonus depreciation allowance to 100 percent for qualified property placed in service after September 1, 2017, and before January 1, 2023. Full bonus depreciation is phased down by 20 percent each year for property placed in service after December 31, 2022, and before January 1, 2027. Bonus depreciation applies to new and used property, and must be acquired in an arm's length transaction. It is not available for assets acquired in the trade or business of the furnishing or sale of electrical energy, water, or sewage disposal services; gas or steam through a local distribution system; or transportation of gas or steam by pipeline.[28]

28. The Commission seeks comment on the effect of the bonus depreciation change under the Tax Cuts and Jobs Act. The Commission also seeks comment on whether, and if so how, the Commission should take action to address bonus depreciation-related issues. Commenters should address the practical application of their proposals, including, among other things, what type of action the Commission should take and whom the Commission should target with its action.

C. Additional Inquiries

29. In addition, the Commission seeks comment on whether, and if so how, it should take further action to address the change in the federal corporate income tax rate. With respect to public utilities, the Commission seeks comment on whether, in addition to the transmission rates addressed in the orders to show cause being issued concurrently, other jurisdictional transmission rates or non-transmission rates should be revised to address the change in the federal income tax rate, and identify the types of these other rates to the extent possible. The Commission also seeks comment on effects of the Tax Cuts and Jobs Act on Commission-jurisdictional rates of non-public utilities. Finally, the Commission seeks comment on any other effects of the Tax Cuts and Jobs Act, and whether, and if so how, the Commission should address them.

[28] Section 13301 of the Tax Cuts and Jobs Act.

III. Comment Procedures

30. The Commission invites interested persons to submit comments on the matters and issues proposed in this NOI, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due May 21, 2018. Comments must refer to Docket No. RM18–12–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. To facilitate the Commission's review of the comments, commenters are requested to provide an executive summary of their position. Additional issues the commenters wish to raise should be identified separately. The commenters should double space their comments.

31. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *http://www.ferc.gov*. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

32. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

33. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

IV. Document Availability

34. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE, Room 2A, Washington, DC 20426.

35. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of

this docnment is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this docnment in eLibrary, type the docket number exclnding the last three digits of this docnment in the docket nnmber field.

36. User assistance is available for eLibrary and the Commission's website during uormal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov*, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

By direction of the Commission.

Issued: March 15, 2018.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2018–05670 Filed 3–20–18; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #2

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC18–70–000.
Applicants: NRG Wholesale Generation LP, Kestrel Acqnisition, LLC.
Description: Application for Authorization under Section 203 of the Federal Power Act of NRG Wholesale Generation LP, et al.
Filed Date: 3/15/18.
Accession Number: 20180315–5109.
Comments Due: 5 p.m. ET 4/5/18.

Take notice that the Commission received the following exempt wholesale generator filings:

Docket Numbers: EG18–56–000.
Applicants: Kestrel Acquisition, LLC.
Description: Self-Certification of Exempt Wholesale Generator Status of Kestrel Acqnisition, LLC.
Filed Date: 3/15/18.
Accession Number: 20180315–5078.
Comments Due: 5 p.m. ET 4/5/18.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER13–1966–002.
Applicants: NRG Wholesale Generation LP.
Description: Compliance filing: Informational Filing Regarding Upstream Change in Control and Request for Waiver to be effective N/A.
Filed Date: 3/15/18.
Accession Number: 20180315–5127.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–839–001.
Applicants: Arizona Pnblic Service Company.
Description: Tariff Amendment: Refile Rate Schedule No. 290 to be effective 4/11/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5001.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1091–000.
Applicants: Southwest Power Pool, Inc.
Description: Notice of Cancellation of Southwest Power Pool, Inc. of Non-Firm Point-To-Point Transmission Service Agreement (No. 496).
Filed Date: 3/15/18.
Accession Number: 20180315–5038.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1092–000.
Applicants: Midcontinent Independent System Operator, Inc.
Description: § 205(d) Rate Filing: 2018–03–15 SA 3104 ENO–ENO GIA (J481) to be effective 3/1/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5045.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1093–000.
Applicants: Sonthwest Power Pool, Inc.
Description: § 205(d) Rate Filing: 1266R10 Kansas Municipal Energy Agency NITSA and NOA to be effective 3/1/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5046.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1094–000.
Applicants: Florida Power & Light Company.
Description: § 205(d) Rate Filing: FPL Revisions to LCEC Rate Schedule No. 317 to be effective 1/1/2016.
Filed Date: 3/15/18.
Accession Number: 20180315–5048.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1095–000.
Applicants: Florida Power & Light Company.
Description: § 205(d) Rate Filing: FPL Revisions to FKEC Rate Schednle No. 322 to be effective 1/1/2016.
Filed Date: 3/15/18.
Accession Number: 20180315–5049.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1098–000.
Applicants: California Independent System Operator Corporation.
Description: § 205(d) Rate Filing: 2018–03–15 Second Amendment to ABAOA with Arizona Public Service to be effective 5/15/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5069.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1102–000.
Applicants: Pacific Gas and Electric Company.
Description: § 205(d) Rate Filing: 3–15–18 Unexecnted Agreement, City and County of San Francisco WDT SA (SA 275) to be effective 5/14/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5075.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1106–000.
Applicants: Kestrel Acquisition, LLC.
Description: Baseline eTariff Filing: Baseline new to be effective 5/15/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5086.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1110–000.
Applicants: Southwest Power Pool, Inc.
Description: § 205(d) Rate Filing: 1795 Oklahoma Gas and Electric Company PTP Notice of Cancellation to be effective 6/1/2014.
Filed Date: 3/15/18.
Accession Number: 20180315–5105.
Comments Due: 5 p.m. ET 4/5/18.

Docket Numbers: ER18–1116–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Original ISA, SA No. 4958; Qneue No. AC1–035 to he effective 2/13/2018.
Filed Date: 3/15/18.
Accession Number: 20180315–5126.
Comments Due: 5 p.m. ET 4/5/18.

Take notice that the Commission received the following electric reliability filings

Docket Numbers: RD18–3–000.
Applicants: North Americau Electric Reliability Corporation, Western Electricity Coordinating Council.
Description: Joint Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Retirement of Regional Reliability Standard PRC–004–WECC–2.
Filed Date: 3/9/18.
Accession Number: 20180309–5269.
Comments Due: 5 p.m. ET 4/16/18.

The filings are accessible iu the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to interveue or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceediug.

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

April 20, 2018

Oregon

Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
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April 9, 2018

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PORTLAND, OR 97205
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RE:

Docket No.	Staff Request Nos.	Response Due By
UG 344	DR 410-412	April 23, 2018

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Income Taxes

410. Regarding the following disclosure found on page 81 of the printed 2017 SEC Form 10k (page 83 of the pdf) "The change in our utility deferred taxes of $18.2 million, associated with tax benefits that have previously been flowed through to customers or for the equity portion of AFUDC, resulted in an identical reduction in the associated regulatory assets."

a. Please provide portion of the total amount due to benefits "previously flowed through to customers" and the amount due to the "equity portion of AFUDC".
b. Please provide the "equity portion of AFUDC" allocable to Oregon along with calculations showing how that amount was derived.
c. For amounts "previously flowed through to customers", please provide a list of dockets, order numbers, and tariffs for all jurisdictions by year showing when the tax benefits flowed through to customers and the Oregon allocated amounts thereof.

411. Regarding the $213,306,000 non-current regulatory income tax liability (2017 10k printed page 63) and the $56.5 million “gross up for income taxes” (2017 10k printed page 81).

a. Please provide both system wide and Oregon allocated portion of the following, both gross and net of tax:
    i. The portion of the liability arising from plant and property
    ii. The portion of the liability subject to IRS normalization rules, if different.
    iii. The portion of the liability arising from other than plant and property including a list of the related book-tax differences.
    iv. The estimated portion of the $213.3m liability the Company expects will be amortized in 2018.

412. Regarding the 2016 and 2017 deferred tax assets and liabilities (2017 10k printed page 80):

a. Please provide a reconciliation of these amounts to the deferred income tax liabilities reported the Commission on page 14 of the 2016 Oregon Earnings Review (docket RG 40(5).
b. Please provide a reconciliation of the 2017 amounts as soon as the information is available.

This is a standing request. Please send updated information to staff as an update to this DR, part (b) as information is updated or amended.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate “Confidential” folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ John Crider
Staff Administrator

Staff Initiator: John Fox john.l.fox@state.or.us 503-378-6436

Oregon

Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
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April 9, 2018

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PORTLAND, OR 97205
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RE:	Docket No.	Staff Request Nos.	Response Due By
	UG 344	DR 413	April 23, 2018

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: Incentives

413. For each of the years 2009 through 2017, please provide by incentive plan and by employee category, the total amount of incentives incurred.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@state.or.us.

/s/ John Crider
Staff Administrator

Staff Initiator: Marianne Gardner marianne.gardner@state.or.us 503-378-6117

CASE: UG 344
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs

UG 344

2017 General Rate Revision

Data Request Response

Request No.: UG 344 NWIGU DR 9

9. Please provide a copy of the Northwest Natural's federal income tax provision workpapers and calculations for calendar years 2016 and 2017.

Response:

Please see the attached file, "CONFIDENTIAL **UG 344 NWIGU DR 9 Attachment 1.xlsx**."

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 NWIGU DR 10

10. Please provide a copy of Northwest Natural's 2016 federal income tax return, Form 1120, including all supporting schedules and whitepapers.

Response:

Please see "**CONFIDENTIAL UG 344 NWIGU DR 10 – Attachment 1.pdf**." For reference purposes, the 2016 federal income tax return included in the attachment agrees to the original rate case submission document, "**GRC 18 SDR 114 Attachment 1.xlsx**."

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 NWIGU DR 37

37. Referring to Mr. McVey's Direct Testimony, please identify the Company's revenue requirements reflecting the TCJA reduction in income tax costs.

Response:

Please see NW Natural's Supplemental Direct Testimony of Mr. McVay's dated March 20, 2018 for revenue requirement reflecting the TCJA reduction in income tax costs.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 NWIGU DR 38

38. Please provide any calculations of the following, on an electronic spreadsheet with all formulas intact, regarding the identification of excess accumulated deferred federal income taxes as a result of current tax reform.

a. The total company and gas portion of excess federal ADIT, at the end of the year, through any year available.

b. The portions of subpart (a) that are "protected" and "unprotected".

c. The annual amount of protected excess federal ADIT that is expected to reverse in the future for any years available.

d. NW Natural's plan for addressing the flowback to customers of the unprotected gas portion of excess federal ADIT identified in subpart (b).

Response:

The excess deferred income tax (EDIT) balance recorded for financial statement purposes, as of December 31, 2017, is an estimate. As noted in the tax workshop, held on February 28, 2017, there are a number of uncertainties that may result in changes to the currently recorded balances. These uncertainties include, but are not limited to:

- Balances may change as a result of refinements made during the preparation of the income tax returns for the 2017 calendar year. These returns will not be complete until October of 2018.

- NW Natural's federal income tax return is generally subject to examination by the Internal Revenue Service. The IRS may not agree with positions as reported on the return that could result in changes to these balances.

- The US Treasury may issue guidance for taxpayers, perhaps in the form of new regulations, which may result in changes to these balances.

- These balances could change as a result of regulatory action. As an example, the current estimated balances include assumptions regarding state allocations.

- Deferred tax balances (balance sheet) are generally created through the recording of deferred income tax expense (income statement). To the extent that utility related deferred income tax expense was not fully recovered, these balances may change.

- State legislatures are currently reviewing the impact of tax reform on state tax revenues. The deliberations of state legislatures may result in new laws or tax rates that could result in changes to these balances.

a) Please see file, "**CONFIDENTIAL UG 344 NWIGU DR 38 – Attachment 1.xlsx**"

b) There is additional analysis to perform to confirm the amount of EDIT balances that are subject to normalization under federal law and those that could be relegated to flow-through treatment. Oregon utility ratemaking has historically taken a normalization approach overall.

   In the Excel file referenced in a) above, the balances at the bottom of the tab 'Remeasurement Summary' labeled, 'Other' and 'Gas Reserves' are likely not subject to normalization and flow-through treatment could be applied. The balances labeled 'Plant' and 'Pipeline Recovery' are primarily subject to normalization.

c) The future annual amortization amounts of EDIT balances subject to normalization is not yet known. It will take additional time to prepare the amortization schedules under the normalization rules. In addition, the amortization schedules would change if the estimated EDIT balances change (see uncertainties – discussed above), or if depreciation recovery studies result in a change to future book depreciation rates.

d) The Company does not have a completed plan at this time for addressing the flowback of the excess federal ADIT that is not required to be normalized. There is a deferral application pending with the Commission that should provide the platform for an agreement with the parties on the flowback of these amounts, as well as for the amortization of the balances that are subject to normalization.

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

April 20, 2018

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

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is: 201 High Street SE, Suite 100, Salem, OR 97301.

Q. Please describe your educational background and work experience.

A. My educational background and work experience are set forth in my Witness Qualification Statement, which is provided as Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I am responsible for four issues in this docket:

<u>Cost of Capital</u>

1. Capital Structure;
2. Cost of Common Equity, also known as Return on Equity (ROE),
3. Cost of Long-Term (LT) Debt; and

<u>Equity Flotation</u>

4. Equity Flotation Costs

Q. What is your summary recommendation?

A. I concur with the Company in recommending a balanced capital structure of 50.0 percent equity and 50.0 percent LT Debt, and a 5.233 percent cost of LT Debt. But I differ from NW Natural in that I recommend a point ROE of 9.0 percent within a range of reasonable ROEs of 8.7 to 9.3 percent, inclusive of equity flotation costs. As a corresponding adjustment, I recommend the removal in its entirety of $1.2 million of Oregon allocated equity flotation expense. This results in a rounded ROR of 7.12 percent.

NW Natural proposes a range of ROEs of 9.7 to 10.3 with a point estimate of 10.0, which when combined with its cost of LT debt results in a rounded ROR of 7.62 percent.

Q. Did you prepare tables showing current, NW Natural-proposed and Staff recommended overall CoC?

A. Yes, the following three tables provide that information.

Table 1

NWN Current OPUC Authorized (UG 221 Order Nos. 12-408,12-437)			NWN
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	50.00%	6.056%	3.028%
Preferred Stock	0.00%		0.000%
Common Stock	50.00%	9.50%	4.750%
	100.00%		**7.778%**

Table 2

NWN Requested – UG 344		NWN Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**50.00%**	**5.233%**	2.617%	**-0.161%**
Preferred Stock	0.00%		0.000%	
Common Stock	**50.00%**	**10.00%**	5.000%	
	100.00%		**7.62%**	

Table 3

Staff Proposed – UG 344		**Opening Testimony**		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**50.0%**	**5.233%**	2.617%	**-0.662%**
Preferred Stock	0.00%		0.000%	
Common Stock	**50.0%**	**9.00%**	4.500%	
	100.00%		**7.117%**	

Q. Have you issued data requests (DRs) in this rate case?

A. Yes. My analysis is informed by Company's responses to 79 multipart DRs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits in support of your opening testimony?

A. Yes. I prepared the following exhibits:

Staff/202 .... Staff Peer Screening
Staff/203 .... Staff Three-Stage DCF Modeling
Staff/204 .... Treasury Inflation Protected Securities (TIPS) Analysis
Staff/205 .... Referent Long Run 10-30 Year GDP Growth Rates
Staff/206 .... Long-Run Real GDP Growth Rates with BEA Data
Staff/207 .... Staff Simple Single Stage DCF Model
Staff/208 **CONFIDENTIAL** Cost of LT Debt Table & Maturity Profile
Staff/209 .... NW Natural Investor Presentation
Staff/210 .... Value Line (VL) Natural Gas Utility Data Profiles
Staff/211 .... News that Investors are Seeing
Staff/212 .... Staff CAPM Modeling

ISSUE 1 – CAPITAL STRUCTURE

Q. What is the basis for your recommendation for a capital structure of 50.0 percent common equity and 50.0 percent LT Debt?

A. I conclude that although it is likely that the Company will have a higher equity ratio for at least part of the test year, this increase will be temporary as debt issuances walk the ratio back to the target balanced capital structure of 50 percent common equity and 50 percent LT debt for the period rates from this case are likely to be effective.[1]

Q. Why do you anticipate that the Company's capital structure will temporarily change in the near future?

A More leverage (debt) at this time would put strong downward pressure on credit ratings. Moody's Investor Service (Moody's) in particular has taken a very hard line on recent tax law changes. Rather than seeing the positives of a tax cut, Moody's changed its outlook to negative for 25 utilities as the

[1] *See* Staff/209, Muldoon/12.

ratings agency focused in on debt to total capitalization trending and the utilities' ratios of cash flow before changes in working capital to debt. This rather unpleasant consequence of what one might suppose would otherwise be good news for NW Natural Corp, Northwest Natural Gas, and many of other utilities and their ratepayers.[2]

The Company is likely to issue more stock than planned and described in this rate case, both A) to relieve pressure on metrics Moody's is examining so closely of late, and B) because there is greater demand for NWN common stock than is generally available in large amounts. It is usual and customary to allow agents supporting a public stock offering to oversubscribe an issue when there is market demand for it. Based on Staff's analysis, NW Natural is at this time the most attractive publicly-traded local natural gas distribution company (LDC) investor-owned utility (IOU) in the United States for large institutional investors and money managers.

Additionally, NW Natural has determined that Gill Ranch is no longer central to the Company's core long-term regulated growth strategy. The Company has recognized a non-cash impairment of $193 million pre-tax or $142 million after-tax dollars. Staff translates certain challenges for this facility as suggesting that NW Natural could decide to sell it to focus on more

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[2] Moody's announced this sweeping change of Outlooks to Negative from Stable for 25 utilities on January 19, 2018, after the Company had already filed its testimony on December 29, 2018. See "For Spire Missouri, State Regulator's Rate Case Order is Credit Positive" by Jeffrey Casella, VP and Senior Analyst of Moody's released by Moody's on March 1, 2018, explaining how **Moody's expects** the **effect** from the **recent changes** in **US tax laws will reduce** the **ratio of cash flow from operations pre-working capital to debt.**

promising and better aligned alternatives. In any case, the Company could have less value of or fewer non-regulated assets in the test year than in the past.[3] This will raise the equity portion of capital structure.

Q. If Staff's insights are correct why isn't this information found in the Company's initial general application for rate revision?

A. The Company filed this request for a general rate revision before various market shocks and material actions.

Q. If Staff is correct in its assessment of market pressures and demand, what would be the impact on the Company's capital structure?

A. NW Natural will move from the current 50 percent equity as calculated in Oregon or 51 percent equity as calculated in Washington to a higher equity ratio for a while, before additional debt issuances incrementally walk that back to the target balanced capital structure of 50 percent common equity and 50 percent LT debt.[4] This is consistent with the lumpiness of equity flotation.

NW Natural may have more equity temporarily in the test year than reflected in Staff's recommendation. But that equity portion will diminish as additional new debt is issued. Therefore, a balanced capital structure with 50 percent equity remains reasonable.

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[3] *See* Staff/209, Muldoon/26 for more detail.

[4] *See* Staff/209, Muldoon/12.

ISSUE 2 – COST OF COMMON EQUITY (ROE)

Q. What point ROE within what range of reasonable ROEs does Staff recommend?

A. Staff recommends a point ROE of 9.0 percent within a range of reasonable ROEs of 8.7 to 9.3 percent.

Q. NW Natural is requesting an ROE of 10.0 percent. What range of reasonable ROE's did the Company recommend?

A. This recommendation is based on the work of the Company's ROE witness, Dr. Bente Villadsen, a principal at The Brattle Group. Dr. Villadsen recommends a range of ROE's of 9.7 percent to 10.3 percent. [5]

Q. Can you summarize what factors lead to the difference in the ROE estimates provided by Staff and PGE?

A. I can, at a high and possibly over-simplified level. I provide more detail on this topic in my testimony below. One reason our estimates differ relates to how we use our modeling results. Dr. Villadsen and I both perform multi-stage discounted cash flow (DCF) modeling, single stage cash flow modeling, risk premium, and Capital Asset Pricing Modeling (CAPM). However, as Dr. Villadsen notes in her testimony, "[t]he Public Utility Commission of Oregon (Commission) has, in the past, given no weight to the CAPM (Order 01-777, p. 32) and preferred analyses using the Discounted Cash Flow Model (Order 12-437 in UG-221, p. 6)."[6] Although not noted by Dr. Villadsen, the

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[5] *See* NW Natural/400, Villadsen/1 to view Table 1 of Dr. Villadsen's ROE modeling results.
[6] NW Natural/400, Villadsen/1 n1.

Commission has also rejected risk premium analysis in previous cases.[7] For this reason I use results of models other than multi-stage DCF as a check of reasonableness on the results obtained from the two different multi-stage models that I employed. In contrast, Dr. Villadsen blends the results of her multi-stage DCF analysis with higher percentages obtained from her risk premium and CAPM-based models to obtain her proposed range of ROEs.[8]

The results of Dr. Villadsen's multi-stage DCF modeling are closer to my recommended range of ROEs than her recommended range based on blended results. Dr. Villadsen obtained a range of ROEs of 9.4 – 10.0 percent with her multi-stage DCF modeling. However, she adjusted this range to what she describes as a of 9.7-10.0 percent by eliminating the lowest results of her multi-stage DCF model.[9]

For her final recommended range of ROEs, she blends the recommended range from her multi-stage DCF modeling (9.7 to 10.0 percent) with results of her risk premium modeling (10.2 - 10.3 percent) and CAPM-Based models (10 – 10.5 percent) to obtain a recommended range of 9.7 to 10.3, and a point estimate of 10.0 percent.[10]

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[7] See e.g., Order No. 01-777, p. 33 ("PGE's proposed methodology using authorized ROEs and yields on treasuries and corporate bonds is unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding.").

[8] See NW Natural/400, Villadsen/46.

[9] NW Natural/400, Villadsen/1

[10] NW Natural/400, Villadsen/46.

The second factor contributing to the difference in modeling results is the difference in growth rates we used for multi-stage DCF modeling. Dr. Villadsen uses more optimistic shorter-term Blue Chip growth rates. Use of near-term growth in lieu of lower longer-run (20-year) growth can overstate required ROE. In contrast, I assume for purposes of my multi-stage DCF model that gas LDC utility growth is bounded by the growth of the US economy and more specifically impacted by challenges regarding U.S. population and productivity in this long-run (20-year) period.

Finally, another difference between our recommended ROEs relates to the different cohorts of peer utilities we used to estimate NWN's ROE. Dr. Villadsen includes three utilities that are engaged in merger discussions as well as a company with 40 percent unregulated assets. In contrast, I exclude from my sample of peer utilities any utilities that are engaged in merger activities for which the current and near-term (five-year) Value Line projections are possibly reflective of the potential for merger rather than typical utility operations. I also exclude utilities whose operations are substantially unregulated as they are not representative of NW Natural.

The difference in the cohort the peer utilities used by myself and Dr. Villadsen does not necessarily explain the difference in the results of our multi-stage DCF modeling. However, I believe that using companies that are not reflective of NW Natural's current operations leads to results that are less reliable than results based on a cohort of more similar utilities.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.0 percent ROE I recommend meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[11] My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[12]

Q. Are these the same standards discussed in NW Natural's testimony starting at NW Natural/400, Villadsen/5?

A. Yes. Staff and NW Natural apply the same legal standards. However, the Company and Staff disagree on what ROE is commensurate with that of other peer utilities and other investment opportunities with risk exposure similar to NW Natural's. When investors' expected rate of return is measured using a reasonable expectation of long-term growth and when risk is measured using an appropriate peer group of utilities, the resulting ROE is within the range recommended by Staff.

WHAT IS NEW IN THIS RATE CASE

Q. What is new in the financial landscape since the Company's last general rate case?

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[11] *See Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

[12] See ORS 756.040(1)(a) and (b).

A. Interestingly, despite general concerns about financial markets, trends are not particularly good or bad or that much different than seven years ago at the time of the Company's last general rate case.

Interest Rates and Inflation: Seven years ago the U.S. Federal Reserve (Fed) expected about 2 percent inflation and to raise interest rates gradually. Now we have about what was expected by the Fed at perhaps a slower pace than predicted. Essentially, inflation diminished and then returned. As of March 22, the Fed continues to gradually walk up rates, consistent with a strengthened economy.

Population, Productivity and GDP Growth: In 2012, there was considerable worry about families deciding to delay having children while working populations aged. That trend has continued and been possibly exacerbated by uncertain immigration policies. Over the next 20 years, those children and immigrants not now present will not be working.

Federal Tax Cut: A federal tax cut has varied implications for utilities and their ratepayers. It has put pressure on credit ratings. It has increased required ROE by 3 to 6 basis points (bps) from what Staff's recommendation would have been otherwise.[13] In general, the tax cut is somewhat more of a mixed message than one might have expected. As an example, Moody's investigated the impact on credit rating metrics,

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[13] *See* Staff/202, Muldoon/4.

which caused it to change quite a number of utilities' credit outlooks from stable to negative, including those of NW Natural.

Easy Money Continues: For the past seven years, investors have worried about the possibility that the central banks of the world would begin the process of slowing the flow of easy-to-borrow money at historically low interest rates and reducing the rollover of maturing securities on central bank balance sheets into more purchases of treasuries, bonds and other securities. This is still a sharp contrast to central banks actually returning to historical policies. Not only has monetary policy remained loose, but the Fed has decided that the neutral or natural equilibrium rate to target for a balanced economy should now be lower than targeted by the Fed before the 2009 financial crisis.[14]

Q. What are the implications of the current state of markets and financial policies?

A. Contrary to what one might expect, the biggest risk to utility prosperity comes not from global uncertainties, but rather from other parts of the economy (that carry greater risks but offer greater returns) starting to do better and appearing to have sustainable momentum toward higher returns. Global uncertainties see investors rush back into safe havens like U.S. Treasuries (UST) and their (in many ways more attractive) proxy Investor Owned Utility (IOU) Stocks with dividend yields higher than UST. As a point in fact in 2017

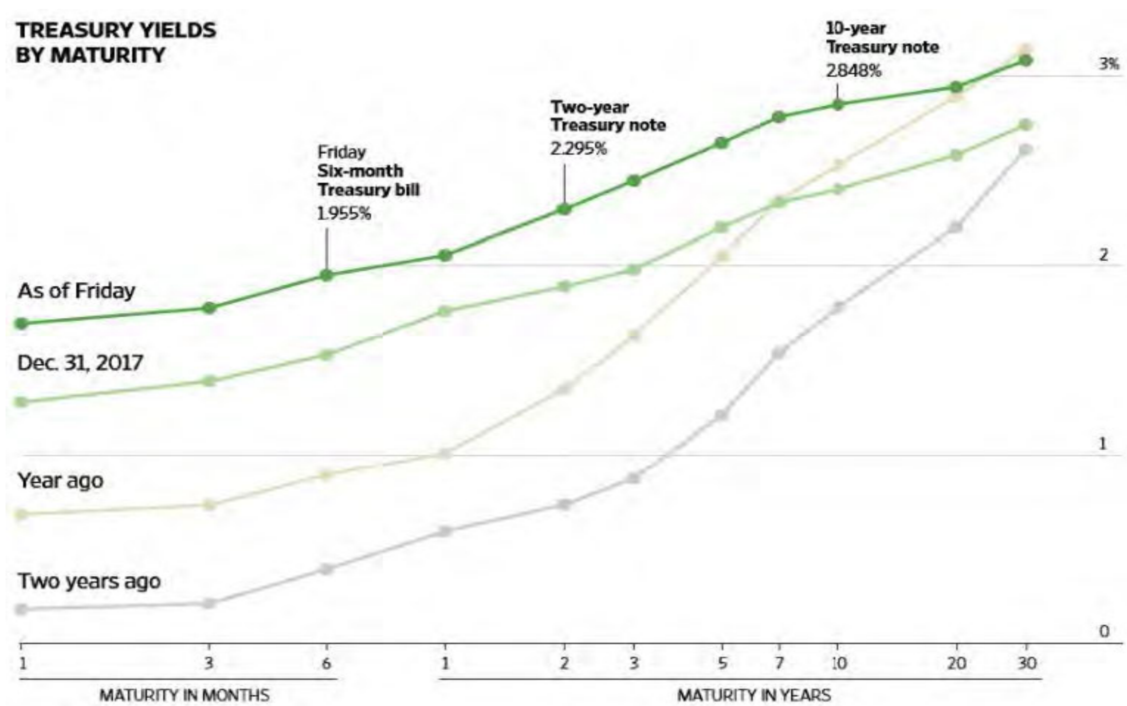
[14] *See* Staff/211, Muldoon/127 for a description of the new Fed rate target.

a billion dollars a day (every business day) flowed into just BlackRock passive stock funds alone, and indirectly into IOU stock.[15]

Q. Are interest rates, dividends and ROE's rising dramatically now?

A. Shorter term interest rates rose quickly in the first quarter of 2018. In contrast 30-year UST and corporate bond yields rose, but much more gradually as shown in Figure 1 below.[16] This has flattened the UST yield curve. In response to this movement in treasury yields, high dividend stocks have increased their dividends recently.[17]

Figure 1



[15] *See* Staff/211, Muldoon/28.

[16] *See* Staff/211, Muldoon/12 for more about trending interest rates and yield curves.

[17] *See* Staff/211, Muldoon/41 for more information about how UST yields have put pressure on stock dividend yields.

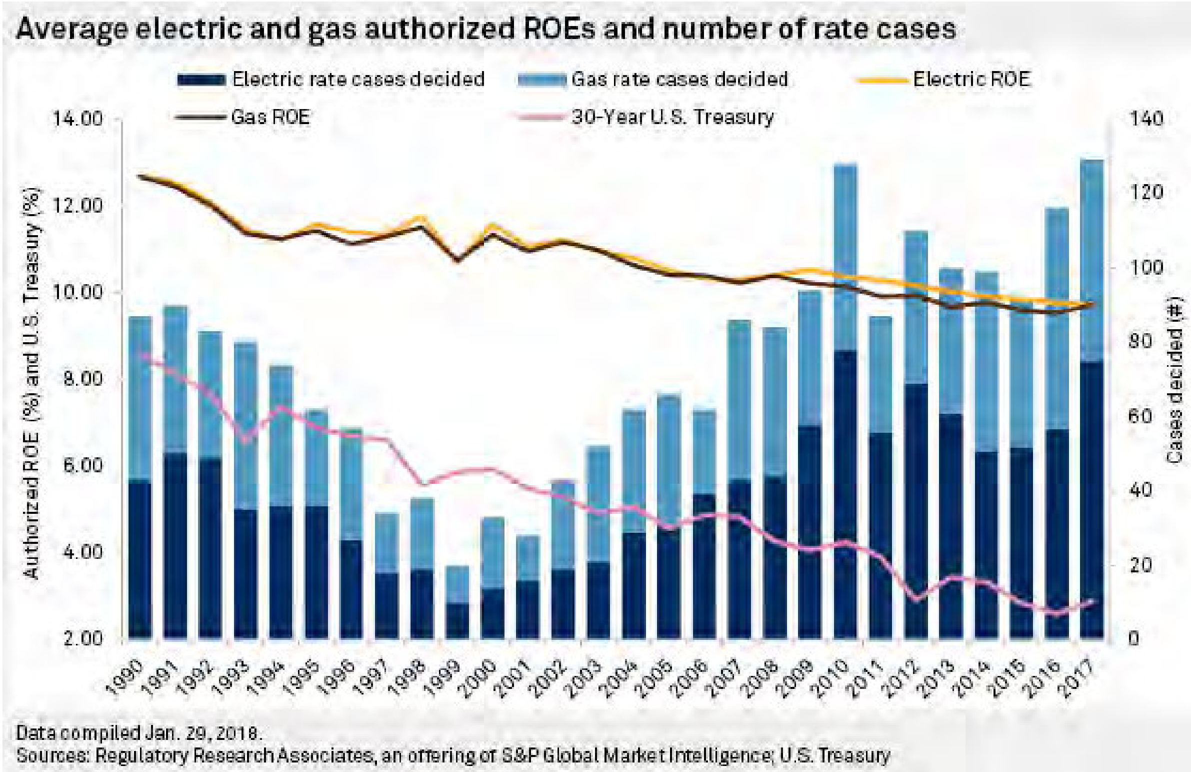
Q. Will we get to a long-anticipated rising interest rate environment?

A. There is now greater uncertainty and the possibility that rates will rise to track Fed increases. Recent market activity makes it more plausible that in about 2020 we could be in such a financial environment. What we now see is the potential on the horizon.

Q. What is the implication for the Commission?

A. Since about 1990, the Commission has seen a long decline to authorized ROEs with substantial lag both due to some utilities delaying coming in for a rate case and a possible preference by regulatory commissions for a gradual and smooth process. There was a similar lag in recognizing falling interest rates. This downward trend in authorized ROEs is reflected as a national trend in Figure 2.

Figure 2



Any decision by this Commission to raise ROE in this case will move against the national trends of falling authorized ROEs and historically falling or flat interest rates.

Of course at some point with an improving economy, one anticipates there would come a time of increasing authorized ROEs and rising interest rates nationally. Staff suggests that given the lag in market recognition on the downward trend, it would be reasonable for a similar lag on a rising trend.

Q. Why might symmetry and consistency in approach falling or rising not be generally embraced?

A. Utilities who chose to stay out of rate cases when ROEs were falling, might file them more frequently if ROEs are rising. Further, utilities could prepare a rate case and then find market elements such as interest rates have increased since their filing. A lag before recognition of lower Cost of Capital components and a lag before recognition of higher Cost of Capital components may not feel identical to jurisdictional utilities. In this case, Staff will frame a very modest example in Cost of LT Debt.

Q. Please summarize your testimony on these issues.

A. Many reasons for long run optimism about growth have not yet materialized. Low estimated future working-age population and productivity trends continue to impair long-run 10- to 30-year projections of GDP growth. Other worries center on a transition from a nearly decade-long “Goldilocks” market, particularly for utilities, to a future with more volatility and change, and just possibly less central bank presence in national economies.

The end result of these general economic trends underscores an economy that is still slow and sluggish in growth. The slow growth of the economy in general requires less of a return on equity to attract investors, indicating an ROE toward the lower end of the range of reasonable ROEs.

OVERVIEW OF STAFF ROE POSITION

Q. Describe the analysis underlying Staff’s ROE recommendation.

A. I continue to rely primarily on two different three-stage “discounted cash flow” (DCF) models[18] applied using a cohort group of peer utilities to estimate the expected return on common equity required by NW Natural investors. I

[18] *See* the Commission’s discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.

compare the results of my three-stage DCF analysis with national historical gas utilities' authorized ROE values as a check on the reasonableness of my ROE estimates. I rely on Simple DCF and CAPM models as directional vectors for a rough check on the results from my two separate three-stage DCF models.

Q. What are the results of your multistage DCF models?

A. Please see Table 4 below drawn from Exhibit Staff/203 Muldoon, Watson/1.[19]

Table 4
Results of Staff's 3-Stage DCF Modeling
(See Exhibit No. Staff/203 for more detail)

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
Range of Modeled Results	8.22%	to	9.33%	ROE	
Best Fit Range of Reasonable ROEs	8.7%	to	9.3%	ROE	
(Best fit is Staff's Hamada adjusted screened gas utilities that have most similar characteristics to NWN regulated gas operations in Oregon)					
Midpoint of Best Fit Modeling Results		9.0%	ROE		
(Staff's informed judegment excludes some of the lower range of modeling results depicted above)					
Staff Point ROE Recommendation:		9.0%	ROE		

Q. How do these estimated ROE values compare with gas utilities' national ROE values for 2017 and 2016 General Rate Cases?

A. These estimated ROEs are low compared with decided average 9.72 percent ROE for regulated U.S. utilities' authorized return on equity capital in 2017 as reported by SNL Financial. 2017 decisions were higher than the 2016 average of 9.54 percent.[20]

[19] Jeffrey Watson assisted in the preparation of select supporting exhibits. Mr. Watson's witness qualification statement is provided in Staff/201.

[20] *See* Staff/211, Muldoon/19 for more information on gas ROE trends in the last two years.

Much of the country including all of the Greater Northwest including Oregon, Washington, Idaho, Montana, Utah, and Wyoming is in line with recent Commission gas utility decisions as shown in Exhibit Staff/205. On the low end, the New York Public Service Commission authorized an 8.7 percent ROE for a gas utility in 2017. On the high end, the Virginia State Corporation Commission authorized a 10.2 percent ROE for a gas utility, including a 100 bps, or one percent, incentive.

Q. Did your analysis include the construction of a synthetic forward curve?

A. Yes, I constructed a synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. My forward curve is provided in Exhibit Staff/204, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Q. Assume one ignored current downward adjustments by a broad spectrum of federal agencies and instead presumed that future U.S. GDP growth would look like the past 30 years. Would a ROE based on that assumption still fall within Staff's recommended range?

A. Yes, I extracted and ran regression on data from U.S. Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate shown in Table 4 above. My recommended range of ROEs includes values that presume GDP growth over the next 30 years would look like that of the past 30 years informed by other federal projections.

Q. Do you show this analysis in your exhibits?

A. Yes. Exhibit Staff/205 shows my analysis in support of this finding.

Q. If utilities' dividends and earnings per share (EPS) are growing at a faster rate than growth for the whole economy, then utilities would become a bigger part of the economy. Is that happening?

A. No. Utilities are not becoming a larger and larger part of the U.S. economy. Rather companies like Amazon, Apple, and Facebook are becoming bigger parts of the U.S. economy and of the indexes that track their stocks. Berkshire Hathaway now has the fifth largest capitalization, but this is more driven by its persistent acquisitions than growth of specific component utility divisions.[21]

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases, and in the last Northwest Natural Gas Company rate case, Docket UG 221?

A. My methods and modeling parallel those employed by Staff in recent general rate cases.

Q. Describe the two DCF models on which you primarily rely.

A. My first model is a conventional three-stage discounted dividend model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). This model captures the thinking of a money manager at a

[21] *See* "Amazon Poised to Pass Alphabet as Second-Largest U.S. Company," by Amrith Ramjumar in the Mar. 20, 2018, WSJ.

pension fund or insurance company, or other institutional investor, who expects to keep NW Natural stock indefinitely and use the dividend cash flow to meet future obligations.

My second model is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model Y"). This model best fits the investor who has a goal they are working towards. In addition to the income stream from dividends, this investor intends to sell the stock as the goal is reached.

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received over the next five years calculated from information provided by Value Line, and a long-term growth rate applicable to dividends 10- to 30-years out. On this last point, Staff recommends the Commission be particularly vigilant for any substitution of a short-term growth rate for a long-term 20- to 30-year growth rate. As investor attention can often be very near term, some growth rates labeled "long" may be supported by information looking at the next ten years or less into the future.

For a smooth transition, I step the rate of dividend growth between the near-term next five years and that of long-run expectations.

Q. How does Model X calculate the terminal value of dividends as a perpetual cash flow into the future?

A. Model X includes a terminal value calculation, in which I assume dividends per share grow indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock where the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why is thirty years the primary horizon for financial decision-making?

A. Investors focus on the 30-year U.S. Treasury (UST) Bond against alternate investment opportunities. Thirty years is a generally accepted period for economists to ascribe to one generation. It is a common time for mortgages of plants, equipment and homes. Many institutional holders of utility securities match the cash flows from utility dividends to future obligations such as the payout of life insurance, preparing to meet future pension and post-retirement obligations and interest service for borrowing. Individuals plan for the education of their children, ownership of their home, and provision for their retirement on this same multi-decade timeframe.

I use five years for Stage One as that is the timeframe for which Value Line estimates of future dividends are available. This is as far as Value Line projects near-future trends. I use five years for Stage Two as a reasonable length of time for individual companies' dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all gas utilities.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values to generate an Internal Rate of Return (IRR) produced with each set of calculations for each peer utility. This approach accounts for the time value of money, closely replicating actual quarterly receipt of dividends by investors.

Q. What accounts for differences in peer capital structures?

A. Each model employs the Hamada equation[22] to calculate an adjustment for differences in capital structure between each peer utility and the NW Natural-proposed and Staff-assumed capital structure for NW Natural.[23] When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Did recent tax changes impact Hamada adjustments?

A. Yes, the results of Staff modeling of its own peer utility group, of the Company's peer utility group, and of the Company's peer utility group without the three utilities involved in mergers and acquisitions, were increased by three, five and six basis points (bps) respectively. This adjustment addresses moving to a 21 percent corporate tax rate from variously higher peer tax rates historically.

Q. What price do you use for each peer utility's stock?

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[22] Dr. Robert Hamada's Equation as used in Staff/202, Muldoon/4 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers. Staff/202, Muldoon/5 shows results had the tax break not occurred.

[23] Staff describes this adjustment in recent cost of capital testimony. *See*, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54-57.

A. I use the average of closing prices for each utility from the first trading day in December 2017, and January and February 2018, to represent a reasonable snapshot of utility stock prices.

Q. How do Staff's two DCF models differ?

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation. This may be the most common approach used in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[24] multiplied by the estimated "earnings per share" (EPS), which establishes the stock's "selling price" for terminal valuation. I estimate the terminal EPS analogously with methods used to estimate the final dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. I followed Staff's practice in recent rate cases of including this model as a method by which to incorporate the fact that most companies have estimates of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation.[25]

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[24] "Current" in this context means the price obtained, as previously described, divided by VL's estimated EPS; i.e., it is a forward P/E, not an historical P/E.

[25] Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

Q. You noted previously that you and Dr. Villadsen obtained different results with multi-stage DCF modeling. Can you please discuss the reasons for this?

A. The difference in the range of ROEs produced by our multi-stage DCF modeling is largely attributable to the choice of long-term interest rates for the third and final stage of the multi-stage model.

GROWTH RATES

Q. Please explain the use of growth rates in the estimation of ROE.

A. The estimated rate of growth of future dividends is a very important element. I refer specifically to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as Staff's two types of three-stage DCF modeling.

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[26]

A. I used three different long-term growth rates, with different methods employed in developing each.

The first method uses the U.S. Congressional Budget Office's (CBO) 4.0 percent nominal 20-year GDP growth rate estimate.[27]

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[26] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233 Exhibit Staff/800, Storm/46 – 52.

[27] *See* Staff/203, Muldoon, Watson/1 for these growth rates.

Staff's second Composite Growth Rate applies a 50 percent weight to the average annual growth rate resulting from estimates of long-term GDP by the U.S. Energy Information Administration (EIA), PricewaterhouseCoopers estimate for long-run (10- to 30-years from now), and the CBO, with each receiving one-third of that 50 percent weight.[28] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2017 calculated as shown in Staff/206, Muldoon/1, to which I apply the TIPS inflation forecast developed in Staff/204, Muldoon/1.

Staff's third "Near Historical" Stage 3 annual growth rate, is an equal weighted average of the earlier described U.S. Bureau of Economic Analysis (BEA) derived projection which presumes the future will look much like the past on the one hand, and on the other hand, the Social Security Administration's long-run projection, which is informed by the "baby problem" or drop in working-age Americans 20 years from now.

[28] The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP as an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings.

Please see Table 5 below for the growth rates I used in my modeling.

Table 5 – Long-Run GDP Growth Rates

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate
Energy Information Administration	2.00%	1.99%	4.03%	12.50%	0.50%
PricewaterhouseCooper	1.80%	1.99%	3.83%	12.50%	0.48%
Social Security Administration	2.20%	1.99%	4.23%	12.50%	0.53%
Congressional Budget Office			4.00%	12.50%	0.50%
BEA Nominal Historical,1980 Q1 – 2017 Q4	2.76%	1.99%	4.80%	50.0%	2.40%
Composite				100%	**4.41%**
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.00%	100.0%	**4.00%**
BEA Nominal Historical,1980 Q1 – 2017 Q4	2.76%	1.99%	4.80%	50.0%	2.40%
Social Security Administration	2.20%	1.99%	4.23%	50.0%	2.12%
Near Historical				100%	**4.52%**
Note: Near Historical assumes that various federal initiatives will have greater long-run positive impact than the Congressional Budget Office expects.					

Q. Does this approach capture a reasonable set of investor expectations similar to Staff's analysis in other recent general rate cases?

A. Yes, Staff modeling captures the expectations of investors who think variously that: A) the non-partisan CBO is reliable, B) blended federal agency expert analysis also informs the historical track record, and C) one should be optimistic about the economy's long-run growth, provided there are still enough non-retired adult Americans to make it happen.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for gas utilities?

A. Yes. In many of the Company's prior rate cases, Staff has shared plots of U.S. gas demand growth since 1950 on a three-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both gas sales and dividend growth rates.

Q. Can relying on a long-term GDP growth rate overstate required ROE?

A. Yes. It is possible that my modeling anticipates greater growth than may be realized and so overstates required ROE to attract investors. My highest growth rate presumes return to near historical U.S. GDP growth rates.

Q. Is it important to distinguish between long-run 20- to 30-year rates and rates over the next five years?

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip and a variety of other financial resources focus most on the next five years. The next five years may be affected by recent events. We have had a tax cut, rising interest rates that prompted many companies to raise dividends more than usual, and we are coming out of a market downturn wherein one might expect a bit of a jump. But that jump or boost does not happen every year forever. Over the long run, people and productivity are key drivers of economic growth.

Q. Is NW Natural growing faster or slower than the rate of the overall economy?

A. Nationally, there is a persistent increase in energy efficiency and a durable downward slope or decline in usage of both electricity and natural gas per residential customer. Giving NW Natural the benefit of doubt, Staff presumes that the Company may be growing as fast as, but no faster than the U.S. economy.

Q. What growth rates did Dr. Villadsen use for the final, constant growth stage in her multi-stage DCF model?

A. Dr. Villadsen used two estimates: (1) the October 2017 long-run GDP growth forecast from Blue Chip Economic indicators, and (2) the average of the OMB and Blue Chip long-term estimate.[29]

Q. Did Staff examine other growth rates including the White House budget growth rates used by Dr. Villadsen?

A. Staff's list of growth rates examined and their sources is provided in Staff/205, Muldoon, Watson. Staff declined to incorporate the hyper optimistic GDP projection of the current administration (the White House Budget projection). Supporting data for the White House projections seemed exceedingly sparse to Staff compared to data supporting prior White House efforts, which tended to be only slightly more optimistic than the CBO.

<u>DISCUSSION OF BLUE CHIP</u>

Q. Do all firms offering advice to investors define "long-term, range, or run" the same way?

A. No. The farthest into the future that an advising firm projects or assembles information is that advising firm's "long" projection. As an example, Value Line (VL) projections only look five years into the future. So three-to-five years out is VL's long-run projection.

Q. In Staff's two different three-stage DCF models, Staff is looking for growth rates for a period between 10 and 30 years in the future, or an

[29] NW Natural/400, Villadsen/39.

average of 20-years out. Why can't Staff just use a 5- or 10-year projection?

A. Staff could, but there is better information available. If a primary concern is whether enough Americans are both working and highly productive 20 years from now to support a robustly growing economy, 10-year data is not yet impacted by retirement of persons born in 1960 or persons not immigrating and not being born to U.S. families now. A better solution is to use data that is projected with those difficulties in mind.

Q. Does the Company provide growth rates used in its modeling?

A. Yes. In response to Staff DR 85, NW Natural provided growth rate source information. As an example, the Company's confidential response to DR 185 Attachment 2 shows Blue Chip Economic Indicators accessed in the Company's modeling.

Q. Are you saying that Blue Chip information is not useful to investors?

A. That is not Staff's point. Rather Staff is suggesting that when focusing on a time period with a mid-point 20 years in the future, taking information reflective of an earlier time period could sidestep known future growth difficulties decades into the future.

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate NW Natural's ROE?

A. I used companies that met the following criteria as peer utilities to the regulated gas utility activities of NW Natural:

1. Covered by Value Line (VL) as a gas utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating equal to or better than BBB- from S&P, or Baa3 from Moody's;
4. No decline in annual dividend in last four years based on VL;
5. Has heavily regulated gas LDC revenue;
6. Has LT Debt under 56 percent in VL Capital Structure; and
7. Has no recent merger and acquisition activity.

Q. What cohort of companies resulted from your screens?

A. Please see Exhibit Staff/202, Muldoon/2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained from Staff screens. Staff/202 also shows the peer utilities the Company obtained from the Company screens in this rate case.

Q. Why do you eliminate companies that are not forecasted to have positive dividend growth?

A. My screening is consistent with Staff past practice. There is evidence that investors find common stock of dividend-cutting utilities much less attractive. General Electric Co. (GE) is the latest example of why a company does not cut long standing gradually growing quarterly dividends.[30] GE lost about 47 percent of its stock value while the S&P 500 rose sharply.

Q. How does NW Natural's cohort of peers differ from Staff's?

A. The Company's cohort includes a substantially unregulated company (Chesapeake Utilities Corporation) and three utilities undergoing substantial mergers and acquisitions that likely change resulting company performance and financial trajectories. Staff does not include such companies. Staff's peer screen is intended to find peers with regulated operations most like NW Natural regulated operations to best capture investor expectations of Company performance.

Q. Did you carefully examine Chesapeake Utilities Corporation (CPK or Chesapeake) as a peer for NW Natural's Oregon gas operations before eliminating CPK?

A. Yes, Staff validates the screening rejection of CPK in Exhibit Staff/202, Muldoon/5. CPK is a company with 40 percent of its business in propane, heating, ventilation, air conditioning, plumbing and other service. Less than two-thirds of CPK's revenues are from regulated gas LDC income.[31]

Q. Does it make sense to use a company with a radically different risk profile as a modeling proxy for NW Natural?

A. No.

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[30] *See* Staff/211, Muldoon/61 for more about the precipitous PGE stock plunge.
[31] *See* Staff/210, Muldoon/3 for VL confirmation that 40 percent of Chesapeake is unregulated.

NW Natural has a reliable regulated growth engine that has satisfied institutional investors and money managers for 62 years. That does not describe Chesapeake, which is not the same caliber of company. Chesapeake is into riskier unregulated business. Adding Chesapeake to boost the count of companies examined just degrades results from modeling. It does not make the modeling results more statistically relevant, rather it means one has averaged the stats for a bicycle in with those for motor vehicles.

Q. Why does Staff exclude utilities engaged in merger activities?

A. Mergers can mean great change in both the acquiring and the acquired companies over time. Before the merger both the target and the purchasing companies may have had regular patterns of management and performance, in part reflective of employees, executives and board members acting consistent with a given corporate culture and identity. A merger can be a break from those prior patterns.

Merger uncertainties can involve changes to computer systems, changes in management focus, changes in staffing, different attitudes about risk and many new initiatives that may or may not succeed. Even when the acquiring company announces it intends to preserve continuity, mergers can bring material changes as different corporate cultures collide in ways that are hard to accurately assess in the moment.

Q. Did Staff's peer group for three-stage DCF modeling reasonably address peer utility capitalization size?

A. Yes. 80 percent of Staff's peer group is the same mid-cap market capitalization size as NW Natural according to value line.[32] Staff therefore makes no adjustments for capitalization size in its three-stage DCF modeling.

SENSITIVITY ANALYSIS

Q. Did Staff's three-stage DCF modeling include sensitivities analysis with the Company's peer utilities?

A. Yes, in Staff 202 and Staff 203, I modeled not only Staff's peer set but also the peer set of the Company. I also modeled the peer set of the Company excluding the three utilities undergoing mergers and acquisitions.

Q. Did Staff find that the sensitivities with Company peer groups raised the recommended ROEs?

A. No, rather the use of the Company's peer groups depressed modeling results. That is logically explained in that NW Natural outperforms companies that are not close peers when both cash flows from dividends and stock price appreciation are considered. This is further support for Staff's expectation that stock offerings from NWN will see oversubscription due to demand for stock of the best performing American LDC.

Q. How does Staff apply informed judgment to its modeling?

A. Staff examined its full range of three-stage DCF modeling results that range from 7.22 percent to 9.33 percent ROE after all adjustments. Within that range, Staff determined that 8.7 percent to 9.3 percent is a reasonable

[32] Staff/202, Muldoon/2.

narrowing of focus, excluding some of the Company's suggested peer companies for reasons earlier articulated. Further narrowing the focus to Staff's primary peers most like NW Natural regulated operations was the best fit to capture investor expectations of Company performance. Again, please note that this range generates the highest modeling results, outperforming the Company's gas peer group in informed modeling.

Q. Does running sensitivities with poorly fitting Company peers replace or modify Staff's primary screening methods?

A. No, sensitivity results could have increased, but not decrease Staff's modeling results.

COMPANY MODELING

Q. Earlier you note that the difference between your recommended ROE and Dr. Villadsen's is due in part to Dr. Villadsen's reliance on results from her Risk Premium and CAPM-based models. Please explain.

A. Dr. Villadsen produced separate "reasonable" ranges of ROEs for her multi-stage DCF, risk premium, and CAPM-based models:

Multi-Stage DCF	9.4 to 10 percent
Risk Premium Models	10.2 to 10.3 percent
CAPM-based Models	10 to 10.5 percent[33]

She then blended these ranges to obtain her final recommended range of 9.7-10.3 percent as explained in her testimony as follows:

[33] NW Natural/400, Villadsen/40, 43, 45.

> The estimated ranges are summarized in Table 3 (DCF), Table 4 (Risk Premium), and Table 5 (CAPM) along with the recommended range. Overall the range is wide from 9.4% to 10.8% but I consider a narrower range that includes the majority of the overlapping ranges to be the most reasonable. Consequently, I consider a range of approximately 9.7 to 10.3 percent to be reasonable given the multi-stage DCF result using the Blue Chip and OMB forecast falls at the midpoint, the risk premium and CAPM based results are in the upper end to above the range while the allowed ROEs are within the range.[34]

After establishing a recommended range of 9.7 to 10.3 percent, Dr. Villadsen chose a point estimate in the middle (10.0 percent). Without the results of the CAPM-based models and the Risk Premium Model, the midpoint of her range would have been lower.

Q. Why is Dr. Villadsen's reliance on these other models significant?

A. As Dr. Villadsen notes in her testimony, the Commission has previously rejected the results of the CAPM.[35] The Commission has also rejected use of the risk premium methodology to establish an estimate of ROE because it is not based on accepted regulatory principles.[36] While it may be appropriate to use results of these models to check the reasonableness of results of models such as the Multi-Stage DCF, Staff disagrees with use of these models to actually estimate ROE.

[34] NW Natural/400, Villadsen/46.

[35] NW Natural/400, Villadsen/1n1 citing Order No. 01-777.

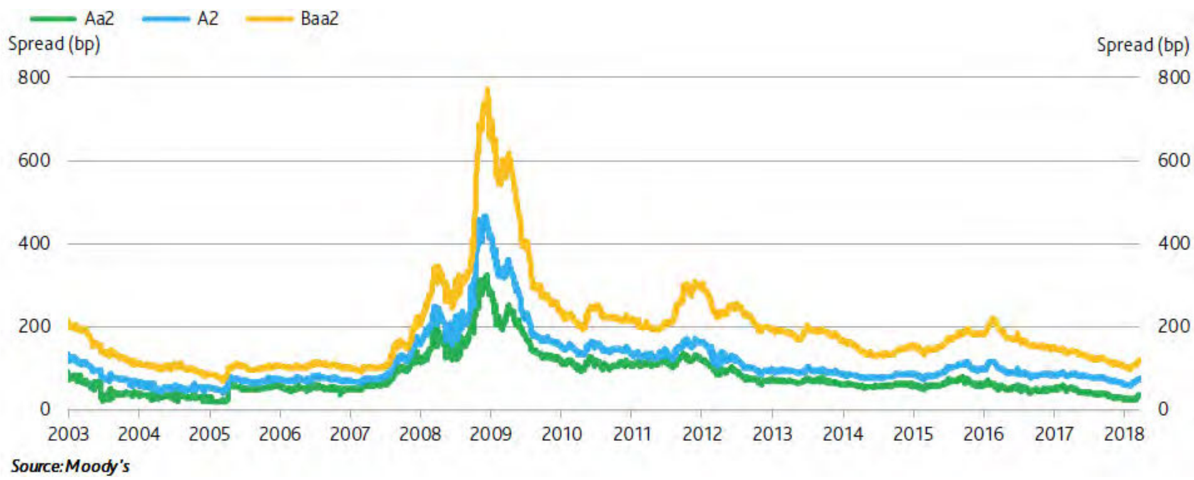
[36] See Order No. 01-777, p. 33. See also Order No. 07-715, p. 47 ("[F]or the reasons given in [Order No. 01-777], we reject the risk positioning model. * * * We find, based on the evidence in this record, that the reasoning expressed in that order remains sound.").

NW NATURAL'S EQUITY RISK PREMIUM MODELING

Q. Did you review the Company's risk premium modeling?

A. Yes, however as a mental exercise consider the following 5-year Median Spreads from Moody's over UST by credit rating in Figure 3 below:[37]

Figure 3



Contemplate in this simple risk premium scenario the dilemma that is posed by whether to include information for the year 2009. Perhaps a finance professor with no money riding on a decision would say that over the long-run it might be good to include the effects of depressions and wars. But then your Bloomberg terminal helpfully offers that the actual spread for the test year in this rate case on a thirty-year bond is just 103 bps, or about one percent for a company rated like NW Natural. Now that is a dilemma. Do you expect looking forward that that eight percent 2009 spread in the chart should be averaged in? Now, let's transition to the more complex question of stock

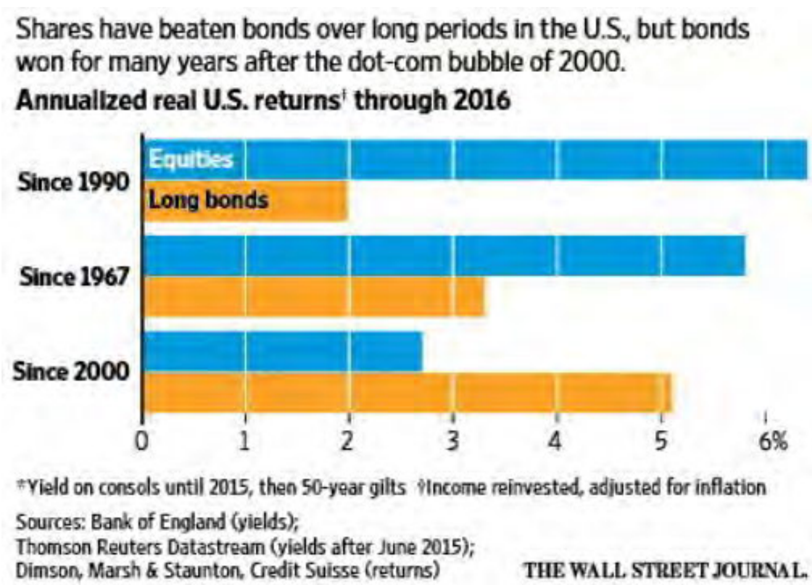
[37] Moody's Analytics of March 22, 2018.

returns over bond returns and whether it would be wise to rely overly much on a given date range to generate a durable correlation.

Q. Is there reason to think that the time period one chooses to model could radically change the outcome of risk premium modeling?

A. Yes. As shown in Figure 4, we could select A) 1990, to show stocks vastly outperform bonds; B) 1967, to show that stocks outperform bonds; or C) 2000, to show bonds outperform stocks.

Figure 4



Q. Would one use an equity risk premium in determining a reasonable price to pay for a utility to acquire that utility, or a reasonable per share price to acquire some of the stock of that utility?

A. That is not Staff's observation.

Figure 5[38]

Q. Looking at Figure 5 above, how does the Wall Street Journal explain correlations between bonds and stocks?

A. At times stock share and bond prices move together, and at other times they move inversely.

Q. Does Figure 5 demonstrate that relying on bond risk premiums might give not just a wrong answer, but an answer not even in the ballpark?

[38] *See* Staff/205, Muldoon/10 for more information about how bonds and stocks have correlated over time.

A. Yes, if there were a change in inflation or Fed monetary policy, your foundation for a material financial decision could be entirely inaccurate.

Q. Is the equity risk premium even a reliable pointer?

A. Not necessarily. Correlations hold until they don't.

Q. Is it wise to presume market correlations will hold for the next 30 years?

A. Certain market correlations failed in 2009 and again in 2018, less than ten years later. Relationships between stocks and bonds change in hard to predict times. Once changed, a different trend will then hold true until it doesn't. Investors relying on this type of approach are living dangerously. Even if they see a trend that looks safe for a good part of a decade, the next year it might not hold true. What was true in 1950 was not in 1960. What was true in 1980 was not in 2000.

Q. Does the market risk premium model look like a good fit to describe prevailing correlations between stocks and bonds 20 years from now?

A. Not that Staff can see.

REBUTTAL OF NW NATURAL'S ECAPM MODELING

Q. Did you examine NW Natural's CAPM and ECAPM modeling?

A. Yes.

Q. What is the formula used in CAPM modeling?

A. The formula follows in Figure 6.

Figure 6 – CAPM Formula

$$\bar{r}_a = r_f + \beta_a (\bar{r}_m - r_f)$$

Where :

r_f = Risk free rate

β_a = Beta of the security

$\bar{r}_m$ = Expected market return

$(\bar{r}_m - r_f)$ = Equity market premium

Q. What is Empirical or E CAPM?

A. Dr. Roger Morin, PhD in his book, “New Regulatory Finance” notes how CAPM seems to be off in its projections of required Rates of Return (ROR). Put another way, CAPM doesn’t seem to be accurately informing investors. Dr. Morin offers a correction, which by pivoting model results, might offer a remedy to investors consistently disappointed by CAPM modeling results. Staff suggests that this approach is interesting, but merits little weight here.

Q. Why should this model be given little weight at this point in time?

A. E CAPM does not appear to have traction yet in economic and financial practice.

Q. In financial markets how did investment banks address the limitations of the Capital Asset Pricing Model (CAPM) – Did they move to E-CAPM?

A. No. For example, the Morgan Stanley Four-Factor Model drew on Arbitrage Pricing Theory (APT), which argued that multiple betas, rather than just one beta, better explained the movement of stock prices.[39] However, that type of modeling added new complexity such as tracking the movement of stock prices against light sweet crude at wellhead commodity prices.

Q. Are these alternatives useful for your analysis?

A. They are not useful as a primary tool, but can provide additional checks on Staff's primary Model X and Model Y three-stage DCF model results.

Q. How do you use additional models to check on your estimates?

A. In Exhibit Staff/212, Muldoon/1 Staff also produces a Capital Asset Pricing Model (CAPM) for Staff's peer group.[40] My CAPM modeling generated a range of comparison ROEs between 6.48 percent and 7.96 percent. Used as a pointer to check on Staff's primary Model X and Model Y three-stage DCF modeling results, my CAPM modeling suggests that a number in the middle of my range such as my 9.0 recommended point ROE would be reasonable.

Q. Did Staff also prepare a Simple DCF or Gordon Growth Model?

A. Yes, Staff prepared a rough adjustment to the Company's Simple DCF model just removing the 40 percent unregulated utility Chesapeake and utilities undergoing merger and acquisitions. This generated a rough point estimate of 8.78 percent required ROE.

Next Staff reproduced the Company's Simple DCF modeling provided in NW Natural/403, Villadsen/13-14, using only dividends from Q4 2017 as

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[39] Beta represents a relationship of a company's stock price to referent information such as a broad market proxy like the Standard and Poor's 500 stock index

[40] Exhibit Staff/212, Muldoon/1.

opposed to a mix of third and fourth quarter dividends. This reflects the timing of Staff's modeling, not a criticism of Dr. Villadsen's selection of then available dividends in her earlier modeling. Staff's work suggested a rough range of reasonable ROEs from 7.69 percent to 9.50 percent with a point estimate of 9.05 percent ROE.[41]

Q. Overall within the limitations of the CAPM and Simple DCF, do these pointers indicate that Staff's three-stage DCF modeling results are reasonable?

A. Yes.

<u>NW NATURAL'S COMPARATIVE RISKINESS</u>

Q. Is NW Natural <u>less risky</u> than the average non-utility publicly traded U.S. stock, and even than some other gas utilities followed by VL?

A. Yes, as a regulated gas utility, the Company's returns have relatively low variability. However, Staff is confident that the peer utilities that Staff has selected to model are comparable to NW Natural's overall risk profile.

This characterization of course does not apply to the Company's reliance on Chesapeake, which as a heavily unregulated company, is managed toward quite different priorities in a far riskier environment than NW Natural. And Staff makes no suggestion that companies in mergers and acquisitions (M&A) would necessarily be progressing along the same trajectory two decades in the future as before the M&A.

[41] *See* Staff/207, Muldoon, Watson/1-2 for Staff's reconstructed Simple DCF modeling.

ALTERNATIVE MODELS EXAMINED

Q. What control modeling did you perform to corroborate your three-Stage DCF results?

A. I performed CAPM and Simple DCF calculations that support my three-stage Model X and Model Y DCF modeling. While I do not recommend that any alternate approach should replace the Commission's reliance on three-stage DCF modeling, such alternate models may offer a check on the reasonableness of my recommendation or provide a directional vector that helps the Commission select a point within Staff's range of reasonable ROEs as best point ROE.

Q. Please discuss the Ibbotson approach you used.

A. The Research Foundation of CFA Institute, an impartial non-profit organization, published "Rethinking the Equity Risk Premium" in 2011. Here, Professor Roger Ibbotson of the Yale School of Management, and other earlier examiners of how best to approach and calculate equity risk premiums, share their current thinking and findings.

"In the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6% against 2.1% for bonds, supporting a 4.5% equity risk premium."[42] Adding that 4.5 percent to about a potential 4.00 percent UST risk free rate for end of 2016, would suggest that an investor looking just for a

[42] "Rethinking the Equity Risk Premium," Research Foundation of CFA Institute, p. 81 (2011).

quick rough estimate should demand about an 8.5 percent ROE to be satisfied to own a stock of average risk at year end 2016.

Q. Did you consider other market risk premiums in your CAPM modeling?

A: Yes, where the Ibbotson analysis mostly focuses on 1980 to present, Morningstar in “Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook” provides a market risk premium of 6.0 percent based on 1926 through 2014. I also run my CAPM modeling using this alternative 6.0 market risk premium.

Q. Did you examine both 10- and 30- year UST yields as your market risk-free rates?

A. Yes, I also utilized VL betas. For these reasons, the Commission can conclude that this modeling was reasonably performed using inputs commonly employed by investors looking for a fast rough general direction of returns.

Q. How do your CAPM results inform consideration of your more robust three-stage DCF models?

A. Staff’s CAPM modeling results generating a range of 6.48 to 8.7 percent can be interpreted as a downward pointing vector in my range of reasonable ROEs.

SINGLE-STAGE GORDON GROWTH DCF MODELING

Q. Did you first examine and reproduce the Company’s Simple DCF – Gordon Growth DCF model?

A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of their textbook “Principles of Corporate Finance” caution “the simple constant-growth DCF formula is an extremely useful rule of thumb, but no more than that.”[43] This text reminds first quarter finance students that misapplication of this model may lead to false conclusions.

Q. With this caveat, what are your Simple DCF modeling results utilizing Staff’s peer utility group?

A. Staff’s Simple DCF modeling provided in Staff/207 Muldoon, Watson/2 shows Staff’s results of a range of reasonable ROEs of 7.69 percent to 9.50 percent implies a point ROE of 9.05 percent.

Q. Why are you uncomfortable relying too much on this simple Gordon Growth Model?

A. Gordon Growth Single-Stage Simple DCF modeling makes the simplifying assumption that information about all future returns is contained in just a few values: namely the next dividend and an appropriate very long-term average growth rate. This assumption does not prove reliable in the real world.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at NW Natural’s target capital structure increases required ROE. Why is this adjustment reasonable?

[43] “Principles of Corporate Finance”, Brealey, Myers, and Allen, p. 83 (10th Edition 2010).

A. Staff employs the Hamada Equation as a check on the reasonableness of its modeling results. This allows Staff to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, my screening criteria already identify peers that have a very close capital structure to NW Natural's. Use of the Hamada adjusted results helps ensure that Staff has captured all material risk in my analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see un-lever and re-lever as meaning removing debt of peer companies with varying capital structures, and then adding enough debt back to equal NW Natural's balanced target capital structure in this general rate case.

Q. The Company uses some variants of those Staff deploys, is this reasonable?

A. Staff merely notes that Dr. Hamada was prolific in his publications and his thinking changed over time possibly in response to the problems he was studying at the time. However, Staff's current work is consistent with methods used in Docket No. UG 221. The difference in this case is that Staff addresses the impact of recent tax cuts, shown in Staff/202, Muldoon/4-5.

INFORMED STAFF ANALYSIS

Q. Did Staff take into account information from other models?

A. Yes. Staff performed CAPM modeling and Simple DCF modeling, and reviewed the Company's testimony, which informed Staff's recommendations.

Q. Do you monitor and analyze current and projected market conditions?

A. Yes. My analysis includes analysis of the current economic climate and its impact on my estimates of long-term growth. I also rely heavily on feeds from SNL Financial LC (SNL), Bloomberg, Moody's, S&P, WSJ and other sources to make sure that my financial understandings are reflective of investor expectations. Please see a cross section of recent news in Staff/211.

Q. Did you develop your recommendations while informed by authorized ROEs in other parts of the country?

A. Yes. I examined 2016 and 2017 authorized ROEs across the nation in comparison with 2015 ROE decisions published by Regulated Research Associates (RRA), an offering of S&P Global Market Intelligence, as discussed earlier.

Q. Did you use robust and proven analytical methodologies?

A. Yes. My methods are robust, proven, and parallel Staff's work over the last decade.

Q. Describe how you performed your analysis.

A. Using the cohort of proxy companies that met my screens, I ran each of Staff's two three-stage DCF models three times, each time using a different long-term growth rate.

Q. Did you evaluate the Company's peer cohorts in this same modeling?

A. Yes.

Q. Is the upper end of your range of reasonable ROEs driven by results from the Company's peer group utilizing the top growth rate?

A. No, the upper range of reasonable ROEs is from my peer group utilizing the highest growth rate adjusted for capital structure divergent from NW Natural's.

Q. Does your recommendation include results from the Company's peer group?

A. Yes, but the Company's peer group did not produce the highest modeling results. My range of reasonable ROEs brackets the results for the Company's peer group. If I were to rely on the Company's gas peer group, my recommended ROE would be lower than my 9.3 percent upper limit of reasonable ROEs.

ISSUE 3 – COST OF LT DEBT

Q. Have you compiled a summary table illustrating your calculation of NW Natural's Cost of LT Debt?

A. Yes, please see Confidential Exhibit Staff/208, Muldoon/4 supporting my recommendation for a 5.233 percent Cost of LT Debt, consistent with NW Natural's requested value.

Q. Is that table updated to reflect NW Natural's test year planned debt issuance(s) and pro forma replacement of the current portion of LT Debt maturing in the test period?

A. Yes. This table remains confidential until the company informs the public of issuance detail. Staff has some concern, discussed below, about the impact of yet-to-be issued debt on NW Natural's cost of LT Debt.

Q. What is Staff's approach to constructing reasonable forward coupon rates?

A. Staff looks at referent underlying U.S. Treasury (UST) forward very-near-term market trends for various maturities out about 18 months. Staff then applies the prevailing spreads over UST informed by Moody's about trends in spreads in the very-near term. Staff compares the sum of the UST forward for the target issuance date and maturity against indicative recent bond issuances of like rated and situated utilities. This generates a reasonable constructed forward bond coupon rate.

Q. Were bond series that mature before the test year removed from your table of outstanding LT Debt in the test year?

A. Yes. Staff's methods herein are consistent with other recent general rate cases.[44] Again, some concerns linger.

Q. Did you prepare a debt maturity profile for NW Natural?

A. Yes, in Exhibit Staff/208, Muldoon/5, I have provided a debt maturity profile for reflecting Staff's proposed Cost of LT Debt table in Staff/208, Muldoon/4. There are no overly concerning debt maturity concentrations. Staff accepts the Company's heavier reliance on 30-year rather than 10-year debt due to

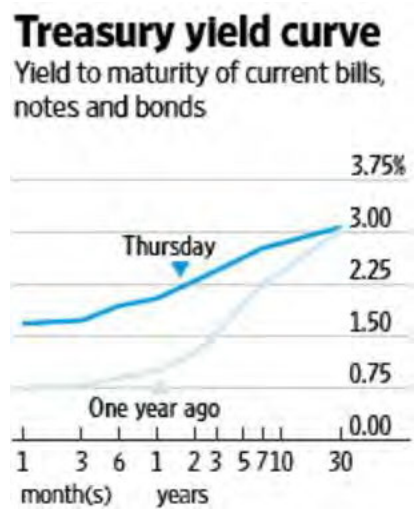
[44] Staff's approach to Cost of LT Debt is consistent with Staff's work in recent gas utility general rate cases, namely: OPUC Order No. 14-015 in Docket UG 246, Order No. 15-109 in Docket No. UG 284, and Order Nos.16-076 and 16-109 in Docket No. UG 288.

the current relative flat UST yield curve. In recent months, the costs of shorter maturity UST have risen much faster than rates on 30-year UST.

Q. Is this curve of UST and spreads there over for A and B rated utilities plotted in your testimony.

A. Yes, please see Staff/208, Muldoon/6 for this graph. A snapshot of the general UST yield curve appears below in Figure 7 for discussion purposes:

Figure 7[45]



Notice how the lighter line for a year ago shows much lower rates for very short maturities and not that much movement in comparison to now for 30-year UST. For this reason, at this moment, ratepayers get a relatively better deal in the issuance of 30-year or longer utility bonds, provided there is good utility purpose therefore.

Q. Please explain your concern related to yet-to-be issued debt.

[45] This treasury yield curve was published in the WSJ of March 23, 2018.

A. Sometimes between general rate cases, utilities will issue lower-cost shorter-maturity debt that will drop off before the next general rate case. Staff's methods will not reflect the long-term impact of such lower cost debt issuances.

Q. What is the second concern you note above?

A. When the test year is not a calendar year, some higher priced debt that is due to expire prior to the end of the calendar year, but not before the end of the test year, is nonetheless included in Staff's calculation of the cost of LT Debt. In this case, Staff's methods will reflect an oversized long-term impact of such higher cost debt that matures a few months after Staff's calculations.

Q. Can you show an example of this?

A. Yes, see Confidential Exhibit No. Staff/208, Muldoon/3 row one and final footnote.

Q. Do the above lingering concerns break any rules?

A. No. However, Staff still wishes to bring these concerns to the Commission's attention, so that it can best put Staff's proposed Cost of LT Debt into context.

Q. Earlier you mentioned you would touch on some impacts were we to start to move into a rising interest rate environment. Can you now elaborate further?

A. Yes, the 5.233 percent Cost of LT Debt recommended by me and the Company is consistent both with the Company's response to DRs and the Company request, as well as with Staff's usual methodologies and calculations. However, Staff has the luxury of recommending best practices even when these translate as something other than the least possible cost in a rate case.

Staff offers its calculations in Staff/208, Muldoon/2 for Commission consideration as an alternative to the Company's filed position. This exhibit clearly shows the impact of recent trends in UST forwards and interest rate spreads for utilities rated like NW Natural intending to issue debt at times consistent with NW Natural's timing. This alternative is a 5.260 percent cost of LT Debt.

Q. Are we in a sharply rising interest rate environment now?

A. No. However, Cost of LT Debt in this general rate case frames a discussion in how best to address rising rather than falling or flat trends in certain Cost of Capital components or inputs thereto.

Q. What is Staff's recommendation in this testimony for Cost of LT Debt?

A. Staff accepts the Company's filed testimony and recommends a Cost of LT Debt of 5.233 percent

ISSUE 4 — EQUITY FLOTATION COST

Q. What is your recommendation regarding the Company's proposed equity flotation costs?[46]

A. Staff recommends that the entirety of the $1.2 million of equity flotation costs be disallowed. Staff fully addresses the cost of equity flotation within ROE

[46] See NW Natural/200, McVay/14.

modeling. Therefore, there is no need to recognize equity flotation expenses elsewhere in an energy general rate case before the Commission.

Q. Why is Staff recommending 12.5 bps within ROE modeling for jurisdictional utilities, on a perpetual basis, even when the energy utility is not issuing common stock as a public offering with an equity forward and associated carrying costs?

A. The Commission has indulged Staff working Cost of Capital in Staff's quest for truth and beauty. As Staff seeks best answers, those recommendations are consistent with jurisdictional energy utilities' adequate access to capital markets and the opportunity but not the guarantee of a competitive return on assets and initiatives, as reflected in the earlier discussion of the *Hope* and *Bluefield* legal standards.

Q. What is the most common treatment at regulatory commissions for equity flotation costs?

A. The last survey some time ago, conducted by the Washington Utility and Transportation Commission, found that most commissions allow no consideration whatsoever of equity flotation costs in general rate cases.

Q. Why does Staff propose a higher recognition of equity flotation costs than even Chapter 10 Flotation Cost Adjustment in the text, "New Regulatory Finance" by Dr. Roger A. Morin, Ph.D. first printing of June, 2006?

A. Staff finds that while the text captures the size dynamics of equity flotation costs, Commission jurisdictional utilities infrequently arrange for public offerings of common stock. Further, historically PGE and other utilities have offered stock in equity forwards, particularly when stock prices are at or near historical highs.

Because it is in ratepayer interest to have high issuance prices so as to reduce costs of leverage, minimize liquidity risks, maximize credit ratings, and control the costs of revolving credit facilities and associated letters of credit and borrowing, Staff does not seek to dissuade equity forwards when stock prices are very high and significantly above aggregate book value. These factors are derived from Staff's deeper look at local stock offerings of energy utilities.

Q. Has each energy utility issuing stock provided permission to Staff to share its information?

A. No.

Q. Is the Commission obligated in any way to accept Staff's higher than prevailing equity flotation costs?

A. No. The Commission may determine that no consideration of equity flotation costs is reasonable in general rate cases in Oregon. That would be consistent with the findings of most other energy regulatory commissions that disallow equity flotation costs with no concurrent upward adjustment to ROE.

Q. Please recap your recommendation.

A. Staff recommends that the Commission incorporate into its consideration of a best point ROE, 12.5 basis points of equity flotation costs even though this is a higher local determination than textbook illustrations; and concurrently remove all other consideration of equity flotation expense from this general rate case, namely $1.2 million Oregon allocated equity flotation expense discussed earlier.

CONCLUSION

Staff Adjustment – Cost of Capital

Q. What is Staff's recommendation regarding Capital Structure?

A. I recommend a 50.0 percent Equity and 50.0 percent LT Debt Capital Structure, reflecting best available information at this time and the considerations earlier articulated.[47]

Q. What is Staff's recommendation regarding ROE?

A. I recommend that the Commission consider a range of reasonable ROEs from 8.7 percent to 9.3 percent, and a point ROE of 9.0 percent – the midpoint in my range of reasonable ROEs.

Q. What is Staff's recommendation regarding LT Debt?

A. I recommend a Cost of LT Debt of 5.233 percent, which is consistent with the Company's filing. I bring the Commission's attention to some of the cost impacts of the timing of the test year, while also asking the Commission to consider an alternate construction of the Cost of LT Debt that draws on more recent market data and trends than present at the time of the Company's filing.

[47] This capital structure is consistent with Figure 16-1 of Chapter 16, Relationship between Capital Structure and the Cost of Capital, in the earlier mentioned text, "New Regulatory Finance" by Dr. Roger A Morin, Ph.D., when a finance practitioner seeks to balance minimization of the Cost of Capital against credit and liquidity cost and risk.

Staff Adjustment – Equity flotation costs

Q. What is Staff's recommendation regarding equity flotation costs.

A. I recommend the Commission consider Staff's 12.5 bps built into and fully addressed in Staff's 9.0 ROE modeling point recommendation as an appropriate way to address equity flotation costs, understanding that the Commission is fully justified in removing all costs related to equity flotation. This results in an adjustment of $1.2 million dollars in this general rate case for equity flotation expense.[48]

Q. What ROR is generated by the above recommendations?

A. Staff's recommendations generate a 7.12 percent rounded Rate of Return.

Q. Is there a Staff preferred rounding to Cost of Capital values appearing in Commission Orders?

A. Yes. Staff recommends the Commission consider three decimal places to the right of the decimal point for Cost of LT Debt, two for ROE and ROR, and one for percentages of Common Equity and LT Debt respectively in Capital Structure. This consistency serves to avoid confusion at ratepayer expense.

Q. Does that conclude your testimony?

A. Yes.

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[48] This value is rounded from the $1,198,000 shown for equity flotation expense in NW Natural/207, McVay/Page 1 of 1, shown at NW Natural/200, McVay/1 as $1.2 million.

CASE: UG 344
WITNESS: MATT MULDOON-JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Energy – Rates Finance and Audit Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION:	In 1981, I received a Bachelor of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186; UG 201, UG 246, UG 284, UG 288, and UG 325 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, and UE 294; and CNG UG 287 and UG 305.. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

WITNESS QUALIFICATION STATEMENT

NAME:	Jeffrey Watson
EMPLOYER:	Public Utility Commission of Oregon (Commission)
TITLE:	Consumer Specialist, Consumer Services; Analyst, Energy Rates, Finance and Audit (ERFA)
ADDRESS:	201 High Street SE, Suite 100, Salem, OR 97301
EDUCATION:	Bachelor of Science, Economics Oregon State University, Corvallis, OR Associate of Arts Chemeketa Community College, Salem, OR
EXPERIENCE:	I have been employed by the Commission since January of 2016 as a Consumer Specialist in the Consumer Services Division (Consumer Services), and as an analyst in the Energy Rates, Finance and Audit (ERFA) Division. For Consumer Services, I investigate and resolve customer claims of inappropriate action by regulated utilities and other service providers. For ERFA, I support audits and Cost of Capital modeling. My analysis also covers a variety of other financial and general rate case topics as reflected in the current general rate cases of Northwest Natural Gas Corporation (NWN UG 344) and Portland General Electric Company (PGE UE 335). Prior to my work at the Commission, I was employed by T-Mobile for six years. First I developed and led continuing education courses, both as a trainer and subject matter expert for 600+ representatives and leaders on customer service and sales operations topics. Next at T-Mobile, I managed a specialized team of customer service representatives to resolve escalated, executive level, and outside-of-policy customer issues. I reviewed call center operations and developed policies based on my analysis of the issues tracked by my team. I presented and defended my analysis and recommendations to site and regional leadership. My recommendations set performance goals to confirm successful resolution of issues and ensured ongoing service quality.

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 202

Staff Peer Screening

Exhibits in Support of Opening Testimony

April 20, 2018

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C	CCC	C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
		CC				CC(high)		
						CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

Natural Gas
NWN UG 344

Screen: 1 — VL Gas Utilities passing Staff Peer Screen — 80% Mid Cap
Sensitivities: 2 — VL Gas Utilities passing Co. Screen
3 — VL Gas Utilities " Co. " w/o M&A

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
#	Abbreviated Utility	Gas Group UG 344 Company	UG 344 Staff	VL Corporate Name Gas Utility	Ticker	VL Cap Small Mid Large	S&P Global Market Intelligence MI Key	SPCIQ Key	IRS EIN	SEC File	VL 2/24/2018 Beta	Yahoo Fin. 2/24/2018 Beta	Yahoo Fin. 2/24/2018 Mkt Cap $ Billions	VL 2/24/2018 Mkt Cap $ Billions	Value Line N-Gas Utility w VL Beta < 1 2/24/2018	SNL or VL No Div Declines 5 years	Either / Or: S&P Local LT 2/24/2018 Rating ≥ BBB-	Either / Or: Moody's Local LT 2/24/2018 Rating ≥ Baa3	Last 10-K Highly Regulated LDC Revenue
1	Atmos	Yes	Yes	Atmos Energy Corporation	ATO	L	4057157	252684	75-1743247	1-10042	0.70	-0.01	9.16	9.50	Yes	Pass	A	A2	R
2	Chesapeake	Yes	No	Chesapeake Utilities Corporation	CPK	M	4057113	260346	51-0064146	1-11590	0.70	-0.55	1.13	1.30	Yes	Pass	A-	N/A	M
3	New Jersey	Yes	No	New Jersey Resources Corporation	NJR	M	4057128	291335	22-2376465	1-08359	0.80	0.07	3.47	3.80	Yes	Pass	A	Aa2	M
4	NiSource	No	No	NiSource Inc.	NI	L	4057051	292092	35-1719974	1-09779	0.80	0.09	7.96	9.10	Yes	Pass	BBB+	Baa2	Fail
5	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	M	4057132	292047	93-0256722	1-15973	0.70	0.09	1.62	1.90	Yes	Pass	A+	A3	R
6	ONE Gas	Yes	Yes	ONE Gas, Inc.	OGS	M	4427129	243685856	46-3561936	1-36108	0.70	-0.06	4.00	3.51	Yes	Pass	A	A2	R
7	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	M	4057145	303963	22-1901645	1-06364	0.85	0.25	2.15	2.60	Yes	Pass	BBB+	A2	M
8	Southwest Gas	Yes	Yes	Southwest Gas Holdings, Inc.	SWX	M	4884928	304227	81-3881866	1-37976	0.80	0.10	3.30	3.90	Yes	Pass	BBB+	A3	R
9	Spire	Yes	Yes	Spire, Inc. (Formerly: The Laclede Group, Inc.)	SR	M	4002506	284847	74-2976504	1-16681	0.70	-0.06	3.30	3.80	Yes	Pass	A-	Baa2	R
10	UGI	No	No	UGI Corporation (Propane Focus / VL)	UGI	L	4057537	190756	23-2668356	1-11071	0.90	0.40	7.64	8.30	Propane	Pass	Fail	W	Fail
11	WGL	Yes	No	WGL Holdings, Inc.	WGL	M	4007261	313220	52-2210912	1-16163	0.80	0.28	4.276	4.30	Yes	Pass	A	A3	R
	TOTAL PEERS	9 all 6 w/o M&A	5 80% Mid Cap																

When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.

R 80% or more of assets are regulated
M 50% - 79% of assets are regulated
W Ratings Withdrawn

Avista Corporation
Peer Screen

Natural Gas
NWN UG 344

Screen: 1
Sensitivities: 2
3

1	2	3	4	21	22	23	24	25	26	27	28
		Gas Group		VL 2018 LT Debt < 56% of Capital	VL 2020-2022 LT Debt % of Capital	VL 2018 Common Equity % of Capital	VL Preferred Stock of Capital	VL Div. Growth Rate > 0%	Major M&A in Last 4 Years	M&A Activity and General Notes re: Last 4 Years	
#	Abbreviated Utility	UG 344 Company	UG 344 Staff								#
1	Atmos	Yes	Yes	44.0%	45.0%	56.0%	0.0%	Pass	Pass	Completed Sale Atmos Marketing to CenterPoint Energy Jan. 4, 2017 **leaving Atmos Energy 100% Regulated.**	1
2	Chesapeake	Yes	No	30.0%	30.0%	70.0%	0.0%	Pass	Pass	**VL indicates this utility is 40% unregulated energy operations.**	2
3	New Jersey	Yes	No	45.5%	43.0%	54.5%	0.0%	Pass	Fail	**New Jersey Resources / South Jersey Industries Proposed Merger Announced Apr 4, 2017**	3
4	NiSource	No	No	61.0%	63.0%	39.0%	0.0%	Fail	Pass	$1.8 B infrastrucutre spend planned for 2018 / VL	4
5	**Northwest Natural**	Yes	Yes	45.0%	45.5%	55.0%	0.0%	Pass	Pass	HoldCo Formation - Purchase of Salmon Valley Water OR & Falls Water ID pending.	5
6	ONE Gas	Yes	Yes	38.0%	38.0%	62.0%	0.0%	Pass	Pass	ONE Gas, Inc was created in 2014 as a spinoff of ONEOK's natural gas distribution operations.	6
7	South Jersey	Yes	No	47.5%	46.0%	52.5%	0.0%	Pass	Fail	**Purchasing Elizabethtown Gas and Elkton Gas from Southern Company for $1.7 B - NJR/SJI Merger**	7
8	Southwest Gas	Yes	Yes	48.0%	44.5%	52.0%	0.0%	Pass	Pass	Reorganized under holding company.	8
9	Spire	Yes	Yes	49.5%	49.0%	50.5%	0.0%	Pass	Pass	About $0.5B STL Pipeline spend.	9
10	UGI	No	No	55.5%	51.0%	44.5%	0.0%	Pass	Pass	**Very Heavy Propane Position**	10
11	WGL	Yes	No	46.0%	44.0%	53.0%	1.0%	Pass	Fail	**Canada's AltaGas announced its intent to buy WGL as of Jan 12, 2017**	11
	TOTAL PEERS	9 all 6 w/o M&A	5 80% Mid Cap								

Peer Screen

Historical and Near Term
VL Dividends, and
VL Earnings per Share

NWN - Gas Peer Dividends

UG 344

Value Line Dividends

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2016 Yr	2014-16 Average	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2017 Yr
1	1	Atmos	Yes	Yes	ATO	0.37	0.37	0.37	0.39	1.50	0.39	0.39	0.39	0.42	1.59	0.42	0.42	0.42	0.45	1.71	1.60	0.45	0.45	0.45	0.485	1.84
2	2	Chesapeake	Yes	No	CPK	0.257	0.257	0.27	0.27	1.05	0.27	0.27	0.288	0.288	1.12	0.288	0.288	0.305	0.305	1.19	1.12	0.305	0.305	0.325	0.325	1.26
3	3	New Jersey	Yes	No	NJR	0.21	0.21	0.21	0.23	0.86	0.23	0.23	0.23	0.24	0.93	0.24	0.24	0.24	0.255	0.98	0.92	0.255	0.255	0.255	0.273	1.04
4	5	Northwest Natural	Yes	Yes	NWN	0.46	0.46	0.46	0.465	1.85	0.465	0.465	0.465	0.4675	1.86	0.4675	0.4675	0.4675	0.47	1.87	1.86	0.47	0.47	0.47	0.4725	1.88
5	6	ONE Gas	Yes	Yes	OGS	0.00	0.28	0.28	0.28	0.84	0.30	0.30	0.30	0.30	1.20	0.35	0.35	0.35	0.35	1.40	1.15	0.42	0.42	0.42	0.42	1.68
6	7	South Jersey	Yes	No	SJI	0.00	0.237	0.237	0.488	0.96	0.00	0.251	0.251	0.515	1.02	0.00	0.264	0.264	0.536	1.06	1.01	0.00	0.273	0.273	0.553	1.10
7	8	Southwest Gas	Yes	Yes	SWX	0.33	0.365	0.365	0.365	1.43	0.365	0.405	0.405	0.405	1.58	0.405	0.45	0.45	0.45	1.76	1.59	0.45	0.495	0.495	0.495	1.94
8	9	Spire	Yes	Yes	SR	0.44	0.44	0.44	0.44	1.76	0.46	0.46	0.46	0.46	1.84	0.49	0.49	0.49	0.49	1.96	1.85	0.525	0.525	0.525	0.525	2.10
9	11	WGL	Yes	No	WGL	0.42	0.44	0.44	0.44	1.74	0.44	0.463	0.463	0.463	1.83	0.463	0.488	0.488	0.488	1.93	1.83	0.488	0.51	0.51	0.51	2.02
		TOTAL PEERS	9 all	5																						
			6 w/o M&A	80% Mid Cap																						

NWN - Gas Peer EPS

Value Line Earnings per Share (EPS)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2014 Yr	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2016 Yr	2014-16 Average	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2017 Yr
1	1	Atmos	Yes	Yes	ATO	0.95	1.38	0.45	0.23	3.01	0.96	1.35	0.55	0.23	3.09	1.00	1.38	0.69	0.33	3.40	3.17	1.08	1.52	0.67	0.34	3.61
2	2	Chesapeake	Yes	No	CPK	1.21	0.35	0.22	0.69	2.47	1.44	0.35	0.33	0.56	2.68	1.33	0.52	0.29	0.73	2.87	2.67	1.17	0.37	0.42	0.69	2.65
3	3	New Jersey	Yes	No	NJR	0.47	1.79	0.05	(0.23)	2.08	0.65	1.16	0.03	(0.06)	1.78	0.58	0.91	0.13	(0.02)	1.60	1.82	0.47	1.21	0.20	(0.14)	1.74
4	5	Northwest Natural	Yes	Yes	NWN	1.40	0.04	(0.32)	1.04	2.16	1.04	0.08	(0.24)	1.08	1.96	1.33	0.07	(0.29)	1.00	2.11	2.08	1.40	0.10	(0.30)	1.05	2.25
5	6	ONE Gas	Yes	Yes	OGS	1.13	0.18	0.09	0.67	2.07	1.13	0.23	0.14	0.74	2.24	1.22	0.38	0.25	0.80	2.65	2.32	1.34	0.39	0.36	0.86	2.95
6	7	South Jersey	Yes	No	SJI	1.01	0.15	(0.05)	0.47	1.58	0.86	0.03	(0.07)	0.62	1.44	0.75	0.12	0.05	0.42	1.34	1.45	0.72	0.06	(0.05)	0.42	1.15
7	8	Southwest Gas	Yes	Yes	SWX	1.51	0.21	0.04	1.25	3.01	1.53	0.10	(0.10)	1.38	2.91	1.58	0.19	0.05	1.36	3.18	3.03	1.45	0.37	0.21	1.52	3.55
8	9	Spire	Yes	Yes	SR	1.09	1.59	0.33	(0.35)	2.66	1.09	2.18	0.32	(0.43)	3.16	0.99	2.36	0.45	(0.28)	3.52	3.11	1.10	2.55	0.40	(0.25)	3.80
9	11	WGL	Yes	No	WGL	0.99	1.84	0.02	(0.17)	2.68	1.16	2.02	0.22	(0.23)	3.17	1.18	1.78	0.33	(0.01)	3.28	3.04	1.15	1.87	0.26	(0.17)	3.11
		TOTAL PEERS	9 all	5																						
			6 w/o M&A	80% Mid Cap																						

Historical and Near Term
VL Dividends, and
VL Earnings per Share

NWN - Gas Peer Dividends

	1	2	3	4	5	27	28	29	30	31	32	33	34	
		UG 344				Value Line Estimated Near Future Dividends					VL Avg.	Div Growth		
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	2018 Yr	2019 Yr	2020 Yr	2021 Yr	2022 Yr	2020 - 22 / Yr	2020-22 vs. 2014-16	#	
1	1	Atmos	Yes	Yes	ATO	1.94	2.05	2.17	2.30	2.43	2.30	6.2%	1	1
2	2	Chesapeake	Yes	No	CPK	1.33	1.40	1.47	1.55	1.63	1.55	5.6%	2	2
3	3	New Jersey	Yes	No	NJR	1.09	1.10	1.11	1.12	1.13	1.12	3.3%	3	3
4	5	Northwest Natural	Yes	Yes	NWN	1.89	1.93	1.96	2.00	2.04	2.00	1.2%	5	4
5	6	ONE Gas	Yes	Yes	OGS	1.88	2.05	2.24	2.45	2.66	2.45	13.5%	6	5
6	7	South Jersey	Yes	No	SJI	1.15	1.20	1.25	1.30	1.35	1.30	4.2%	7	6
7	8	Southwest Gas	Yes	Yes	SWX	2.08	2.21	2.35	2.50	2.65	2.50	7.9%	8	7
8	9	Spire	Yes	Yes	SR	2.25	2.33	2.41	2.50	2.59	2.50	5.1%	9	8
9	11	WGL	Yes	No	WGL	2.08	2.12	2.16	2.20	2.24	2.20	3.1%	11	9
		TOTAL PEERS	9 all	5							Staff Gas Screen	6.8%	Mean	
			6 w/o M&A	80% Mid Cap							Company Peer Screen	5.6%		
											Company Peer Screen - w/o M&A	6.6%		

NWN - Gas Peer EPS

	1	2	3	4	5	27	28	29	30	31	32	33	34	35	36	37	38	
						Value Line Estimated Near Future Earnings per Share in Blue									VL Avg	EPS Growth VL Avg		
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2018 Yr	2019 Yr	2020 Yr	2021 Yr	2022 Yr	2020- 22 / Yr	2020-22 vs. 2014-16	#	
1	1	Atmos	Yes	Yes	ATO	1.15	1.51	0.75	0.39	3.80	4.02	4.25	4.50	4.75	4.50	6.0%	1	1
2	2	Chesapeake	Yes	No	CPK	1.37	0.44	0.42	0.72	2.95	3.32	3.73	4.20	4.67	4.20	7.8%	2	2
3	3	New Jersey	Yes	No	NJR	0.51	1.25	0.24	(0.10)	1.90	1.95	2.00	2.05	2.10	2.05	2.0%	3	3
4	5	Northwest Natural	Yes	Yes	NWN	1.45	0.10	(0.25)	1.15	2.45	2.66	2.90	3.15	3.40	3.15	7.2%	5	4
5	6	ONE Gas	Yes	Yes	OGS	1.42	0.48	0.41	0.94	3.25	3.48	3.73	4.00	4.27	4.00	9.5%	6	5
6	7	South Jersey	Yes	No	SJI	0.78	0.10	0.03	0.54	1.45	1.61	1.80	2.00	2.20	2.00	5.5%	7	6
7	8	Southwest Gas	Yes	Yes	SWX	1.52	0.40	0.20	1.58	3.70	4.04	4.40	4.80	5.20	4.80	7.9%	8	7
8	9	Spire	Yes	Yes	SR	0.82	0.12	0.00	0.56	1.50	2.19	3.19	4.65	6.11	4.65	6.9%	9	8
9	11	WGL	Yes	No	WGL	1.25	1.95	0.40	(0.10)	3.50	3.48	3.47	3.45	3.43	3.45	2.1%	11	9
		TOTAL PEERS	9 all	5											Staff Gas Screen	7.5%	Mean	
			6 w/o M&A	80% Mid Cap											Company Peer Screen	6.1%		
															Company Peer Screen - w/o M&A	7.6%		

NWN GRC
UG 344 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22	
						Yahoo Finance									* Tax Cut and Jobs Act Impact						Hamada		
						$ Stock Closing Price			*3-Day*	*Div Yield*	*VL 2018*		VL 2018 Cap Structure			*		*Relevered*			*Adjustment*		
						1st Trading Day of Month			*Avg $*	*at*	*Return on*		% Long	%		2018	Hamada	*Beta*		Equity	*Equity*		
		Abbreviated	UG 344	UG 344		Dec.	Jan.	Feb.	*Stock*	*Recent*	*Common*		Term	Common	VL	21%	Unlevered	*Equity at*		Risk	*At*		
	#	Utility	Company	Staff	Ticker	12/31/2017	1/1/2018	2/1/2018	*Price*	*Price*	*Equity*		Debt	Equity	Beta	Tax Rate	Beta	*50.0%*		Premium	*50.0%*	#	
1	1	Atmos	Yes	Yes	ATO	85.89	82.90	81.05	83.28	2.2%	10.5%		44.0	56.0	0.70	21.0%	0.43	0.77		4.20%	0.31%	1	1
2	2	Chesapeake	Yes	No	CPK	78.55	73.50	68.00	73.35	1.7%	9.5%		30.0	70.0	0.70	21.0%	0.52	0.94		4.20%	0.99%	2	2
3	3	New Jersey	Yes	No	NJR	40.20	38.80	38.80	39.27	2.6%	12.5%		45.5	54.5	0.80	21.0%	0.48	0.86		4.20%	0.26%	3	3
4	5	Northwest Natural	Yes	Yes	NWN	59.65	57.35	53.45	56.82	3.3%	8.0%		45.0	55.0	0.70	21.0%	0.43	0.76		4.20%	0.26%	4	4
5	6	ONE Gas	Yes	Yes	OGS	73.26	70.83	64.56	69.55	2.4%	8.5%		38.0	62.0	0.70	21.0%	0.47	0.84		4.20%	0.61%	5	5
6	7	South Jersey	Yes	No	SJI	31.23	29.44	26.65	29.11	3.8%	8.5%		47.5	52.5	0.85	21.0%	0.50	0.89		4.20%	0.16%	6	6
7	8	Southwest Gas	Yes	Yes	SWX	80.48	73.58	68.20	74.09	2.6%	9.5%		48.0	52.0	0.80	21.0%	0.46	0.83		4.20%	0.12%	7	7
8	9	Spire	Yes	Yes	SR	75.15	66.50	68.65	70.10	3.0%	8.5%		49.5	50.5	0.70	21.0%	0.39	0.71		4.20%	0.03%	8	8
9	11	WGL	Yes	No	WGL	85.84	84.22	83.01	84.36	2.4%	11.0%		46.0	54.0	0.80	21.0%	0.48	0.86		4.20%	0.24%	9	9
		TOTAL PEERS	9 all	5																Staff Gas Screen	0.26%	Mean	
			6 w/o M&A	80% Mid Cap																Company Peer Screen	0.33%		
																				Company Peer Screen - w/o M&A	0.38%		

Dividend Yield = (Annual Dividends per Share) / Price per Share

When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, VI shows "NMF" for 'no meaningful figure'.

* Difference	Increase of:
Staff Gas Screen	0.03%
Company Peer Screen	0.05%
Company Peer Screen - w/o M&A	0.06%

NWN GRC
UG 344 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22	
						Yahoo Finance $ Stock Closing Price 1st Trading Day of Month							VL 2018 Cap Structure										
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	Dec. 12/31/2017	Jan. 1/1/2018	Feb. 2/1/2018	*3-Day Avg $ Stock Price*	*Div Yield at Recent Price*	*VL 2018 Return on Common Equity*		% Long Term Debt	% Common Equity	VL Beta	2018 VL Tax Rate	Hamada Unlevered Beta	*Relevered Beta Equity at 50.0%*		Equity Risk Premium	*Hamada Adjustment Equity At 50.0%*	#	
1	1	Atmos	Yes	Yes	ATO	85.89	82.90	81.05	83.28	2.2%	10.5%		44.0	56.0	0.70	37.0%	0.47	0.76		4.20%	0.27%	1	1
2	2	Chesapeake	Yes	No	CPK	78.55	73.50	68.00	73.35	1.7%	9.5%		30.0	70.0	0.70	40.0%	0.56	0.89		4.20%	0.80%	2	2
3	3	New Jersey	Yes	No	NJR	40.20	38.80	38.80	39.27	2.6%	12.5%		45.5	54.5	0.80	32.0%	0.51	0.86		4.20%	0.24%	3	3
4	5	Northwest Natural	Yes	Yes	NWN	59.65	57.35	53.45	56.82	3.3%	8.0%		45.0	55.0	0.70	35.0%	0.46	0.75		4.20%	0.23%	4	4
5	6	ONE Gas	Yes	Yes	OGS	73.26	70.83	64.56	69.55	2.4%	8.5%		38.0	62.0	0.70	36.0%	0.50	0.82		4.20%	0.52%	5	5
6	7	South Jersey	Yes	No	SJI	31.23	29.44	26.65	29.11	3.8%	8.5%		47.5	52.5	0.85	25.0%	0.51	0.89		4.20%	0.15%	6	6
7	8	Southwest Gas	Yes	Yes	SWX	80.48	73.58	68.20	74.09	2.6%	9.5%		48.0	52.0	0.80	35.0%	0.50	0.83		4.20%	0.11%	7	7
8	9	Spire	Yes	Yes	SR	75.15	66.50	68.65	70.10	3.0%	8.5%		49.5	50.5	0.70	23.5%	0.40	0.71		4.20%	0.03%	8	8
9	11	WGL	Yes	No	WGL	85.84	84.22	83.01	84.36	2.4%	11.0%		46.0	54.0	0.80	39.0%	0.53	0.85		4.20%	0.20%	9	9
		TOTAL PEERS	9 all	5														Staff Gas Screen			0.23%	Mean	
			6 w/o M&A	80% Mid Cap														Company Peer Screen			0.28%		
																		Company Peer Screen - w/o M&A			0.32%		

Dividend Yield = (Annual Dividends per Share) / Price per Share

When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, Vl shows "NMF" for 'no meaningful figure'.

CASE: UG 344
WITNESS: MATT MULDOON-JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Staff Three-Stage DCF Modeling

Exhibits in Support
of Opening Testimony

April 20, 2018

UG 344 Staff ROE Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate
Energy Information Administration	2.00%	1.99%	4.03%	12.50%	0.50%
PricewaterhouseCooper	1.80%	1.99%	3.83%	12.50%	0.48%
Social Security Administration	2.20%	1.99%	4.23%	12.50%	0.53%
Congressional Budget Office			4.00%	12.50%	0.50%
BEA Nominal Historical,1980 Q1 – 2017 Q4	2.76%	1.99%	4.80%	50.0%	2.40%
Composite				100%	4.41%
Congressional Budget Office Long-Term 20-Year Budget Outlook			4.00%	100.0%	4.00%
BEA Nominal Historical,1980 Q1 – 2017 Q4	2.76%	1.99%	4.80%	50.0%	2.40%
Social Security Administration	2.20%	1.99%	4.23%	50.0%	2.12%
Near Historical				100%	4.52%

Note: Near Historical assumes that various federal initiatives will have greater long-run positive impact than the Congressional Budget Office expects.

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity

	X	CBO	4.00%	Composite	4.41%	Near Historical	4.52%
1	Staff Gas Screen	7.43%		7.74%		7.83%	
2	Company Peer Screen	7.11%		7.44%		7.52%	
3	Company Peer Screen - w/o M&A	7.20%		7.52%		7.61%	

Hamada to Right →

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)

X	CBO	4.00%	Composite	4.41%	Near Historical	4.52%	
Staff Gas Screen	7.69%		8.00%		8.09%		1
Company Peer Screen	7.44%		7.77%		7.85%		2
Company Peer Screen - w/o M&A	7.58%		7.90%		7.99%		3

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale

	Y	CBO	4.00%	Composite	4.41%	Near Historical	4.52%
1	Staff Gas Screen	8.61%		8.87%		8.94%	
2	Company Peer Screen	7.87%		8.14%		8.21%	
3	Company Peer Screen - w/o M&A	8.39%		8.66%		8.73%	

Hamada to Right →

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)

Y	CBO	4.00%	Composite	4.41%	Near Historical	4.52%	
Staff Gas Screen	8.87%		9.13%		9.20%		1
Company Peer Screen	8.20%		8.47%		8.54%		2
Company Peer Screen - w/o M&A	8.77%		9.04%		9.11%		3

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by : 12.5 bps

Range of Modeled Results 8.22% to 9.33% ROE

Best Fit Range of Reasonable ROEs 8.7% to 9.3% ROE

(Best fit is Staff's Hamada adjusted screened gas utilities that have most similar characteristics to NWN regulated gas operations in Oregon)

Midpoint of Best Fit Modeling Results 9.0% ROE

(Staff's informed judgement excludes some of the lower range of modeling results depicted above)

Staff Point ROE Recommendation: 9.0% ROE

4.52% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows Staff UG 344 Model X

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									Initial Stage					Transition Stage				
1	1	Atmos	Yes	Yes	7.1%	49.6%	0.00	(83.28)	1.94	2.05	2.17	2.30	2.43	2.58	2.75	2.92	3.10	3.29
2	2	Chesapeake	Yes	No	6.5%	59.0%	0.00	(73.35)	1.33	1.40	1.47	1.55	1.63	1.72	1.82	1.92	2.03	2.14
3	3	New Jersey	Yes	No	6.8%	52.0%	(0.00)	(39.27)	1.09	1.10	1.11	1.12	1.13	1.17	1.21	1.25	1.29	1.33
4	5	Northwest Natural	Yes	Yes	7.2%	46.7%	0.00	(56.82)	1.89	1.93	1.96	2.00	2.04	2.06	2.09	2.12	2.14	2.17
5	6	ONE Gas	Yes	Yes	8.8%	34.0%	0.00	(69.55)	1.88	2.05	2.24	2.45	2.66	3.02	3.43	3.88	4.37	4.91
6	7	South Jersey	Yes	No	8.4%	34.7%	0.00	(29.11)	1.15	1.20	1.25	1.30	1.35	1.41	1.47	1.54	1.60	1.67
7	8	Southwest Gas	Yes	Yes	7.9%	41.0%	0.00	(74.09)	2.08	2.21	2.35	2.50	2.65	2.86	3.09	3.33	3.59	3.87
8	9	Spire	Yes	Yes	7.7%	42.0%	0.00	(70.10)	2.25	2.33	2.41	2.50	2.59	2.72	2.87	3.01	3.17	3.33
9	11	WGL	Yes	No	6.6%	55.1%	(0.00)	(84.36)	2.08	2.12	2.16	2.20	2.24	2.31	2.39	2.46	2.54	2.62
		TOTAL PEERS	9 all	5	Mean													
			6 w/o M&A	80% Mid Cap	7.56%	42.65%	0.00	Staff Gas Screen										
					7.45%	46.01%	(0.00)	Company Peer Screen										
					7.54%	45.37%	0.00	Company Peer Screen - w/o M&A										

#	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2046 Terminal Value	2047 Div	2047 Perpetuity	#	
	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	
	Final Stage																							
1	3.44	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.35	5.60	5.85	6.11	6.39	6.68	6.98	7.29	7.62	326.48	7.97	318.51	1	1
2	2.24	2.34	2.45	2.56	2.67	2.79	2.92	3.05	3.19	3.33	3.48	3.64	3.81	3.98	4.16	4.34	4.54	4.75	4.96	283.51	5.19	278.32	2	2
3	1.40	1.46	1.52	1.59	1.66	1.74	1.82	1.90	1.99	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	148.76	3.23	145.53	3	3
5	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.85	4.03	4.21	4.40	4.60	4.81	5.02	212.08	5.25	206.82	5	4
6	5.13	5.37	5.61	5.86	6.13	6.40	6.69	7.00	7.31	7.64	7.99	8.35	8.73	9.12	9.53	9.96	10.41	10.88	11.38	299.97	11.89	288.08	6	5
7	1.74	1.82	1.91	1.99	2.08	2.18	2.27	2.38	2.48	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	113.27	4.04	109.23	7	6
8	4.04	4.22	4.42	4.62	4.82	5.04	5.27	5.51	5.76	6.02	6.29	6.57	6.87	7.18	7.51	7.85	8.20	8.57	8.96	297.97	9.36	288.60	8	7
9	3.48	3.64	3.80	3.97	4.15	4.34	4.54	4.74	4.96	5.18	5.42	5.66	5.92	6.18	6.46	6.76	7.06	7.38	7.71	272.95	8.06	264.88	9	8
11	2.74	2.86	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.66	4.87	5.09	5.32	5.56	5.81	6.07	319.63	6.34	313.29	11	9

B.O.Y. Cash Flows Staff UG 344 Model X

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									Initial Stage					Transition Stage				
1	1	Atmos	Yes	Yes	7.3%	47.8%	0.00	(83.28)	2.05	2.17	2.30	2.43	2.58	2.75	2.92	3.10	3.29	3.44
2	2	Chesapeake	Yes	No	6.6%	57.5%	(0.00)	(73.35)	1.40	1.47	1.55	1.63	1.72	1.82	1.92	2.03	2.14	2.24
3	3	New Jersey	Yes	No	6.9%	50.9%	(0.00)	(39.27)	1.10	1.11	1.12	1.13	1.17	1.21	1.25	1.29	1.33	1.40
4	5	Northwest Natural	Yes	Yes	7.3%	45.6%	0.00	(56.82)	1.93	1.96	2.00	2.04	2.06	2.09	2.12	2.14	2.17	2.27
5	6	ONE Gas	Yes	Yes	9.1%	31.5%	0.00	(69.55)	2.05	2.24	2.45	2.66	3.02	3.43	3.88	4.37	4.91	5.13
6	7	South Jersey	Yes	No	8.6%	33.2%	0.00	(29.11)	1.20	1.25	1.30	1.35	1.41	1.47	1.54	1.60	1.67	1.74
7	8	Southwest Gas	Yes	Yes	8.1%	39.0%	0.00	(74.09)	2.21	2.35	2.50	2.65	2.86	3.09	3.33	3.59	3.87	4.04
8	9	Spire	Yes	Yes	7.8%	40.5%	0.00	(70.10)	2.33	2.41	2.50	2.59	2.72	2.87	3.01	3.17	3.33	3.48
9	11	WGL	Yes	No	6.7%	54.0%	0.00	(84.36)	2.12	2.16	2.20	2.24	2.31	2.39	2.46	2.54	2.62	2.74
		TOTAL PEERS	9 all	5	Mean													
			6 w/o M&A	80% Mid Cap	7.91%	40.88%	0.00	Staff Gas Screen										
					7.59%	44.43%	(0.00)	Company Peer Screen										
					7.68%	43.65%	(0.00)	Company Peer Screen - w/o M&A										

#	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2046 Terminal Value	2047 Div	2047 Perpetuity	#	
	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	
	Final Stage																							
1	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.35	5.60	5.85	6.11	6.39	6.68	6.98	7.29	7.62	7.97	326.14	8.33	317.81	1	1
2	2.34	2.45	2.56	2.67	2.79	2.92	3.05	3.19	3.33	3.48	3.64	3.81	3.98	4.16	4.34	4.54	4.75	4.96	5.19	283.44	5.42	278.02	2	2
3	1.46	1.52	1.59	1.66	1.74	1.82	1.90	1.99	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	149.47	3.38	146.09	3	3
5	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.85	4.03	4.21	4.40	4.60	4.81	5.02	5.25	213.45	5.49	207.96	5	4
6	5.37	5.61	5.86	6.13	6.40	6.69	7.00	7.31	7.64	7.99	8.35	8.73	9.12	9.53	9.96	10.41	10.88	11.38	11.89	297.29	12.43	284.86	6	5
7	1.82	1.91	1.99	2.08	2.18	2.27	2.38	2.48	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	4.04	113.53	4.22	109.30	7	6
8	4.22	4.42	4.62	4.82	5.04	5.27	5.51	5.76	6.02	6.29	6.57	6.87	7.18	7.51	7.85	8.20	8.57	8.96	9.36	297.15	9.79	287.36	8	7
9	3.64	3.80	3.97	4.15	4.34	4.54	4.74	4.96	5.18	5.42	5.66	5.92	6.18	6.46	6.76	7.06	7.38	7.71	8.06	273.42	8.43	264.99	9	8
11	2.86	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.66	4.87	5.09	5.32	5.56	5.81	6.07	6.34	320.85	6.63	314.22	11	9

Average B.O.Y. & E.O.Y. Cash Flows Model X

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2016 - 2020 Dividend Growth Rates EOY	BOY	Average	#	
	1	2	3	4	5	6	7	8	9		
1	1	Atmos	Yes	Yes	7.2%	48.7%	5.8%	5.9%	5.8%	1	1
2	2	Chesapeake	Yes	No	6.5%	58.2%	5.2%	5.3%	5.2%	2	2
3	3	New Jersey	Yes	No	6.9%	51.5%	0.9%	1.5%	1.2%	3	3
4	5	Northwest Natural	Yes	Yes	7.2%	46.2%	1.9%	1.7%	1.8%	5	4
5	6	ONE Gas	Yes	Yes	9.0%	32.8%	9.0%	10.1%	9.6%	6	5
6	7	South Jersey	Yes	No	8.5%	33.9%	4.1%	4.2%	4.2%	7	6
7	8	Southwest Gas	Yes	Yes	8.0%	40.0%	6.2%	6.7%	6.4%	8	7
8	9	Spire	Yes	Yes	7.8%	41.2%	3.5%	4.0%	3.8%	9	8
9	11	WGL	Yes	No	6.7%	54.5%	1.9%	2.2%	2.0%	11	9
		TOTAL PEERS	9 all	5	Mean						
			6 w/o M&A	80% Mid Cap	7.83%	41.77%	5.5%	Staff Gas Screen			
					7.52%	45.22%	4.5%	Company Peer Screen			
					7.61%	44.51%	5.4%	Company Peer Screen - w/o M&A			

4.52% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal V EPS Growth

E.O.Y. Cash Flows

Staff UG 344 Model Y

	1	2	3	4	5	6	7	8	9	10	11	12	13
	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2018	2019	2020	2021	2022
									Initial Stage				
1	1	Atmos	Yes	Yes	7.4%	51.2%	0.00	(83.28)	1.94	2.05	2.17	2.30	2.43
				e					3.80	4.02	4.25	4.50	4.75
2	2	Chesapeake	Yes	No	7.6%	64.6%	0.00	(73.35)	1.33	1.40	1.47	1.55	1.63
				e					2.95	3.32	3.73	4.20	4.67
3	3	New Jersey	Yes	No	6.4%	49.4%	0.00	(39.27)	1.09	1.10	1.11	1.12	1.13
				e					1.90	1.95	2.00	2.05	2.10
4	5	Northwest Natural	Yes	Yes	7.9%	51.2%	0.00	(56.82)	1.89	1.93	1.96	2.00	2.04
				e					2.45	2.66	2.90	3.15	3.40
5	6	ONE Gas	Yes	Yes	9.3%	37.5%	0.00	(69.55)	1.88	2.05	2.24	2.45	2.66
				e					3.25	3.48	3.73	4.00	4.27
6	7	South Jersey	Yes	No	9.0%	39.0%	0.00	(29.11)	1.15	1.20	1.25	1.30	1.35
				e					1.45	1.61	1.80	2.00	2.20
7	8	Southwest Gas	Yes	Yes	8.6%	45.4%	0.00	(74.09)	2.08	2.21	2.35	2.50	2.65
				e					3.70	4.04	4.40	4.80	5.20
8	9	Spire	Yes	Yes	11.2%	60.4%	0.00	(70.10)	2.25	2.33	2.41	2.50	2.59
				e					1.50	2.19	3.19	4.65	6.11
9	11	WGL	Yes	No	5.9%	50.8%	0.00	(84.36)	2.08	2.12	2.16	2.20	2.24
				e					3.50	3.48	3.47	3.45	3.43

Abbreviated Utility	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Transition Stage					Final Stage								
Atmos	2.58	2.75	2.92	3.10	3.29	3.44	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90
	5.04	5.35	5.68	6.02	6.38	6.67	6.97	7.28	7.61	7.96	8.32	8.69	9.08	9.49
Chesapeake	1.72	1.82	1.92	2.03	2.14	2.24	2.34	2.45	2.56	2.67	2.79	2.92	3.05	3.19
	5.04	5.44	5.87	6.32	6.80	7.11	7.43	7.76	8.11	8.48	8.86	9.26	9.68	10.12
New Jersey	1.17	1.21	1.25	1.29	1.33	1.40	1.46	1.52	1.59	1.66	1.74	1.82	1.90	1.99
	2.15	2.19	2.23	2.28	2.33	2.43	2.54	2.66	2.78	2.90	3.03	3.17	3.32	3.47
Northwest Natural	2.06	2.09	2.12	2.14	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23
	3.66	3.92	4.21	4.50	4.82	5.04	5.27	5.50	5.75	6.01	6.28	6.57	6.87	7.18
ONE Gas	3.02	3.43	3.88	4.37	4.91	5.13	5.37	5.61	5.86	6.13	6.40	6.69	7.00	7.31
	4.68	5.13	5.62	6.13	6.69	6.99	7.31	7.64	7.98	8.35	8.72	9.12	9.53	9.96
South Jersey	1.41	1.47	1.54	1.60	1.67	1.74	1.82	1.91	1.99	2.08	2.18	2.27	2.38	2.48
	2.33	2.46	2.59	2.74	2.88	3.01	3.15	3.29	3.44	3.60	3.76	3.93	4.11	4.29
Southwest Gas	2.86	3.09	3.33	3.59	3.87	4.04	4.22	4.42	4.62	4.82	5.04	5.27	5.51	5.76
	5.62	6.08	6.56	7.07	7.62	7.96	8.32	8.70	9.09	9.50	9.93	10.38	10.85	11.34
Spire	2.72	2.87	3.01	3.17	3.33	3.48	3.64	3.80	3.97	4.15	4.34	4.54	4.74	4.96
	6.55	7.01	7.49	8.01	8.55	8.93	9.34	9.76	10.20	10.66	11.15	11.65	12.18	12.73
WGL	2.31	2.39	2.46	2.54	2.62	2.74	2.86	2.99	3.13	3.27	3.42	3.57	3.73	3.90
	3.51	3.59	3.66	3.74	3.82	4.00	4.18	4.37	4.56	4.77	4.99	5.21	5.45	5.69

Abbreviated Utility	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2046 Terminal Value	2047 Div	2047 Sale	2048	#	
	Final Stage															
Atmos	5.12	5.35	5.60	5.85	6.11	6.39	6.68	6.98	7.29	7.62	361.68	7.97	353.71		1	1
	9.92	10.37	10.84	11.33	11.84	12.38	12.94	13.52	14.13	14.77		15.44		16.14		
Chesapeake	3.33	3.48	3.64	3.81	3.98	4.16	4.34	4.54	4.75	4.96	432.89	5.19	427.70		2	2
	10.58	11.06	11.55	12.08	12.62	13.19	13.79	14.41	15.06	15.75		16.46		17.20		
New Jersey	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	124.96	3.23	121.73		3	3
	3.62	3.79	3.96	4.14	4.32	4.52	4.72	4.94	5.16	5.39		5.64		5.89		
Northwest Natural	3.38	3.53	3.69	3.85	4.03	4.21	4.40	4.60	4.81	5.02	288.10	5.25	282.85		5	4
	7.50	7.84	8.19	8.56	8.95	9.36	9.78	10.22	10.68	11.16		11.67		12.20		
ONE Gas	7.64	7.99	8.35	8.73	9.12	9.53	9.96	10.41	10.88	11.38	374.17	11.89	362.28		6	5
	10.41	10.88	11.37	11.89	12.42	12.98	13.57	14.19	14.83	15.50		16.20		16.93		
South Jersey	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	150.54	4.04	146.50		7	6
	4.49	4.69	4.90	5.12	5.36	5.60	5.85	6.12	6.39	6.68		6.98		7.30		
Southwest Gas	6.02	6.29	6.57	6.87	7.18	7.51	7.85	8.20	8.57	8.96	395.29	9.36	385.93		8	7
	11.85	12.39	12.95	13.53	14.14	14.78	15.45	16.15	16.88	17.64		18.44		19.27		
Spire	5.18	5.42	5.66	5.92	6.18	6.46	6.76	7.06	7.38	7.71	1,018.97	8.06	1,010.90		9	8
	13.30	13.90	14.53	15.19	15.87	16.59	17.34	18.13	18.94	19.80		20.70		21.63		
WGL	4.08	4.26	4.45	4.66	4.87	5.09	5.32	5.56	5.81	6.07	239.58	6.34	233.24		11	9
	5.95	6.22	6.50	6.79	7.10	7.42	7.76	8.11	8.48	8.86		9.26		9.68		

TOTAL PEERS	9 all	5	Mean			
	6 w/o M&A	10% Mid Ca	8.87%	50.06%	0.00	Staff Gas Screen
			8.15%	49.94%	0.00	Company Peer Screen
			8.67%	51.72%	0.00	Company Peer Screen - w/o M&A

B.O.Y. Cash Flows Staff Model Y EPS Growth

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
									Initial Stage					Transition Stage				
1	1	Atmos	Yes	Yes	7.5%	49.5%	0.00	(83.28)	2.05	2.17	2.30	2.43	2.58	2.75	2.92	3.10	3.29	3.44
				e					3.80	4.02	4.25	4.50	4.75	5.04	5.35	5.68	6.02	6.38
2	2	Chesapeake	Yes	No	7.7%	63.3%	0.00	(73.35)	1.40	1.47	1.55	1.63	1.72	1.82	1.92	2.03	2.14	2.24
				e					2.95	3.32	3.73	4.20	4.67	5.04	5.44	5.87	6.32	6.80
3	3	New Jersey	Yes	No	6.5%	48.1%	0.00	(39.27)	1.10	1.11	1.12	1.13	1.17	1.21	1.25	1.29	1.33	1.40
				e					1.90	1.95	2.00	2.05	2.10	2.15	2.19	2.23	2.28	2.33
4	5	Northwest Natural	Yes	Yes	8.0%	50.1%	(0.00)	(56.82)	1.93	1.96	2.00	2.04	2.06	2.09	2.12	2.14	2.17	2.27
				e					2.45	2.66	2.90	3.15	3.40	3.66	3.92	4.21	4.50	4.82
5	6	ONE Gas	Yes	Yes	9.5%	35.1%	0.00	(69.55)	2.05	2.24	2.45	2.66	3.02	3.43	3.88	4.37	4.91	5.13
				e					3.25	3.48	3.73	4.00	4.27	4.68	5.13	5.62	6.13	6.69
6	7	South Jersey	Yes	No	9.1%	37.4%	0.00	(29.11)	1.20	1.25	1.30	1.35	1.41	1.47	1.54	1.60	1.67	1.74
				e					1.45	1.61	1.80	2.00	2.20	2.33	2.46	2.59	2.74	2.88
7	8	Southwest Gas	Yes	Yes	8.7%	43.5%	0.00	(74.09)	2.21	2.35	2.50	2.65	2.86	3.09	3.33	3.59	3.87	4.04
				e					3.70	4.04	4.40	4.80	5.20	5.62	6.08	6.56	7.07	7.62
8	9	Spire	Yes	Yes	11.3%	59.0%	0.00	(70.10)	2.33	2.41	2.50	2.59	2.72	2.87	3.01	3.17	3.33	3.48
				e					1.50	2.19	3.19	4.65	6.11	6.55	7.01	7.49	8.01	8.55
9	11	WGL	Yes	No	6.0%	49.5%	0.00	(84.36)	2.12	2.16	2.20	2.24	2.31	2.39	2.46	2.54	2.62	2.74
				e					3.50	3.48	3.47	3.45	3.43	3.51	3.59	3.66	3.74	3.82

Abbreviated Utility	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2046 Terminal Value	2047 Div	2047 Sale	2048	#	
	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
	Final Stage																								
Atmos	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.35	5.60	5.85	6.11	6.39	6.68	6.98	7.29	7.62	7.97	362.04	8.33	353.71		1	1
	6.67	6.97	7.28	7.61	7.96	8.32	8.69	9.08	9.49	9.92	10.37	10.84	11.33	11.84	12.38	12.94	13.52	14.13	14.77		15.44		16.14		
Chesapeake	2.34	2.45	2.56	2.67	2.79	2.92	3.05	3.19	3.33	3.48	3.64	3.81	3.98	4.16	4.34	4.54	4.75	4.96	5.19	433.12	5.42	427.70		2	2
	7.11	7.43	7.76	8.11	8.48	8.86	9.26	9.68	10.12	10.58	11.06	11.55	12.08	12.62	13.19	13.79	14.41	15.06	15.75		16.46		17.20		
New Jersey	1.46	1.52	1.59	1.66	1.74	1.82	1.90	1.99	2.08	2.17	2.27	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	125.11	3.38	121.73		3	3
	2.43	2.54	2.66	2.78	2.90	3.03	3.17	3.32	3.47	3.62	3.79	3.96	4.14	4.32	4.52	4.72	4.94	5.16	5.39		5.64		5.89		
Northwest Natural	2.37	2.48	2.59	2.71	2.83	2.96	3.09	3.23	3.38	3.53	3.69	3.85	4.03	4.21	4.40	4.60	4.81	5.02	5.25	288.34	5.49	282.85		5	4
	5.04	5.27	5.50	5.75	6.01	6.28	6.57	6.87	7.18	7.50	7.84	8.19	8.56	8.95	9.36	9.78	10.22	10.68	11.16		11.67		12.20		
ONE Gas	5.37	5.61	5.86	6.13	6.40	6.69	7.00	7.31	7.64	7.99	8.35	8.73	9.12	9.53	9.96	10.41	10.88	11.38	11.89	374.71	12.43	362.28		6	5
	6.99	7.31	7.64	7.98	8.35	8.72	9.12	9.53	9.96	10.41	10.88	11.37	11.89	12.42	12.98	13.57	14.19	14.83	15.50		16.20		16.93		
South Jersey	1.82	1.91	1.99	2.08	2.18	2.27	2.38	2.48	2.60	2.71	2.84	2.97	3.10	3.24	3.39	3.54	3.70	3.87	4.04	150.73	4.22	146.50		7	6
	3.01	3.15	3.29	3.44	3.60	3.76	3.93	4.11	4.29	4.49	4.69	4.90	5.12	5.36	5.60	5.85	6.12	6.39	6.68		6.98		7.30		
Southwest Gas	4.22	4.42	4.62	4.82	5.04	5.27	5.51	5.76	6.02	6.29	6.57	6.87	7.18	7.51	7.85	8.20	8.57	8.96	9.36	395.71	9.79	385.93		8	7
	7.96	8.32	8.70	9.09	9.50	9.93	10.38	10.85	11.34	11.85	12.39	12.95	13.53	14.14	14.78	15.45	16.15	16.88	17.64		18.44		19.27		
Spire	3.64	3.80	3.97	4.15	4.34	4.54	4.74	4.96	5.18	5.42	5.66	5.92	6.18	6.46	6.76	7.06	7.38	7.71	8.06	1,019.33	8.43	1,010.90		9	8
	8.93	9.34	9.76	10.20	10.66	11.15	11.65	12.18	12.73	13.30	13.90	14.53	15.19	15.87	16.59	17.34	18.13	18.94	19.80		20.70		21.63		
WGL	2.86	2.99	3.13	3.27	3.42	3.57	3.73	3.90	4.08	4.26	4.45	4.66	4.87	5.09	5.32	5.56	5.81	6.07	6.34	239.87	6.63	233.24		11	9
	4.00	4.18	4.37	4.56	4.77	4.99	5.21	5.45	5.69	5.95	6.22	6.50	6.79	7.10	7.42	7.76	8.11	8.48	8.86		9.26		9.68		

TOTAL PEERS	9 all	5	Mean			
	6 w/o M&A	10% Mid Ca	9.01%	47.42%	0.00	Staff Gas Screen
			8.27%	48.38%	0.00	Company Peer Screen
			8.80%	50.06%	0.00	Company Peer Screen - w/o M&A

Average B.O.Y. & E.O.Y. Cash Flows Model Y EPS Growth

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2018 - 2022 Dividend Growth Rates EOY	BOY	Average	#	
	1	2	3	4	5	6	7	8	9	10	
1	1	Atmos	Yes	Yes	7.5%	50.3%	5.8%	5.9%	5.8%	1	1
2	2	Chesapeake	Yes	No	7.7%	64.0%	5.2%	5.3%	5.2%	2	2
3	3	New Jersey	Yes	No	6.5%	48.8%	0.9%	1.5%	1.2%	3	3
4	5	Northwest Natural	Yes	Yes	8.0%	50.7%	1.9%	1.7%	1.8%	5	4
5	6	ONE Gas	Yes	Yes	9.4%	36.3%	9.0%	10.1%	9.6%	6	5
6	7	South Jersey	Yes	No	9.1%	38.2%	4.1%	4.2%	4.2%	7	6
7	8	Southwest Gas	Yes	Yes	8.6%	44.4%	6.2%	6.7%	6.4%	8	7
8	9	Spire	Yes	Yes	11.2%	59.7%	3.5%	4.0%	3.8%	9	8
9	11	WGL	Yes	No	6.0%	50.1%	1.9%	2.2%	2.0%	11	9

TOTAL PEERS	9 all	5	Mean			
	6 w/o M&A	10% Mid Ca	8.94%	40.23%	5.45%	Staff Gas Screen
			8.21%	49.16%	4.46%	Company Peer Screen
			8.73%	50.89%	5.45%	Company Peer Screen - w/o M&A

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
of Opening Testimony

April 20, 2018

2028 through 2047 TIPs-Implied Average Annual Inflation Rate: **1.99%**

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied Forward Curve/Price Level 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied Price Level	Check
Dec-17	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-18	1	101.75	101.81	101.87	101.89	101.95	101.75					101.75	
Dec-19	2	103.52	103.65	103.77	103.82	103.93	103.52					103.52	
Dec-20	3	105.33	105.52	105.72	105.79	105.95	105.33					105.33	
Dec-21	4	107.17	107.42	107.69	107.79	108.02	107.17					107.17	
Dec-22	5	109.04	109.37	109.71	109.83	110.12	109.04					109.04	
Dec-23	6		111.34	111.76	111.91	112.26		111.18				111.18	
Dec-24	7		113.35	113.85	114.03	114.45		113.35				113.35	
Dec-25	8			115.98	116.19	116.68			115.64			115.64	
Dec-26	9			118.15	118.39	118.95			117.97			117.97	
Dec-27	10			120.35	120.63	121.26			120.35			120.35	
Dec-28	11				122.91	123.62				122.66		122.66	122.74
Dec-29	12				125.24	126.03				125.01		125.01	125.18
Dec-30	13				127.61	128.48				127.41		127.41	127.67
Dec-31	14				130.03	130.99				129.85		129.85	130.20
Dec-32	15				132.49	133.54				132.34		132.34	132.78
Dec-33	16				135.00	136.13				134.88		134.88	135.42
Dec-34	17				137.56	138.78				137.46		137.46	138.11
Dec-35	18				140.16	141.49				140.10		140.10	140.85
Dec-36	19				142.81	144.24				142.78		142.78	143.65
Dec-37	20				145.52	147.05				145.52		145.52	146.50
Dec-38	21					149.91					148.51	148.51	149.40
Dec-39	22					152.83					151.56	151.56	152.37
Dec-40	23					155.80					154.67	154.67	155.39
Dec-41	24					158.84					157.84	157.84	158.48
Dec-42	25					161.93					161.08	161.08	161.63
Dec-43	26					165.08					164.39	164.39	164.83
Dec-44	27					168.30					167.77	167.77	168.11
Dec-45	28					171.57					171.21	171.21	171.44
Dec-46	29					174.91					174.73	174.73	174.85
Dec-47	30					178.32					178.32	178.32	178.32

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis   Quarterly Aggregation

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	-1.08	-0.75	-0.35	0.35	0.66
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	-1.42	-1.15	-0.76	-0.02	0.36
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	-1.04	-0.62	-0.25	0.47	0.80
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	-0.29	0.25	0.57	1.19	1.50
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	-0.25	0.27	0.43	0.88	1.14
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	0.19	0.39	0.45	0.75	0.95
2015-Q1	0.11	0.23	0.27	0.52	0.71
2015-Q2	-0.10	0.22	0.30	0.67	0.91
2015-Q3	0.26	0.48	0.57	0.92	1.14
2015-Q4	0.36	0.51	0.66	1.02	1.24
2016-Q1	0.15	0.32	0.49	0.88	1.11
2016-Q2	-0.24	-0.05	0.19	0.62	0.85
2016-Q3	-0.22	-0.09	0.08	0.44	0.62
2016-Q4	-0.06	0.12	0.33	0.69	0.86
2017-Q1	0.07	0.33	0.44	0.75	0.95
2017-Q2	0.10	0.30	0.44	0.76	0.94
2017-Q3	0.17	0.36	0.45	0.75	0.94
2017-Q4	0.32	0.44	0.50	0.72	0.87

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	0.79	1.24	1.82	2.55	2.94
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	0.69	1.12	1.71	2.46	2.86
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	0.92	1.39	2.00	2.78	3.15
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	1.44	2.12	2.75	3.50	3.79
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	1.66	2.19	2.62	3.18	2.87
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	1.60	2.00	2.28	2.69	2.97
2015-Q1	1.45	1.77	1.97	2.32	2.55
2015-Q2	1.52	1.91	2.17	2.62	2.89
2015-Q3	1.55	1.94	2.22	2.65	2.96
2015-Q4	1.59	1.94	2.19	2.60	2.96
2016-Q1	1.37	1.69	1.92	2.32	2.72
2016-Q2	1.24	1.54	1.75	2.15	2.57
2016-Q3	1.13	1.40	1.56	1.91	2.28
2016-Q4	1.61	1.93	2.13	2.52	2.82
2017-Q1	1.94	2.25	2.44	2.78	3.04
2017-Q2	1.81	2.07	2.26	2.64	2.90
2017-Q3	1.82	2.06	2.24	2.58	2.82
2017-Q4	2.07	2.25	2.37	2.62	2.82

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	1.86	1.99	2.17	2.21	2.28
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	2.11	2.27	2.47	2.48	2.50
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	1.95	2.01	2.25	2.32	2.34
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	1.73	1.86	2.17	2.31	2.29
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	1.90	1.92	2.20	2.30	1.73
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	1.41	1.61	1.83	1.95	2.02
2015-Q1	1.35	1.54	1.70	1.79	1.85
2015-Q2	1.63	1.69	1.86	1.95	1.97
2015-Q3	1.29	1.47	1.65	1.73	1.82
2015-Q4	1.23	1.43	1.53	1.58	1.72
2016-Q1	1.23	1.37	1.43	1.45	1.61
2016-Q2	1.48	1.58	1.56	1.53	1.72
2016-Q3	1.35	1.49	1.48	1.47	1.66
2016-Q4	1.67	1.80	1.80	1.83	1.96
2017-Q1	1.87	1.92	2.01	2.03	2.10
2017-Q2	1.71	1.78	1.82	1.88	1.96
2017-Q3	1.65	1.70	1.79	1.83	1.88
2017-Q4	1.75	1.81	1.87	1.89	1.95

FRB H.15 Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

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https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Monthly					Monthly				
TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.M	UST-05m	5	Year	H.15 ID	RIFLGFCY05_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M	UST-07m	7			RIFLGFCY07_N.M
TIPS-10m	10				RIFLGFCY10_XII_N.M	UST-10m	10			RIFLGFCY10_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M	UST-20m	20			RIFLGFCY20_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M	UST-30m	30			RIFLGFCY30_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**
2015-01	0.17	0.24	0.27	0.50	0.66
2015-02	0.11	0.22	0.26	0.52	0.73
2015-03	0.04	0.23	0.28	0.55	0.73
2015-04	**-0.26**	**-0.01**	**0.08**	**0.42**	**0.65**
2015-05	**-0.10**	**0.27**	**0.33**	**0.70**	**0.96**
2015-06	**0.05**	**0.39**	**0.50**	**0.89**	**1.13**
2015-07	0.14	0.42	0.50	0.87	1.11
2015-08	0.31	0.49	0.56	0.87	1.08
2015-09	0.33	0.52	0.65	1.01	1.24
2015-10	**0.21**	**0.39**	**0.57**	**0.98**	**1.22**
2015-11	**0.40**	**0.55**	**0.69**	**1.03**	**1.25**
2015-12	**0.45**	**0.59**	**0.73**	**1.06**	**1.26**
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	**-0.22**	**-0.03**	**0.19**	**0.60**	**0.86**
2016-05	**-0.22**	**-0.04**	**0.21**	**0.64**	**0.86**
2016-06	**-0.27**	**-0.07**	**0.17**	**0.63**	**0.82**
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	**-0.26**	**-0.10**	**0.10**	**0.49**	**0.69**
2016-11	**-0.07**	**0.11**	**0.32**	**0.69**	**0.86**
2016-12	**0.15**	**0.36**	**0.56**	**0.89**	**1.04**
2017-01	0.03	0.27	0.42	0.74	0.92
2017-02	0.01	0.29	0.40	0.73	0.93
2017-03	0.18	0.42	0.49	0.79	0.99
2017-04	**0.08**	**0.28**	**0.39**	**0.72**	**0.91**
2017-05	**0.09**	**0.29**	**0.47**	**0.80**	**0.99**
2017-06	**0.14**	**0.32**	**0.46**	**0.75**	**0.93**
2017-07	0.23	0.42	0.55	0.84	1.01
2017-08	0.16	0.35	0.43	0.74	0.93
2017-09	0.12	0.31	0.37	0.67	0.87
2017-10	**0.25**	**0.42**	**0.50**	**0.77**	**0.94**
2017-11	**0.30**	**0.43**	**0.50**	**0.72**	**0.87**
2017-12	**0.42**	**0.48**	**0.50**	**0.68**	**0.80**

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.56	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	**1.35**	**1.69**	**1.94**	**2.33**	**2.59**
2015-05	**1.54**	**1.93**	**2.20**	**2.69**	**2.96**
2015-06	**1.68**	**2.10**	**2.36**	**2.85**	**3.11**
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	**1.39**	**1.76**	**2.07**	**2.50**	**2.89**
2015-11	**1.67**	**2.02**	**2.26**	**2.69**	**3.03**
2015-12	**1.70**	**2.04**	**2.24**	**2.61**	**2.97**
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	**1.26**	**1.57**	**1.81**	**2.21**	**2.62**
2016-05	**1.30**	**1.60**	**1.81**	**2.22**	**2.63**
2016-06	**1.17**	**1.44**	**1.64**	**2.02**	**2.45**
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	**1.27**	**1.56**	**1.76**	**2.17**	**2.50**
2016-11	**1.60**	**1.93**	**2.14**	**2.54**	**2.86**
2016-12	**1.96**	**2.29**	**2.49**	**2.84**	**3.11**
2017-01	1.92	2.23	2.43	2.75	3.02
2017-02	1.90	2.22	2.42	2.76	3.03
2017-03	2.01	2.30	2.48	2.83	3.08
2017-04	**1.82**	**2.10**	**2.30**	**2.67**	**2.94**
2017-05	**1.84**	**2.11**	**2.30**	**2.70**	**2.96**
2017-06	**1.77**	**2.01**	**2.19**	**2.54**	**2.80**
2017-07	1.87	2.13	2.32	2.65	2.88
2017-08	1.78	2.03	2.21	2.55	2.80
2017-09	1.80	2.03	2.20	2.53	2.78
2017-10	**1.98**	**2.20**	**2.36**	**2.65**	**2.88**
2017-11	**2.05**	**2.23**	**2.35**	**2.60**	**2.80**
2017-12	**2.18**	**2.32**	**2.40**	**2.60**	**2.77**

Staff Accessed , Mar. 8, 2018 at: http://federalreserve.gov/releases/h15/data.htm

https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Annual						Annual				
TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.A	UST-05a	5	Year	H.15 ID	RIFLGFCY05_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A	UST-07a	7			RIFLGFCY07_N.A
TIPS-10a	10				RIFLGFCY10_XII_N.A	UST-10a	10			RIFLGFCY10_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A	UST-20a	20			RIFLGFCY20_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A	UST-30a	30			RIFLGFCY30_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	-0.09	0.32	0.44	0.86	1.11
2015	0.15	0.36	0.45	0.78	1.00
2016	-0.01	0.07	0.27	0.65	0.86
2017	**0.17**	**0.36**	**0.46**	**0.75**	**0.92**

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.84
2016	1.33	1.63	1.84	2.22	2.59
2017	**1.91**	**2.16**	**2.33**	**2.65**	**2.89**

NWN UG 344

CASE: UG 344
WITNESS: MATT MULDOON-JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Long Run 10- to 30- Year Growth Rates

Exhibits in Support
of Opening Testimony

April 20, 2018

Resource	10-Year GDP Projection	20-Year GDP Projection	30-Year GDP Projection	Date Accessed	Last Updated	Page
White House Budget, FY 2019, Table 2-1, Economic Assumptions URL https://www.whitehouse.gov/wp-content/uploads/2018/02/ap_2_assumptions-fy2019.pdf	4.9 (N), 2.8 (Real)	N/A	N/A	3/7/2018	2/1/2018	11
CBO, 2017 LT Budget Outlook, Table A-1, Average Annual Values URL https://www.cbo.gov/system/files/115th-congress-2017-2018/reports/52480-ltbo.pdf	3.9 (N), 1.9 (Real) Note: CBO to release annual update on 4/9/2018	**4.0** (**N**), 2.0 (Real)	**4.0** (**N**), 1.9 (Real)	3/7/2018	3/1/2017	30
SSA OASDI Trustee Report, Table V.B2, Additional Economic Factors URL https://www.ssa.gov/oact/TR/2017/tr2017.pdf	2.1 (Real, FY 2030) Note: Using intermediate measure, low cost and high cost available	**2.2 (Real,** FY 2040)	**2.2 (Real,** FY 2050)	3/7/2018	7/13/2017	112
EIA Assumptions to **Annual Energy Outlook**, Table 3.2, Average Annual **Real GDP**, **2010-40** URL https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2017).pdf	N/A Note: Measure is for OECD - **Americas,** not US individually	2.5 (Real, FY 2040)	N/A	3/8/2018	7/1/2017	24
EIA Annual Energy Outlook 2018, **Macroeconomic Indicators** URL https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf	N/A Note: Measures shown are for Low economic growth, **Reference** case, and High economic growth (respectively)	N/A	1.5%, **2.0%**, 2.6% (Real, FY 2050)	3/8/2018	8/1/2017	N/A
BLS, Projections Overview and Highlights, **2016-26**, Figure 5 URL https://www.bls.gov/opub/mlr/2017/article/projections-overview-and-highlights-2016-26.htm	2.0 (Real, FY 2026)	N/A	N/A	3/8/2018	10/1/2017	N/A
PwC, The Long View, Table B2, Breakdown of...average real growth in GPD at MERs (**2016-2050**) URL https://www.pwc.com/gx/en/world-2050/assets/pwc-the-world-in-2050-full-report-feb-2017.pdf	N/A	N/A	**1.8% (Real,** FY 2050)	3/8/2018	2/1/2017	69

Acronyms Used	
BLS	Bureau of Labor Statistics
CBO	Congressional Budget Office
EIA	Energy Information Administration
FY	Fiscal Year
GDP	Gross Domestic Product
MERs	Market Exchange Rates
N	Nominal
N/A	Not Available
OASDI	Old Age Survivors Disability Insurance (Socal Security)
PwC	PricewaterhouseCooper
R	Real
SSA	Social Security Administration

Long-Run GDP Growth Rates

ECONOMIC ASSUMPTIONS AND INTERACTIONS WITH THE BUDGET

Long-Run GDP Growth Rates

Table 2–1. ECONOMIC ASSUMPTIONS [1]

(Calendar Years, Dollar Amounts in Billions)

	Actual 2016	Projections 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gross Domestic Product (GDP):													
Levels, Dollar Amounts in Billions:													
Current Dollars	18,624	19,372	20,262	21,263	22,345	23,482	24,672	25,923	27,234	28,598	30,001	31,461	32,991
Real, Chained (2009) Dollars	16,716	17,090	17,601	18,157	18,727	19,296	19,875	20,471	21,085	21,705	22,320	22,945	23,588
Chained Price Index (2009=100), Annual Average	111.4	113.4	115.1	117.1	119.3	121.7	124.1	126.6	129.2	131.8	134.4	137.1	139.9
Percent Change, Fourth Quarter over Fourth Quarter:													
Current Dollars	3.4	4.1	4.7	5.1	5.1	5.1	5.1	5.1	5.1	5.0	4.9	4.9	4.9
Real, Chained (2009) Dollars	1.8	2.5	3.1	3.2	3.1	3.0	3.0	3.0	3.0	2.9	2.8	2.8	2.8
Chained Price Index (2009=100)	1.5	1.6	1.6	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Percent Change, Year over Year:													
Current Dollars	2.8	4.0	4.6	4.9	5.1	5.1	5.1	5.1	5.1	5.0	4.9	4.9	4.9
Real, Chained (2009) Dollars	1.5	2.2	3.0	3.2	3.1	3.0	3.0	3.0	3.0	2.9	2.8	2.8	2.8
Chained Price Index (2009=100)	1.3	1.7	1.6	1.7	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Incomes, Billions of Current Dollars:													
Domestic Corporate Profits	1,679	1,753	1,893	1,985	2,050	2,060	2,047	2,035	2,043	2,048	2,041	2,049	2,046
Employee Compensation	9,979	10,320	10,750	11,225	11,774	12,408	13,104	13,843	14,622	15,438	16,291	17,160	18,092
Wages and Salaries	8,085	8,365	8,713	9,094	9,550	10,058	10,620	11,217	11,844	12,506	13,195	13,902	14,642
Other Taxable Income [2]	4,427	4,576	4,793	5,068	5,386	5,704	6,053	6,398	6,738	7,072	7,360	7,683	7,943
Consumer Price Index (All Urban): [3]													
Level (1982–1984 = 100), Annual Average	240.0	245.1	250.2	255.1	260.7	266.7	272.7	278.9	285.2	291.7	298.3	305.1	312.0
Percent Change, Fourth Quarter over Fourth Quarter	1.8	2.1	1.9	2.0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Percent Change, Year over Year	1.3	2.1	2.1	2.0	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Unemployment Rate, Civilian, Percent:													
Fourth Quarter Level	4.7	4.1	3.8	3.7	3.8	3.9	4.1	4.2	4.4	4.5	4.8	4.8	4.8
Annual Average	4.9	4.4	3.9	3.7	3.8	3.9	4.0	4.2	4.3	4.5	4.7	4.8	4.8
Federal Pay Raises, January, Percent:													
Military [4]	1.3	2.1	2.4	2.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Civilian [5]	1.3	2.1	1.9	0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Interest Rates, Percent:													
91-Day Treasury Bills [6]	0.3	0.9	1.5	2.3	2.9	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.9
10-Year Treasury Notes	1.8	2.3	2.6	3.1	3.4	3.6	3.7	3.7	3.6	3.6	3.6	3.6	3.6

N/A=Not Available

[1] Based on information available as of mid-November 2017.

[2] Rent, interest, dividend, and proprietors' income components of personal income.

[3] Seasonally adjusted CPI for all urban consumers.

[4] Percentages apply to basic pay only; percentages to be proposed for years after 2019 have not yet been determined.

[5] Overall average increase, including locality pay adjustments. Percentages to be proposed for years after 2019 have not yet been determined.

[6] Average rate, secondary market (bank discount basis).

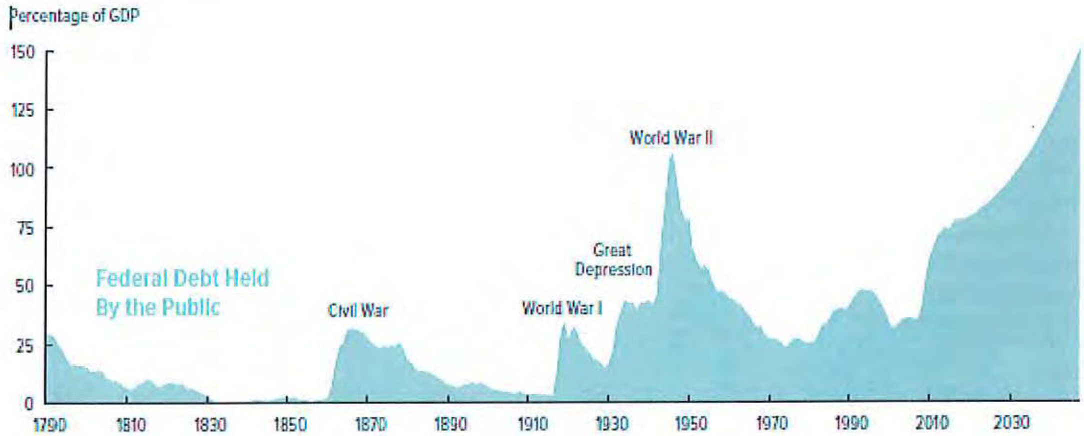
* 0.05 percent or less.

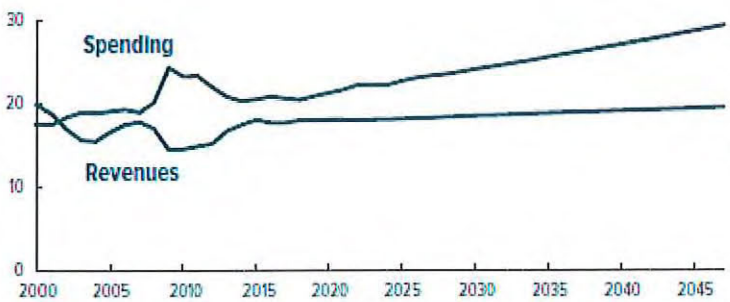
Long-Run GDP Growth Rates

CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

CBO

The 2017 Long-Term Budget Outlook





Under current law, spending growth—driven by outlays for Social Security, the major health care programs, and net interest—is projected to outpace revenue growth.

MARCH 2017

Long-Run GDP Growth Rates

Table A-1.

Average Annual Values for Demographic and Economic Variables That Underlie CBO's Extended Baseline

	1987–2016	2017–2027	2028–2037	2038–2047	Overall, 2017–2047
			Demographic Variables		
Growth of the Population (Percent)	0.9	0.7	0.6	0.4	0.6
Fertility Rate (Children per woman)	2.0	1.9	1.9	1.9	1.9
Immigration Rate (Per 1,000 people in the U.S. population)	3.8	3.2	3.2	3.2	3.2
Life Expectancy at Birth, End of Period (Years)[a]	79.1	80.5	81.6	82.8	82.8
Life Expectancy at Age 65, End of Period (Years)[a]	19.3	20.1	20.8	21.5	21.5
			Economic Variables (Percent)		
Growth of GDP					
Real GDP	2.5	1.9	2.0	1.9	1.9
Nominal GDP	4.8	3.9	4.0	4.0	4.0
Growth of the Labor Force	1.0	0.6	0.4	0.4	0.5
Labor Force Participation Rate	65.7	62.0	60.2	59.4	60.6
Unemployment					
Unemployment rate	6.0	4.8	4.9	4.8	4.8
Natural rate of unemployment	5.2	4.7	4.6	4.6	4.6
Growth of Average Hours Worked	-0.1	-0.1	-0.1	-0.1	-0.1
Growth of Total Hours Worked	1.0	0.4	0.3	0.4	0.3
Earnings as a Share of Compensation	81	81	81	80	81
Growth of Real Earnings per Worker	1.0	1.1	1.2	1.1	1.1
Share of Earnings Below the Taxable Maximum	85	81	79	79	80
Growth of Productivity					
Total factor productivity	1.2	1.1	1.2	1.2	1.2
Labor productivity	1.5	1.5	1.6	1.6	1.6
Inflation					
Growth of the CPI-U	2.6	2.4	2.4	2.4	2.4
Growth of the GDP price index	2.2	2.0	2.0	2.0	2.0
Interest Rates					
Real rates					
On 10-year Treasury notes and Social Security bonds	2.5	0.9	1.5	2.1	1.5
Nominal rates					
On 10-year Treasury notes and Social Security bonds	5.1	3.2	3.9	4.5	3.8
On all federal debt held by the public[b]	5.2	2.7	3.6	4.1	3.4

Source: Congressional Budget Office.

The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2027 and then extending most of the concepts underlying those baseline projections for the rest of the long-term projection period.

CPI-U = consumer price index for all urban consumers; GDP = gross domestic product.

a. Life expectancy as used here is period life expectancy, which is the amount of time that a person in a given year would expect to survive beyond his or her current age on the basis of that year's mortality rates for various ages.

b. The interest rate on all federal debt held by the public equals net interest payments in the current fiscal year divided by debt held by the public at the end of the previous fiscal year.

Long-Run GDP Growth Rates

THE 2017 ANNUAL REPORT OF THE BOARD OF TRUSTEES OF THE FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

COMMUNICATION

FROM

THE BOARD OF TRUSTEES, FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

TRANSMITTING

THE 2017 ANNUAL REPORT OF THE BOARD OF TRUSTEES OF THE FEDERAL OLD-AGE AND SURVIVORS INSURANCE AND FEDERAL DISABILITY INSURANCE TRUST FUNDS

Long-Run GDP Growth Rates

Assumptions and Methods

Table V.B2.—Additional Economic Factors (Cont.)

Calendar year	Average annual unemployment rate[a]	Annual percentage change[b] in—			Average annual interest rate	
		Labor force[c]	Total employment[d]	Real GDP[e]	Nominal[f]	Real[g]
Intermediate:						
2017	5.0	1.2	1.1	2.9	2.7	-0.3
2018	5.3	1.5	1.1	3.0	3.7	-.3
2019	5.5	1.3	1.1	3.0	4.3	1.1
2020	5.5	1.0	1.0	2.9	4.6	1.7
2021	5.5	.9	.9	2.7	4.8	2.0
2022	5.5	.7	.7	2.4	5.0	2.2
2023	5.5	.6	.5	2.2	5.0	2.4
2024	5.6	.6	.6	2.2	5.2	2.4
2025	5.6	.6	.6	2.2	5.3	2.6
2026	5.6	.5	.5	2.1	5.3	2.7
2030	5.5	.5	.5	2.1	5.3	2.7
2035	5.5	.5	.5	2.1	5.3	2.7
2040	5.5	.6	.6	2.2	5.3	2.7
2045	5.5	.6	.6	2.2	5.3	2.7
2050	5.5	.5	.5	2.2	5.3	2.7
2055	5.5	.5	.5	2.1	5.3	2.7
2060	5.5	.4	.4	2.1	5.3	2.7
2065	5.5	.4	.4	2.1	5.3	2.7
2070	5.5	.5	.5	2.1	5.3	2.7
2075	5.5	.5	.5	2.1	5.3	2.7
2080	5.5	.5	.5	2.1	5.3	2.7
2085	5.5	.4	.4	2.1	5.3	2.7
2090	5.5	.4	.4	2.0	5.3	2.7
2095	5.5	.4	.4	2.0	5.3	2.7
Low-cost:						
2017	4.6	1.2	1.5	3.8	3.5	-.9
2018	4.6	1.7	1.7	4.4	5.1	-.3
2019	4.6	1.6	1.6	4.2	5.7	1.7
2020	4.6	1.2	1.2	3.6	5.7	2.5
2021	4.6	.9	.9	3.0	5.8	2.5
2022	4.6	.8	.7	2.8	5.9	2.6
2023	4.6	.8	.7	2.8	6.1	2.7
2024	4.6	.8	.8	2.9	6.3	2.9
2025	4.6	.8	.8	2.9	6.4	3.1
2026	4.6	.7	.7	2.7	6.4	3.2
2030	4.5	.6	.6	2.6	6.4	3.2
2035	4.5	.6	.6	2.7	6.4	3.2
2040	4.5	.8	.7	2.8	6.4	3.2
2045	4.5	.8	.8	2.8	6.4	3.2
2050	4.5	.8	.8	2.8	6.4	3.2
2055	4.5	.7	.7	2.7	6.4	3.2
2060	4.5	.7	.7	2.7	6.4	3.2
2065	4.5	.7	.7	2.7	6.4	3.2
2070	4.5	.8	.7	2.8	6.4	3.2
2075	4.5	.8	.8	2.8	6.4	3.2
2080	4.5	.8	.8	2.8	6.4	3.2
2085	4.5	.7	.7	2.8	6.4	3.2
2090	4.5	.7	.7	2.7	6.4	3.2
2095	4.5	.7	.7	2.7	6.4	3.2

Long-Run GDP Growth Rates

Independent Statistics & Analysis
U.S. Energy Information Administration

Assumptions to the Annual Energy Outlook 2017

July 2017

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Long-Run GDP Growth Rates

Table 3.2. Average annual real gross domestic product rates, 2010-40

2010 purchasing power parity weights and prices

Region	Average Annual Percentage Change
OECD	2.0%
OECD Americas	2.5%
OECD Europe	1.8%
OECD Asia	1.3%
Non-OECD	4.2%
Non-OECD Europe and Eurasia	3.0%
Non-OECD Asia	4.5%
Middle East	3.8%
Africa	5.0%
Non-OECD Americas	2.8%
Total World	3.3%

Source: U.S. Energy Information Administration, Derived from Oxford Economic Model (February 2014).

Long-Run GDP Growth Rates

Annual Energy Outlook 2018

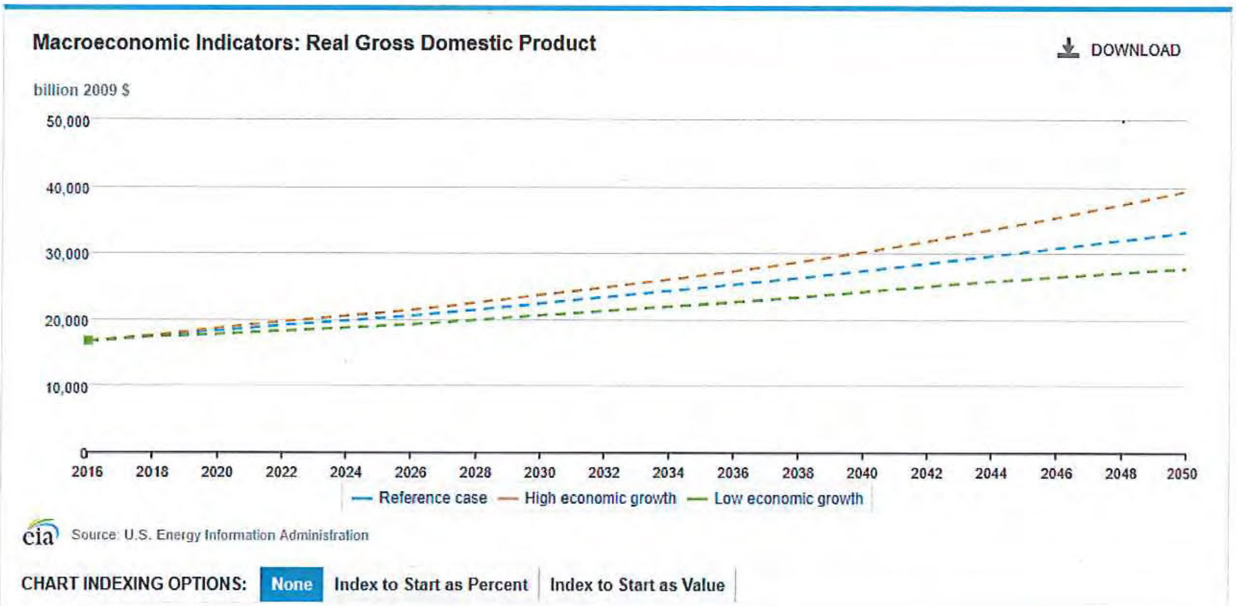
with projections to 2050

Independent Statistics & Analysis
U.S. Energy Information Administration

#AEO2018

February 6, 2018
www.eia.gov/aeo

Long-Run GDP Growth Rates



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Time-series Map Annual Every 5th Year 2016 2050

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	6	2047	2048	2049	2050	Growth (2017-2050)
Real Gross Domestic Product						
Reference case (billion 2009 $)	5	31,404	31,998	32,584	33,205	2.0%
High economic growth (billion 2009 $)	7	36,408	37,352	38,338	39,348	2.6%
Low economic growth (billion 2009 $)	2	26,764	27,096	27,413	27,710	1.5%

Long-Run GDP Growth Rates

Monthly Labor Review mlr BLS

BLS
October 2017

ERRATA Corrections to this article were made on January 30, 2018. Specifically, table 2 and figures 12–15 and related text were revised to include corrected estimates of self-employed workers. For more detailed information, see the errata notice at https://www.bls.gov/bls/errata/employment-projections-2016-26-corrections.htm.

Projections overview and highlights, 2016–26

Figure 5. GDP, 10-year compound average annual rate, 1966-2016 and projected 2016-26

Years	GDP (percent)
1966-76	3.0
1976-86	3.3
1986-96	3.0
1996-2006	3.3
2006-16	1.4
Projected 2016-26	2.0

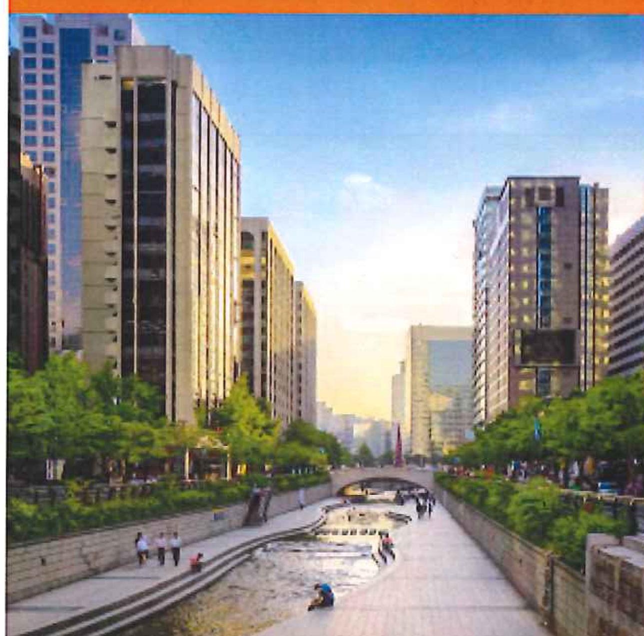
Note: GDP = gross domestic product.

Source: U.S. Bureau of Labor Statistics.

Long-Run GDP Growth Rates

The Long View
How will the global economic order change by 2050?

February 2017



pwc

Long-Run GDP Growth Rates

Table B2: Breakdown of components of average real growth in GDP at MERs (2016-2050)

Country	Average Pop Growth p.a %	Average Real Growth per capita p.a %	% of growth due to MER	Average GDP growth p.a. (in USD)
India	0.7%	4.1%	2.8%	7.7%
Vietnam	0.5%	4.5%	2.4%	7.4%
Bangladesh	0.6%	4.1%	2.2%	7.0%
Pakistan	1.4%	2.9%	2.6%	7.0%
Egypt	1.4%	2.6%	2.5%	6.6%
Philippines	1.1%	3.1%	2.1%	6.3%
Nigeria	2.3%	1.9%	2.1%	6.2%
Indonesia	0.6%	3.1%	2.5%	6.2%
South Africa	0.5%	3.2%	2.1%	5.8%
Malaysia	0.8%	2.7%	2.3%	5.8%
Iran	0.4%	2.5%	2.6%	5.5%
Colombia	0.4%	2.9%	2.0%	5.3%
Saudi Arabia	1.1%	1.9%	2.2%	5.1%
Mexico	0.7%	2.5%	1.7%	5.0%
Thailand	-0.3%	2.9%	2.3%	4.9%
Turkey	0.5%	2.4%	1.8%	4.8%
Poland	-0.4%	2.5%	2.5%	4.5%
China	-0.1%	3.1%	1.4%	4.4%
Russia	-0.3%	2.2%	2.3%	4.2%
Argentina	0.7%	2.2%	1.1%	4.1%
Brazil	0.4%	2.2%	1.3%	3.9%
South Korea	0.0%	1.8%	1.0%	2.8%
Spain	-0.1%	1.5%	0.9%	2.3%
Australia	0.9%	1.3%	-0.2%	2.1%
United Kingdom	0.4%	1.5%	0.2%	2.1%
Canada	0.6%	1.2%	0.3%	2.1%
Netherlands	0.1%	1.5%	0.4%	2.0%
France	0.3%	1.3%	0.3%	1.9%
United States	0.5%	1.3%	0.0%	1.8%
Germany	-0.2%	1.5%	0.4%	1.7%
Italy	-0.2%	1.2%	0.5%	1.5%
Japan	-0.5%	1.4%	0.1%	1.1%

Source: PwC analysis

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Staff GDP Analysis with BEA Historical Data

Exhibits in Support
of Opening Testimony

April 20, 2018

Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Staff Accessed March 6, 2018

Data Recompiled by BEA on Feb. 28, 2018

Annual

http://www.bea.gov/national/index.htm

Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,056.6
1930	92.2	966.7
1931	77.4	904.8
1932	59.5	788.2
1933	57.2	778.3
1934	66.8	862.2
1935	74.3	939.0
1936	84.9	1,060.5
1937	93.0	1,114.6
1938	87.4	1,077.7
1939	93.5	1,163.6
1940	102.9	1,266.1
1941	129.4	1,490.3
1942	166.0	1,771.8
1943	203.1	2,073.7
1944	224.6	2,239.4
1945	228.2	2,217.8
1946	227.8	1,960.9
1947	249.9	1,939.4
1948	274.8	2,020.0
1949	272.8	2,008.9
1950	300.2	2,184.0
1951	347.3	2,360.0
1952	367.7	2,456.1
1953	389.7	2,571.4
1954	391.1	2,556.9
1955	426.2	2,739.0
1956	450.1	2,797.4
1957	474.9	2,856.3
1958	482.0	2,835.3
1959	522.5	3,031.0
1960	543.3	3,108.7
1961	563.3	3,188.1
1962	605.1	3,383.1
1963	638.6	3,530.4
1964	685.8	3,734.0
1965	743.7	3,976.7
1966	815.0	4,238.9
1967	861.7	4,355.2
1968	942.5	4,569.0
1969	1,019.9	4,712.5
1970	1,075.9	4,722.0
1971	1,167.8	4,877.6
1972	1,282.4	5,134.3
1973	1,428.5	5,424.1
1974	1,548.8	5,396.0
1975	1,688.9	5,385.4
1976	1,877.6	5,675.4
1977	2,086.0	5,937.0
1978	2,356.6	6,267.2
1979	2,632.1	6,466.2
1980	2,862.5	6,450.4
1981	3,211.0	6,617.7
1982	3,345.0	6,491.3
1983	3,638.1	6,792.0
1984	4,040.7	7,285.0
1985	4,346.7	7,593.8
1986	4,590.2	7,860.5
1987	4,870.2	8,132.6
1988	5,252.6	8,474.5
1989	5,657.7	8,786.4
1990	5,979.6	8,955.0
1991	6,174.0	8,948.4
1992	6,539.3	9,266.6
1993	6,878.7	9,521.0
1994	7,308.8	9,905.4
1995	7,664.1	10,174.8
1996	8,100.2	10,561.0
1997	8,608.5	11,034.9
1998	9,089.2	11,525.9
1999	9,660.6	12,065.9
2000	10,284.8	12,559.7
2001	10,621.8	12,682.2
2002	10,977.5	12,908.8
2003	11,510.7	13,271.1
2004	12,274.9	13,773.5
2005	13,093.7	14,234.2
2006	13,855.9	14,613.8
2007	14,477.6	14,873.7
2008	14,718.6	14,830.4
2009	14,418.7	14,418.7
2010	14,964.4	14,783.8
2011	15,517.9	15,020.6
2012	16,155.3	15,354.6
2013	16,691.5	15,612.2
2014	17,427.6	16,013.3
2015	18,120.7	16,471.5
2016	18,624.5	16,716.2
2017	19,386.2	17,092.5

Quarterly

(Seasonally adjusted annual rates)

1980 through 2017 Q4

Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#	Average	2.67%	Real
1947Q1	243.1	1,934.5	1	1	8.783381	1980
1947Q2	246.3	1,932.3	2	2	8.762896	
1947Q3	250.1	1,930.3	3	3	8.761378	
1947Q4	260.3	1,960.7	4	4	8.779742	
1948Q1	266.2	1,989.5	5	5	8.800219	1981
1948Q2	272.9	2,021.9	6	6	8.792899	
1948Q3	279.5	2,033.2	7	7	8.804310	
1948Q4	280.7	2,035.3	8	8	8.792565	
1949Q1	275.4	2,007.5	9	9	8.775704	1982
1949Q2	271.7	2,000.8	10	10	8.781125	
1949Q3	273.3	2,022.8	11	11	8.777525	
1949Q4	271.0	2,004.7	12	12	8.778495	
1950Q1	281.2	2,084.6	13	13	8.791516	1983
1950Q2	290.7	2,147.6	14	14	8.814078	
1950Q3	308.5	2,230.4	15	15	8.833463	
1950Q4	320.3	2,273.4	16	16	8.853880	
1951Q1	336.4	2,304.5	17	17	8.873552	1984
1951Q2	344.5	2,344.5	18	18	8.890961	
1951Q3	351.8	2,392.8	19	19	8.900753	
1951Q4	356.6	2,398.1	20	20	8.908695	
1952Q1	360.2	2,423.5	21	21	8.918583	1985
1952Q2	361.4	2,428.5	22	22	8.927699	
1952Q3	368.1	2,446.1	23	23	8.943140	
1952Q4	381.2	2,526.4	24	24	8.950611	
1953Q1	388.5	2,573.4	25	25	8.959838	1986
1953Q2	392.3	2,593.5	26	26	8.964414	
1953Q3	391.7	2,578.9	27	27	8.974441	
1953Q4	386.5	2,539.8	28	28	8.979606	
1954Q1	385.9	2,528.0	29	29	8.986572	1987
1954Q2	386.7	2,530.7	30	30	8.997729	
1954Q3	391.6	2,559.4	31	31	9.006754	
1954Q4	400.3	2,609.3	32	32	9.023131	
1955Q1	413.8	2,683.8	33	33	9.028735	1988
1955Q2	422.2	2,727.5	34	34	9.041863	
1955Q3	430.9	2,764.1	35	35	9.047621	
1955Q4	437.8	2,780.8	36	36	9.060784	
1956Q1	440.5	2,770.0	37	37	9.070814	1989
1956Q2	446.8	2,792.9	38	38	9.078647	
1956Q3	452.0	2,790.6	39	39	9.086080	
1956Q4	461.3	2,836.2	40	40	9.088195	
1957Q1	470.6	2,854.5	41	41	9.099085	1990
1957Q2	472.8	2,848.2	42	42	9.102944	
1957Q3	480.3	2,875.9	43	43	9.103189	
1957Q4	475.7	2,846.4	44	44	9.094638	
1958Q1	468.4	2,772.7	45	45	9.089934	1991
1958Q2	472.8	2,790.9	46	46	9.097664	
1958Q3	486.7	2,855.5	47	47	9.102454	
1958Q4	500.4	2,922.3	48	48	9.106800	
1959Q1	511.1	2,976.6	49	49	9.118554	1992
1959Q2	524.2	3,049.0	50	50	9.129510	
1959Q3	525.2	3,043.1	51	51	9.139188	
1959Q4	529.3	3,055.1	52	52	9.149156	
1960Q1	543.3	3,123.2	53	53	9.151026	1993
1960Q2	542.7	3,111.3	54	54	9.156950	
1960Q3	546.0	3,119.1	55	55	9.161812	
1960Q4	541.1	3,081.3	56	56	9.175076	
1961Q1	545.9	3,102.3	57	57	9.184838	1994
1961Q2	557.4	3,159.9	58	58	9.198409	
1961Q3	568.2	3,212.6	59	59	9.204292	
1961Q4	581.6	3,277.7	60	60	9.215577	
1962Q1	595.2	3,336.8	61	61	9.218993	1995
1962Q2	602.6	3,372.7	62	62	9.222476	
1962Q3	609.6	3,404.8	63	63	9.231005	
1962Q4	613.1	3,418.0	64	64	9.238072	
1963Q1	622.7	3,456.1	65	65	9.244616	1996
1963Q2	631.8	3,501.1	66	66	9.261927	
1963Q3	645.0	3,569.5	67	67	9.271134	
1963Q4	654.8	3,595.0	68	68	9.281647	
1964Q1	671.1	3,672.7	69	69	9.289235	1997
1964Q2	680.8	3,716.4	70	70	9.304213	
1964Q3	692.8	3,766.9	71	71	9.316860	
1964Q4	698.4	3,780.2	72	72	9.324588	
1965Q1	719.2	3,873.5	73	73	9.334432	1998
1965Q2	732.4	3,926.4	74	74	9.344084	
1965Q3	750.2	4,006.2	75	75	9.357087	
1965Q4	773.1	4,100.6	76	76	9.373369	
1966Q1	797.3	4,201.9	77	77	9.381323	1999
1966Q2	807.2	4,219.1	78	78	9.389532	
1966Q3	820.8	4,249.2	79	79	9.402043	
1966Q4	834.9	4,285.6	80	80	9.419247	
1967Q1	846.0	4,324.9	81	81	9.422148	2000
1967Q2	851.1	4,328.7	82	82	9.440857	
1967Q3	866.6	4,366.1	83	83	9.442063	
1967Q4	883.2	4,401.2	84	84	9.447726	
1968Q1	911.1	4,490.6	85	85	9.444883	2001
1968Q2	936.3	4,566.4	86	86	9.450168	
1968Q3	952.3	4,599.3	87	87	9.447000	
1968Q4	970.1	4,619.8	88	88	9.449775	
1969Q1	995.4	4,691.6	89	89	9.458941	2002
1969Q2	1,011.4	4,706.7	90	90	9.464440	
1969Q3	1,032.0	4,736.1	91	91	9.469299	
1969Q4	1,040.7	4,715.5	92	92	9.469932	
1970Q1	1,053.5	4,707.1	93	93	9.475102	2003
1970Q2	1,070.1	4,715.4	94	94	9.484337	
1970Q3	1,088.5	4,757.2	95	95	9.500948	
1970Q4	1,091.5	4,708.3	96	96	9.512569	
1971Q1	1,137.8	4,834.3	97	97	9.518303	2004
1971Q2	1,159.4	4,861.9	98	98	9.525604	
1971Q3	1,180.3	4,900.0	99	99	9.534653	
1971Q4	1,193.6	4,914.3	100	100	9.543263	
1972Q1	1,233.8	5,002.4	101	101	9.553866	2005
1972Q2	1,270.1	5,118.3	102	102	9.559073	
1972Q3	1,293.8	5,165.4	103	103	9.567441	
1972Q4	1,332.0	5,251.2	104	104	9.573135	
1973Q1	1,380.7	5,380.5	105	105	9.585078	2006
1973Q2	1,417.6	5,441.5	106	106	9.588064	
1973Q3	1,436.8	5,411.9	107	107	9.588955	
1973Q4	1,479.1	5,462.4	108	108	9.596752	
1974Q1	1,494.7	5,417.0	109	109	9.597370	2007
1974Q2	1,534.2	5,431.3	110	110	9.604994	
1974Q3	1,563.4	5,378.7	111	111	9.611697	
1974Q4	1,603.0	5,357.2	112	112	9.615259	
1975Q1	1,619.6	5,292.4	113	113	9.608412	2008
1975Q2	1,656.4	5,333.2	114	114	9.613362	
1975Q3	1,713.8	5,421.4	115	115	9.608553	
1975Q4	1,765.9	5,494.4	116	116	9.587200	
1976Q1	1,824.5	5,618.5	117	117	9.573246	2009
1976Q2	1,856.9	5,661.0	118	118	9.571895	
1976Q3	1,890.5	5,689.8	119	119	9.575157	
1976Q4	1,938.4	5,732.5	120	120	9.584789	
1977Q1	1,992.5	5,799.2	121	121	9.589106	2010
1977Q2	2,060.2	5,913.0	122	122	9.598720	
1977Q3	2,122.4	6,017.6	123	123	9.605452	
1977Q4	2,168.7	6,018.2	124	124	9.611731	
1978Q1	2,208.7	6,039.2	125	125	9.607861	2011
1978Q2	2,336.6	6,274.0	126	126	9.615112	
1978Q3	2,398.9	6,335.3	127	127	9.617211	
1978Q4	2,482.2	6,420.3	128	128	9.628412	
1979Q1	2,531.6	6,433.0	129	129	9.635020	2012
1979Q2	2,595.9	6,440.8	130	130	9.639678	
1979Q3	2,670.4	6,487.1	131	131	9.640875	
1979Q4	2,730.7	6,503.9	132	132	9.641103	
1980Q1	2,796.5	6,524.9	133	133	9.648073	2013
1980Q2	2,799.9	6,392.6	134	134	9.649988	
1980Q3	2,860.0	6,382.9	135	135	9.657670	
1980Q4	2,993.5	6,501.2	136	136	9.667379	
1981Q1	3,131.8	6,635.7	137	137	9.665078	2014
1981Q2	3,167.3	6,587.3	138	138	9.676323	
1981Q3	3,261.2	6,662.9	139	139	9.689025	
1981Q4	3,283.5	6,585.1	140	140	9.694013	
1982Q1	3,273.8	6,475.0	141	141	9.701983	2015
1982Q2	3,331.3	6,510.2	142	142	9.708743	
1982Q3	3,367.1	6,486.8	143	143	9.712787	
1982Q4	3,407.8	6,493.1	144	144	9.713996	
1983Q1	3,480.3	6,578.2	145	145	9.715446	2016
1983Q2	3,583.8	6,728.3	146	146	9.720976	
1983Q3	3,692.3	6,860.0	147	147	9.727830	
1983Q4	3,796.1	7,001.5	148	148	9.732189	

OLS Regression

Annualized Real LN GPD Q

2.76%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.987298453
R Square	0.974758234
Adjusted R Square	0.974589956
Standard Error	0.048462262
Observations	152

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	13.60428747	13.60428747	5792.532028	9.4979E-122
Residual	150	0.352288621	0.002348591		
Total	151	13.95657609			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.795133966	0.007900568	1113.228024	1.0678E-295	8.779523191	8.810744741	8.779523191	8.810744741
X Variable 1	0.006818244	8.95856E-05	76.10868563	9.4979E-122	0.006641231	0.006995257	0.006641231	0.006995257

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

www.bea.gov

Note

July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:

1. Artistic Works
2. Research and Development

as Capital Investments that Depreciate Over Time rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

1984Q1	3,912.8	7,140.6	149
1984Q2	4,015.0	7,266.0	150
1984Q3	4,087.4	7,337.5	151
1984Q4	4,147.6	7,396.0	152
1985Q1	4,237.0	7,469.5	153
1985Q2	4,302.3	7,537.9	154
1985Q3	4,394.6	7,655.2	155
1985Q4	4,453.1	7,712.6	156
1986Q1	4,516.3	7,784.1	157
1986Q2	4,555.2	7,819.8	158
1986Q3	4,619.6	7,898.6	159
1986Q4	4,669.4	7,939.5	160
1987Q1	4,736.2	7,995.0	161
1987Q2	4,821.5	8,084.7	162
1987Q3	4,900.5	8,158.0	163
1987Q4	5,022.7	8,292.7	164
1988Q1	5,090.6	8,339.3	165
1988Q2	5,207.7	8,449.5	166
1988Q3	5,299.5	8,498.3	167
1988Q4	5,412.7	8,610.9	168
1989Q1	5,527.4	8,697.7	169
1989Q2	5,628.4	8,766.1	170
1989Q3	5,711.6	8,831.5	171
1989Q4	5,763.4	8,850.2	172
1990Q1	5,890.8	8,947.1	173
1990Q2	5,974.7	8,981.7	174
1990Q3	6,029.5	8,983.9	175
1990Q4	6,023.3	8,907.4	176
1991Q1	6,054.9	8,865.6	177
1991Q2	6,143.6	8,934.4	178
1991Q3	6,218.4	8,977.3	179
1991Q4	6,279.3	9,016.4	180
1992Q1	6,380.8	9,123.0	181
1992Q2	6,492.3	9,223.5	182
1992Q3	6,586.5	9,313.2	183
1992Q4	6,697.6	9,406.5	184
1993Q1	6,748.2	9,424.1	185
1993Q2	6,829.6	9,480.1	186
1993Q3	6,904.2	9,526.3	187
1993Q4	7,032.8	9,653.5	188
1994Q1	7,136.3	9,748.2	189
1994Q2	7,269.8	9,881.4	190
1994Q3	7,352.3	9,939.7	191
1994Q4	7,476.7	10,052.5	192
1995Q1	7,545.3	10,086.9	193
1995Q2	7,604.9	10,122.1	194
1995Q3	7,706.5	10,208.8	195
1995Q4	7,799.5	10,281.2	196
1996Q1	7,893.1	10,348.7	197
1996Q2	8,061.5	10,529.4	198
1996Q3	8,159.0	10,626.8	199
1996Q4	8,287.1	10,739.1	200
1997Q1	8,402.1	10,820.9	201
1997Q2	8,551.9	10,984.2	202
1997Q3	8,691.8	11,124.0	203
1997Q4	8,788.3	11,210.3	204
1998Q1	8,889.7	11,321.2	205
1998Q2	8,994.7	11,431.0	206
1998Q3	9,146.5	11,580.6	207
1998Q4	9,325.7	11,770.7	208
1999Q1	9,447.1	11,864.7	209
1999Q2	9,557.0	11,962.5	210
1999Q3	9,712.3	12,113.1	211
1999Q4	9,926.1	12,323.3	212
2000Q1	10,031.0	12,359.1	213
2000Q2	10,278.3	12,592.5	214
2000Q3	10,357.4	12,607.7	215
2000Q4	10,472.3	12,679.3	216
2001Q1	10,508.1	12,643.3	217
2001Q2	10,638.4	12,710.3	218
2001Q3	10,639.5	12,670.1	219
2001Q4	10,701.3	12,705.3	220
2002Q1	10,834.4	12,822.3	221
2002Q2	10,934.8	12,893.0	222
2002Q3	11,037.1	12,955.8	223
2002Q4	11,103.8	12,964.0	224
2003Q1	11,230.1	13,031.2	225
2003Q2	11,370.7	13,152.1	226
2003Q3	11,625.1	13,372.4	227
2003Q4	11,816.8	13,528.7	228
2004Q1	11,988.4	13,606.5	229
2004Q2	12,181.4	13,706.2	230
2004Q3	12,367.7	13,830.8	231
2004Q4	12,562.2	13,950.4	232
2005Q1	12,813.7	14,099.1	233
2005Q2	12,974.1	14,172.7	234
2005Q3	13,205.4	14,291.8	235
2005Q4	13,381.6	14,373.4	236
2006Q1	13,648.9	14,546.1	237
2006Q2	13,799.8	14,589.6	238
2006Q3	13,908.5	14,602.6	239
2006Q4	14,066.4	14,716.9	240
2007Q1	14,233.2	14,726.0	241
2007Q2	14,422.3	14,838.7	242
2007Q3	14,569.7	14,938.5	243
2007Q4	14,685.3	14,991.8	244
2008Q1	14,668.4	14,889.5	245
2008Q2	14,813.0	14,963.4	246
2008Q3	14,843.0	14,891.6	247
2008Q4	14,549.9	14,577.0	248
2009Q1	14,383.9	14,375.0	249
2009Q2	14,340.4	14,355.6	250
2009Q3	14,384.1	14,402.5	251
2009Q4	14,566.5	14,541.9	252
2010Q1	14,681.1	14,604.8	253
2010Q2	14,888.6	14,745.9	254
2010Q3	15,057.7	14,845.5	255
2010Q4	15,230.2	14,939.0	256
2011Q1	15,238.4	14,881.3	257
2011Q2	15,460.9	14,989.6	258
2011Q3	15,587.1	15,021.1	259
2011Q4	15,785.3	15,190.3	260
2012Q1	15,973.9	15,291.0	261
2012Q2	16,121.9	15,362.4	262
2012Q3	16,227.9	15,380.8	263
2012Q4	16,297.3	15,384.3	264
2013Q1	16,475.4	15,491.9	265
2013Q2	16,541.4	15,521.6	266
2013Q3	16,749.3	15,641.3	267
2013Q4	16,999.9	15,793.9	268
2014Q1	17,031.3	15,757.6	269
2014Q2	17,320.9	15,935.8	270
2014Q3	17,622.3	16,139.5	271
2014Q4	17,735.9	16,220.2	272
2015Q1	17,874.7	16,350.0	273
2015Q2	18,093.2	16,460.9	274
2015Q3	18,227.7	16,527.6	275
2015Q4	18,287.2	16,547.6	276
2016Q1	18,325.2	16,571.6	276
2016Q2	18,538.0	16,663.5	276
2016Q3	18,729.1	16,778.1	276
2016Q4	18,905.5	16,851.4	277
2017Q1	19,057.7	16,903.2	278
2017Q2	19,250.0	17,031.1	279
2017Q3	19,500.6	17,163.9	280
2017Q4	19,736.5	17,271.7	281

149	9.735258	2017
150	9.742796	
151	9.750564	
152	9.756825	

CASE: UG 344
WITNESS: MATT MULDOON-JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Simple – Single-Stage – Gordon Growth Discounted Cash Flow (DCF) Modeling

Exhibits in Support of Opening Testimony

April 20, 2018

Simple DCF Model with **Staff Local Natural Gas Distribution Company (LDC) Peers**
AKA: **Gordon Growth Model**
This simple model presumes that whatever is happening next quarter will happen forever.

	A	B	C	D	E	F	G	H	I	
						E/D*(1+H)		$(1+G)^{1/4}-1$	$(1+F+H)^4-1$	
	Utility	Ticker	Staff	Recent Stock Price	2017 VL "Last" Q-3,4 $ Quarterly Dividend	Quarterly Dividend Yield t + 1	Company Combined "LT" Growth Rate	Quarterly VL EPS Growth Rate	Simple DCF ROE %	
1	Atmos	ATO	Yes	86.50	$ 0.45	0.53%	6.8%	1.7%	9.00	1
2	Northwest Natural	NWN	Yes	65.57	$ 0.47	0.73%	6.4%	1.6%	9.50	2
3	ONE Gas	OGS	Yes	75.19	$ 0.42	0.57%	6.3%	1.5%	8.70	3
4	Southwest Gas	SWX	Yes	80.29	$ 0.50	0.63%	6.4%	1.6%	9.00	4
5	Spire	SR	Yes	77.02	$ 0.53	0.69%	4.8%	1.2%	7.70	5
								Average	8.78	

- **A** Staff LDC Peers followed by VL
- **B** Ticker Symbol of A
- **C** Passed Staff Peer Screening (Regulated Utility, No M&A, etc.)
- **D** Recent Price from Table No. BV-GAS found on NW Natural/403 Villadsen/Page 14 of 20.
- **E** Most Recent Q3 or Q4 Dividend of 2017 used by Company.
- **F** Quarterly Dividend Yield for the quarter following **E** used by the Company.
- **G** Combined Weighted "Long-Term" VL and IBES Growth Weight used by the Company.
- **H** Quarterly Growth Rate used by the Company.
- **I** Simple DCF (Gordon Growth) Rate used by the Company.

This is a tool used to introduce students to certain elementary concepts in their first quarter of finance.
If dividends were to grow at a steady rate forever, regardless of everything known otherwise,
then: $P_0 = D_1 / (r - g)$ See NW Natural / 402 Villadsen/Page 3 of 21

P_0	The current stock price
D_1	The quarterly dividend expected in the next quarter
r	The cost of equity capital
g	The perpetual growth rate

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	
										$(1+L)^{1/4}-1$		(O/F)*(1+N)		$(1+L+J)^{4}-1$			
													SIMPLE DCF ROE				
	Utility	Ticker	Staff	NWN Peers w M&A	NWN W/O M & A	Recent Stock Price	VL EPS 2017	VL EPS 2020-2022	Company "Combined LT Growth Rate"	Quarterly Co. Growth Rate	2017 VL "Last" Q-4 $ Quarterly Dividend	t+1 Dividend Yield Co. Growth Rate	Staff Peers	Co. Peers with M&A	Co. Peers without M&A	Utility	
1	Atmos	ATO	Yes	Yes	Yes	86.50	3.61	4.50	6.8%	1.7%	0.4850	0.57%	9.22%	9.22%	9.22%	Atmos	1
2	Chesapeake	CPK	No	Yes	Yes	80.73	2.65	4.20	10.7%	2.6%	0.3250	0.41%	N/A	12.49%	12.49%	Chesapeake	2
3	New Jersey	NJR	No	Yes	No	43.56	1.74	2.05	5.6%	1.4%	0.2730	0.64%	N/A	8.27%	N/A	New Jersey	3
4	Northwest Natural	NWN	Yes	Yes	Yes	65.57	2.25	3.15	6.4%	1.6%	0.4725	0.73%	9.50%	9.50%	9.50%	Northwest Natural	4
5	ONE Gas	OGS	Yes	Yes	Yes	75.19	2.95	4.00	6.3%	1.5%	0.4200	0.57%	8.70%	8.70%	8.70%	ONE Gas	5
6	South Jersey	SJI	No	Yes	No	33.83	1.15	2.00	12.2%	2.9%	0.5530	1.68%	N/A	19.72%	N/A	South Jersey	6
7	Southwest Gas	SWX	Yes	Yes	Yes	80.29	3.55	4.80	6.4%	1.6%	0.4950	0.63%	9.05%	9.05%	9.05%	Southwest Gas	7
8	Spire	SR	Yes	Yes	Yes	77.02	3.80	4.65	4.8%	1.2%	0.5250	0.69%	7.69%	7.69%	7.69%	Spire	8
9	WGL	WGL	No	Yes	No	85.66	3.11	3.15	5.1%	1.3%	0.5100	0.60%	N/A	7.63%	N/A	WGL	9
												Average	8.83%	10.25%	9.44%		
												Range	7.69%-9.50%	7.63%-19.72%	7.69%-12.49%		
												Median	9.05%	9.05%	9.13%		

Staff duplicates NW Natural/403 Villadsen/Page 13 of 20 Table No BV-GAS-6 Value Line Growth Rates
Staff duplicates the NW Natural/403 Villadsen/Page 14 of 20 Table No BV-GAS-6
Note: Staff uses the Company's Combined Growth Rate for discussion purposes only.
Both the Company and Staff appear to target Q4 of 2017 final dividend.
Staff writing testimony later uses the Q4 dividend in all cases rather than the Q3 dividend where the Q4 dividend was not yet know.
K Staff shows dividends with parts of pennies when those are paid out per common share held, while the Company's numbers just display 2 digits.

In General,Staff Disagrees with the Company's

Growth Rates: Staff disagrees that this construct depicts forever at all well, however this is a reasonable rebuild of the Company's model.
Peer Groups: Staff does Not include Chesapeake because of its heavy portion of non-regulated business.
Staff does not include several other utilies in the middle of mergers.

Once basic and logical corrections are made, results are supportive of Staff's 3-stage DCF modeling.
Over manipulating this simple model would make no sense.
Investors and money managers know this model generates an imprecise answer.
If one wants to actually inject information known about the long-run (10- to 30-year) future, one would move to a 3-stage DCF model.

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 208

Cost of Long-Term Debt

Exhibits in Support
of Opening Testimony

REDACTED
April 20, 2018

STAFF EXHIBIT 208

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 18-002

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 209

Recent Investor Presentation

Exhibits in Support
of Opening Testimony

April 20, 2018

LEAD. INNOVATE. GROW.

Investor Presentation
February 2018

NW Natural®

INVESTOR INFORMATION

COMPANY INFORMATION

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FORWARD LOOKING STATEMENTS

This and other presentations made by NW Natural from time to time, may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, which are subject to the safe harbors created by such Act. Forward-looking statements can be identified by words such as "anticipates," "intends," "plans," "seeks," "believes," "estimates," "expects" and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: plans, objectives, goals, strategies, future events, acquisitions and integration thereof, storage, pipeline and other infrastructure investments, commodity costs and sourcing, competitive advantage, service territory, customer service, customer and business growth, weather, customer preference, conversion potential, multifamily development, business risk, efficiency of business operations, regulatory recovery, business development and new business initiatives, water industry and investments, environmental remediation recoveries, gas storage markets and business opportunities, gas storage development, costs, timing or returns related thereto, financial positions and performance, economic and housing market trends and performance shareholder return and value, capital expenditures, liquidity, strategic goals, carbon savings, workforce trends, hedge efficacy, cash flows and adequacy thereof, return on equity, capital structure, return on invested capital, revenues and earnings and timing thereof, margins, net income, operations and maintenance expense, dividends, credit ratings and profile, debt and equity issuances, the regulatory environment, effects of regulatory disallowance, timing or effects of future regulatory proceedings or future regulatory approvals, regulatory prudence reviews, effects of regulatory mechanisms, including, but not limited to, the Company's rate case, tax reform, SRRM and the Company's infrastructure investments, effects of legislation, including but not limited to bonus depreciation and PHMSA regulations and carbon regulations, and other statements that are other than statements of historical facts.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements, so we caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A "Risk Factors," and Part II, Item 7 and Item 7A "Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Quantitative and Qualitative Disclosure about Market Risk" in the Company's most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", and Part II, Item 1A, "Risk Factors", in the Company's quarterly reports filed thereafter.

All forward-looking statements made in this presentation and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

We provide **safe, reliable** and **affordable energy** in an environmentally responsible way to **better the lives** of the public we serve.


INTRODUCTION

NW NATURAL LEADERSHIP

Frank Burkhartsmeyer
Senior Vice President, Chief Financial Officer

Mr. Burkhartsmeyer is currently NW Natural's Senior Vice President and CFO effective May 17, 2017. Previously, Mr. Burkhartsmeyer served as President and CEO of Avangrid Renewables and Senior Vice President of Finance at Iberdrola Renewables US. He also held various director-level positions at PPM Energy (a subsidiary of ScottishPower), ScottishPower and PacificCorp (a subsidiary of ScottishPower). Mr. Burkhartsmeyer has an MBA from the University of Oregon and a Bachelor of Arts in Liberal Arts from the University of Montana.

Brody J. Wilson
Vice President, Treasurer and Chief Accounting Officer & Controller

Mr. Wilson is currently serving as NW Natural's Vice President and Treasurer effective May 17, 2017 in addition to his duties as Chief Accounting Officer and Controller. Mr. Wilson was appointed Chief Accounting Officer and Assistant Treasurer in 2016 and has been serving as NW Natural's Controller since 2013. Prior to joining the Company in 2012, he was a Senior Manager at PricewaterhouseCoopers LLP where he worked in PwC's Energy & Utility Group in Portland, Oregon and London, England. Mr. Wilson holds a Bachelor of Science in Accounting from George Fox University and is a CPA in Oregon.

INVESTMENT HIGHLIGHTS

Stable, Regulated Earnings Profile

- Low-risk business profile with over 95% of revenues from pure-play LDC
- Nearly 740,000 utility customers with nearly 14,000 miles of distribution and transmission mains
- Supportive regulatory environments in Oregon and Washington with progressive recovery mechanisms
- Modern distribution system – no identified cast iron or bare steel

Proven Financial Performance

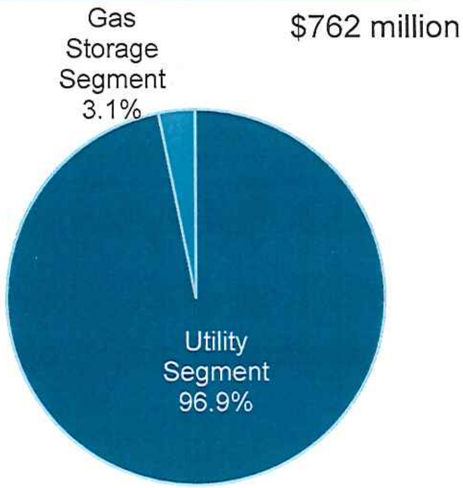
- Stable dividends with 62-year record of increasing annual dividends
- Investment grade credit ratings from S&P and Moody's
- Experienced management team with broad knowledge of the energy industry

Tangible Growth Opportunities

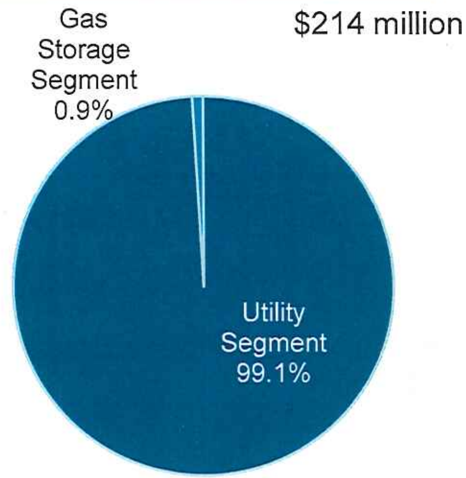
- Projected five-year capital expenditures plan of $750 to $850 million
- LDC service territory experiencing above average customer growth (1.8% for the twelve months ending December 31, 2017)
- Continuous replacement of existing infrastructure to support reliability and safety
- Constructing $132 million regulated expansion of Mist facility, in-service Q4 2018
- Initiated water strategy with two planned acquisitions of small privately owned water utilities

HIGHLY REGULATED BUSINESS

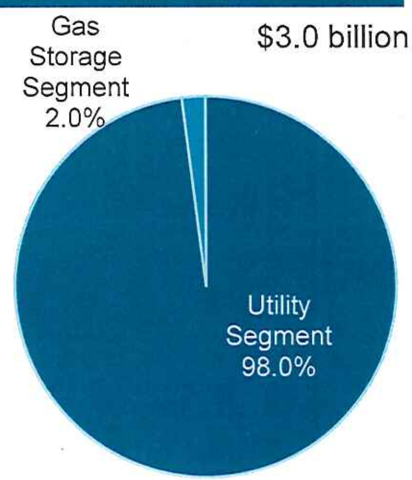
2017 Operating Revenues



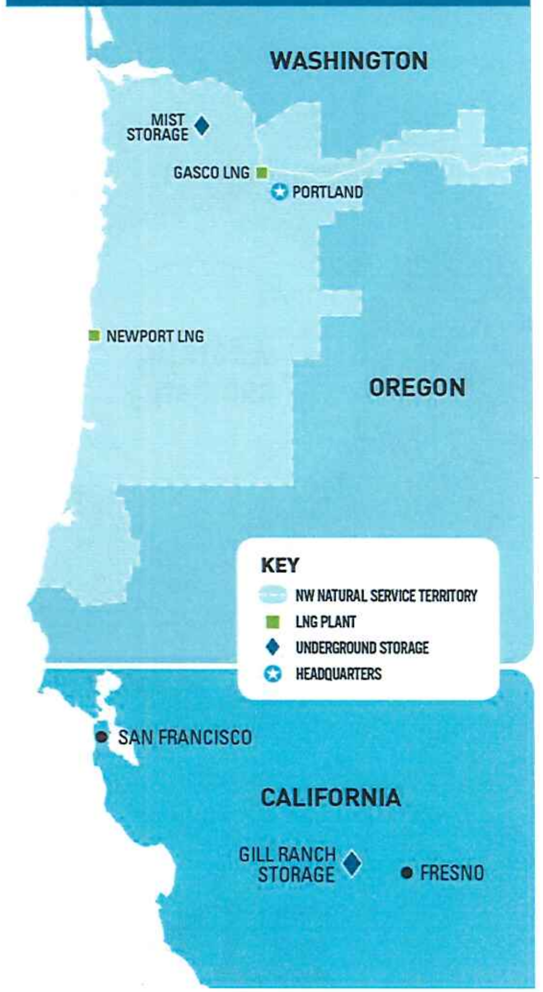
2017 Capital Expenditures



2017 Total Assets

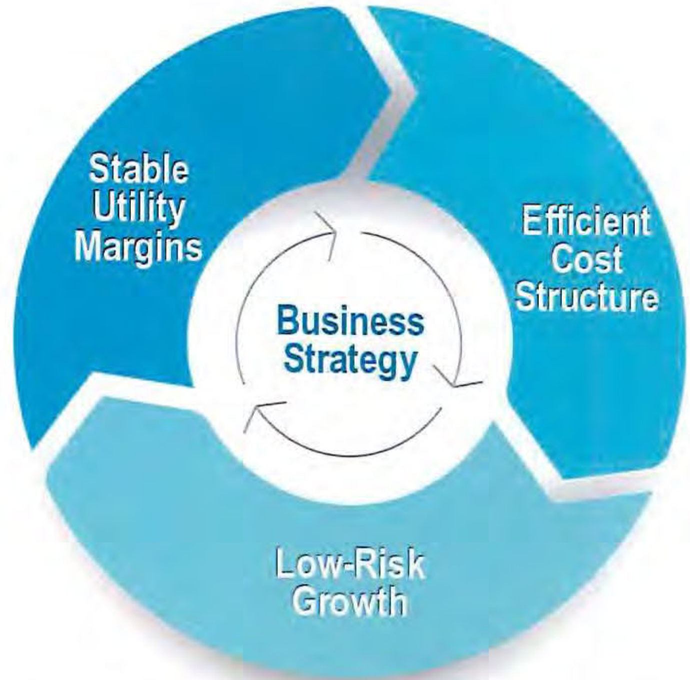


SERVICE TERRITORY AND STORAGE FACILITIES



Notes: Percentages exclude Other segment due to values consistently being less than 1.0% of total.

CONSERVATIVE CORPORATE STRATEGY



Stable utility margins through progressive regulation

- Weather & decoupling mechanisms in Oregon
- Environmental cost recovery mechanism in Oregon
- Constructive relationships with regulators and customer groups

Excellent operations and efficient cost structure

- Commitment to safety, reliability, and quality service
- Continued focus on efficient business operations

Long-term growth opportunities that fit NWN's profile

- Utility: attractive and growing service territory driving above-average customer growth compared to peers and investments
- Mist facility: high-value long-term contracts, asset optimization, North Mist expansion
- Regulated water: announced long-term, disciplined strategy to acquire regulated water utilities in a highly fragmented industry with ample infrastructure investment opportunities

OUR STRATEGIC UTILITY GOALS

Low-Carbon Pathway

Effectively position our Company for a low-carbon future.

- Target: 30% carbon emissions savings associated with current and new customers by 2035, from a 2015 baseline.
- Build public policy coalitions to support this goal.

Constructive Regulation

Further a successful regulatory agenda that serves the interests of customers, benefits the company, meets the duties of regulators and furthers stakeholders' missions.

Enable Growth

Channel our organizational energies around revenue growth so we can succeed in an increasingly competitive and complex marketplace.

- Simplify processes and leverage technology.
- Examine our tariffs to meet new market demands and a low-carbon business model.

Superior Customer Experience

Improve processes, deploy new technology and use metrics to continually improve and meet evolving customer expectations.

Continue to drive operational priorities that ensure we are delivering safe, reliable and superior service.

Workforce of the Future

Foster a culture of accountability, creativity and collaboration that is inclusive and supports opportunities for cross-functional effectiveness.

Photo courtesy: Andy Bauer

CORE UTILITY SEGMENT

Over 95% of Revenues and Assets from Pure-Play LDC

Attractive Service Territory

- About 89% of customer base in Oregon and 11% in Washington
- Territory covers over 75% of Oregon's population
- Includes Clark County, Washington — historically rapidly growing area that is projected to be the fastest growing county in Washington[1]
- Supportive and progressive regulation

Growth Potential

- Organic opportunities — gas in about 63% of single-family homes
- Strong customer growth
- Positive economic trends and housing fundamentals in region

Safe, Reliable Service

- Strong safety record
- Modern distribution and transmission system — No known cast iron and bare steel since 2015
- State of the art training facility
- Hands-on scenario-based safety training
- Outstanding customer satisfaction — #1 in West, JD Power and Associates (2017)
- Resource diversity — 11 Bcf regulated gas storage and 2 Bcf LNG storage

Focus on Safety

Cap-Ex Focused on Safety, Reliability, and Growth

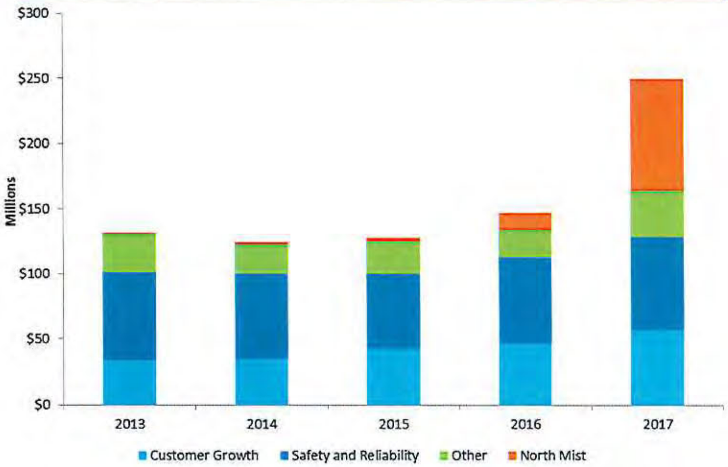


Chart above is based on accrual capital expenditure figures.

[1]Source: Woods & Poole 2015 Forecast projects Clark County to have the highest rate of population growth from 2010 to 2050 among Washington counties.

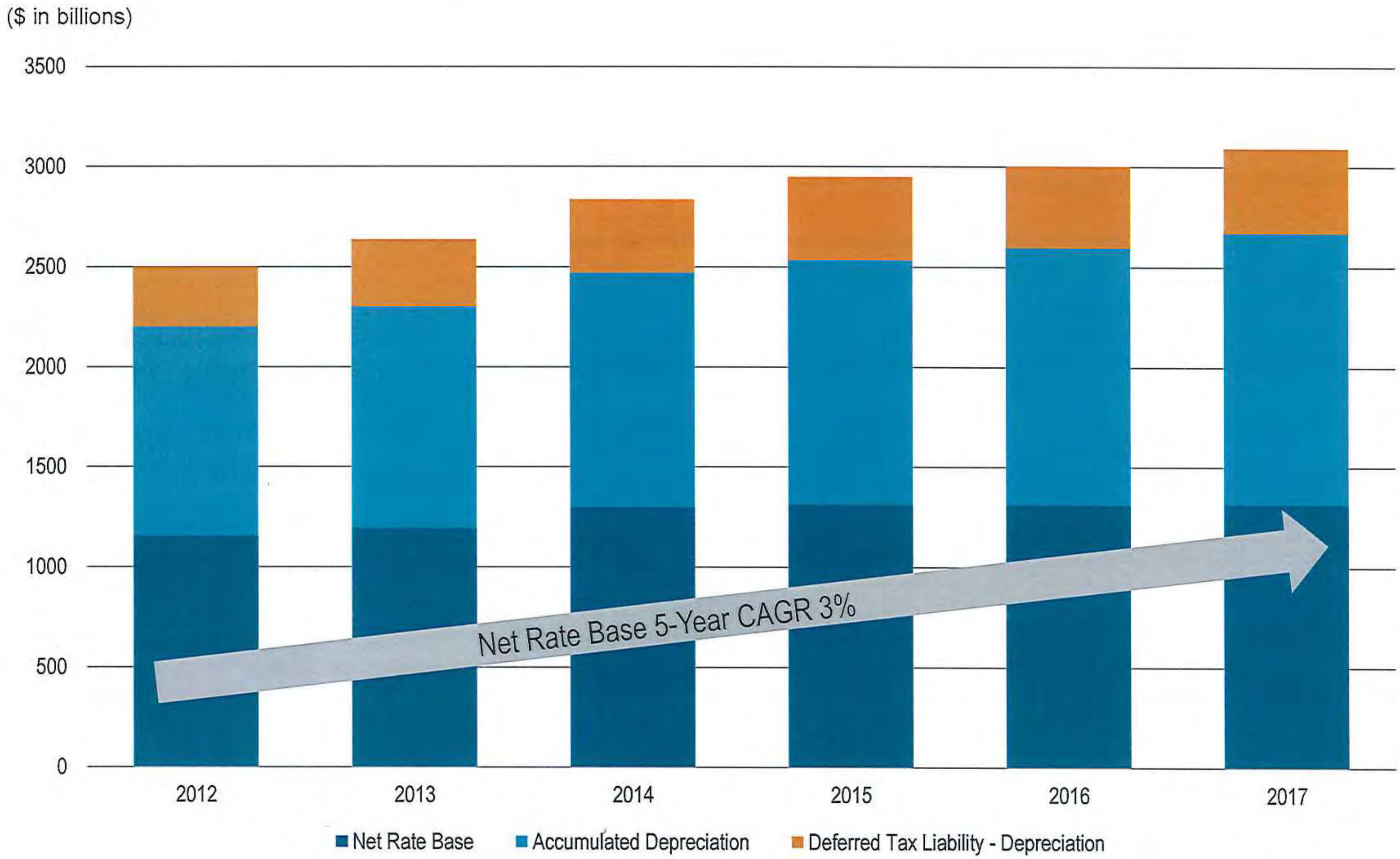
KEY REGULATORY ITEMS

	Oregon	Washington
Rate Structures:		
Rate Case Year	2012	2009
ROE	9.5%	10.1%
ROR	7.8%	8.4%
Equity Ratio	50%	51%
2017 Rate Base	$1.2B	$0.1B
Key Mechanisms:		
Decoupling/WARM	X	
Purchased Gas Adjustment	X	X
Environmental Cost	Recovery	Deferral(1)
Pension Balancing	X	
Incentive Sharing(2)	X	X

(1) Washington allows deferral of environmental costs, but a cost recovery mechanism or methodology has not yet been established by the Washington Commission. A carrying charge related to deferred amounts will be determined in a future proceeding.

(2) In Oregon, NW Natural shares PGA gains and losses. In both Oregon and Washington, NW Natural shares with customers revenues it achieves through interstate storage and optimization activities.

GROWING RATE BASE



SUPPORTIVE MECHANISMS

Oregon	**Decoupling**	• Breaks link between earnings and consumption by removing incentive to increase usage • Employs use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes
Oregon	**Weather Normalization (WARM)**	• Stabilizes collection of fixed costs for residential and commercial customers • Adjusts billings based on temperature variances compared to average weather • Applied from December through May of each heating season
Oregon and Washington	**Purchased Gas Adjustment (PGA)**	• Adjusts annual rates to reflect changes in expected cost of gas commodity purchases • Includes spot purchases, contract supplies, derivatives, storage inventories, in OR gas reserves • Includes temporary rate adjustments amortizing deferred regulatory account balances
Oregon and Washington	**Environmental Cost Deferral**	• Allows for deferral of environmental costs and in OR the accrual of carrying costs • Recovers environmental costs allocated to OR through a site remediation recovery mechanism (SRRM), subject to an annual prudence review and earnings test[1] • Defer costs in WA, recovery & carrying charge to be determined in future proceeding
Oregon	**Pension Balancing**	• Defers annual pension expenses above the amount set in rates • Expect deferral account to come to zero after nearer-term years of higher pension costs are balanced with future years of lower pension costs

(1) To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

2018 OREGON RATE CASE

Key Components of Filing

On Dec. 29, 2017 we filed an Oregon general rate case to support operating and maintaining our distribution system and continue providing safe reliable service to our customers. Our request included:

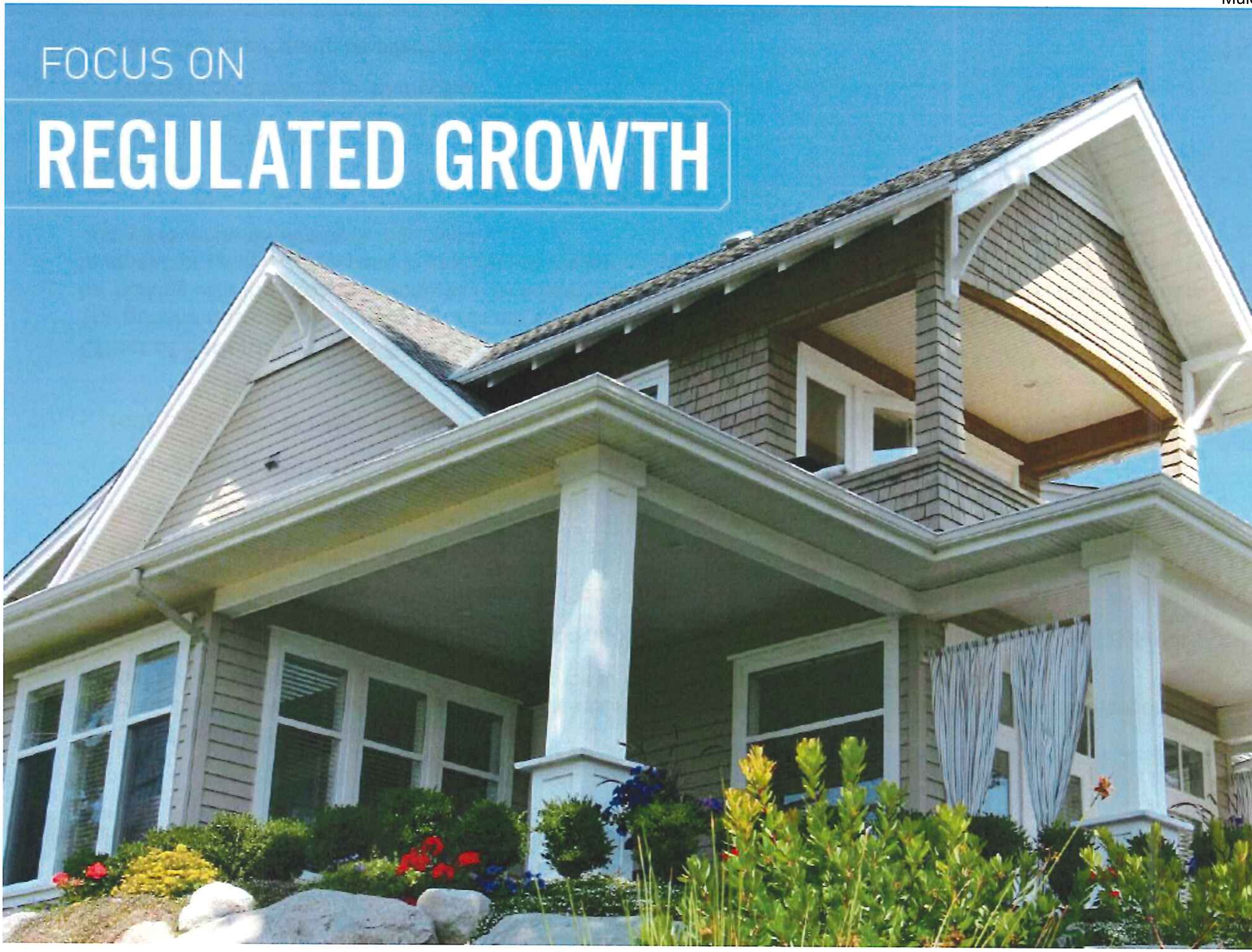
- Revenue requirement increase of $40.4 million or 6% after an adjustment for the conservation tariff deferral
- Forward test year from Nov. 1, 2018 through Oct. 31, 2019
- Capital structure of 50% debt and 50% equity
- Return on equity of 10.0%
- Cost of capital 7.62%
- Rate base of $1.19 billion or an increase of $304 million since the last Oregon rate case in 2012

Effect of Federal Tax Cuts & Job Act

The general rate case filing does not include the benefit to customers' rates of the federal tax legislation. We will be working with the Oregon Commission to determine how to return these benefits to customers, and we expect to amend or refile our rate case to incorporate the benefit of federal tax reform, which would likely lower the original revenue requirement requested.

Timeline

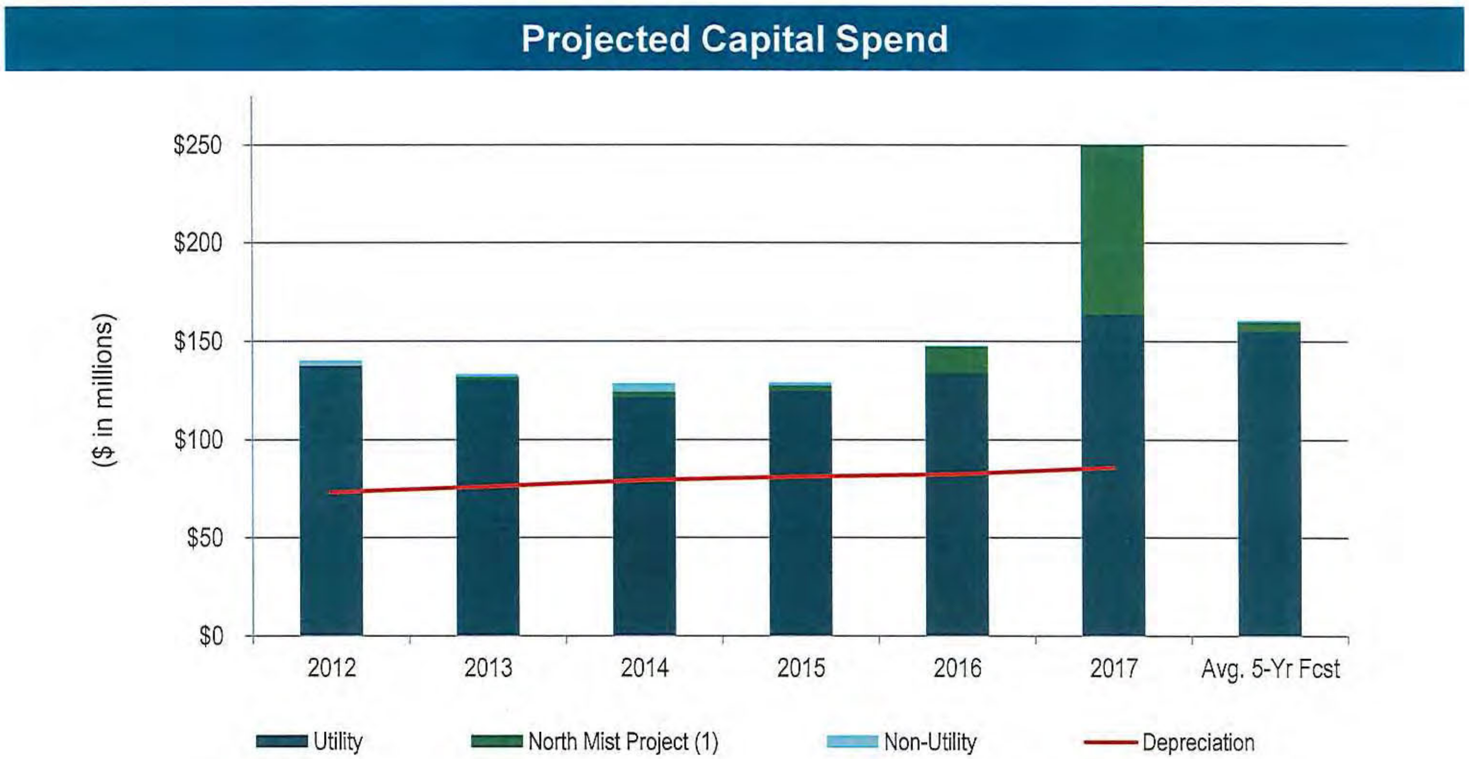
- Filed on Dec 29, 2017
- Process could take up to 10 months
- New rates expected to be effective Nov. 1, 2018


FOCUS ON
REGULATED GROWTH

HISTORICAL & PROJECTED CAPITAL SPEND

Projected Investment of $750 to $850 million in from 2018 to 2022

- Strong organic customer growth from new construction and conversions
- Reliability and maintenance cap-ex with projects to upgrade Mist gas storage facility and resource centers
- Completing North Mist gas storage expansion in Oregon to support renewables in region



(1) Total project spend is currently estimated at $132 million.

HIGH-GROWTH TERRITORY

Strong Total Customer Growth Rate of 1.8% for 12 Months Ended December 31, 2017

Residential - Over 60% of utility margin with growth rate of 1.8% for 2017

Commercial - Over 25% of utility margin with growth rate of 1.1% for 2017

Industrial - Less than 10% of utility margin with growth rate of 0.8% for 2017

INNOVATIVE ACQUISITION TOOL

Competitive Advantage

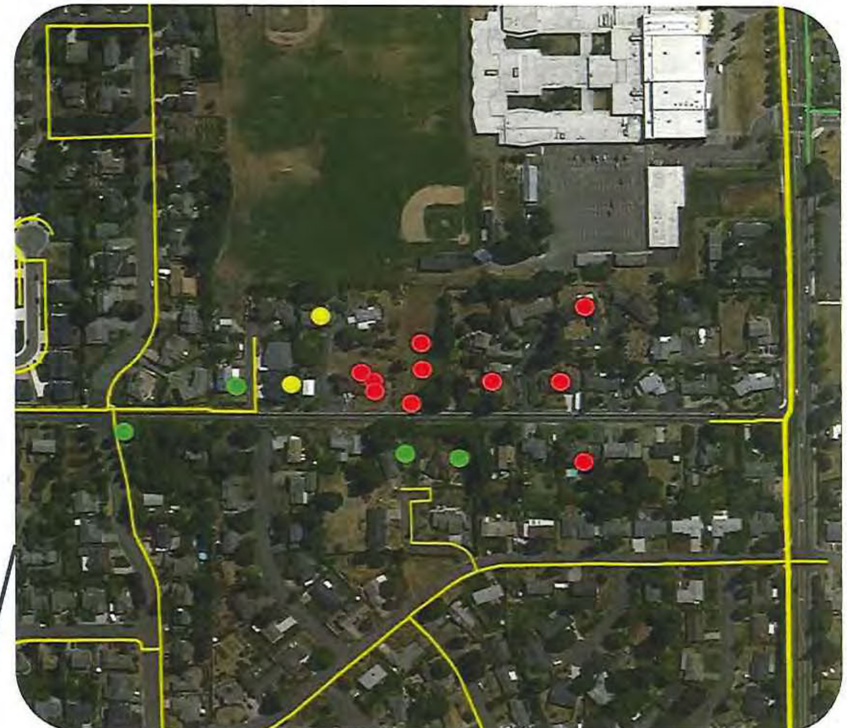
- Preferred energy source with recent survey showing 9 out of 10 new or future homeowners primarily in the Portland/Vancouver area would pick a home with all natural gas appliances versus electric
- Low-cost, reliable, clean energy choice
- Natural gas in approximately 63% of single-family homes

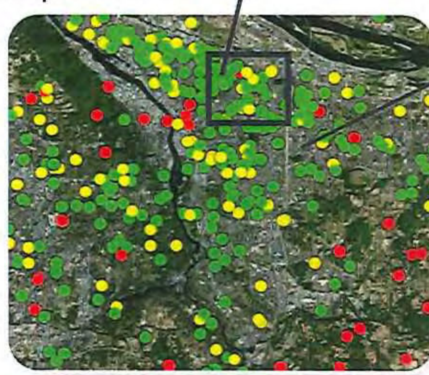
Customer Connections Portal

- Cutting edge web-based tool for targeted conversions, validates customer interest
- Enhanced web services for trade allies

Leveraging the Portal

- Ability to identify potential main extensions
- Beginning to identify targets and analyze cost profiles





FOCUSING ON MULTIFAMILY

Market activity

- Increase in multifamily construction, especially mixed-use developments in urban areas
- Tight rental market, in-migration, and positive economic trends have led to stable growth in Portland area
- Despite some cooling, the Portland market remains strong

Executing on the Opportunity

- See apartments as an untapped growth opportunity and a priority segment moving forward
- Analyzed renter preferences and natural gas availability - showing a competitive opportunity
- Created comprehensive marketing program, including a streamlined piping design, technical support and financial incentives to target apartment developers and pursue sector
- Multifamily tariff approved in July 2017

INVESTING FOR RELIABILITY & GROWTH

Mist Gas Storage & Resource Center Upgrades
- Refurbishments, replacements, and upgrades
- Projects totaling $60-$70 million from 2018 – 2022

Vancouver, Washington Infrastructure
- Fastest growing region in service territory
- Upgrades underway totaling approx. $25 million with construction from 2015 – 2018

System Integrity, Replacement, and Betterments
- General system replacements and betterments at Mist, operating facilities, and information technology enhancements
- Proposed PHMSA gas safety regulations in April 2016; comment phase in 2016; expect final rules in 2018

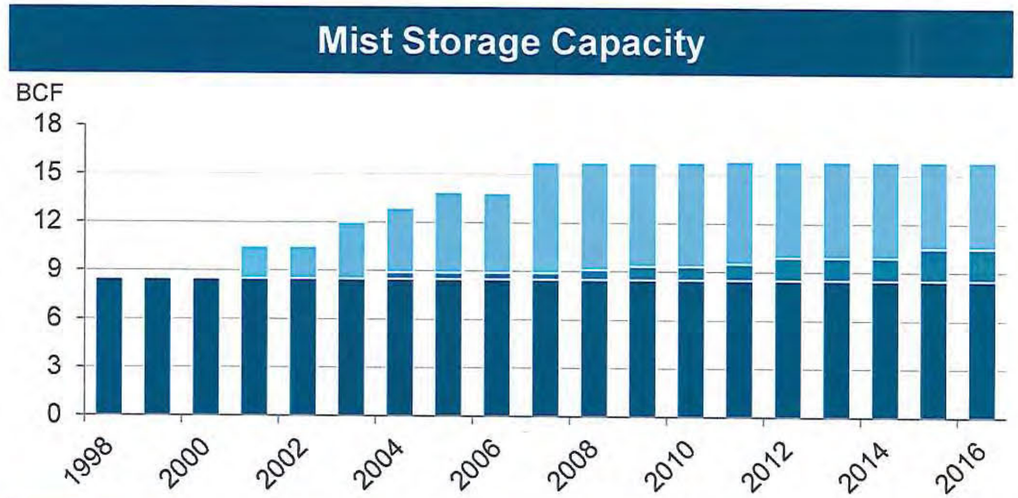
UTILITY STORAGE AT MIST

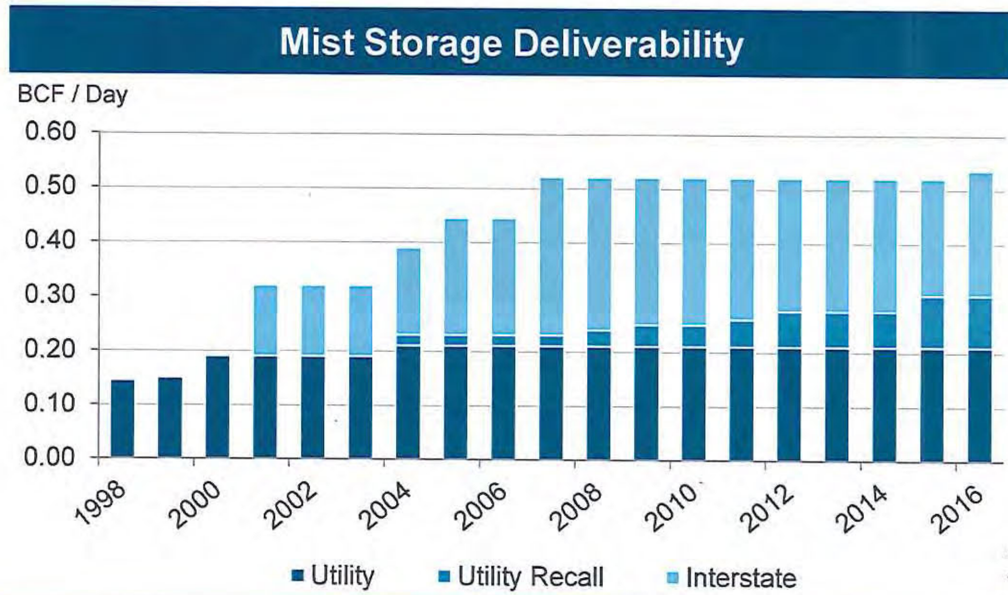
Overview

- In operation since 1989
- Storage capacity at Mist 16 Bcf
  - 11 Bcf Core Utility
  - 5 Bcf Interstate Storage Services

Unique Asset

- Limited storage options in Pacific Northwest
- Part of utility's diverse, reliable gas supply strategy
- Utility can recall Interstate portion for Core Utility demand
- Optimize Interstate portion and share with customers

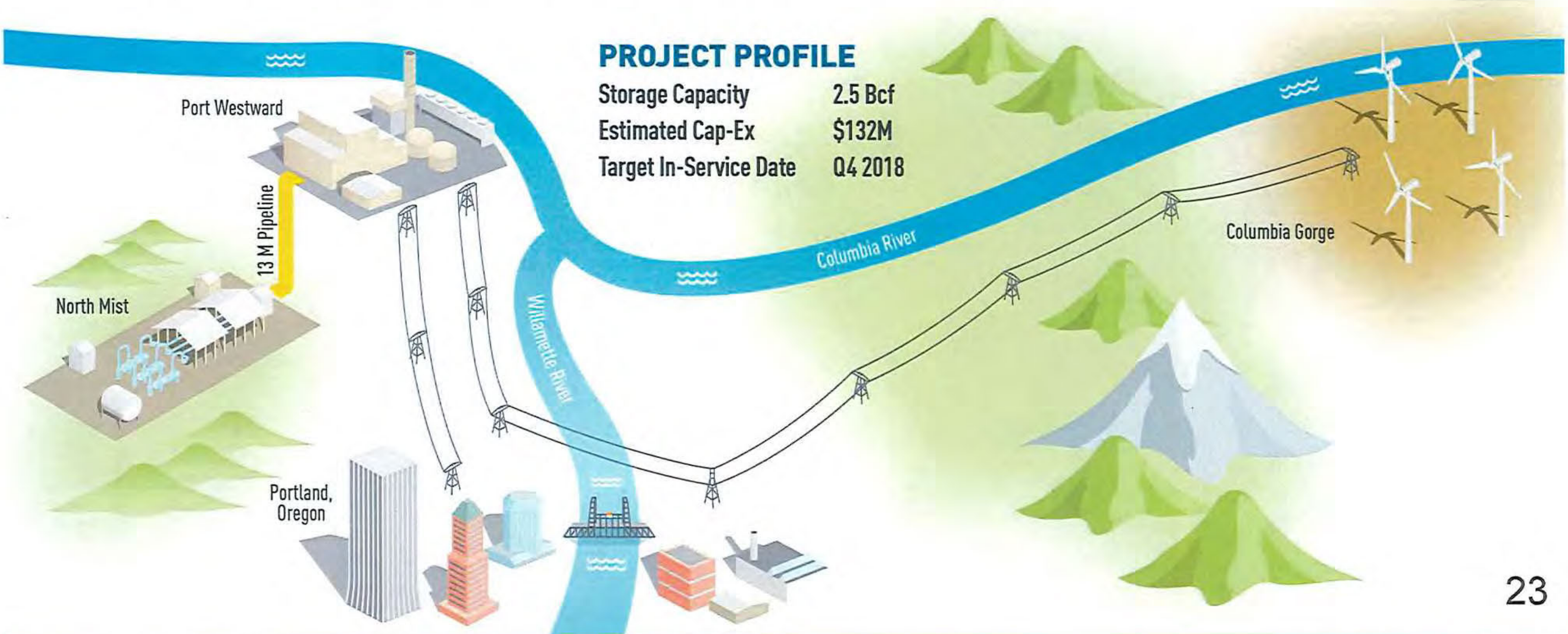




REGULATED EXPANSION

North Mist gas storage expansion supporting the integration of renewables

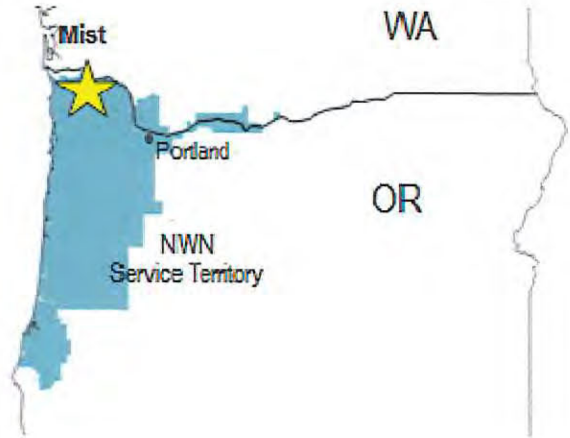
- Innovative no-notice 24/7 storage service supporting gas-fired electric generating facilities that are integrating wind into energy generation mix
- Contracted under long-term agreement with single-customer: Portland General Electric
- Included in rate base under established tariff schedule when placed into service with an initial 30-year contract and options to extend up to an additional 50 years




GAS STORAGE

MIST STORAGE

- 5 Bcf of the total 16 total Bcf Mist storage facility serves Interstate market and is reported in Gas Storage Segment
- Remaining 11 Bcf of the Mist gas storage facility is dedicated to serving utility customers and is reported in the Utility Segment
- High-value asset in premium geographic location with limited competition from other Pacific Northwest storage facilities
- Facility fully contracted with longer-term, multi-year contracts
- Strong and stable operating results
- Interstate capacity is fully recallable by the utility in the future



16 Bcf Total Mist Gas Storage Capacity

GILL RANCH STORAGE

- Determined Gill Ranch is no longer central to our long-term regulated growth strategy and we will pursue all strategic options to maximize the value of the facility
- At Dec. 31, 2017 recognized non-cash impairment of $193 million pre-tax ($142 million after-tax)

Background

- NW Natural owns 15 Bcf or 75% of the 20 Bcf Gill Ranch storage facility near Fresno, CA. PG&E owns the remaining 5 Bcf or 25% of the Gill Ranch facility.
- California storage challenged by low market prices and low price volatility due to abundant supply of natural gas and storage facilities in region
- Gill Ranch remains in short-term contracts at lower prices relative to our original contracts for the facility


WATER

STRATEGIC RATIONALE

Strategy & Core Competencies

- NWN strives to provide stable earnings streams that have a similar risk and cash flow profile as our regulated gas utility.
- The regulated water sector fits our conservative business profile and provides an avenue to add value
- Aligns with our core competencies including: customer service, developing and managing critical distribution infrastructure safely and reliably, environmental stewardship, and constructive regulatory engagement
- Deliberate and disciplined roll-up strategy focused on Pacific Northwest

Water Sector Characteristics

- Water industry represents a substantial infrastructure investment opportunity
- Highly-fragmented industry
  - In the West there are about 17,000 privately held water systems
  - Of that 17,000 there are more than 16,000 systems with fewer than 1,000 customers
  - Oregon has nearly 1,600 water systems serving 1.5 million customers

PLANNED ACQUISITIONS

Salmon Valley and Falls Water Companies

- In December 2017 NW Natural entered into agreements to acquire Salmon Valley Water Company and Falls Water Company, two privately owned water utilities in the Pacific Northwest
- Salmon Valley, based in Welches, Ore., serves approximately 975 customers, and Falls Water, based in Idaho Falls, Idaho, serves approximately 5,500 customers
- The financial implications of these transactions are immaterial to NW Natural's consolidated results

Approvals and Timeline

- The transactions are subject to certain conditions, including approvals by the Public Utility Commission of Oregon and the Idaho Public Utilities Commission
- Expect transactions to close in 2018


FINANCIAL PERFORMANCE

2017 CONSOLIDATED RESULTS

	2017				2016				Change	
In millions, except per share data	Pre-Tax	Tax	After-Tax	Per Share	Pre-Tax	Tax	After-Tax	Per Share	After-Tax	Per Share
GAAP net income (loss)			$ (55.6)	$ (1.94)			$ 58.9	$ 2.12	$ (114.5)	$ (4.06)
Gill Ranch impairment	$ 192.5	$ (51.0)	141.5				—		141.5	
Regulatory disallowance			—		$ 3.3	$ (1.3)	2.0		(2.0)	
Tax reform benefit	—	(21.4)	(21.4)				—		(21.4)	
Adjusted net income			$ 64.5	$ 2.24			$ 60.9	$ 2.19	$ 3.6	$ 0.05
Diluted shares				28.7				27.8		0.9

- GAAP net loss of $1.94 for 2017 primarily driven by Gill Ranch impairment partially offset by benefits from tax reform
- Adjusted net income grew 5 cents to $2.24 for 2017, compared to $2.19 for 2016 reflecting the strongest utility customer growth in a decade and colder weather partially offset by higher O&M
- Adjusted net income excludes the non-cash impact of the Gill Ranch impairment and tax reform in 2017 and the regulatory environmental disallowance in 2016 to provide comparability with previous periods and transparency into underlying drivers of results. See Non-GAAP reconciliation in Appendix.

Strong utility performance offset by accounting impairment due to Gill Ranch, partially offset by tax reform

STRONG BALANCE SHEET & AMPLE LIQUIDITY

Strong Cash Flows and Liquidity

Cash Flows

- Operating cash flows support capital needs
- Environmental mechanism providing ongoing cash flow for environmental cost recovery

Tax Reform: Generally favorable, some cash flow impacts

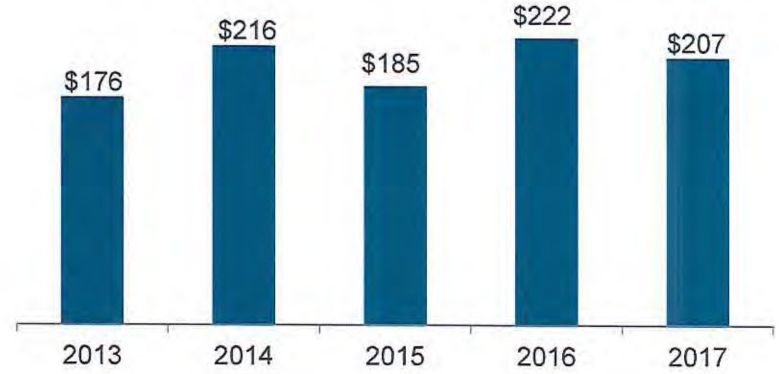
- **Earnings** – Modest long-term earnings uplift from additional rate base growth. Tax expense benefit of $21 million in 2017 from re-measurement of deferred taxes associated with non-utility operations
- **Balance Sheet** - Recorded $213 liability at 12/31/2017 for historical deferred taxes to be returned to customers
- **Cash Flows** – Some near-term pressure from early elimination of bonus depreciation with long-term upside from higher rate-base growth
- Working with regulators to determine details of returning benefits to customers

Liquidity

- $300 million credit facility through 2019
- Access to capital markets
- Solid credit ratings(1)

Cash Flow from Operations

($ in millions)



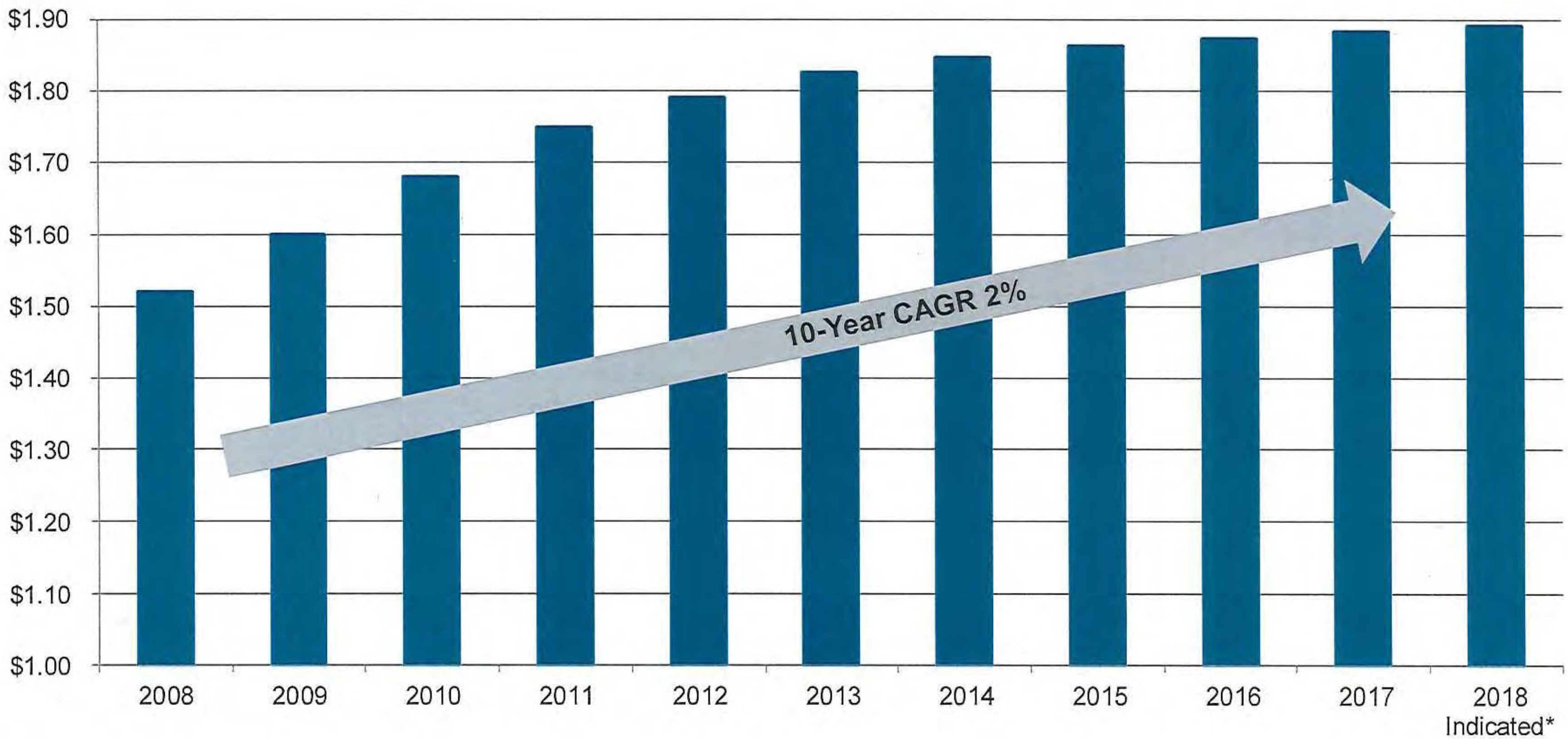
Credit Ratings(1)

	S&P	Moody's
Secured Debt	AA-	A1
Commercial Paper	A-1	P-2
Outlook	Stable	Negative

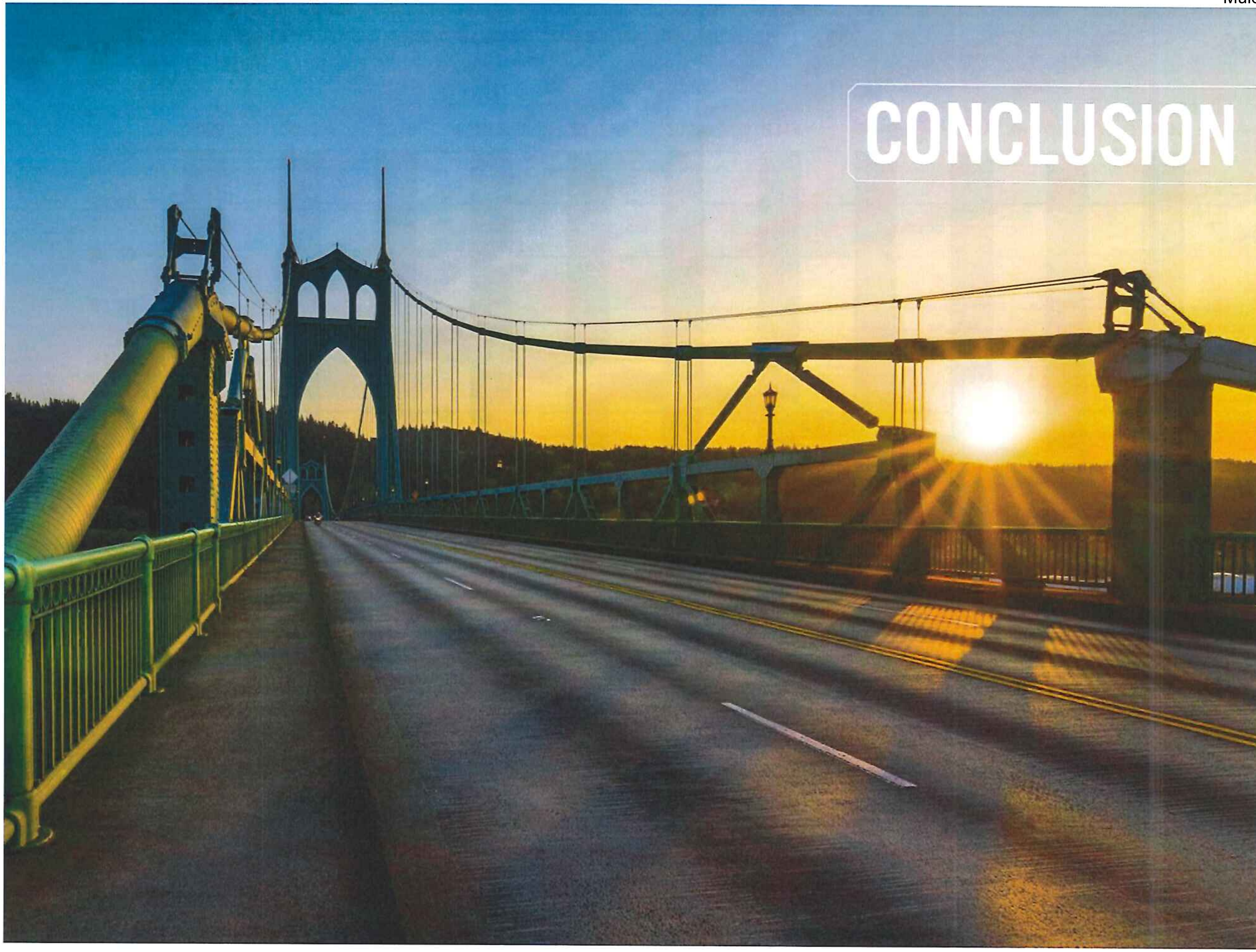
(1) The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities.

LEGACY OF INCREASING DIVIDENDS

- 2017 marked the 62nd consecutive year of increasing dividends to shareholders
- Supported by strong and stable cash flows



* Future dividends are subject to Board of Director discretion and approval.


CONCLUSION

CONSISTENT STRATEGY

Stable utility margins

- Company results reflect strong growth from utility
- Utility-focused business with stable core customer revenues
- Organic growth potential with strong economics driving single and multifamily construction

Excellent operations and efficient cost structure

- Consistently high customer satisfaction ratings and system reliability
- Strong balance sheet and cash flows
- 62-year history of increasing annual dividends to shareholders

Long-term growth opportunities

- Growing natural gas utility with innovative ideas and programs for continued growth
- Mist gas storage facility opportunities for high-value long-term contracts, asset optimization, and North Mist expansion
- Long-term, disciplined regulated water strategy to acquire utilities in a highly fragmented industry with infrastructure investment opportunities
- Regional pipeline expansion opportunity

INVESTMENT HIGHLIGHTS

Stable, Regulated Earnings Profile

- Low-risk business profile with 95%+ of revenues from pure-play LDC
- Nearly 740,000 utility customers with nearly 14,000 miles of distribution and transmission mains
- Supportive regulatory environments in Oregon and Washington with progressive recovery mechanisms
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- Continuous replacement of existing infrastructure to support reliability and safety
- Constructing $132 million regulated expansion of Mist facility, in-service Q4 2018
- Initiated water strategy with two planned acquisitions of small privately owned water utilities


APPENDIX

NON-GAAP RECONCILIATION

In thousands, except per share data	Twelve Months Ended December 31, 2017 Amount	2017 Per Share	2016 Amount	2016 Per Share
CONSOLIDATED				
GAAP consolidated net income (loss)	$ (55,623)	$ (1.94)	$ 58,895	$ 2.12
Adjustments, pre-tax:				
Gill Ranch impairment[1]	192,478	6.71	—	—
Regulatory environmental disallowance[2]	—	—	3,300	0.12
Income tax effect of pre-tax adjustments[1,2]	(50,956)	(1.78)	(1,304)	(0.05)
Income tax benefit from tax reform[3]	(21,429)	(0.75)	—	—
Adjusted consolidated net income	$ 64,470	$ 2.24	$ 60,891	$ 2.19
Diluted shares		28,669		27,779
UTILITY				
GAAP utility net income	$ 60,509	$ 2.11	$ 54,567	$ 1.96
Adjustments, pre-tax:				
Regulatory environmental disallowance[2]	—	—	3,300	0.12
Income tax effect of pre-tax adjustment[2]	—	—	(1,304)	(0.05)
Income tax expense from tax reform[3]	1,036	0.03	—	—
Adjusted utility net income	$ 61,545	$ 2.14	$ 56,563	$ 2.03

[1] Gill Ranch non-cash impairment recognized as of Dec. 31, 2017. Tax effect of adjustment is calculated using a combined federal and state statutory rate of 26.5%.
[2] Regulatory environmental non-cash disallowance taken in the first quarter of 2016 related to the Company's compliance filing under the environmental recovery mechanism with the total pre-tax charge of $3.3 million recorded in utility other income ($2.8 million) and utility operation and maintenance expense ($0.5 million). Tax effect of adjustment is calculated using a combined federal and state statutory rate of 39.5%.
[3] Tax reform non-cash (benefit) expense recognized in income tax expense as a result of feral tax rate changing from 35% to 21% effective Dec. 22, 2017.

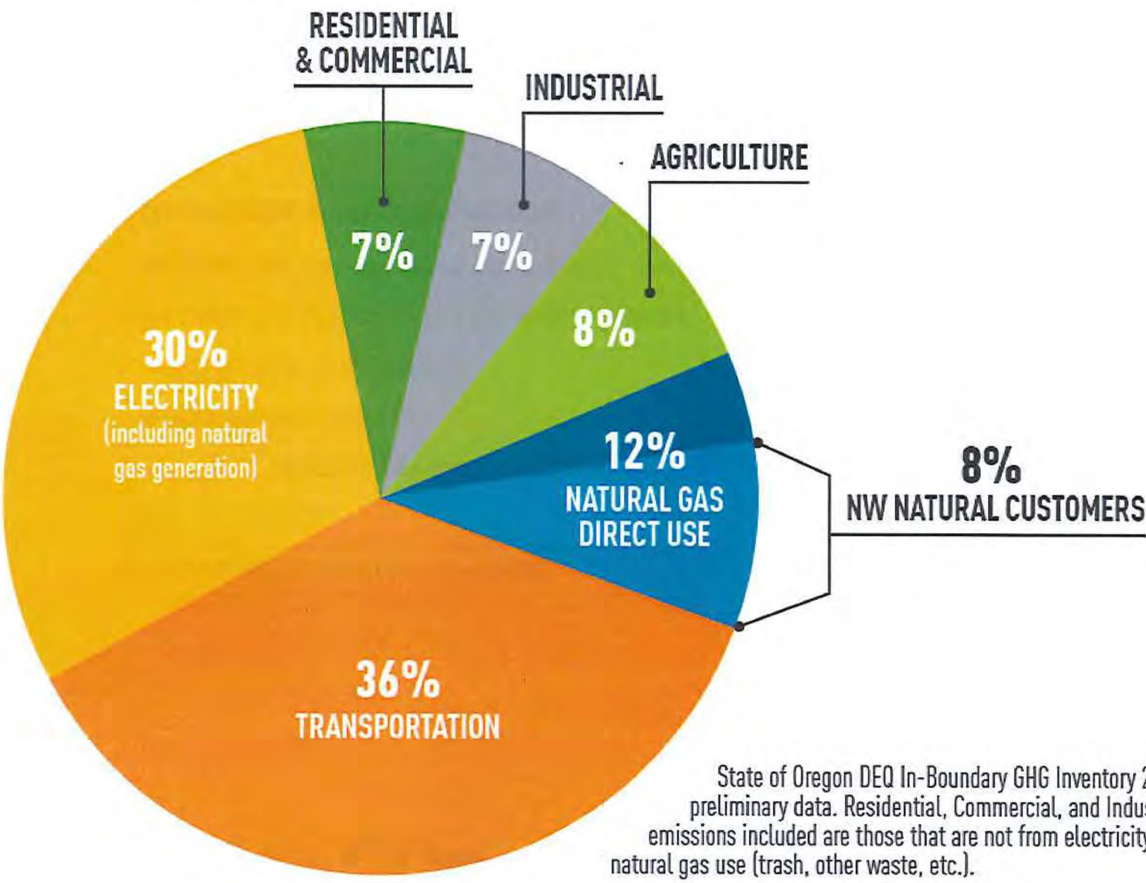
NON-GAAP RECONCILIATION

In thousands, except per share data	Twelve Months Ended December 31, 2017 Amount	2017 Per Share	2016 Amount	2016 Per Share
GAS STORAGE				
GAAP gas storage net income (loss)	$ (116,209)	$ (4.05)	$ 4,303	$ 0.16
Adjustments, pre-tax:				
Gill Ranch impairment[1]	192,478	6.71	—	—
Income tax effect of pre-tax adjustments[1]	(50,956)	(1.78)	—	—
Income tax benefit from tax reform[3]	(21,869)	(0.76)	—	—
Adjusted gas storage net income	$ 3,444	$ 0.12	$ 4,303	$ 0.16
OTHER				
GAAP other net income	$ 77	$ —	$ 25	$ —
Income tax benefit from tax reform[3]	(596)	(0.02)	—	—
Adjusted other net income (loss)	$ (519)	$ (0.02)	$ 25	$ —

[1] Gill Ranch non-cash impairment recognized as of Dec. 31, 2017. Tax effect of adjustment is calculated using a combined federal and state statutory rate of 26.5%.
[2] Regulatory environmental non-cash disallowance taken in the first quarter of 2016 related to the Company's compliance filing under the environmental recovery mechanism with the total pre-tax charge of $3.3 million recorded in utility other income ($2.8 million) and utility operation and maintenance expense ($0.5 million). Tax effect of adjustment is calculated using a combined federal and state statutory rate of 39.5%.
[3] Tax reform non-cash (benefit) expense recognized in income tax expense as a result of feral tax rate changing from 35% to 21% effective Dec. 22, 2017.

NWN SYSTEM HIGHLY EFFICIENT

Oregon's GHG Emissions



State of Oregon DEQ In-Boundary GHG Inventory 2015 preliminary data. Residential, Commercial, and Industrial emissions included are those that are not from electricity or natural gas use (trash, other waste, etc.).

NW Natural's System

- **Heats 74%** of residential square footage in the areas we serve
- **Provides 90%** of peak day energy needs for our residential space and water heat customers
- Yet, of the total 12% in the state our customers' emissions **account for just 8%** of Oregon's total carbon emissions

OUR LOW-CARBON PATHWAY

VOLUNTARY GOAL: 30% CARBON SAVINGS BY 2035

OUR PRODUCT	OUR CUSTOMERS	TRANSPORTATION
REDUCE CARBON INTENSITY	REDUCE AND OFFSET CONSUMPTION	REPLACE MORE CARBON INTENSIVE FUELS
NW NATURAL OPERATIONS UPSTREAM METHANE REDUCTION RENEWABLE NATURAL GAS POWER TO GAS (hydrogen pathway)	ENERGY EFFICIENCY SMART ENERGY (voluntary offsets) GAS + RENEWABLE HYBRID EQUIPMENT (solar thermal)	CNG AND RNG SERVE TRASH TRUCKS AND RETURN-TO-BASE FLEETS
achievable savings 5↔20% low to high case	achievable savings 15↔30% low to high case	achievable savings 1↔5% low to high case

Baseline: 2015 emissions associated with customer use.

CURRENT COMMISSIONERS

Oregon Commission (OPUC)

Lisa Hardie, Chair (D)

- Appointed June 2016
- Current term ends May 2020

Stephen Bloom, Commissioner (R)

- Originally appointed December 2011
- Reappointed May 2016
- Current term ends November 2019

Megan Walseth Decker, Commissioner (D)

- Appointed April 2017
- Term ends March 2021

Washington Commission (WUTC)

David Danner, Chair (D)

- Appointed chair February 2013
- Current term ends January 2019

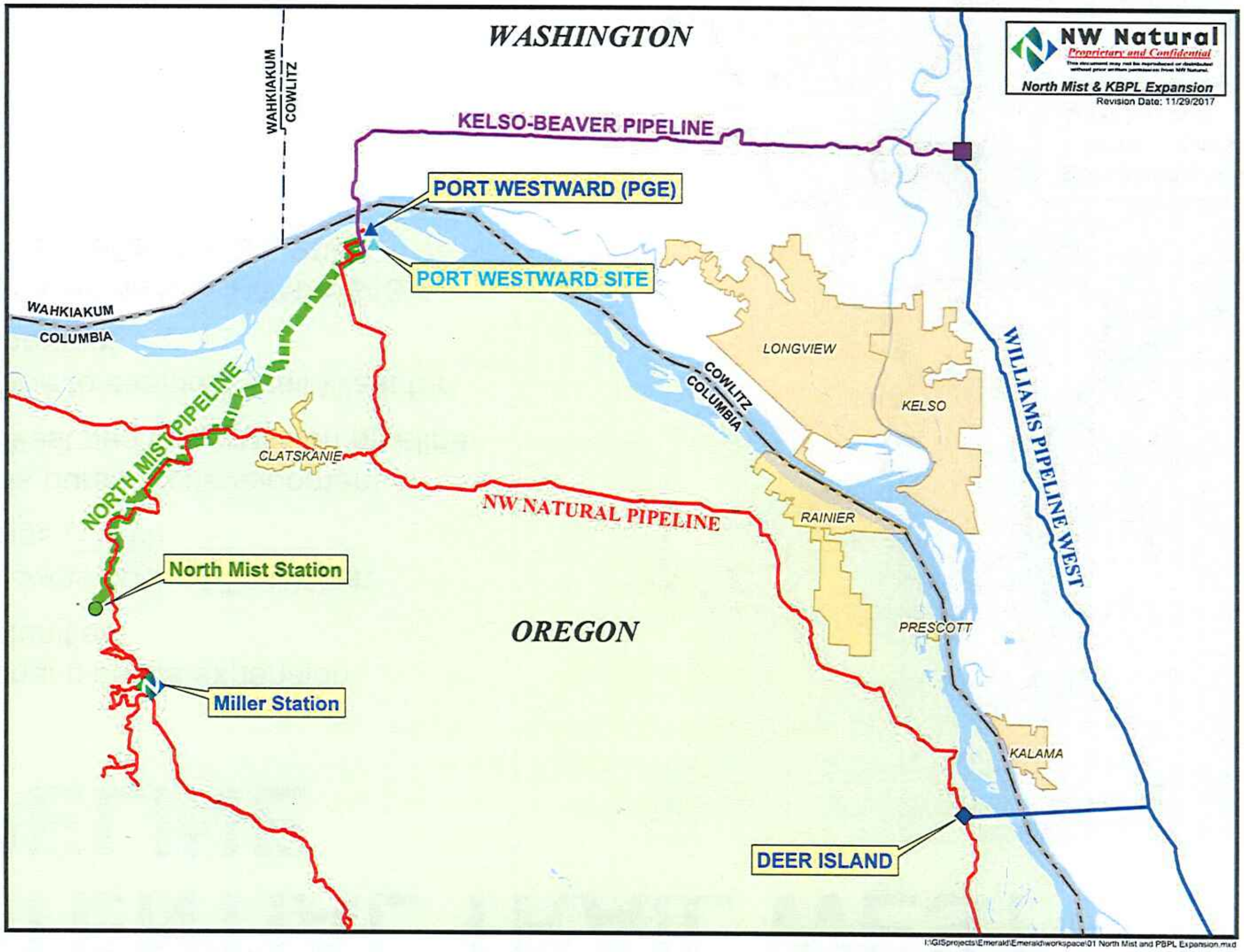
Ann Rendahl, Commissioner (D)

- Appointed December 2014
- Current term ends November 2020

Jay Balasbas, Commissioner (R)

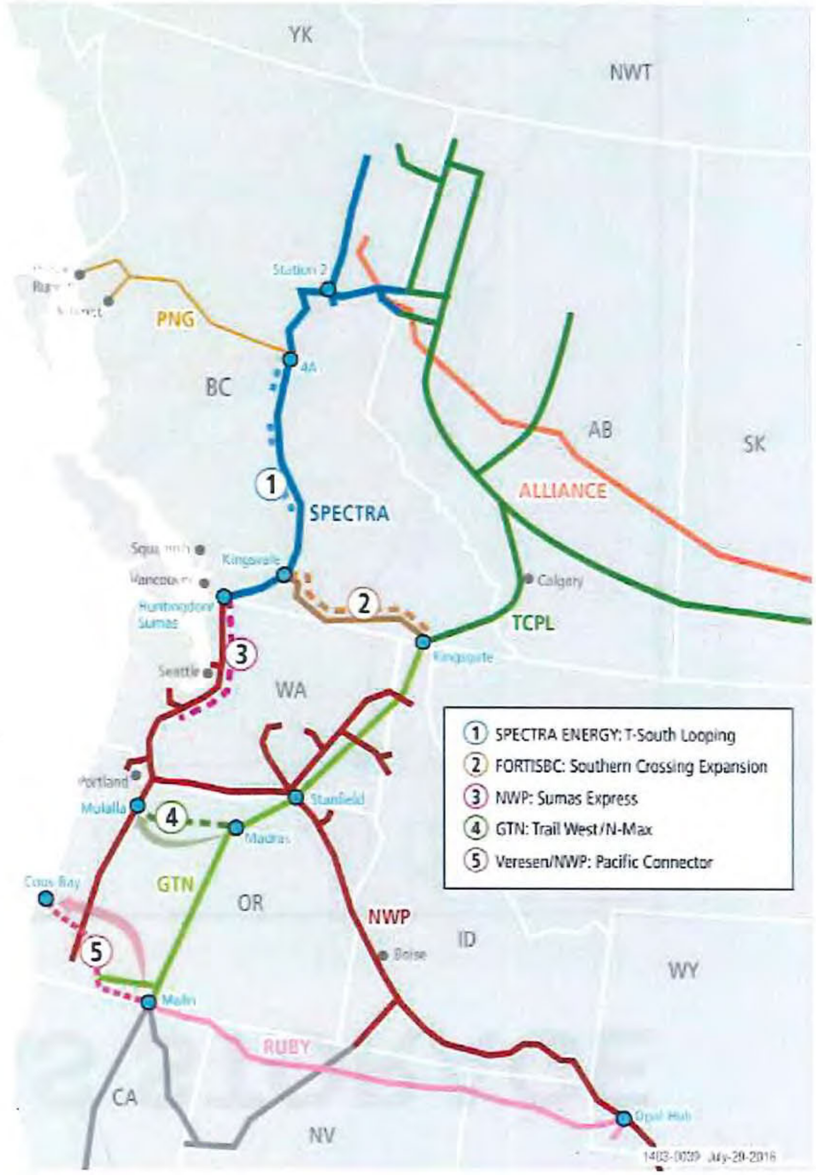
- Appointed May 2017
- Term ends January 2023

NORTH MIST GAS STORAGE



POTENTIAL TRAIL WEST PIPELINE

- Regional pipeline expansion opportunities
- NWN owns 50% of Trail West Holdings (TWH)
- TWH is pursuing development of Trail West gas transmission pipeline
- Continue to evaluate Trail West for development
- NWN investment in TWH is $13.4 million at December 31, 2017



LEAD. INNOVATE. GROW.

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 210

Value Line (VL)
Natural Gas Utility Profiles

Exhibits in Support
of Opening Testimony

April 20, 2018

Many stocks in *Value Line's* Natural Gas Utility Industry have been trading at relatively high levels of late. We believe those price movements are attributable partially to improved corporate earnings during 2017, and expectations of more good things in the coming year. A better performance across the financial markets has also provided a boost. It's worth mentioning that several of the equities in our category are favorably ranked for Timeliness. But the main draw here is the attractive dividends, which tend to act like an anchor, so to speak, when the financial markets encounter heightened volatility, which is sometimes the case. Of course, no sector (even the most defensive) is invulnerable.

How's The Weather?

Weather is a factor that affects the demand for natural gas, especially from small commercial businesses and consumers. Not surprisingly, earnings for utilities are vulnerable to seasonal temperature patterns, with consumption normally at its peak during the winter heating months. Unseasonably warm or cold weather can cause substantial volatility in quarterly operating results. But some companies strive to counteract this exposure through temperature-adjusted rate mechanisms, which are available in a number of states. Therefore, investors interested in utilities with more-stable profits from one year to the next are advised to look for companies that are able to hedge this risk.

Recent hurricanes that tore through the Gulf Coast and Eastern Seaboard regions of the United States might end up causing more than $200 billion in damage (according to some estimates). Notably, natural gas distribution pipelines are located mostly underground, providing a good amount of protection against hostile weather conditions. Still, these assets can be damaged by uprooted trees and shifted foundations. In addition, fallen tree limbs and other debris can crush meters and related piping near homes and other buildings. It appears that companies in the group with operations in the affected areas held up reasonably well, though.

Business Prospects Over 2020-2022

We are optimistic, in general, about the sector's operating performance over the long term. Natural gas should remain an abundant resource in the United States, brought about partially by new technologies, so a shortage does not appear probable anytime soon. Too, there are limited alternatives for the services the companies in this category offer. What's more, it's a challenge for new entrants in the market, given such factors as the size of existing competitors and the considerable initial capital outlays that are required. Finally, the country's population (presently numbering more than 320 million) ought to remain on a steady, upward trajectory, which augurs well for future demand for utility services.

Nevertheless, there are some risks to consider. For one thing, companies are subject to state and local regulatory authorities. That being the case, there are no guarantees that petitions for rate increases will be accepted or that certain favorable provisions (including temperature-adjusted rate mechanisms) will continue indefinitely. To further complicate matters, a slowdown in the economy may prompt customers to conserve gas and push up bad-debt expense. Lastly, operational difficulties created by leaks and other accidents could result in substantial financial losses (if not adequately covered by insurance).

INDUSTRY TIMELINESS: 22 (of 97)

Attractive Dividends

The primary feature of utility equities is their dividend income, which tends to be well covered by corporate profits. (It's important to mention that the Financial Strength ratings for the 11 companies in our universe continue to be no lower than B+.) At the time of this industry report, the average yield for the group was about 2.5%, relative to the *Value Line* median of 2.0%. Standouts include *South Jersey Industries*, *Northwest Natural Gas*, *Spire Inc.*, and *NiSource Inc.* When the financial markets experience heightened volatility, solid dividend yields tend to provide a measure of much-needed stability.

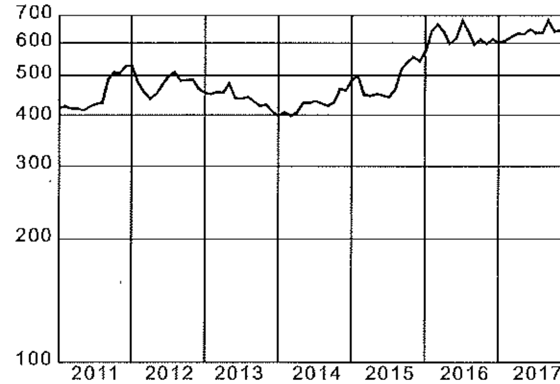
Conclusion

Stocks within *Value Line's* Natural Gas Utility Industry ought to draw the interest of income-hungry accounts with a conservative orientation, given that a number of these issues are ranked favorably for Safety and boast high marks for Price Stability. Furthermore, investors with a short-term focus should find some appealing selections here for Timeliness, such as *Atmos Energy Corp.*, *Chesapeake Utilities*, and *ONE Gas, Inc.* (This is not commonplace, however, because their historical price movements have tended to be on the steady side.) It's important to bear in mind that companies possessing more-established nonregulated operations might well offer a higher potential for returns, but profits could be more volatile than for firms with a greater emphasis on the more stable utility segment. As always, our subscribers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III

Natural Gas Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

ATMOS ENERGY CORP. NYSE-ATO

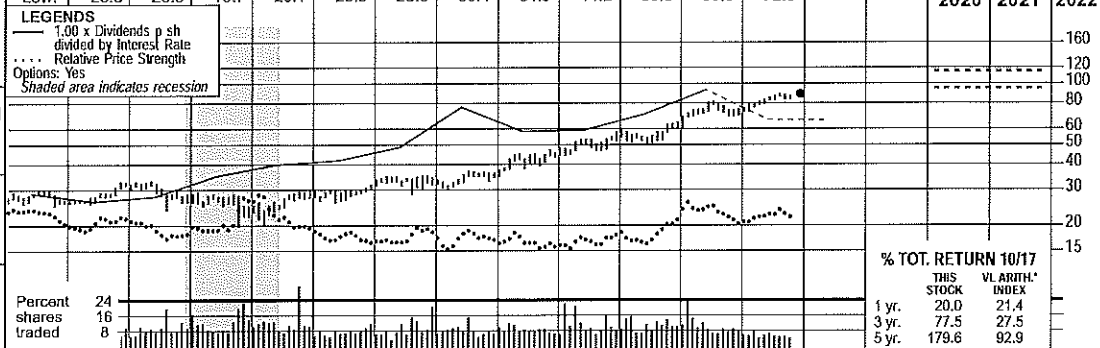
RECENT PRICE 89.11 | P/E RATIO 23.8 (Trailing: 24.7 Median: 16.0) | RELATIVE P/E RATIO 1.19 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 2 Raised 11/3/17
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Raised 12/1/17
BETA .70 (1.00 = Market)

High:	33.1	33.5	29.3	30.3	32.0	35.6	37.3	47.4	58.2	64.8	82.0	91.0
Low:	25.5	23.9	19.7	20.1	25.9	28.5	30.4	34.9	44.2	50.8	60.0	72.5

Target Price Range 2020 | 2021 | 2022

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+30%)	9%
Low	95	(+5%)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	1	0
Options	2	2	0	2	7	0	2	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	186	166	181
to Sell	163	181	165
Hld's(000)	76006	85813	84773

Percent shares traded 24 16 8

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.0	21.4
3 yr.	77.5	27.5
5 yr.	179.6	92.9

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.05	28.00	Revenues per sh A	45.85
4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.60	6.90	"Cash Flow" per sh	7.55
1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	3.80	Earnings per sh AB	4.50
1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	Div'ds Decl'd per sh C■	2.30
4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.75	12.25	Cap'l Spending per sh	12.75
22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.80	37.00	Book Value per sh	38.50
89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.00	110.00	Common Shs Outst'g D	120.00
15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0		Avg Ann'l P/E Ratio	23.5
.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.09		Relative P/E Ratio	1.45
4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%		Avg Ann'l Div'd Yield	2.2%
5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3080	Revenues ($mill) A	5500
170.5	180.3	179.7	201.2	199.3	192.2	230.7	289.8	315.1	350.1	382.7	420	Net Profit ($mill)	540
35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	37.0%	Income Tax Rate	40.0%
2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	13.6%	Net Profit Margin	9.8%
52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	44.0%	Long-Term Debt Ratio	45.0%
48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	56.0%	Common Equity Ratio	55.0%
4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965	7270	Total Capital ($mill)	8400
3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9260	9885	Net Plant ($mill)	11500
5.9%	5.9%	5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	7.0%	7.0%	Return on Total Cap'l	8.0%
8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	10.0%	10.5%	Return on Shr. Equity	11.5%
8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	10.0%	10.5%	Return on Com Equity	11.5%
3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	5.0%	5.0%	Retained to Com Eq	5.5%
65%	65%	68%	62%	62%	65%	56%	50%	51%	50%	50%	51%	All Div'ds to Net Prof	51%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $3325.3 mill. Due in 5 Yrs $1600.0 mill.
LT Debt $3066.7 mill. LT Interest $170.0 mill.
(LT interest earned: 5.8x; total interest coverage: 5.8x)
Leases, Uncapitalized Annual rentals $17.1 mill.
Pfd Stock None
Pension Assets-9/16 $474.0 mill. Oblig. $545.5 mill.
Common Stock 106,065,596 shs. as of 7/28/17
MARKET CAP: $9.5 billion (Large Cap)

CURRENT POSITION ($MILL.)	2015	2016	6/30/17
Cash Assets	28.7	47.5	69.8
Other	602.3	634.2	464.6
Current Assets	631.0	681.7	534.4
Accts Payable	238.9	259.4	164.4
Debt Due	457.9	1079.8	258.6
Other	458.0	449.1	322.7
Current Liab.	1154.8	1788.3	745.7
Fix. Chg. Cov.	743%	768%	775%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-4.0%	-4.5%	2.0%
"Cash Flow"	4.5%	5.0%	4.5%
Earnings	6.0%	8.0%	6.0%
Dividends	2.5%	3.5%	6.5%
Book Value	5.0%	5.5%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	1255.1	1964.3	942.7	778.8	4940.9
2015	1258.8	1540.1	686.4	656.8	4142.1
2016	906.2	1132.3	632.9	678.5	3349.9
2017	780.2	988.2	526.5	464.8	2759.7
2018	800	1030	640	610	3080

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	.95	1.38	.45	.23	2.96
2015	.96	1.35	.55	.23	3.09
2016	1.00	1.38	.69	.33	3.38
2017	1.08	1.52	.67	.34	3.60
2018	1.15	1.51	.75	.39	3.80

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.35	.35	.35	.37	1.42
2014	.37	.37	.37	.39	1.50
2015	.39	.39	.39	.42	1.59
2016	.42	.42	.42	.45	1.71
2017	.45	.45	.45	.485	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to roughly three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2016: 67%, residential; 28%, commercial; 2%, industrial; and 3% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.6% of common stock (12/16 Proxy). President and Chief Executive Officer: Michael E. Haefner. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy looks poised to generate respectable results in fiscal 2018. (Years begin October 1st.) The natural gas distribution unit, which accounts for the biggest portion of total revenues, stands to benefit from increased throughput, assuming that both the weather and economic climate are generally favorable (leading to a boost in consumption levels). Moreover, we expect a decent performance from the pipeline & storage division. At this juncture, *Value Line* expects the bottom line to rise around 6%, to $3.80 a share, compared to the previous year's tally of $3.60. Concerning fiscal 2019, earnings per share stand to increase at a similar percentage rate, to $4.00, as operating margins widen further.

A new CEO took command on October 1st. Michael E. Haefner, who had served as the chief operating officer, replaced Kim R. Cocklin. Given that the succession process was in the works for some time, we believe the energy company is in capable hands.

The fiscal 2018 capital spending budget is anticipated to fall between $1.3 billion and $1.4 billion. That would be around 18% higher than the prior-year figure, assuming that the midpoint of that range is used. Similar to fiscal 2017, it appears that a substantial portion of the resources will be deployed to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems.

The quarterly common stock dividend was increased about 7.8%, to $0.485 a share. Furthermore, our 2020-2022 projections show that additional, steady hikes in the distribution will occur. The payout ratio during that span ought to be in the neighborhood of 50%, which seems manageable.

These shares have traded at their highest level ever since our last full-page review in September. We think that can be traced partially to the company's healthy fiscal 2017 earnings, and expectations of more glad tidings in the new fiscal year. As a consequence, the equity is currently ranked 2 (Above Average) for Timeliness. Other noteworthy characteristics include the top Safety rank and relatively high grade (95 out of 100) for Price Stability.

Frederick L. Harris, III *December 1, 2017*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Feb.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	95

CHESAPEAKE UTIL. NYSE-CPK

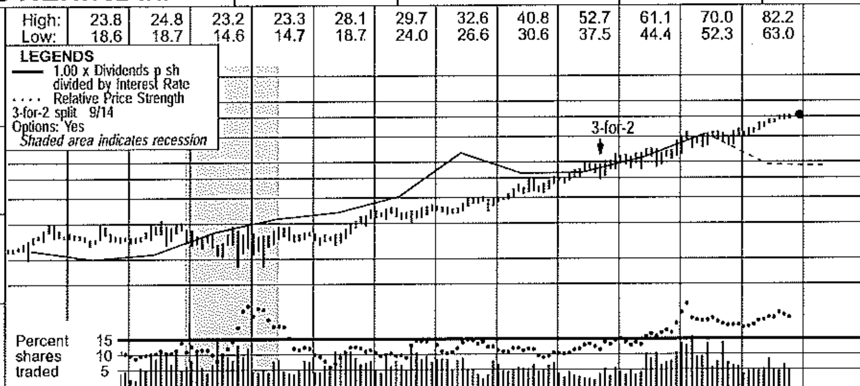
RECENT PRICE 81.80 | P/E RATIO 28.0 (Trailing: 30.4; Median: 15.0) | RELATIVE P/E RATIO 1.41 | DIV'D YLD 1.6% | VALUE LINE

TIMELINESS 2 Raised 11/24/17
SAFETY 2 New 6/5/15
TECHNICAL 3 Lowered 10/27/17
BETA .70 (1.00 = Market)

High:	23.8	24.8	23.2	23.3	28.1	29.7	32.6	40.8	52.7	61.1	70.0	82.2	
Low:	18.6	18.7	14.6	14.7	18.7	24.0	26.6	30.6	37.5	44.4	52.3	63.0	

Target Price Range
2020 | 2021 | 2022

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/14
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+35%)	9%
Low	80	(Nil)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	1	1	0	0	0	0
Options	0	5	0	0	8	0	0	0	0
to Sell	0	0	2	2	0	1	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	68	78	73
to Sell	81	52	61
Hld's(000)	9652	10785	11057

Percent shares traded 15 / 10 / 5

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.0	21.4
3 yr.	76.7	27.5
5 yr.	188.8	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
40.82	17.12	19.11	20.70	26.02	23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	*34.85*	*37.05*	Revenues per sh	*43.75*
1.95	1.93	2.42	2.26	2.35	2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	*4.85*	*5.30*	"Cash Flow" per sh	*7.50*
.83	.69	1.17	1.09	1.18	1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	*2.65*	*2.95*	Earnings per sh A	*4.20*
.73	.73	.73	.75	.76	.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	*1.26*	*1.33*	Div'ds Decl'd per sh B■	*1.55*
3.61	1.77	1.39	2.07	3.74	4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	*10.30*	*10.50*	Cap'l Spending per sh	*11.80*
8.26	8.03	8.59	9.07	9.60	11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	*28.65*	*30.70*	Book Value per sh	*32.90*
8.09	8.31	8.49	8.60	8.82	10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	*16.50*	*17.00*	Common Shs Outst'g C	*20.00*
15.0	18.6	12.7	15.0	16.8	17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
.77	1.02	.72	.79	.89	.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.16	*Value Line*		Relative P/E Ratio	*1.40*
5.8%	5.7%	4.9%	4.6%	3.8%	3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	*estimates*		Avg Ann'l Div'd Yield	*1.6%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $416.4 mill. Due in 5 Yrs $280.0 mill.
LT Debt $201.2 mill. LT Interest $9.0 mill.
(LT interest earned: 7.9x; total interest coverage: 7.9x) (30% of Cap'l)
Leases, Uncapitalized Annual rentals $1.4 mill.
Pfd Stock None
Pension Assets-12/16 $51.9 mill. Oblig. $75.2 mill.
Common Stock 16,344,442 shs. as of 10/31/17

MARKET CAP: $1.3 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
258.3	291.4	268.8	427.5	418.0	392.5	444.3	498.8	459.2	498.9	*575*	*630*	Revenues ($mill)	*875*
13.2	14.4	15.9	26.1	27.6	28.9	32.8	36.1	40.2	44.7	*43.5*	*50.0*	Net Profit ($mill)	*85.0*
39.4%	39.1%	41.8%	39.7%	39.4%	40.1%	40.2%	39.9%	39.5%	38.8%	*39.5%*	*40.0%*	Income Tax Rate	*41.5%*
5.1%	4.9%	5.9%	6.1%	6.6%	7.4%	7.4%	7.2%	8.8%	9.0%	*7.6%*	*7.9%*	Net Profit Margin	*9.7%*
34.6%	41.3%	32.0%	28.4%	31.4%	28.4%	29.7%	34.5%	29.4%	23.5%	*30.0%*	*30.0%*	Long-Term Debt Ratio	*30.0%*
65.4%	58.7%	68.0%	71.6%	68.6%	71.6%	70.3%	65.5%	70.6%	76.5%	*70.0%*	*70.0%*	Common Equity Ratio	*70.0%*
182.8	209.5	308.6	315.9	351.1	358.5	396.4	458.8	507.5	583.0	*675*	*745*	Total Capital ($mill)	*940*
260.4	280.7	436.4	462.8	487.7	541.8	631.2	689.8	855.0	986.7	*1120*	*1230*	Net Plant ($mill)	*1630*
8.4%	7.9%	6.1%	9.1%	8.9%	8.8%	8.8%	8.5%	8.9%	8.6%	*7.5%*	*7.5%*	Return on Total Cap'l	*10.0%*
11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	*9.0%*	*9.5%*	Return on Shr. Equity	*13.0%*
11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	*9.0%*	*9.5%*	Return on Com Equity	*13.0%*
5.2%	5.2%	3.8%	6.6%	6.6%	6.4%	7.1%	7.4%	6.8%	6.0%	*5.0%*	*5.5%*	Retained to Com Eq	*8.0%*
53%	55%	50%	42%	42%	43%	40%	38%	40%	39%	*48%*	*45%*	All Div'ds to Net Prof	*37%*

CURRENT POSITION ($MILL.)

	2015	2016	9/30/17
Cash Assets	2.9	4.2	3.4
Other	109.6	137.0	145.6
Current Assets	112.5	141.2	149.0
Accts Payable	39.3	56.9	53.3
Debt Due	182.5	222.0	215.2
Other	57.8	55.2	70.8
Current Liab.	279.6	334.1	339.3
Fix. Chg. Cov.	898%	859%	865%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	3.0%	4.0%	5.5%
"Cash Flow"	8.0%	10.0%	7.0%
Earnings	9.0%	9.0%	8.0%
Dividends	4.0%	5.5%	5.5%
Book Value	9.0%	8.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	186.3	100.5	91.6	120.4	498.8
2015	170.1	92.7	91.9	104.5	459.2
2016	146.3	102.3	108.3	142.0	498.9
2017	185.2	125.1	126.9	*137.8*	*575*
2018	*200*	*140*	*140*	*150*	*630*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.21	.35	.22	.69	2.47
2015	1.44	.35	.33	.56	2.68
2016	1.33	.52	.29	.73	2.86
2017	1.17	.37	.42	*.69*	*2.65*
2018	*1.37*	*.44*	*.42*	*.72*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.243	.243	.257	.257	1.00
2014	.257	.257	.27	.27	1.05
2015	.27	.27	.288	.288	1.12
2016	.288	.288	.305	.305	1.19
2017	.305	.305	.325	.325	

BUSINESS: Chesapeake Utilities Corporation consists of two units: Regulated Energy and Unregulated Energy. The Regulated Energy segment (60% of 2016 revenues) distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation (40% of 2016 revenues) wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Officers and directors own 4.2% of common stock; T. Rowe Price, 9.4; BlackRock, 6.0% (4/17 Proxy). CEO: Michael P. McMasters. Inc.: Delaware. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities appears to be headed for a down year, earningswise, versus 2016. (That's in spite of the good third quarter.) Notably, through the first nine months, the bottom line slipped around 8%, to $1.96 a share. This can be traced partly to a 27% jump in total operating expenses, reflecting investments to support growth of the company's businesses, among other factors. Moreover, warmer temperatures held back customer consumption. (But it appears that the recent hurricanes had minimal impact on the Florida units.) Finally, an increase in the number of common shares outstanding, given an offering in September, 2016, reduced the bottom line by $0.12 a share through the first nine months of 2017. Since *Value Line* expects a difficult fourth-quarter comparison, share net may fall some 7%, to $2.65, for the whole year.

We believe brighter things are in store for 2018, nevertheless. That ought to be brought about by growing benefits from new projects, additional natural gas infrastructure improvement initiatives, plus further expansions of Chesapeake's natural gas distribution and transmission systems. Consequently, profits stand to advance more than 10%, to $2.95 a share.

Finances are solid. Through the first nine months of 2017, cash on hand resided at $3.4 million. Elsewhere, long-term debt was just 30% of total capital, and short-term obligations did not seem to present a major hurdle. Also, the company possessed four unsecured bank credit facilities totaling $180 million. Lastly, it is able to issue more equity and debt, if necessary. All told, we believe Chesapeake is well positioned to satisfy, for a while, its capital requirements, such as investments in new plants and equipment and dividends.

Our 2020-2022 projections call for steady dividend increases. Also, the good-quality stock's payout ratio over that span should be in the 35% to 40% range, which is reasonable. But the current yield is not exciting, compared to the other equities in our Natural Gas Utility Industry.

These shares, though timely, are not a standout choice for relative price action in the long term. Indeed, capital appreciation potential during the 3- to 5-year period is below the *Value Line* median.

Frederick L. Harris, III December 1, 2017

(A) Diluted shrs. Excludes nonrecurring items: '02, d23¢; '08, d7¢; '15, 6¢. Excludes discontinued operations: '03, d9¢; '04, d1¢. Next earnings report due early Feb.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	90
Earnings Predictability	90

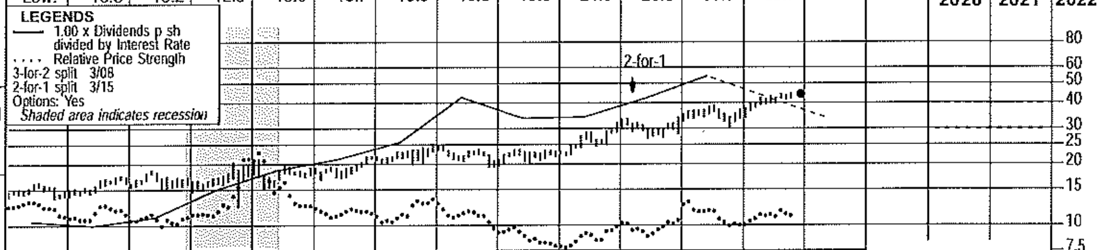
NEW JERSEY RES. NYSE-NJR

RECENT PRICE 44.30 | P/E RATIO 23.8 (Trailing: 24.7 Median: 16.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 2 Raised 8/25/17
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Lowered 10/27/17
BETA .80 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	17.7	18.8	20.6	21.2	22.0	25.2	25.1	23.8	32.1	34.1	38.9	45.4
Low:	13.8	15.2	12.3	15.0	16.7	19.8	19.3	19.5	21.9	26.8	30.5	33.7

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(-10%)	Nil
Low	30	(-30%)	-6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	2	4	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	126	114	131
to Sell	94	99	82
Hld's(000)	54513	68340	66939

Percent shares traded 30 20 10

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.4	21.4
3 yr.	65.9	27.5
5 yr.	134.6	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
25.61	22.06	31.14	30.44	38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	27.75	Revenues per sh A	29.70
1.06	1.07	1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	2.90	"Cash Flow" per sh	3.25
.65	.70	.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	1.90	Earnings per sh B	2.05
.39	.40	.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.09	Div'ds Decl'd per sh C■	1.12
.55	.51	.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	2.15	2.20	Cap'l Spending per sh	2.35
4.40	4.35	5.13	5.62	5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.40	15.25	Book Value per sh D	17.85
79.99	83.00	81.70	83.22	82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	86.50	Common Shs Outst'g E	86.50
14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4		Avg Ann'l P/E Ratio	17.0
.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.17		Relative P/E Ratio	1.05
4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%		Avg Ann'l Div'd Yield	3.2%
						3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2400	Revenues ($mill) A	2565
						65.3	113.9	101.0	101.8	106.5	112.4	113.7	176.9	153.7	138.1	149.4	165	Net Profit ($mill)	180
						38.8%	37.8%	27.1%	41.4%	30.2%	7.1%	25.4%	30.2%	26.3%	15.5%	32.0%	32.0%	Income Tax Rate	32.0%
						2.2%	3.0%	3.9%	3.9%	3.5%	5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	7.0%	Net Profit Margin	7.0%
						37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	36.6%	38.2%	43.2%	47.7%	46.5%	45.5%	Long-Term Debt Ratio	43.0%
						62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	63.4%	61.8%	56.8%	52.3%	53.5%	54.5%	Common Equity Ratio	57.0%
						1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	1400.3	1564.4	1950.6	2230.1	2320	2410	Total Capital ($mill)	2720
						970.9	1017.3	1064.4	1135.7	1295.9	1484.9	1643.1	1884.1	2128.3	2407.7	2455	2505	Net Plant ($mill)	2660
						7.7%	10.7%	9.7%	9.7%	9.7%	9.2%	9.0%	12.1%	8.6%	6.9%	7.4%	8.0%	Return on Total Cap'l	7.5%
						10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.0%	12.5%	Return on Shr. Equity	11.5%
						10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.0%	12.5%	Return on Com Equity	11.5%
						3.6%	9.5%	7.2%	6.7%	6.2%	6.2%	5.2%	11.0%	7.0%	4.8%	1.8%	6.0%	Retained to Com Eq	5.5%
						64%	40%	50%	52%	55%	55%	59%	40%	50%	60%	60%	54%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $1347.4 mill. Due in 5 Yrs $450 mill.
LT Debt $897.7 mill. LT Interest $31.0 mill.
Incl. $46.9 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/16 $311.9 mill. Oblig. $454.1 mill.
Pfd Stock None

Common Stock 86,538,661 shs. as of 7/31/17
MARKET CAP: $3.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2015	2016	6/30/17
Cash Assets	4.9	37.5	62.2
Other	539.6	569.8	575.4
Current Assets	544.5	607.3	637.6
Accts Payable	273.2	269.8	263.2
Debt Due	77.5	183.2	449.7
Other	85.4	118.6	63.0
Current Liab.	436.1	571.6	775.9
Fix. Chg. Cov.	1007%	1088%	669%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.0%	--	-1.5%
"Cash Flow"	7.0%	9.5%	2.5%
Earnings	7.5%	8.0%	2.0%
Dividends	7.5%	6.5%	3.5%
Book Value	7.5%	7.5%	6.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	878.4	1579.6	688.3	591.9	3738.1
2015	824.1	1013.1	458.5	438.3	2734.0
2016	444.3	574.2	393.2	469.2	1880.9
2017	541.0	733.5	457.5	536.6	2268.6
2018	575	765	490	570	2400

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	.47	1.79	.05	d.23	2.08
2015	.65	1.16	.03	d.06	1.78
2016	.58	.91	.13	d.02	1.61
2017	.47	1.21	.20	d.14	1.73
2018	.51	1.25	.24	d.10	1.90

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	--	.20	.20	.20	.60
2014	.21	.21	.21	.23	.86
2015	.23	.23	.23	.24	.93
2016	.24	.24	.24	.255	.98
2017	.255	.255	.255	.273	

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 521,200 customers at 9/30/16 in Monmouth and Ocean and other N.J. counties. Fiscal 2016 volume: 337 bill. cu. ft. (18% interruptible, 17% residential and commercial and electric utility, 65% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2016 dep. rate: 2.6%. Has 1,034 empls. Off./dir. own about 1.5% of common (12/16 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted solid fourth-quarter and fiscal-year financial results (ended September 30th). To that end, the company's top line advanced approximately 20%, to $2.27 billion, stemming largely from double-digit growth at its nonutility business segment. Meanwhile, the New Jersey Natural Gas (NJNG) regulated utility division was also a contributing factor, despite that unit experiencing slightly more modest revenue gains, of late. That division has been getting a boost from new customer accounts, as well as from higher base rates. Over the course of this past 12 months, NJNG added 9,126 new meters. On the profitability front, overall expenses rose 150 basis points, as a function of revenues. Combined, these factors equated to an almost 7.5% bottom-line increase, to $1.73 a share. This was in line with our call.

The company appears poised to register mid- to high-single-digit revenue and earnings gains in fiscal 2018. The regulated utility division has more than $120 million in capital projects planned to support new customer growth in the next three years. Those growth projects should help to expand the companies service territory, boost capacity, and improve system-wide integrity and safety. Management anticipates those efforts will eventually add 26,000-28,000 new customer accounts through 2020. Elsewhere, we look for the NJR Clean Energy Ventures, Energy Services, Midstream, and Home Service segments to be nicely additive to net earnings.

Acquisitions augur well for prospects. Adelphi Gateway, a subsidiary of NJR, has entered into an agreement with Talen Generation to purchase all of Talen's membership interest in Interstate Energy Company LLC, which owns and operates an 84-mile pipeline in southeastern PA, for roughly $166 million. Assuming all regulatory approvals are received, this deal would add about 250,000 dekatherms of natural gas per day to the greater Philadelphia market.

At its recent quotation, these shares appear richly valued. That said, our Timeliness Ranking System has the equity pegged to outpace the broader market averages in the coming year.

Bryan J. Fong *December 1, 2017*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late Jan.
(C) Dividends historically paid in early Jan., April, July, and October. 1Q '13 div'd paid in 4Q '12. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2016: $441.3 million, $5.13/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	80
Price Growth Persistence	55
Earnings Predictability	55

NISOURCE INC. NYSE-NI

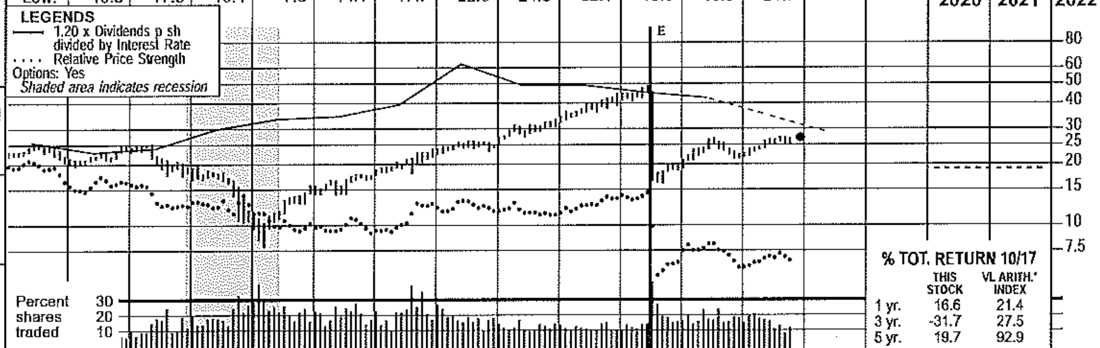
RECENT PRICE 27.09 | P/E RATIO 24.9 (Trailing: 33.0 / Median: 19.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 2.6%

TIMELINESS 3 New 12/1/17
SAFETY 3 New 9/4/15
TECHNICAL 1 New 12/1/17
BETA .60 (1.00 = Market)

High:	24.8	25.4	19.8	15.8	18.0	24.0	26.2	33.5	44.9	49.2	26.9	27.8
Low:	19.5	17.5	10.4	7.8	14.1	17.7	22.3	24.8	32.1	16.0	19.0	21.7

Target Price Range 2020 | 2021 | 2022

LEGENDS
—— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	6%
Low	19	(-30%)	-4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	1	0	0	0	0	0	0	1	0
Options	11	0	0	0	10	0	1	0	0
to Sell	0	0	2	0	4	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	208	215	198
to Sell	221	196	201
Hld's(000)	265350	289511	291718

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	21.4
3 yr.	-31.7	27.5
5 yr.	19.7	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
45.59	26.09	23.78	24.63	28.97	27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.80	16.20	Revenues per sh	17.85
4.23	3.94	3.47	3.47	3.14	3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.45	2.80	"Cash Flow" per sh	3.30
1.13	1.91	1.59	1.62	1.08	1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.01	.85	1.25	Earnings per sh A	1.50
1.16	1.16	1.10	.92	.92	.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.74	Div'd Decl'd per sh B ■	1.20
3.22	2.50	2.19	1.91	2.17	2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	4.75	5.00	Cap'l Spending per sh	5.70
16.72	16.78	16.81	17.69	18.09	18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.10	12.65	Book Value per sh C	13.60
207.49	248.86	262.63	270.63	272.62	273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	338.00	340.00	Common Shs Outst'g D	350.00
23.4	10.8	12.2	13.0	21.4	19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	Bold figures are		Avg Ann'l P/E Ratio	16.0
1.20	.59	.70	.69	1.14	1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.23	Value Line		Relative P/E Ratio	1.00
4.4%	5.6%	5.7%	4.4%	4.0%	4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 9/30/17
Total Debt $8651.6 mill. Due in 5 Yrs $2598.8 mill.
LT Debt $7518.6 mill. LT Interest $450 mill.
(Interest cov. earned: 2.5x) (66% of Cap'l)

Leases, Uncapitalized Annual rentals $15.4 mill.
Pension Assets-12/16 $1.75 bill. Oblig. $2.22 bill.

Pfd Stock None

Common Stock 336,793,693 shs.
as of 10/23/17
MARKET CAP: $9.1 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
7939.8	8874.2	6649.4	6422.0	6019.1	5061.2	5657.3	6470.6	4651.8	4492.5	5000	5500	Revenues ($mill)	6250
312.0	369.8	231.2	294.6	303.8	410.6	490.9	530.7	198.6	328.1	325	405	Net Profit ($mill)	495
35.6%	33.4%	41.8%	32.4%	35.0%	34.4%	34.8%	36.9%	41.6%	35.7%	35.5%	35.5%	Income Tax Rate	35.5%
6.6%	--	--	--	--	--	--	--	2.9%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
52.4%	55.7%	55.1%	54.7%	55.6%	55.1%	56.3%	56.9%	60.7%	59.8%	61.0%	61.0%	Long-Term Debt Ratio	63.0%
47.6%	44.3%	44.9%	45.3%	44.4%	44.9%	43.7%	43.1%	39.3%	40.2%	39.0%	39.0%	Common Equity Ratio	37.0%
10671	10673	10819	10859	11264	12373	13480	14331	9792.0	10129	10485	10985	Total Capital ($mill)	12225
10032	10276	10592	11097	11800	12916	14365	16017	12112	13068	13590	14135	Net Plant ($mill)	15595
4.6%	5.2%	4.0%	4.5%	4.4%	5.0%	5.2%	5.3%	4.0%	5.0%	4.5%	6.0%	Return on Total Cap'l	6.0%
6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	7.0%	10.0%	Return on Shr. Equity	11.5%
6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	7.0%	10.0%	Return on Com Equity	11.5%
1.2%	2.5%	NMF	.8%	.9%	2.5%	3.1%	3.4%	NMF	3.0%	1.0%	4.0%	Retained to Com Eq	2.5%
81%	68%	110%	87%	85%	67%	62%	61%	NMF	63%	82%	61%	All Div'ds to Net Prof	80%

CURRENT POSITION ($MILL.)	2015	2016	9/30/17
Cash Assets	15.5	26.4	19.3
Other	1561.7	1735.7	1313.1
Current Assets	1577.2	1762.1	1332.4
Accts Payable	433.4	539.4	447.4
Debt Due	1001.1	1851.1	1133.0
Other	1223.0	1061.7	986.4
Current Liab.	2657.5	3452.2	2566.8
Fix. Chg. Cov.	210%	245%	245%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-5.0%	-6.5%	1.5%
"Cash Flow"	-1.5%	-1.5%	2.5%
Earnings	-1.5%	2.5%	5.5%
Dividends	-1.0%	-2.0%	6.5%
Book Value	-2.0%	-3.5%	-1.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	2320.5	1335.1	1123.9	1691.1	6470.6
2015	1852.2	884.6	817.2	1097.8	4651.8
2016	1436.6	897.6	861.3	1297.0	4492.5
2017	1598.6	990.7	917.0	1493.7	5000
2018	1750	1000	1050	1700	5500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.85	.25	.10	.49	1.67
2015	.61	d.23	.05	.20	.63
2016	.58	.09	.07	.27	1.01
2017	.65	d.14	.04	.30	.85
2018	.65	.10	.10	.40	1.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.24	.24	.25	.25	.98
2014	.25	.25	.26	.26	1.02
2015	.26	.26	.155	.155	.83
2016	.155	.155	.165	.165	.64
2017	.175	.175	.175	.175	

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 461,000 electric in Indiana, 3.4 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, Massachusetts through its Columbia subsidiaries. Revenue breakdown, 2016: electrical, 34%; gas, 66%; other, less than 1%. Generating sources, 2016: coal, 77.3%; purchased & other, 22.7%. 2016 reported depreciation rates: 3.0% electric, 1.8% gas. Has 7,596 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Joseph Hamrock. Incorporated: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.

NiSource reported mixed third-quarter results. Revenues increased 6% to $917 million, aided by higher natural gas prices and higher trackers in several states. However, maintenance expense expanded 14% year over year, as the company worked to improve the reliability of its systems before winter. Too, a higher share count and greater total interest expense caused earnings per share to fall to $0.04. The utility appears poised for a decent fourth-quarter performance, as cooler weather boosts throughput at its natural gas operations and allows for better fixed-cost coverage. However, we have lowered our full-year estimate by a nickel to $0.85 per share.

Investment trackers should allow for decent growth over the coming years. Indeed, the company has trackers pending for its gas infrastructure in Kentucky, Maryland, Massachusetts, and Virginia. Approvals would allow for better recoveries and revenues. In addition, NiSource has achieved higher rates in Maryland, and filed a new gas base rate in Indiana. NiSource is on track to spend between $1.7 billion and $1.8 billion in infrastructure spending across its utilities in 2018, with around $30 billion in total long-haul spending. This ought to improve recoveries and earnings per share, which we project will increase to $1.25 in 2018 and $1.50 by the 2020-2022 period.

The balance sheet remains in mixed condition. Debt makes up around 66% of total capital. However, the weighted average maturity is around 18 years and has an interest rate of 4.8%. This ought to provide an advantage should interest rates increase, which appears likely over the coming years. Still, we project the debt total will rise further to fund infrastructure replacement and buildouts. In addition, equity sales appear likely, which will probably hamper share-net growth.

NiSource shares are neutrally-ranked for year-ahead relative performance (Timeliness: 3). They are trading near the high end of our long-term Target Price Range. The yield is below average for the industry, but management projects payouts will grow between 5% and 7% annually. Long-term investors would be best served waiting for a price dip.

John E. Seibert III *December 1, 2017*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢). Next egs. report due late January. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '16: $1933.4 million, $5.98/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	NMF
Earnings Predictability	45

N.W. NAT'L GAS NYSE-NWN

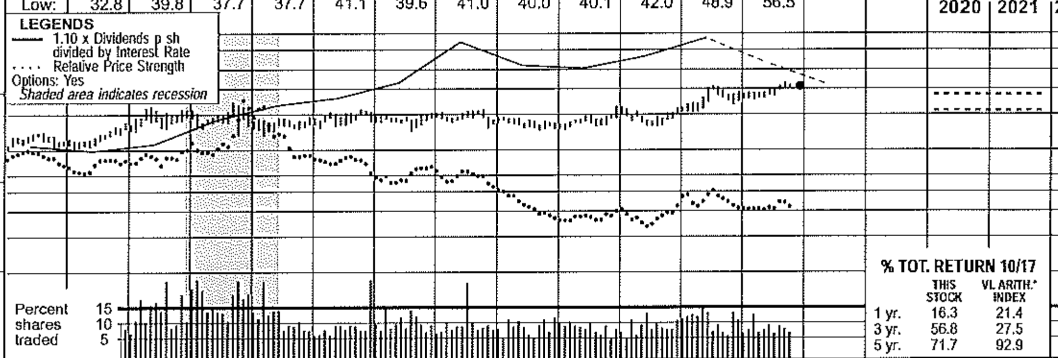
RECENT PRICE 66.15 | P/E RATIO 28.8 (Trailing: 30.1, Median: 19.0) | RELATIVE P/E RATIO 1.45 | DIV'D YLD 2.9%

VALUE LINE

TIMELINESS 4 Lowered 11/17/17
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 11/3/17
BETA .70 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	43.7	52.8	55.2	46.5	50.9	49.0	50.8	46.6	52.6	52.3	66.2	68.6
Low:	32.8	39.8	37.7	37.7	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(-10%)	1%
Low	50	(-25%)	-3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	11	1	1	4	4	0	1	2
to Sell	0	0	3	0	0	6	0	1	3

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	106	99	105
to Sell	81	74	86
Hld's(000)	18267	21952	21864

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.3	21.4
3 yr.	56.8	27.5
5 yr.	71.7	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	*26.20*	*27.10*	Revenues per sh	*29.65*
3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	*5.40*	*5.15*	"Cash Flow" per sh	*6.10*
1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	*2.25*	*2.45*	Earnings per sh A	*3.15*
1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	*1.88*	*1.89*	Div'ds Decl'd per sh B■	*2.00*
3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	*6.20*	*6.45*	Cap'l Spending per sh	*6.35*
16.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	*29.95*	*30.45*	Book Value per sh D	*32.25*
25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	*29.00*	*29.50*	Common Shs Outst'g C	*30.00*
12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.43	*Value Line*		Relative P/E Ratio	*1.05*
5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $779.4 mill. Due in 5 Yrs $360.0 mill.
LT Debt $757.4 mill. LT Interest $40.0 mill.

(Total interest coverage: 3.6x)

Pension Assets-12/16 $257.7 mill.
Oblig. $457.8 mill.

Pfd Stock None

Common Stock 28,713,052 shares
as of 10/27/17

MARKET CAP $1.9 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
1033.2	1037.9	1012.7	812.1	848.8	730.6	758.5	754.0	723.8	676.0	*760*	*800*	Revenues ($mill)	*890*
74.5	68.5	75.1	72.7	63.9	59.9	60.5	58.7	53.7	58.9	*65.0*	*72.0*	Net Profit ($mill)	*90.0*
37.2%	36.9%	38.3%	40.5%	40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
7.2%	6.6%	7.4%	8.9%	7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	*8.6%*	*9.0%*	Net Profit Margin	*10.6%*
46.3%	44.9%	47.7%	46.1%	47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*45.5%*
53.7%	55.1%	52.3%	53.9%	52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	*55.5%*	*55.0%*	Common Equity Ratio	*54.5%*
1106.8	1140.4	1261.8	1284.8	1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	*1570*	*1625*	Total Capital ($mill)	*1775*
1495.9	1549.1	1670.1	1854.2	1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	*2350*	*2445*	Net Plant ($mill)	*2750*
8.5%	7.7%	7.3%	7.0%	6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	*7.5%*	*8.0%*	Return on Shr. Equity	*10.0%*
12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	*7.5%*	*8.0%*	Return on Com Equity	*10.0%*
6.0%	4.5%	5.0%	4.0%	2.4%	1.6%	1.5%	1.1%	.6%	.9%	*1.0%*	*1.5%*	Retained to Com Eq	*3.5%*
52%	59%	56%	61%	73%	80%	81%	85%	92%	87%	*84%*	*78%*	All Div'ds to Net Prof	*64%*

CURRENT POSITION ($MILL.)

	2015	2016	9/30/17
Cash Assets	4.2	3.5	15.8
Other	327.9	284.6	183.7
Current Assets	332.1	288.1	199.5
Accts Payable	73.2	85.7	87.5
Debt Due	295.0	93.3	22.0
Other	109.5	95.5	93.5
Current Liab.	477.7	274.5	203.0
Fix. Chg. Cov.	300%	390%	358%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-2.0%	-5.0%	2.5%
"Cash Flow"	1.5%	-.5%	3.5%
Earnings	--	-4.5%	7.0%
Dividends	3.5%	2.0%	1.0%
Book Value	3.0%	2.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	293.4	133.1	87.2	240.3	754.0
2015	261.7	138.3	93.1	230.7	723.8
2016	255.5	99.2	87.7	233.5	676.0
2017	297.3	136.2	88.2	*238.3*	*760*
2018	*310*	*125*	*110*	*255*	*800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.40	.04	d.32	1.04	2.16
2015	1.04	.08	d.24	1.08	1.96
2016	1.33	.07	d.29	1.00	2.12
2017	1.40	.10	d.30	*1.05*	*2.25*
2018	*1.45*	*.10*	*d.25*	*1.15*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.455	.455	.455	.460	1.83
2014	.460	.460	.460	.465	1.85
2015	.465	.465	.465	.4675	1.86
2016	.4675	.4675	.4675	.470	1.87
2017	.470	.470	.470	.4725	

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 704,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 35%; commercial, 22%; industrial, gas transportation, and other, 43%. Employs 1,092. BlackRock Inc. owns 11.9% of shares; officers and directors, 1.5% (4/17 proxy). CEO: David H. Anderson. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas' third-quarter results were in line with the previous year. Revenues expanded to $88.2 million, as growth in the customer base largely offset the effect of warmer temperatures. However, higher maintenance costs caused losses to reach $0.30 per share during the quarter. The company appears to be on track for decent fourth-quarter operations, as cooler weather takes hold and a bigger customer base allows for better fixed-cost coverage. Thus, we are keeping intact our 2017 top- and bottom-line estimates of $760 million and $2.25 per share, respectively.

Near-term performance will be driven by growth in the coverage area. New housing permits were up 6% in the coverage area, while unemployment rates continue to be low. This likely drove up the population in the Portland area. In addition, more households are being fueled by natural gas, which ought to drive its usage higher. Better operations will allow for greater fixed-cost coverage. This will likely allow for earnings to reach $2.45 per share in 2018.

Long-term operations will benefit from the Mist Storage project. The company is in the final stages of building its no-notice natural gas storage facility, which will provide ample fuel to Portland General Electric in the coming years. The pipeline construction will likely be completed by the end of 2017, should current construction schedules hold. Early in 2018, Northwest ought to start deployment of its reservoir for testing. This capital expansion project is expected to be in service during the fourth quarter of 2018, and should allow for a sizable increase in fuel sold. We believe this will be a major factor that will drive earnings to $3.15 per share by the 2020-2022 period.

Shares of Northwest Natural Gas are unfavorably ranked for Timeliness (4). Although we project significant earnings growth out to 2020-2022, we think a lot of this is priced into the stock already, given the high price-to-earnings multiple. Still, interest-rate increases could hamper this. However, the yield is decent, and the payout ought to grow at a much faster pace starting in 2019. Too, Northwest is ranked Highest (1) for Safety.

John E. Seibert III *December 1, 2017*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, 6¢; May not sum due to rounding. Next earnings report due in early February.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2016: $357.5 million, $12.48/share.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	15
Earnings Predictability	85

ONE GAS, INC. NYSE-OGS

RECENT PRICE	76.95	P/E RATIO	24.7 (Trailing: 26.6; Median: NMF)	RELATIVE P/E RATIO	1.24	DIV'D YLD	2.4%	VALUE LINE

	2014	2015	2016	2017
High:	44.3	51.8	67.4	78.3
Low:	31.9	38.9	48.0	61.4

TIMELINESS 2 Raised 11/10/17
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 12/1/17
BETA .70 (1.00 = Market)

2020-22 PROJECTIONS

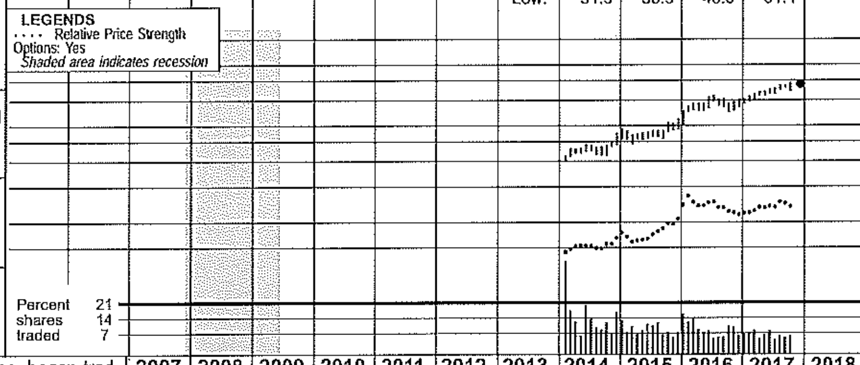
	Price	Gain	Ann'l Total Return
High	115	(+50%)	13%
Low	85	(+10%)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	5	6	6	9	0	0	0	0
to Sell	0	0	1	0	1	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	127	122	136
to Sell	133	122	111
Hld's(000)	38323	43973	43668



Target Price Range
2020 | 2021 | 2022
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.7	21.4
3 yr.	117.3	27.5
5 yr.	—	92.9

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
--	--	--	--	--	--	--	34.92	29.62	27.30	29.70	31.60	Revenues per sh	35.10
--	--	--	--	--	--	--	4.52	4.82	5.43	5.90	6.40	"Cash Flow" per sh	7.70
--	--	--	--	--	--	--	2.07	2.24	2.65	2.95	3.25	Earnings per sh A	4.00
--	--	--	--	--	--	--	.84	1.20	1.40	1.68	1.88	Div'ds Decl'd per sh B■	2.45
--	--	--	--	--	--	--	5.70	5.63	5.91	6.75	6.95	Cap'l Spending per sh	6.90
--	--	--	--	--	--	--	34.45	35.24	36.12	37.20	38.40	Book Value per sh	41.45
--	--	--	--	--	--	--	52.08	52.26	52.28	52.50	52.50	Common Shs Outst'g C	55.00
--	--	--	--	--	--	--	17.8	19.8	22.7	Bold figures are		Avg Ann'l P/E Ratio	25.0
--	--	--	--	--	--	--	.94	1.00	1.20	Value Line		Relative P/E Ratio	1.55
--	--	--	--	--	--	--	2.3%	2.7%	2.3%	estimates		Avg Ann'l Div'd Yield	2.5%
--	--	--	--	--	--	--	1818.9	1547.7	1427.2	1560	1660	Revenues ($mill)	1930
--	--	--	--	--	--	--	109.8	119.0	140.1	155	170	Net Profit ($mill)	220
--	--	--	--	--	--	--	38.4%	38.0%	37.8%	35.5%	36.0%	Income Tax Rate	38.0%
--	--	--	--	--	--	--	6.0%	7.7%	9.8%	9.9%	10.2%	Net Profit Margin	11.4%
--	--	--	--	--	--	--	40.1%	39.5%	38.7%	38.0%	38.0%	Long-Term Debt Ratio	38.0%
--	--	--	--	--	--	--	59.9%	60.5%	61.3%	62.0%	62.0%	Common Equity Ratio	62.0%
--	--	--	--	--	--	--	2995.3	3042.9	3080.7	3150	3250	Total Capital ($mill)	3675
--	--	--	--	--	--	--	3293.7	3511.9	3731.6	3970	4180	Net Plant ($mill)	4850
--	--	--	--	--	--	--	4.4%	4.7%	5.2%	6.0%	6.5%	Return on Total Cap'l	7.0%
--	--	--	--	--	--	--	6.1%	6.5%	7.4%	8.0%	8.5%	Return on Shr. Equity	9.5%
--	--	--	--	--	--	--	6.1%	6.5%	7.4%	8.0%	8.5%	Return on Com Equity	9.5%
--	--	--	--	--	--	--	3.7%	3.1%	3.5%	3.5%	3.5%	Retained to Com Eq	4.0%
--	--	--	--	--	--	--	40%	53%	52%	57%	58%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 9/30/17
Total Debt $1367.1 mill. Due in 5 Yrs $445.0 mill.
LT Debt $1193.1 mill. LT Interest $70.0 mill.
(LT interest earned: 6.3x; total interest coverage: 5.8x)
Leases, Uncapitalized Annual rentals $5.6 mill.
Pfd Stock None
Pension Assets-12/16 $739.6 mill.
Oblig. $966.5 mill.
Common Stock 52,273,783 shs.
as of 10/24/17
MARKET CAP: $4.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2015	2016	9/30/17
Cash Assets	2.4	14.7	6.9
Other	480.4	554.2	438.7
Current Assets	482.8	568.9	445.6
Accts Payable	107.5	132.0	68.2
Debt Due	12.5	145.0	174.0
Other	184.2	166.9	150.0
Current Liab.	304.2	443.9	392.2
Fix. Chg. Cov.	624%	685%	670%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	--	--	2.5%
"Cash Flow"	--	--	7.5%
Earnings	--	--	9.5%
Dividends	--	--	13.5%
Book Value	--	--	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	766.2	296.8	241.5	514.4	1818.9
2015	676.5	256.8	225.2	389.2	1547.7
2016	508.4	245.9	232.2	440.7	1427.2
2017	550.4	279.7	247.1	482.8	1560
2018	590	300	262	508	1660

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.13	.18	.09	.67	2.07
2015	1.13	.23	.14	.74	2.24
2016	1.22	.38	.25	.80	2.65
2017	1.34	.39	.36	.86	2.95
2018	1.42	.48	.41	.94	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	--	--	--	--	--
2014	--	.28	.28	.28	.84
2015	.30	.30	.30	.30	1.20
2016	.35	.35	.35	.35	1.40
2017	.42	.42	.42		

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to over two million customers. It has three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 134 Bcf of natural gas supply in fiscal 2016, compared to 157 Bcf in 2015. Total volumes delivered by customer (fiscal 2016): transportation, 60%; residential, 30%; commercial & industrial, 9%; wholesale, 1%. BlackRock owns approximately 10.0% of common stock; The Vanguard Group, 9.5%; American Century Investment Management, 9.3%; officers and directors, less than 1% (4/17 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. appears to be on track to register higher profits in 2017. Indeed, through the first nine months, share net climbed 13%, to $2.09, relative to $1.85 for the same period last year. The outperformance reflected new rates in Texas and Kansas. Weather-normalization mechanisms also aided the Tulsa-headquartered company. Other positives included a rise in residential sales (supported by net customer growth in Oklahoma and Texas) plus higher transportation volumes from customers in Kansas and Oklahoma. A lower effective income tax rate was beneficial, too. Elsewhere, total operating expenses rose at a manageable 2.5%, as ONE Gas has emphasized such initiatives as pipeline maintenance and expansionary efforts. Since it seems that the fourth quarter will end fairly well, we expect the bottom line to advance around 11%, to $2.95 a share, for the year as a whole. Assuming additional growth of operating margins, 2018 earnings per share may increase at a similar percentage rate, to $3.25.

This year's capital expenditures are expected to lie between $350 million and $360 million. (That would be some 15% above the 2016 level if the midpoint of that range is used.) Over 70% of the budget is dedicated to system integrity and pipeline replacement projects. Finances are quite sufficient to make those moves possible.

The stock price has reached a historic high since our last full-page report in September. The company's improved 2017 results are surely a driving force. As a consequence, these shares are now pegged to outshine the broader market averages over the next six to 12 months (Timeliness rank 2: Above Average). Moreover, long-term capital appreciation potential continues to look worthwhile. Other mentionable qualities are the 2 (Above Average) Safety rank and lower-than-market Beta coefficient.

But the dividend yield is not spectacular, when compared to the other companies within *Value Line's* Natural Gas Utility universe. Still, the payout is well covered by corporate profits, and we expect steady annual hikes out to the 2020-2022 horizon.

Frederick L. Harris, III   December 1, 2017

(A) Diluted shrs. Excludes nonrecurring gain: Q1 2017, $0.10. Next earnings report due early Feb.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	NMF
Earnings Predictability	NMF

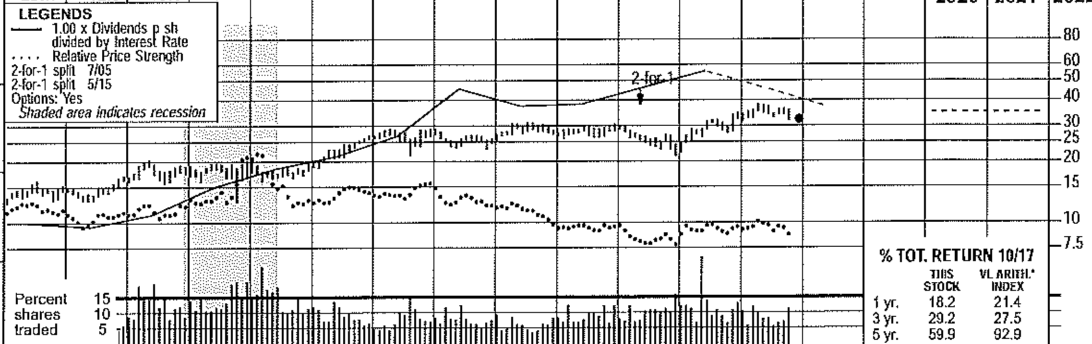
SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 32.39 | P/E RATIO 25.9 (Trailing: 28.2 / Median: 18.0) | RELATIVE P/E RATIO 1.30 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Raised 6/30/17
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 11/24/17
BETA .85 (1.00 = Market)

High:	17.1	20.6	20.3	20.4	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4
Low:	12.8	15.6	12.6	16.0	18.6	21.4	22.9	25.3	25.9	21.2	22.1	31.4

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+10%)	6%
Low	25	(-25%)	-1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	20	0	10	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	100	92	101
to Sell	89	95	85
Hld's(000)	56733	66551	66240

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.2	21.4
3 yr.	29.2	27.5
5 yr.	59.9	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	*15.25*	*15.80*	Revenues per sh	*17.25*
.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	*2.40*	*2.70*	"Cash Flow" per sh	*3.50*
.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	*1.15*	*1.45*	Earnings per sh A	*2.00*
.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	*1.10*	*1.15*	Div'ds Decl'd per sh B ■	*1.30*
1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	*3.25*	*3.70*	Cap'l Spending per sh	*5.35*
3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	*15.95*	*17.00*	Book Value per sh C	*20.85*
47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	*80.00*	*81.00*	Common Shs Outst'g D	*84.00*
13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*16.0*
.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	*estimates*		Relative P/E Ratio	*1.00*
4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%			Avg Ann'l Div'd Yield	*4.1%*

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
	956.4	962.0	845.4	925.1	828.6	706.3	731.4	887.0	959.6	1036.5	*1220*	*1280*	Revenues ($mill)	*1450*
	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	99.0	102.8	*90.0*	*115*	Net Profit ($mill)	*170*
	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	--	--	5.9%	42.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	*7.4%*	*9.0%*	Net Profit Margin	*11.7%*
	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	*48.5%*	*47.5%*	Long-Term Debt Ratio	*46.0%*
	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	*51.5%*	*52.5%*	Common Equity Ratio	*54.0%*
	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	*2475*	*2625*	Total Capital ($mill)	*3250*
	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	*2750*	*2900*	Net Plant ($mill)	*3500*
	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	*4.5%*	*5.0%*	Return on Total Cap'l	*6.0%*
	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	*7.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	*7.0%*	*8.5%*	Return on Com Equity	*9.5%*
	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	*.5%*	*1.5%*	Retained to Com Eq	*3.5%*
	48%	49%	51%	50%	52%	55%	59%	61%	71%	80%	*98%*	*81%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $1471.3 mill. Due in 5 Yrs $630 mill.
LT Debt $1180.3 mill. LT Interest $40.0 mill.
(Total interest coverage: 2.0x)

Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/16 $189.5 mill. **Oblig.** $278.3 mill.

Pfd Stock None

Common Stock 79,549,080 shs. as of 11/1/17

MARKET CAP: $2.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2015	2016	9/30/17
Cash Assets	3.9	18.3	13.7
Other	427.4	455.0	309.8
Current Assets	431.3	473.3	323.5
Accts Payable	186.4	243.7	208.0
Debt Due	461.2	528.0	291.0
Other	184.9	180.9	185.2
Current Liab.	832.5	952.6	684.2
Fix. Chg. Cov.	496%	602%	174%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.5%	-2.0%	*4.5%*
"Cash Flow"	6.5%	4.5%	*5.0%*
Earnings	4.0%	1.5%	*5.5%*
Dividends	9.0%	8.5%	*4.0%*
Book Value	8.0%	9.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	350.2	133.3	122.4	281.1	887.0
2015	383.0	177.7	141.1	257.8	959.6
2016	333.0	154.4	219.1	330.0	1036.5
2017	425.8	244.4	227.1	*322.7*	*1220*
2018	*440*	*240*	*245*	*355*	*1280*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.01	.15	d.05	.47	1.57
2015	.86	.03	d.07	.62	1.44
2016	.75	.12	.05	.42	1.34
2017	.72	.06	d.05	*.42*	*1.15*
2018	*.78*	*.10*	*.03*	*.54*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	--	.222	.222	.458	.90
2014	--	.237	.237	.488	.96
2015	--	.251	.251	.515	1.02
2016	--	.264	.264	.536	1.06
2017	--	.273	.273	.553	

BUSINESS: South Jersey Industries, Inc. is a holding company. Subsidiary South Jersey Gas Co. distributes natural gas to 377,625 customers in New Jersey's southern counties. Gas revenue mix '16: residential, 42%; commercial, 21%; cogeneration and electric generation, 16%; industrial, 21%. Nonutility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 750 employees. Off./dir. own less than 1% of common; BlackRock, Inc., 11.6%; The Vanguard Group, Inc., 9.0% (3/17 proxy). Pres. & CEO: Michael J. Renna. Chairman: Walter M. Higgins III. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

Shares of South Jersey Industries have pulled back in price in recent weeks. The company reported mixed results for the third quarter. Revenue of roughly $227 million increased 4% on a year-to-year basis, and surpassed our expectation. However, cost of sales increased significantly on the nonutility side, and operating expenses were considerably greater. South Jersey posted a share loss of $0.05 for the recent interim, which was a dime below the prior-year figure.

The company has agreed to acquire two entities from Southern Company Gas. South Jersey will purchase Elizabethtown Gas and Elkton Gas from Southern Company for total consideration of $1.7 billion. This move will make SJI the second-largest natural gas provider in New Jersey, servicing over 675,000 customers. These additions should nicely complement the company's existing utility assets. The deal is expected to close by mid-2018, subject to regulatory approvals. Assuming this occurs, utility earnings would comprise over 80% of total earnings. The company expects that the transaction will be accretive to earnings by 2020.

Prospects appear favorable for the long haul. Utility South Jersey Gas ought to further benefit from an expansion in the customer base and investments in infrastructure. On the nonutility side, SJ Energy Group will likely gain from increased contributions from fuel supply management contracts. The Penn-East Pipeline should also support performance.

This good-quality issue has a number of positive attributes. South Jersey Industries earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is below average here, as well. Moreover, the dividend yield is respectable for a utility.

But the stock offers limited appeal at this juncture. The equity is ranked to lag the broader market averages for the coming six to 12 months. Moreover, long-term appreciation potential is below average. The valuation remains fairly rich, and the shares presently trade well within our Target Price Range. A price pullback some time in the future may present conservative, income-oriented investors with a more attractive entry point.

Michael Napoli, CFA *December 1, 2017*

(A) Based on economic egs. from 2007 onward. GAAP EPS: '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56. Excl. nonrecur. gain (loss): '08, $0.16; '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22. Egs. may not sum due to change in shares. Next egs. rpt. due late February. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2016: $410.7 mill., $5.17 per shr. (D) In mill., adj. for split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	30
Earnings Predictability	75

SOUTHWEST GAS NYSE-SWX

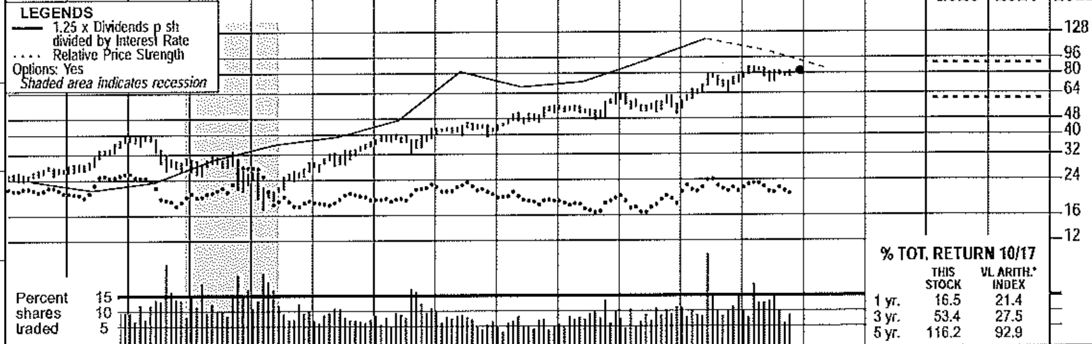
RECENT PRICE 82.13 | P/E RATIO 22.5 (Trailing: 24.2, Median: 17.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 2 Lowered 11/24/17
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 12/1/17
BETA .80 (1.00 = Market)

High:	39.4	39.9	33.3	29.5	37.3	43.2	46.1	56.0	64.2	63.7	79.6	86.6
Low:	26.0	26.5	21.1	17.1	26.3	32.1	39.0	42.0	47.2	50.5	53.5	72.3

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+10%)	5%
Low	60	(-25%)	-4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	17	17	4	0	1	0	0	2	0
to Sell	0	0	0	0	1	0	0	2	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	118	139	150
to Sell	125	109	109
Hld's(000)	37062	42400	41669

Percent shares traded 15 10 5

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.5	21.4
3 yr.	53.4	27.5
5 yr.	116.2	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	**52.60**	**54.10**	Revenues per sh	**62.50**
4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	**9.05**	**9.90**	"Cash Flow" per sh	**13.10**
1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	**3.55**	**3.70**	Earnings per sh A	**4.80**
.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	**1.98**	**2.08**	Div'ds Decl'd per sh B■†	**2.50**
8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	**12.00**	**12.75**	Cap'l Spending per sh	**14.40**
17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	**37.30**	**40.80**	Book Value per sh	**50.00**
32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	**48.00**	**49.00**	Common Shs Outst'g C	**52.00**
19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.14	*Value Line*		Relative P/E Ratio	**1.00**
3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	*estimates*		Avg Ann'l Div'd Yield	**3.3%**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
	2152.1	2144.7	1893.8	1830.4	1887.2	1927.8	1950.8	2121.7	2463.6	2460.5	**2525**	**2650**	Revenues ($mill)	**3250**
	83.2	61.0	87.5	103.9	112.3	133.3	145.3	141.1	138.3	152.0	**175**	**185**	Net Profit ($mill)	**255**
	36.5%	40.1%	34.0%	34.7%	36.2%	36.2%	35.0%	35.7%	36.4%	33.9%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
	3.9%	2.8%	4.6%	5.7%	6.0%	6.9%	7.4%	6.7%	5.6%	6.2%	**6.9%**	**7.0%**	Net Profit Margin	**7.8%**
	58.1%	55.3%	53.5%	49.1%	43.2%	49.2%	49.4%	52.4%	49.3%	48.2%	**49.5%**	**48.0%**	Long-Term Debt Ratio	**44.5%**
	41.9%	44.7%	46.5%	50.9%	56.8%	50.8%	50.6%	47.6%	50.7%	51.8%	**50.5%**	**52.0%**	Common Equity Ratio	**55.5%**
	2349.7	2323.3	2371.4	2291.7	2155.9	2576.9	2793.7	3123.9	3143.5	3213.5	**3540**	**3850**	Total Capital ($mill)	**4700**
	2845.3	2983.3	3034.5	3072.4	3218.9	3343.8	3486.1	3658.4	3891.1	4132.0	**4450**	**4750**	Net Plant ($mill)	**5800**
	5.5%	4.5%	5.4%	6.1%	6.4%	6.4%	6.3%	5.7%	5.5%	5.8%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	**10.0%**	**9.5%**	Return on Shr. Equity	**10.0%**
	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	**10.0%**	**9.5%**	Return on Com Equity	**10.0%**
	4.8%	2.1%	4.1%	5.1%	5.3%	6.1%	6.1%	5.0%	4.0%	4.1%	**4.5%**	**4.0%**	Retained to Com Eq	**5.0%**
	44%	63%	48%	43%	43%	40%	41%	47%	54%	55%	**54%**	**55%**	All Div'ds to Net Prof	**51%**

CAPITAL STRUCTURE as of 9/30/17
Total Debt $1870.9 mill. Due in 5 Yrs $350 mill.
LT Debt $1732.0 mill. LT Interest $75.0 mill.
(Total interest coverage: 4.2x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $7.0 mill.
Pension Assets-12/16 $787.1 mill. Oblig. $1122.2 mill.
Pfd Stock None

Common Stock 47,731,840 shs. as of 10/27/17

MARKET CAP: $3.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2015	2016	9/30/17
Cash Assets	36.0	28.1	59.2
Other	522.2	505.2	479.7
Current Assets	558.2	533.3	538.9
Accts Payable	164.9	184.7	159.4
Debt Due	37.5	50.1	139.0
Other	332.6	393.6	358.0
Current Liab.	535.0	628.4	656.4
Fix. Chg. Cov.	401%	401%	407%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	1.0%	4.0%	4.0%
"Cash Flow"	4.5%	6.5%	7.0%
Earnings	6.5%	6.5%	8.0%
Dividends	7.0%	10.0%	7.5%
Book Value	5.5%	5.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	608.4	453.1	432.5	627.7	2121.7
2015	734.2	538.6	505.4	685.4	2463.6
2016	731.2	547.8	540.0	641.5	2460.5
2017	654.7	560.5	593.2	**716.6**	**2525**
2018	**685**	**590**	**625**	**750**	**2650**

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.51	.21	.04	1.25	3.01
2015	1.53	.10	d.10	1.38	2.92
2016	1.58	.19	.05	1.36	3.18
2017	1.45	.37	.21	**1.52**	**3.55**
2018	**1.52**	**.40**	**.20**	**1.58**	**3.70**

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.295	.330	.330	.330	1.29
2014	.330	.365	.365	.365	1.43
2015	.365	.405	.405	.405	1.58
2016	.405	.450	.450	.450	1.76
2017	.450	.495	.495	.495	

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas end Centuri Construction Group. Southwest Gas is a regulated gas distributor serving about 2.0 million customers in sections of Arizona, Nevada, and California. Centuri provides construction services. 2016 margin mix: residential and small commercial, 85%; large commercial and industrial, 3%; transportation, 12%. Total throughput: 2.1 billion therms. Has 6,277 employees. Off. & dir. own 1.1% of common stock; BlackRock Inc., 11.3%; The Vanguard Group, Inc., 9.4% (3/17 Proxy). Chairman: Michael J. Melarkey. President & CEO: John P. Hester. Inc.: CA. Addr.: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have moved higher in price in recent times. The company posted a strong performance for the third quarter. The top line increased 10%, on a year-to-year basis. The utility benefited from rate relief in Arizona and California, along with growth in the customer base. Elsewhere, construction services segment Centuri gained from an increase in pipe replacement demand from existing customers. Overall, revenue growth outstripped that of operating costs, thanks to a decline in depreciation expense. As a result, share earnings of $0.21 marked a considerable improvement from the prior-year tally. We anticipate favorable comparisons for the fourth quarter, and greater revenues and earnings per share for full-year 2017.

The company should continue to fare well from 2018 onward. The utility segment ought to further benefit from rate relief, expansion projects, infrastructure tracker mechanisms, and steady growth in the customer base. Meanwhile, Centuri will probably continue to perform well going forward. This operation has a healthy base of large utility clients, many with multiyear pipe replacement programs. Centuri should be able to capitalize on the need to replace aging infrastructure in the coming years.

Short-term accounts might want to take a closer look. This stock is ranked to outperform the broader equity market for the coming six to 12 months. Moreover, this issue offers some appeal for conservative subscribers. Southwest Gas earns favorable marks for Financial Strength, Price Stability, and Earnings Predictability. Volatility is subdued, as well (Beta: .80).

But patient investors can probably find more-suitable choices elsewhere at this juncture. We anticipate solid growth in revenues and earnings per share for the company over the pull to early next decade. But this seems to be largely reflected in the recent quotation, following fairly strong share-price appreciation over the past couple of years. Long-term capital gains potential appears to be limited, as the shares presently trade well within our Target Price Range. The stock's dividend yield is not compelling for a utility, either.

Michael Napoli, CFA *December 1, 2017*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due late February. (B) Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	90
Earnings Predictability	90

SPIRE INC. NYSE-SR

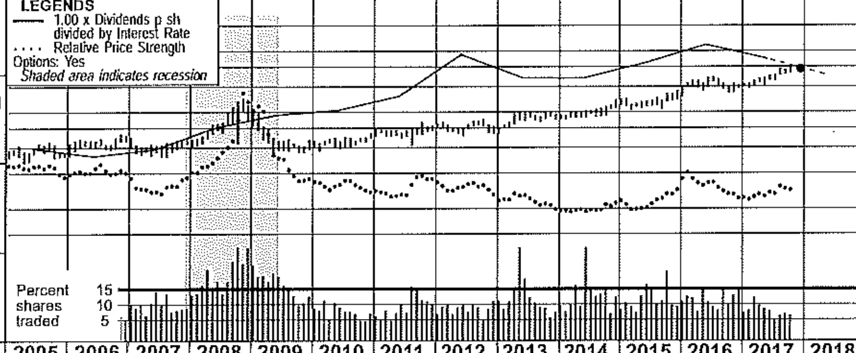
RECENT PRICE 78.20 | P/E RATIO 20.7 (Trailing: 22.2 Median: 16.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 2 Raised 11/10/17
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 12/1/17
BETA .70 (1.00 = Market)

High:	37.5	36.0	55.8	48.3	37.8	42.8	44.0	48.5	55.2	61.0	71.2	79.6	
Low:	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	

Target Price Range 2020 | 2021 | 2022

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+10%)	5%
Low	65	(-15%)	-1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	7	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	135	121	128
to Sell	109	112	93
Hld's(000)	35783	41441	43554

Percent shares traded 15 10 5

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.6	21.4
3 yr.	71.4	27.5
5 yr.	125.8	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	*44.35*	Revenues per sh A	*58.50*
3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	*6.90*	"Cash Flow" per sh	*8.15*
1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	*3.80*	Earnings per sh A B	*4.65*
1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	*2.25*	Div'ds Decl'd per sh C■	*2.50*
2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	*6.90*	Cap'l Spending per sh	*7.10*
15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	*43.90*	Book Value per sh D	*48.30*
18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	*48.50*	Common Shs Outst'g E	*50.00*
14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8		Avg Ann'l P/E Ratio	*16.0*
.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	.97		Relative P/E Ratio	*1.00*
5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/17
Total Debt $2572.3 mill. Due in 5 Yrs $625.0 mill.
LT Debt $1995.0 mill. LT Interest $70.0 mill.
(Total interest coverage: 3.6x)

Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-9/17 $531.6 mill. Oblig. $748.8 mill.

Pfd Stock None
Common Stock 48,266,858 shs. as of 11/10/17

MARKET CAP: $3.8 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	*2150*	Revenues ($mill) A	*2925*
49.8	57.6	64.3	54.0	63.8	62.6	52.8	84.6	136.9	144.2	161.6	*185*	Net Profit ($mill)	*230*
33.4%	31.3%	33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	*23.5%*	Income Tax Rate	*24.0%*
2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	*8.6%*	Net Profit Margin	*7.9%*
45.3%	44.4%	42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	*49.5%*	Long-Term Debt Ratio	*49.0%*
54.6%	55.5%	57.1%	59.5%	61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	*50.5%*	Common Equity Ratio	*51.0%*
784.5	876.1	906.3	899.9	937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	*4225*	Total Capital ($mill)	*4755*
793.8	823.2	855.9	884.1	928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	*3850*	Net Plant ($mill)	*4215*
8.5%	8.1%	8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	*5.0%*	Return on Total Cap'l	*5.5%*
11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	*8.5%*	Return on Shr. Equity	*9.5%*
11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	*8.5%*	Return on Com Equity	*9.5%*
4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	*3.5%*	Retained to Com Eq	*4.5%*
63%	56%	53%	64%	56%	59%	81%	73%	58%	59%	60%	*59%*	All Div'ds to Net Prof	*54%*

CURRENT POSITION ($MILL.)	2015	2016	9/30/17
Cash Assets	13.8	5.2	7.4
Other	516.3	564.4	718.1
Current Assets	530.1	569.6	725.5
Accts Payable	146.5	210.9	257.1
Debt Due	418.0	648.7	577.3
Other	289.3	301.7	263.5
Current Liab.	853.8	1161.3	1097.9
Fix. Chg. Cov.	365%	366%	361%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '20-'22
Revenues	-8.0%	-10.5%	*7.0%*
"Cash Flow"	6.0%	7.0%	*7.0%*
Earnings	4.0%	4.0%	*8.0%*
Dividends	3.5%	4.0%	*5.0%*
Book Value	7.5%	9.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	468.6	694.5	241.8	222.3	1627.2
2015	619.6	877.4	275.2	204.2	1976.4
2016	399.4	609.3	249.3	279.3	1537.3
2017	495.1	663.4	323.5	258.7	1740.7
2018	*600*	*800*	*300*	*450*	*2150*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	1.09	1.59	.33	d.35	2.35
2015	1.09	2.18	.32	d.43	3.16
2016	1.08	2.31	.24	d.31	3.24
2017	.99	2.36	.45	d.28	3.43
2018	*1.10*	*2.55*	*.40*	*d.25*	*3.80*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.44	.44	.44	.44	1.76
2015	.46	.46	.46	.46	1.84
2016	.49	.49	.49	.49	1.96
2017	.525	.525	.525	.525	
2018	.5625				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2017: 3.0 bill. Revenue mix for regulated operations: residential, 29%; commercial and industrial, 15%; transportation, 49%; other, 6%. Has around 3,279 employees. Officers and directors own 3.1% of common shares (1/17 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Spire recorded mixed fiscal fourth-quarter results (year ended September 30th). Revenues declined to $258.7 million, as gas utility increases were more than offset by a decline in gas marketing activities. Better operations allowed for margins to expand a bit, though higher maintenance expense still put some pressure on the bottom line during the quarter. In all, losses narrowed to $0.28 per share.

The company appears poised for solid near-term results. It will work to further integrate its operations, through the rebranding of its utility operations into the *Spire* brand. This will allow for marketing efficiencies. Meantime, it will spend around $485 million in capital expenditures, including increased outlays on the STL Pipeline. Spire also has new cases pending for its two Missouri utilities, which may allow for greater rates. In all, we think the company will be able to earn $3.80 per share in fiscal 2018.

The STL Pipeline appears to be on track. Spire received its FERC environmental assessment, and will look to increase its spending on the STL Pipeline in calendar 2018. This project is expected to be in service by fiscal 2019, and will cost between $190 million and $210 million in additional capital expenditures. This project ought to allow for greater return rates, and will improve margins at its utilities with cheaper natural gas sources. This should help drive long-term earnings to $4.65 per share.

The company recently raised its dividend 7% to $2.25 per share annually. This represents a decent increase, and management expects to raise the payout 4% to 6% annually over the coming years. As the payout is covered by cash flows, we expect that this goal will be easily achieved. The balance sheet remains manageable, though debt is slated to increase for infrastructure buildouts.

Shares of Spire are ranked to outperform the broader market averages (Timeliness: 2). In addition, they offer a decent yield. Still, they are trading near the high end of our long-term Target Price Range, and at an elevated price-to-earnings ratio. Long-term accounts would be best served looking elsewhere, for now.

John E. Seibert III *December 1, 2017*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late January. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '17: $920.2 mill., $19.07/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding in 2014, 2016, and 2017.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

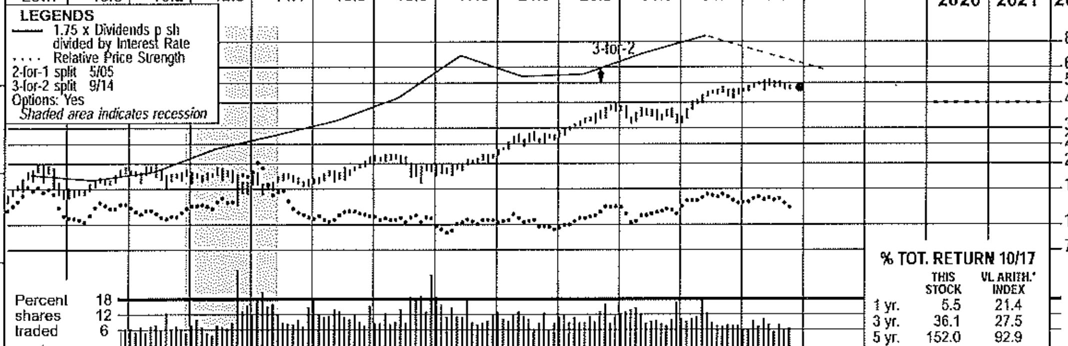
UGI CORP. NYSE-UGI

RECENT PRICE	47.70	P/E RATIO	19.2 (Trailing: 20.8 / Median: 15.0)	RELATIVE P/E RATIO	0.96	DIV'D YLD	2.1%	VALUE LINE

TIMELINESS 3 Lowered 7/14/17
SAFETY 2 Raised 9/17/04
TECHNICAL 3 Raised 12/1/17
BETA .90 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	19.3	19.8	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6	48.1	52.0
Low:	13.5	15.2	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5	31.6	45.0

Target Price Range
2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	3%
Low	40	(-15%)	-2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	7	4	2	0	3	2	0	0	0
to Sell	0	3	2	0	3	2	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	166	194	188
to Sell	204	163	192
Hld's(000)	135594	151549	151091

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.5	21.4
3 yr.	36.1	27.5
5 yr.	152.0	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
20.09	17.76	23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	32.84	35.24	37.65	Revenues per sh A	42.35
1.32	1.36	1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	4.39	4.67	5.00	"Cash Flow" per sh	5.40
.47	.60	.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	2.05	2.29	2.50	Earnings per sh AB	2.85
.35	.36	.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.89	.94	.96	1.02	Div'ds Decl'd per sh C ■	1.10
.64	.76	.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	3.26	3.15	3.25	Cap'l Spending per sh	3.25
2.08	2.55	4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	16.46	17.90	18.90	Book Value per sh D	24.25
122.83	124.66	128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	173.15	173.66	170.00	Common Shs Outst'g E	170.00
12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	19.3	21.2		Avg Ann'l P/E Ratio	16.0
.62	.62	.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	.89	1.06	1.10		Relative P/E Ratio	1.00
6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	2.4%	2.0%		Avg Ann'l Div'd Yield	2.4%
						5476.9	6648.2	5737.8	5591.4	6091.3	6519.2	7194.7	8277.3	6691.1	5685.7	6120.7	6400	Revenues ($mill) A	7200
						191.8	215.5	258.5	261.0	232.9	199.4	278.1	337.2	353.8	360.0	405	435	Net Profit ($mill)	500
						23.8%	30.6%	29.4%	32.0%	29.8%	34.8%	27.6%	30.6%	30.0%	30.0%	30.0%	30.0%	Income Tax Rate	30.0%
						3.5%	3.2%	4.5%	4.7%	3.8%	3.1%	3.9%	4.1%	5.3%	6.3%	6.6%	6.8%	Net Profit Margin	7.0%
						60.7%	58.4%	56.2%	44.0%	51.6%	60.0%	58.7%	56.4%	56.1%	56.9%	57.5%	55.5%	Long-Term Debt Ratio	51.0%
						39.3%	41.6%	43.8%	56.0%	48.4%	40.0%	41.3%	43.6%	43.9%	43.1%	42.5%	44.5%	Common Equity Ratio	49.0%
						3360.7	3405.0	3630.0	3256.7	4088.0	5580.7	6034.7	6092.7	6133.8	6616.9	6940	7215	Total Capital ($mill)	8420
						2397.4	2449.5	2903.6	3053.2	3204.5	4233.1	4480.2	4543.7	4994.1	5238.0	5495	5760	Net Plant ($mill)	6650
						7.4%	7.9%	8.9%	10.1%	7.4%	5.6%	6.6%	7.5%	7.7%	5.4%	5.5%	6.0%	Return on Total Cap'l	6.0%
						14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	12.6%	13.0%	13.5%	Return on Shr. Equity	12.0%
						14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	12.6%	13.0%	13.5%	Return on Com Equity	12.0%
						8.7%	9.5%	10.9%	8.9%	6.0%	3.6%	6.1%	7.6%	7.4%	7.0%	7.5%	8.5%	Retained to Com Eq	8.0%
						40%	38%	33%	38%	49%	60%	45%	40%	43%	45%	41%	38%	All Div'ds to Net Prof	37%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $4297.6 mill. Due in 5 Yrs $879.4 mill.
LT Debt $4014.6 mill. LT Interest $228.9 mill.
(Total interest coverage: 4.2x) (51% of Cap'l)

Leases, Uncapitalized Annual rentals $80.1 mill.
Pension Assets-9/16 $507 mill. **Oblig.** $739 mill.

Pfd Stock None

Common Stock 173,373,824 shares as of 7/31/17

MARKET CAP: $8.3 bill. (Large Cap)

CURRENT POSITION ($MILL.)	2015	2016	6/30/17
Cash Assets	369.7	502.8	604.3
Other	1090.1	921.0	963.0
Current Assets	1459.8	1423.8	1567.3
Accts Payable	392.9	391.2	359.0
Debt Due	447.9	321.2	283.0
Other	838.1	729.6	637.6
Current Liab.	1678.9	1442.0	1279.6
Fix. Chg. Cov.	338%	338%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	5.0%	3.0%	1.0%
"Cash Flow"	8.5%	8.0%	4.0%
Earnings	7.5%	4.0%	6.5%
Dividends	7.0%	8.5%	4.0%
Book Value	11.0%	9.0%	7.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	2316	3163	1486	1311	8277.3
2015	2005	2456	1148	1082	6691.1
2016	1607	1972	1131	976	5685.7
2017	1680	2174	1153	1114	6120.7
2018	1750	2245	1225	1180	6400

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	.70	1.23	.10	d.11	1.92
2015	.66	1.23	.03	.01	2.01
2016	.64	1.24	.23	d.05	2.05
2017	.91	1.31	.09	d.02	2.29
2018	.97	1.37	.16	Nil	2.50

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.18	.18	.19	.19	.74
2014	.19	.19	.20	.22	.80
2015	.22	.22	.23	.23	.90
2016	.23	.238	.238	.238	.94
2017	.238	.238	.25	.25	

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 14.2% of net income in 2016), UGI International (35.8%), Gas Utility (27.1%), Midstream & Marketing (24.2%), and Corp. & Other -1.3%. UGI Utilities distributes natural gas and electricity to over 626,000 customers mainly in Pennsylvania; 26%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). The Vanguard Group holds 10.2% of stock; Wellington Mngt., 9.3%; Offs./dir., 2.2% (12/16 proxy). Has 8,300 empls. Pres. & CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.

UGI Corp. posted solid results for fiscal 2017 (ended September 30, 2017). Indeed, the company's top line advanced 7.7% on a year-over-year basis, to $6.12 billion. This reflected greater contributions from the AmeriGas Propane, UGI International, Midstream & Marketing, and UGI Utility divisions. Additionally, UGI brought new midstream assets on line, broadened its geographic footprint in Europe, and updated some of its customer information systems, all of which should drive volumes and improve efficiency. On the profitability front, operating expenses increased 100 basis points as a function of the top line. Combined, after accounting for a reduced income tax expense and lower net income attributable to noncontrolling interests, these factors equated to an 11.7% rise in the bottom line, to $2.29 a share. This was modestly above our call of $2.25. Nonetheless, we have left our earnings outlook for fiscal 2018 unchanged at $2.50 a share.

Capital projects and acquisitions augur well for prospects. The Midstream & Marketing unit completed its Sunbury pipeline, and its Manning LNG liquefaction plant. The UGI International division launched an energy marketing business in the United Kingdom. That segment also acquired a Dutch energy marketing and services company as well as Totalgaz Italia, an LPG distribution business. Finally, the AmeriGas arm completed a total of five acquisitions over 2017. As soon as integration costs subside, we look for those bolt-on purchases to be accretive to the bottom line.

The balance sheet is in decent shape. At the end of the June quarter, the last period for which financial information was available, cash reserves had swelled about 20%, to $604 million. Meanwhile, the long-term debt load represented about half of the capital structure, which is in line for this industry.

At this juncture, these neutrally ranked shares do not stand out. The steadily rising quotation places UGI inside our Target Price Range, thus leaving it with minimal capital appreciation potential for the pull to 2020-2022. Meantime, the dividend yield is a bit below average for a utility.

Bryan J. Fong *December 1, 2017*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. items: '01, d1¢; '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢. Next egs. report due late Jan. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. inteng. At 9/16: $3,569 mill., $20.34/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	70

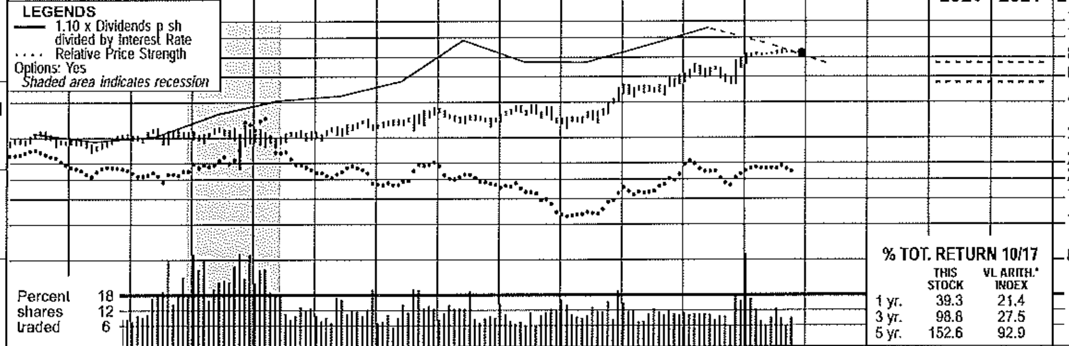
WGL HOLDINGS NYSE-WGL

RECENT PRICE 84.30 | P/E RATIO 24.6 (Trailing: 25.1 Median: 16.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS – Suspended 2/3/17
SAFETY 1 Raised 4/2/93
TECHNICAL – Suspended 2/3/17
BETA .80 (1.00 = Market)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	33.6	35.9	37.1	35.5	40.0	45.0	45.0	47.0	56.8	65.6	80.0	86.9
Low:	27.0	29.8	22.4	28.6	31.0	34.7	36.0	38.0	35.4	50.9	58.7	73.5

Target Price Range 2020 | 2021 | 2022



2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(-10%)	Nil
Low	60	(-30%)	-5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	7	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	1	0	0	1

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	132	141	132
to Sell	106	123	105
Hld's(000)	34971	40425	40665

% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	39.3	21.4
3 yr.	98.6	27.5
5 yr.	152.6	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	47.07	47.70	53.73	53.43	45.74	45.99	47.15	Revenues per sh A	49.65
3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	4.53	4.29	4.80	5.60	5.77	6.10	6.40	"Cash Flow" per sh	6.50
1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	2.31	2.68	3.16	3.27	3.11	3.50	Earnings per sh B	3.45
1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	1.66	1.72	1.83	1.93	2.02	2.08	Div'ds Decl'd per sh C■	2.20
2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	4.87	6.04	7.63	9.33	10.33	10.75	10.85	Cap'l Spending per sh	11.80
16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.69	22.82	23.49	24.64	24.65	24.08	24.97	26.78	29.35	32.45	Book Value per sh D	37.55
48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	51.52	51.70	51.76	49.78	51.37	51.21	53.00	Common Shs Outst'g E	55.00
14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3	18.2	15.2	17.0	20.0	25.4		Avg Ann'l P/E Ratio	20.0
.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.97	1.02	.80	.86	1.05	1.32		Relative P/E Ratio	1.25
4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	3.9%	3.9%	4.2%	3.4%	2.9%	2.6%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 6/30/17
Total Debt $2024.5 mill. Due in 5 Yrs $988.9 mill.
LT Debt $1235.6 mill. LT Interest $52.3 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x) (44% of Total Capital)
Pension Assets-9/16 $1,355.0 mill. Oblig. $1,393.6 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 51,219,000 shs. as of 7/31/17

MARKET CAP: $4.3 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	2466.1	2780.9	2659.8	2349.6	2354.7	2500	Revenues ($mill) A	2730
102.9	122.9	128.7	115.0	115.5	138.4	119.7	139.0	158.2	165.1	160	185	Net Profit ($mill)	190
39.1%	37.1%	39.1%	38.7%	42.4%	40.1%	30.2%	29.0%	39.9%	37.9%	39.0%	39.0%	Income Tax Rate	39.0%
3.9%	4.7%	4.8%	4.2%	4.2%	5.7%	4.9%	5.0%	5.9%	7.0%	7.0%	7.0%	Net Profit Margin	7.0%
37.9%	35.9%	33.3%	33.4%	32.3%	31.2%	28.7%	34.8%	42.6%	50.7%	48.3%	46.0%	Long-Term Debt Ratio	44.0%
60.3%	62.4%	65.0%	65.0%	66.2%	67.3%	69.8%	63.8%	56.1%	48.3%	50.7%	53.0%	Common Equity Ratio	55.0%
1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	1826.8	1954.0	2215.6	2848.0	2961.7	3245	Total Capital ($mill)	3740
2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	2907.5	3314.4	3672.7	4127.2	4630.1	5195	Net Plant ($mill)	7335
7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	7.5%	8.1%	8.3%	6.7%	6.7%	7.0%	Return on Total Cap'l	6.5%
10.2%	11.4%	11.4%	9.7%	9.4%	10.7%	9.2%	10.9%	12.4%	11.8%	10.6%	11.0%	Return on Shr. Equity	9.5%
10.4%	11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.6%	11.9%	10.6%	11.0%	Return on Com Equity	9.5%
3.5%	5.0%	5.0%	3.3%	3.4%	4.8%	2.6%	4.3%	5.4%	5.3%	3.7%	4.5%	Retained to Com Eq	3.0%
66%	57%	57%	67%	64%	56%	72%	62%	58%	56%	65%	59%	All Div'ds to Net Prof	63%

CURRENT POSITION ($MILL.)	2015	2016	6/30/17
Cash Assets	6.7	5.6	9.6
Other	774.7	837.9	952.7
Current Assets	781.4	843.5	962.3
Accts Payable	325.1	405.4	377.1
Debt Due	357.0	331.4	788.9
Other	300.8	290.1	267.9
Current Liab.	982.9	1026.9	1433.9
Fix. Chg. Cov.	576%	546%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	1.0%	-1.0%	-.5%
"Cash Flow"	3.5%	5.0%	3.0%
Earnings	4.0%	5.5%	2.0%
Dividends	3.5%	4.0%	3.0%
Book Value	3.5%	2.0%	6.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	680.5	1174.0	467.5	458.9	2780.9
2015	749.2	1001.7	441.2	467.7	2659.8
2016	613.4	835.7	440.6	459.9	2349.6
2017	609.5	841.8	474.3	429.1	2354.7
2018	645	875	510	470	2500

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2014	.99	1.84	.02	d.17	2.68
2015	1.16	2.02	.22	d.23	3.16
2016	1.18	1.78	.33	d.01	3.27
2017	1.15	1.87	.26	d.17	3.11
2018	1.25	1.95	.40	d.10	3.50

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.40	.42	.42	.42	1.66
2014	.42	.44	.44	.44	1.74
2015	.44	.463	.463	.463	1.83
2016	.463	.488	.488	.488	1.93
2017	.488	.51	.51	.51	

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,129,865 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy-related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. The Vanguard Group owns 9.8% of common stock; Off./dir. less than 1% (1/17 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

The acquisition of WGL Holdings by AltaGas Ltd. appears to be on schedule to close in the March quarter. As a result of the deal, the stock's price continues to hover 3%-5% below the tender offer price of $88.25. To recap, this price point represents an almost 28% premium from the level WGL was trading at on November 28, 2016, the day prior to the announcement of the takeover. The current discount from the purchase price is likely a reflection of the possibility that the purchase could be derailed in the months ahead. At this point, the equity will no longer be trading on earnings, and as a result, we have suspended the Timeliness rank of these shares until the deal is finalized. If for some reason the transaction is not completed, we would expect these shares to fall back toward preannouncement levels. Back in May, it was announced that 96.22% of the voting shares had approved the acquisition and management is awaiting regulatory approvals.

WGL posted somewhat mixed financial results for the fourth quarter and fiscal year (ended September 30th). Indeed, the company's annual revenues advanced less than 1%, to roughly $2.355 billion. This reflected a 9.5% rise in utility volumes, largely offset by a 7.2% drop in nonutility volumes. On the margin front, operating expenses increased 230 basis points as a percentage of the top line. After accounting for a sizable downturn in other income and higher interest expenses, WGL's fiscal 2017 earnings fell 4.9%, to $3.11 a share. This was moderately below our call of $3.30.

Therefore, we have reduced our fiscal 2018 top- and bottom-line estimates. The company may well register a revenue increase of about 6% this year, to $2.5 billion. This would stem from customer additions at the regulated utility business, as well as from capital projects coming on line at the Commercial Energy and Midstream Energy divisions. On balance, these factors could drive share net 12.5% higher, to $3.50, albeit when viewed against 2017's somewhat easy comparison.

Conservative investors may be wise to lock in gains now and redeploy capital elsewhere, rather than to wait for the acquisition to close.

Bryan J. Fong *December 1, 2017*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Jan. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '16: $726.8 million, $14.36/sh.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	75

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

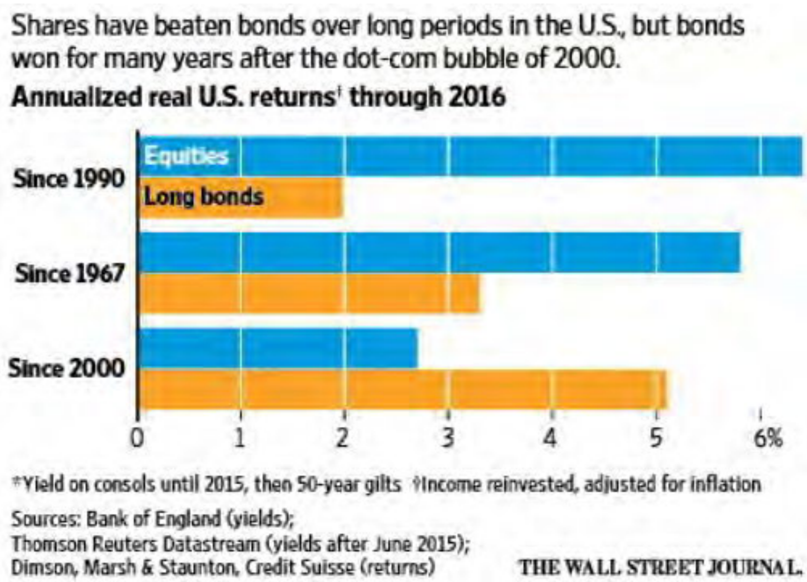
STAFF EXHIBIT 211

Security Market News
(News Investors Are Seeing)

Exhibits in Support
of Opening Testimony

April 20, 2018

News Investors Are Seeing



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Utility Dividends Grow Over 6% in 2017

by Tom Serzan – Regulatory Resesearch Associates (RRA)
An Offering of S&P Global Market Intelligence – Jan. 29, 2019

The **average dividend growth rate** for the **full year 2017** by the **60 RRA-covered utilities that increased their dividends**, **including** the **nine publicly traded water utilities**, was **6.6%**. That rate was **up from** the **5.9% growth rate** in **2016**.

* **During 2017**, **33 electric utilities increased dividends** by an **average** of **5.8%**; two electrics kept their dividends **unchanged**. **All 16 gas utilities increased dividends** by an **average** of **6.4%**, while **all nine water utilities** each **increased dividends** by **8.6% on average**.

* The **average utility dividend payout ratio**, based on S&P Capital IQ 2017 consensus earnings and dividend estimates, was **61.6%, up from** a **60% average payout level** that had existed **for both 2015 and 2016**. Industry payout ratios are projected to continue trending up marginally over the next couple of years.

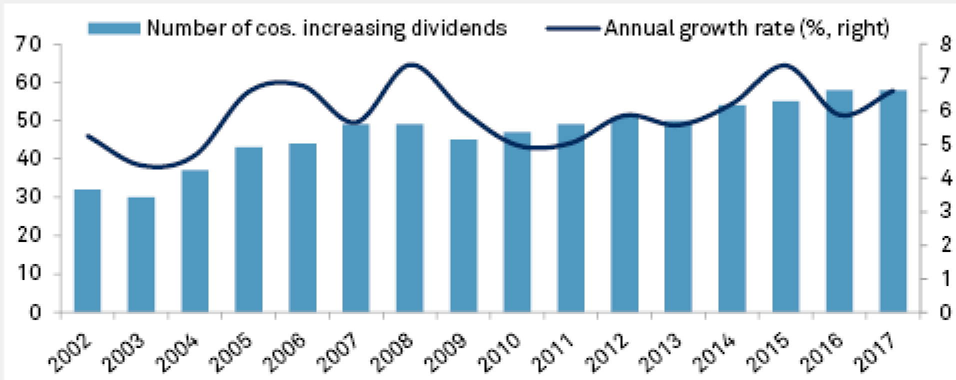
* Consensus earnings estimates suggest that profits will grow by about 5% over the next three years, with this level toward the upper end of the level we have generally observed from many mainstream utility managements — in the 4% to 5% range.

* Variations in growth among the electric, gas, and water sectors is expected in 2018. Electric companies are expected to grow dividends by 6.6% on average this year, while growth in the gas sector is forecast at 4.8% rate, with that lower number due

mostly to forecasts for a reduction in SCANA's dividend. Average growth in the smaller water sector in 2018 is projected at 5.2% in 2018.

* We expect that profit forecasts across all utility sectors may be changed as managements disclose their interpretations of recently changed tax laws. Cash flow implications may well impact corporate uses of cash across the spectrum of capital spending, merger activity and dividend expansion.

Utility annual dividend increases



Excludes zero-dividend companies.
Source: S&P Global Market Intelligence

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VA. Staff Pares Down Kentucky Utilities' Rate Request for Tax Effects, Lower ROE
by Lillian Federico – Regulatory Research Associates (RRA)
An offering of S&P Global Market Intelligence – Mar. 1, 2018

In testimony filed Feb. 28, the **Virginia State Corporation Commission staff recommended** a $1.3 million, or 2.1%, rate increase for PPL Corp. subsidiary Kentucky Utilities Co. versus the $6.7 million increase requested by Kentucky Utilities.

The staff recommendation **reflects** the **impacts** of the **federal Tax Cuts and Jobs Act**, which was **enacted** in **December 2017**, **lowering** the **federal corporate income tax rate to 21% from 35%**. According to the staff, reflecting the impacts of this change **reduced** the **revenue requirement** by **about $4 million.**

Kentucky Utilities

Virginia — Case No. PUR-2017-00106

Current case (filed 09/29/17)	Rate change ($M)	ROE (%)	ROR (%)	Rate base value ($M)
Requested by company	6.7	10.42	7.47	214.1
Recommended by staff	1.3	9.20	6.89	211.2
Previous case (decided 02/02/16)	**Rate change ($M)**	**ROE (%)**	**ROR (%)**	**Rate base value ($M)**
Requested by company	7.2	10.50	7.51	222.2
Authorized by commission*	5.5	NA	NA	NA

Data as of Feb. 28, 2018.
* Decision followed a settlement.
ROE= return on equity; ROR = return on rate base; NA = not specified in filing
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

The **staff proposes** that the State Corporation Commission, or **SCC**, **approve** a **9.2% return on equity** (**53.849% of capital**) and a **6.892% return on an average rate base** valued at $211.2 million for a calendar 2016 test period, with adjustments for known and measurable changes through Dec. 31, 2018.

The staff indicates that adoption of the staff-proposed overall return versus the 7.467% overall return sought by Kentucky Utilities, or KU, would reduce the company-proposed revenue requirement by about $1.5 million.

The **9.2%** recommended ROE is consistent with the generic base ROE approved by the SCC for Dominion Energy Inc. subsidiary Virginia Electric and Power Co.'s, or VEPCO's, rider mechanisms and applied in recent rider adjustments for VEPCO. However, this **ROE** is **below** the 9**.68% average ROE** and **9.6% median ROE authorized in electric rate case decisions issued during 2017**, **excluding** incentive **returns approved in limited-issue rider proceedings**, as calculated by Regulatory Research Associates, an offering of S&P Global Market Intelligence.

This is **somewhat unusual**, as the **SCC** has **typically adopted ROEs** that are **at or above prevailing industry averages** when established and KU does not have access to the risk-reducing rider mechanisms that VEPCO employs.

Rebuttal testimony is due by March 15, 2018. Hearings are to begin March 29; RRA expects that a Hearing Examiner's report will be issued in mid-May or so, with a final decision by June 30.

Rate Case History

This proceeding was initiated July 31, 2017, when KU submitted a notice of intent to file a rate case; the notice provided no detail regarding the increase or underlying parameters to be requested (Case No. PUR-2017-00106).

On Sept. 29, 2017, KU filed for a $6.7 million electric base rate increase, equivalent to a 10.4% increase in overall Virginia-jurisdictional revenues, including fuel recoveries. The requested increase is premised upon a 10.42% return on equity (53.849% of capital) and a 7.467% return on an average rate base valued at $214.1 million for a calendar-2016 test period, with adjustments for known and measurable changes through Dec. 31, 2018.

KU indicated that the increase is necessary because the company "continues to make significant investments to provide safe, reliable service to customers while complying with increasing environmental regulations." The company estimates that between Jan. 1, 2016 and Dec. 31, 2018, it will expend $1.5 billion in generation, transmission and distribution infrastructure company-wide, including closing existing ash ponds and constructing landfills at its generating stations; removing the remaining equipment at the former coal units at the Green River, Pineville and Tyrone stations; and a five-year transmission upgrade program to replace aging equipment and install "intelligent control equipment" in order to improve reliability. In addition to these items, KU cited an increase in depreciation expense and property taxes as drivers of the request.

Previous Rate Case

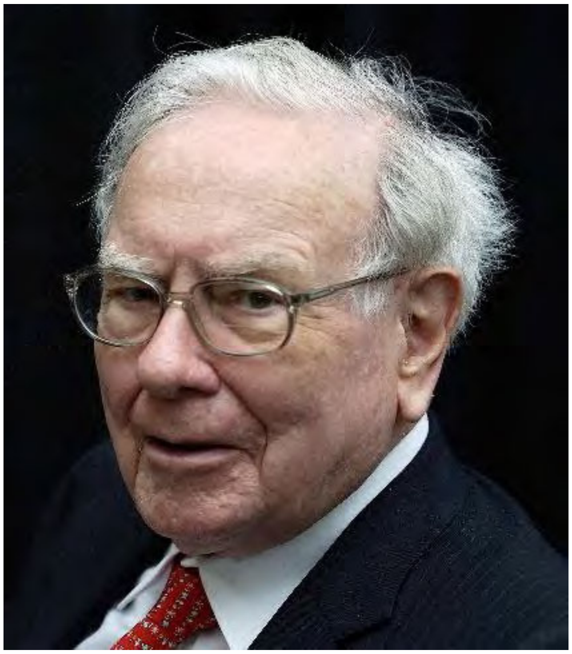
KU's prior rate case was decided in February 2016, when the SCC adopted a settlement authorizing the company a $5.5 million rate increase. The settlement and order were **silent as to rate of return** and other traditional rate case parameters underlying the authorized increase, **but specified that an ROE range of 9.5% to 10.5% would be utilized for the purposes of earnings reviews and annual information filings**, beginning with calendar year 2015 and continuing thereafter until the ROE is reset by the SCC.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the S&P Global Market Intelligence Energy Research Home Page.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the S&P Global Market Intelligence Energy Research Library.

Berkshire Hathaway Posted $29 Billion Gain in 2017 from U.S. Tax Plan

by Nicole Friedman – WSJ – Feb 24, 2018



Mounting cash pile, mostly invested in Treasury bills, grew to **$116 billion at year-end.**

Left: Berkshire Hathaway's Warren Buffett.

Berkshire Hathaway Inc. BRK.A 0.87% said Saturday it posted a **$29 billion gain in 2017 related to changes in U.S. tax law, a one-time boost that inflated annual profits** for the Omaha conglomerate.

New legislation signed last December by President Donald Trump lowered Berkshire's estimate of how much it would have to pay in taxes if it sold the stock investments it currently holds. **Berkshire has billions in unrealized gains on equity investments**, and those gains are **now** expected to be **taxed at a 21% rate, down from 35%**.

The **immediate net windfall** for **Berkshire** was **$29 billion**, which **helped push Berkshire's net earnings to $44.94 billion in 2017 from $24.07 billion** the **prior year** while offsetting declines in certain businesses. Berkshire's operating earnings fell 18%, from $17.6 billion in 2016 to $14.5 billion in 2017, as hurricanes and other catastrophes caused losses in the company's insurance operations.

Berkshire's book value per share rose 23% in 2017, the company said, compared with a 22% total return in the S&P 500, including dividends.

Berkshire Chairman Warren Buffett said in a letter released to shareholders Saturday that the large gain in the company's net worth was "real" but "did not come from anything we accomplished at Berkshire."

He also lamented the lack of well-priced acquisition opportunities for a company that already owns everything from a railroad and utilities to industrial manufacturers and retailers. Berkshire's mounting cash pile, which is mostly invested in Treasury bills, ballooned to a record $116 billion at year-end.

"We will need to make one or more huge acquisitions," Mr. Buffett wrote in his annual letter. Prices for businesses were too high for his taste in 2017, he said, but "our smiles will broaden when we have redeployed Berkshire's excess funds into more productive assets."

In October, Berkshire took a 38.6% stake in truck-stop company Pilot Travel Centers LLC, which will increase to an 80% stake in 2023. But two potential large deals fell through last year. Kraft Heinz Co. dropped a $143 billion offer, which would have been partly backed by Berkshire, for Unilever PLC. And Texas power-transmission company Oncor terminated a deal with Berkshire's utility arm in favor of a higher offer from Sempra Energy.

Some of Berkshire's 60-odd subsidiaries did complete acquisitions, but those deals tend to be small. **Berkshire spent $2.7 billion on bolt-on acquisitions in 2017**, the company said, up from $1.4 billion the prior year.

The annual letter from Mr. Buffett is widely read by investors and analysts. This year, the 17-page document was shorter than usual and left out some of Mr. Buffett's usual themes on the U.S. economy and the future prospects of the U.S. He also avoided giving any new hints about his succession planning after promoting two executives to vice chairmen last month.

He did, however, reiterate his advice that individuals should invest passively and avoid high money management fees while discussing the final tally from his bet that an S&P 500 index fund would outperform a basket of hedge funds over a decade.

Mr. Buffett won the bet at the end of 2017, and the winning proceeds of more than $2 million were given to Girls Inc. of Omaha, a charity in Mr. Buffett's hometown.

Over the bet's 10 years, the index fund had an average annual gain of 8.5%. The five funds of hedge funds selected by asset manager Protégé Partners reported average annual gains between 0.3% and 6.5%. One of the funds was liquidated last year.

He also explained a quirk of the bet: The stakes were originally placed in Treasury bonds, but Mr. Buffett and his opponents reinvested the money in Berkshire stocks after the bonds' yields fell. Yields fall when prices rise.

He **cautioned** that **long-term investors like pension funds should not measure** their **investment risk based on** the **ratio** of **stocks to bonds, because bonds can be riskier than stocks over time**.

"Our **bonds had become** a dumb—a **really dumb**—**investment compared** to **American equities**," he said.

As Easy Money Ends, Uncertainty Rises

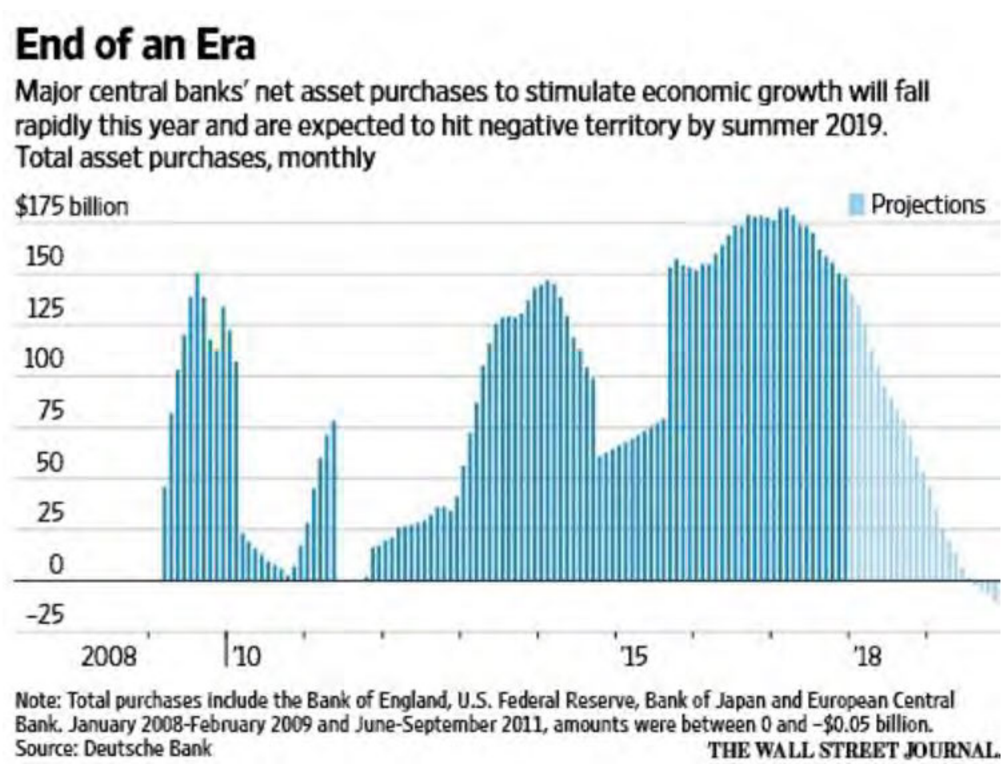
by Tom Fairless – WSj – Jan 22, 2018

Strong economic indicators allow officials to pull back from stimulus policies of recent years

The **tide of easy money** that lifted advanced economies out of recession **will recede** in earnest in 2018, opening a new phase in the global economic expansion.

From Frankfurt to Tokyo, central- bank officials are seizing on stronger economic indicators, including tentative signs of higher inflation, to signal an **exit from stimulus policies that were rolled out after the financial crisis**. **Asset purchases by** the **four major central banks** — the **Federal Reserve**, **European Central Bank**, **Bank of Japan** and **Bank of England** — **will shrink by more than 70% by the end of 2018**, to around $50 billion a month, after peaking at $182 billion in March 2017, **according to Deutsche Bank**. And some banks are planning or signaling possible **interest-rate increases** this year.

The coordinated retreat by some of the biggest buyers in global financial markets raises the **prospect of increased volatility** and a **possible correction in asset prices**. Adding to the uncertainty, the generation of central bankers who handled the crisis is stepping aside, and it's unclear if their successors will share their desire to continue with aggressive monetary stimulus to support global growth.



Some central-bank officials worry that investors are failing to price in the new policy course, and may get hit hard. Meanwhile, there **may be tougher times ahead** for **business** and consumers, who are currently **benefiting from ultralow borrowing costs.**

"It is indeed surprising that long-term interest rates are now lower than they were in the summer, although growth has surprised very positively and growth and inflation forecasts have been adjusted upwards," Yves Mersch, a member of the ECB's six-member executive board, told German reporters in an interview published on the ECB's website in late December. "It doesn't really follow."

Are Times Too Good?

The reversal from major central banks comes as economic growth accelerates and inflation starts to approach targets after years of staying below projections.

Growth accelerated in about three-quarters of all countries last year, the highest share since 2010, the International Monetary Fund said in December. In the U.S., growth recently hit a three-year high of 3.3%, while the Fed's preferred inflation measure climbed 1.5% on the year in November, up from a 1.4% rate over the previous two months.

Higher U.S. inflation is a key risk for stock markets, because the Fed would likely raise rates more quickly than expected to cool the economy. Outgoing Fed Chairwoman Janet Yellen has suggested that the period of weak inflation is likely to prove temporary.

The Fed has projected another trio of quarter-point rate rises this year and two more in 2019, but some investors think it might act more aggressively given strong growth and the likely economic boost from recent tax cuts.

In the Euro-Zone, the ECB signaled on Jan. 11 it might move sooner than expected to phase out its giant bond-buying program, surprising investors and sending the euro higher. The change of course comes amid a rebound in the Euro-Zone economy, where business and consumer confidence are at their highest levels in more than 17 years. Average inflation, at 1.4% in December, remains too weak for the ECB to raise rates, but it is expected to edge up over the coming months and recently hit a five-year high in Germany.

German 10-year government bond yields have started to edge up since mid-December, a possible harbinger of higher market interest rates.

In the U.K., the Bank of England raised rates in November for the first time in 10 years in response to higher inflation, and officials have signaled more rate increases could be coming.

In Japan, too, inflation is edging up. Core consumer prices, excluding volatile fresh-food prices, rose 0.9% in November from a year earlier, up from 0.8% in October. Bank of Japan Governor Haruhiko Kuroda has said he expects companies will soon start passing the higher labor costs that stem from worker shortages on to consumers.

While **major central banks** have done all they could to push up consumer- price growth, which has lingered below target in recent years, a **sudden increase in inflation** would **force them to change course**, which could prove destabilizing for financial markets and the world economy.

"What is unthinkable today is [higher] inflation [in the U.S. and Europe], that's what scares me the most," says one top ECB official. "Markets would react incredibly."

Easing Up

Another concern is the debt market. In response to record-low bond yields, global debt issuance by companies and governments reached a high in 2017, with U.S. and European companies particularly active.

But on the demand side, purchases by the ECB under its giant bond-buying program fell by half this month, and that flow of money could dry up entirely by October. Meanwhile, the **Fed** is **gradually reducing its $4.5 trillion balance sheet**, and the Bank of Japan has slowed its asset purchases and is hinting at an exit from easy money.

All of which raises the **prospect** of an "**enormous mismatch between supply and demand" in global debt markets this year**, according to Torsten Slok, an economist with Deutsche Bank in New York.

Central-bank officials hope their large stock of assets means market interest rates will rise only gradually. But some investors worry about a sharp correction given the mismatch between supply and demand of bonds, particularly as markets have so far been slow to adjust to the new direction of central- bank policies.

"There is a **regime change in what central banks are trying to tell us**," says Mr. Slok. "**Investor sentiment could change suddenly**."

After Years of Investing Magic, What's Next

by James Mackintosh – WSJ Streetwise Column – Jan 22, 2018

The perfect investment is one that only goes up. Almost as good is an investment that does well when the rest of your portfolio hits a rough patch, but over time still makes money.

Such a perfect investment shouldn't exist. Yet, for the past two decades, government bonds have offered exactly this free insurance, moving in the opposite direction of shares in the short run but producing gains almost as good as equities in the long run.

The scale of the magic is stunning: From the start of 2000 to the end of last year, holding the latest 10-year Treasury and reinvesting coupons returned 155%, the S& P 500 with dividends 158%, while a 60-40 equitybond portfolio beat both.

But the magic can't continue forever. If **the link between equity and bond prices were to return to what once counted as normal, the magic disappears** — and there are **good reasons to fear that could happen soon**.

The danger is that bond yields rise without any corresponding strength in the real economy to protect profits and stock prices. The

would be the **return of inflation or a shift of stance by the Federal Reserve to stop protecting investors from losses.**

Both of those possibilities are worth worrying about.

Unnatural Order

Start with **how shares and bonds behave**. Prices of the two biggest asset classes have **tended to move in opposite directions since the late 1990s**, measured as a **strong negative correlation**.

This **pattern is so well-established it seems like the natural order of things**. **But** since the start of the 19th century, there has been only one other significant period where stocks and bonds behaved this way, according to Ian Harnett of Absolute Strategy Research. The late 1950s and early 1960s had a similar stock-bond relationship to the past few years, and were also the last time inflation was quiescent.

The **stock-bond link** is complex, but **depends to a large extent on inflation**, **uncertainty about inflation and** more recently the **central bank**.

When investors are **confident that inflation is under control**, they **focus** instead **on the real economy, and economic news pushes bonds and equities in different directions**. A **strong economy** generally means **bond yields rise** (and so **bond prices fall**) **in anticipation of higher inflation and higher interest rates**, **while share prices rise in anticipation of higher profits**. **When** there are **fears of slowing growth, investors dump stocks and buy bonds**.

Fear of inflation alone usually has the same upward effect on bond yields (and so downward effect on bond prices) **as economic growth**. **But inflation doesn't help corporate profits much**, while higher yields mean a higher discount rate applied to future profits, which — in theory at least — should **push down stock prices**.

It's too soon to be sure that inflation is awake again after lying dormant for a decade, but there are signs that the **tight U.S. jobs market** is leading to higher wages. Technological advances such as online shopping still weigh on prices, but with **little spare capacity, inflation should pick up. If investors switch focus from the economy to inflation,** the nightmare would be **higher bond yields** and **lower share prices**.

Dangerous Belief

Inflation itself isn't the only concern. Alongside low inflation has come a belief that inflation has been conquered. The **extra yield on Treasurys that investors demand to compensate them for inflation uncertainty, known as the term premium, is extremely low**.

Inflation options are pricing the lowest chance of inflation being badly behaved over the next five years — that is, inflation being above 3% or below 1% — since at least 2009, according to Minneapolis Fed calculations.

It's hard to see how investors could be much less concerned about inflation, so the risk is that anxiety returns, bringing with it higher bond yields and arriving with enough force to pummel share prices.

The **final risk is the Fed**. Almost everyone thinks that the Fed's multitrillion-dollar bond purchases succeeded in lowering yields and pushing up stock prices.

Quantitative easing has **only just** been **put into reverse**, and the Fed's **$4 trillion balance sheet ended last year only $3 billion smaller than it started**.

As the **balance sheet shrinks** this year, the **effects** the **Fed had on stocks and bonds should also go into reverse**, **creating upward pressure on bond yields** and **downward pressure on stock prices.**

Worse would be if the Fed's new leadership decided that investors have had it too easy. The late-1990s switch in the stock-bond relationship came as investors realized the Fed would bail out the market with rate cuts in bad times, while letting the good times roll. This asymmetric "Greenspan put" has continued, and will probably become the "Powell put" when Jerome Powell takes over this year. However, **if Mr. Powell** wanted to **take a hawkish tone**, he could make clear that the **Fed will no longer mollycoddle the markets**.

None of these dangers is **sure** to **materialize in 2018**. **Inflation can stay low for longer**. The **economy can improve even further**. The **Fed can keep feeding** its friends on **Wall Street**. Or correlations might be overwhelmed by a new market mania; after all, the S&P 500 managed a near-20% gain in 2017 even as bond yields ended the year where they began. But **high on the list of things to worry about** is that higher bond yields will finally arrive in 2018, and bring with them not even more new stock-market highs but a **correlation crisis**.

The **recent inverse link between stock and bond prices is a historical anomaly**.

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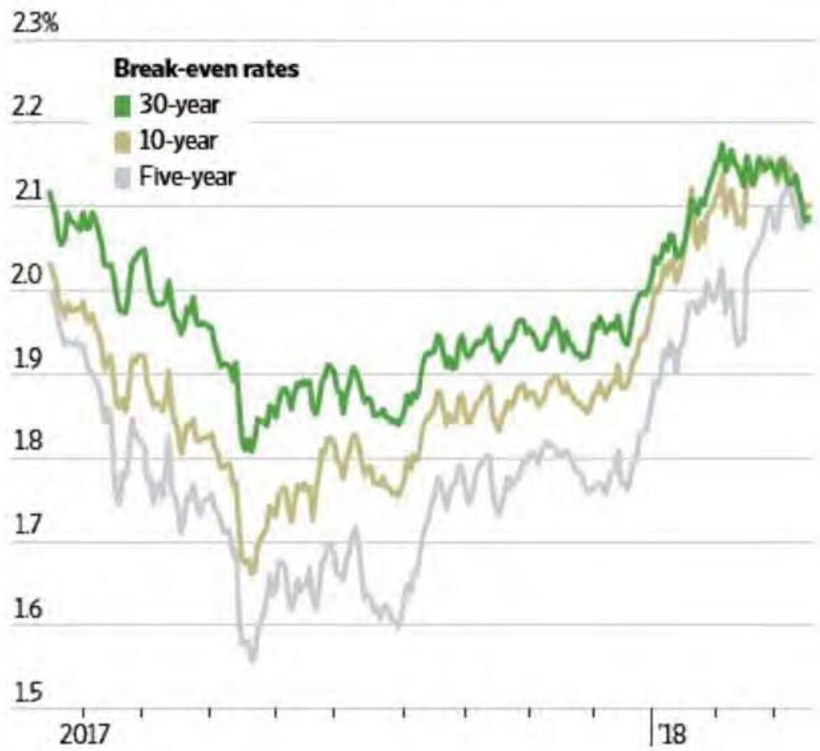
A Deeper Look at the Flattening U.S. Yield Curve

WSJ – Mar. 19, 2018

The long-awaited repricing of the U.S. bond market has stalled once again. The 10-year U.S. Treasury yield has been stuck between 2.8% and 2.9% after an early 2018 debt selloff took the yield within a hair of 3% for the first time in four years. The rise in yields since 2016 **signals investors no longer fear** the **global economy will suddenly fall apart, but** the recent leveling off suggests **investors doubt growth is truly picking up in a sustained way.** Next on deck for bond investors is the coming week's meeting of the Federal Open Market Committee, due to conclude Wednesday. The **Fed** is **expected** to **raise** its **fed-funds short-term interest-rate target then and at least twice more this year**, **depending** on **how** the **economy performs** and **whether inflation increases further**.

BREAK-EVENS

Short-term inflation expectations have risen in the past year, propelled by the $1.5 trillion tax cut passed at the end of 2017. Yet a smaller change in expectations for longer-term inflation suggests many investors still think the U.S. growth trend is stuck around 2%.



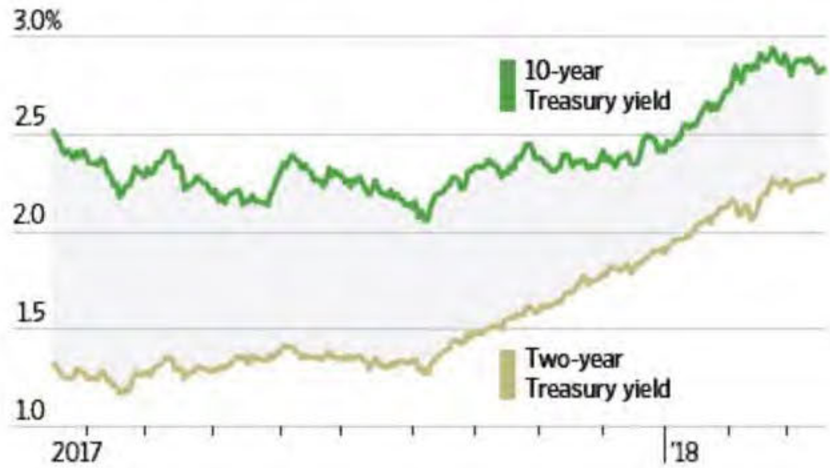
Sources: Treasury Department (yields by maturity); Thomson Reuters (break-evens); Ryan ALM (spreads)

Fed interest-rate increases translate almost mechanically into higher short-term Treasury rates. A bigger question for investors is whether those increases will curb growth along with inflation. That would pull down yields "further out on the curve," as Wall Street jargon would have it, potentially signaling a slowdown.

Here is a look at a few key yield-curve soundings that investors will be making for the balance of 2018.

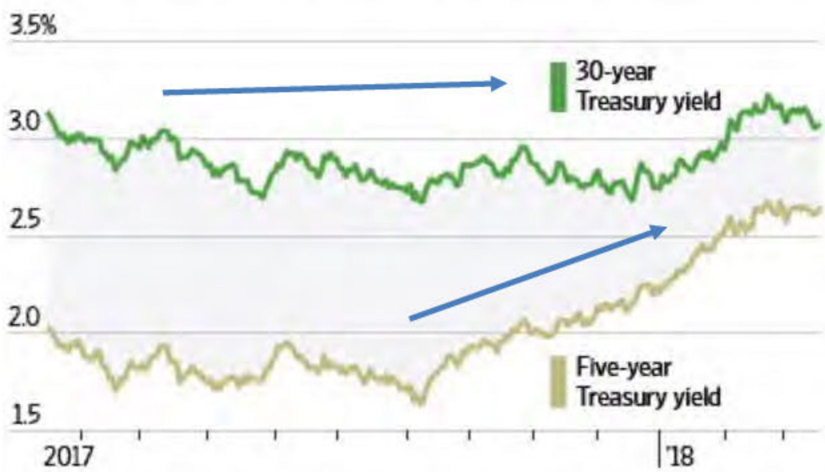
THE 'TWO-10' SPREAD

The gap between two- and 10-year Treasury yields is watched closely as a barometer of economic health. The rise in 10-year yields since December is a sign to many analysts that the economic expansion is far from over.

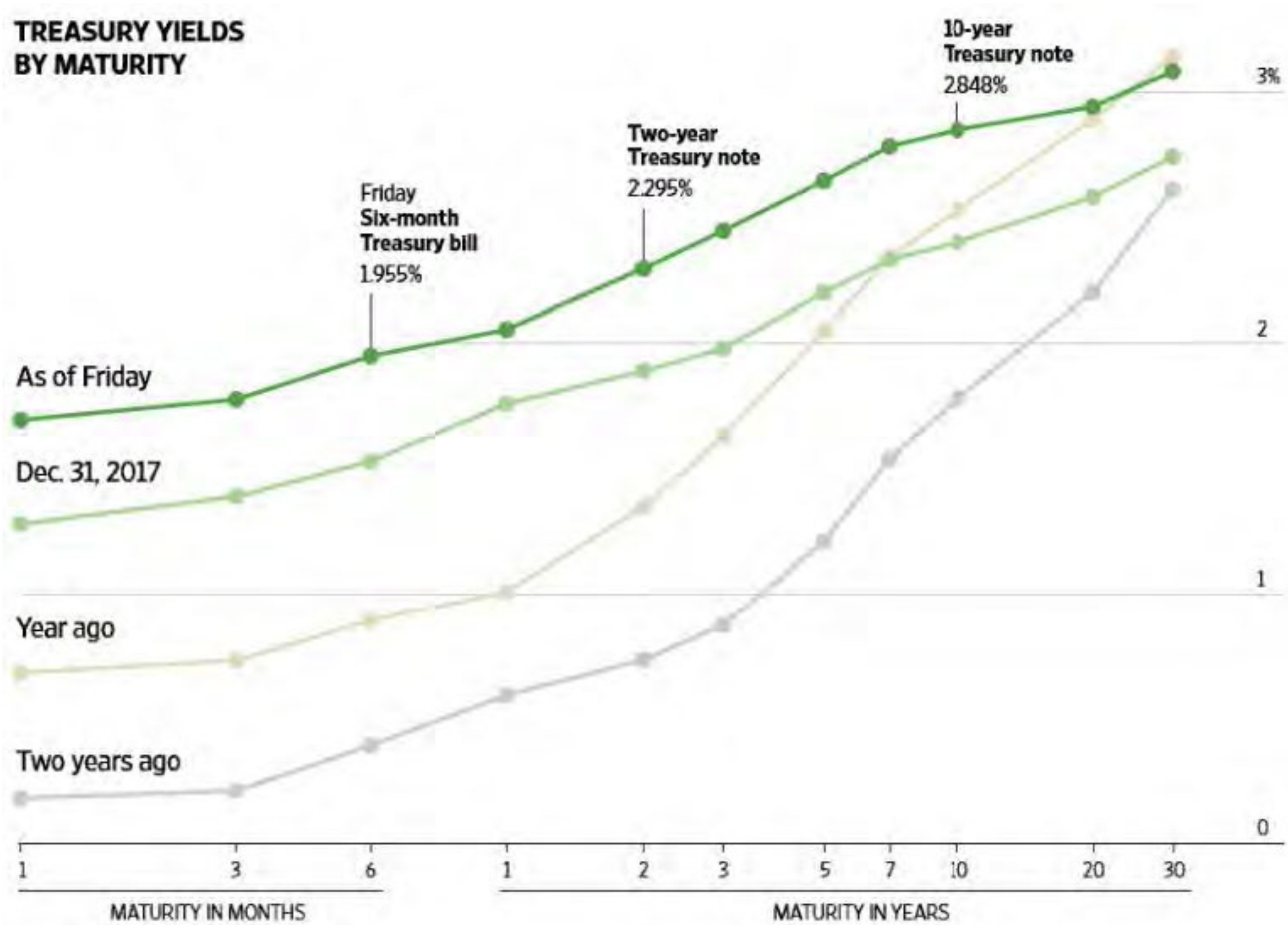


THE 'FIVE-30' SPREAD

Investors watch the difference between five- and 30-year yields for a read on the outlook for growth and inflation, which threatens the value of bonds because it chips away at the purchasing power of their fixed payments. The larger the difference, the greater the expectation for economic expansion and inflationary pressures.



Reporting by Daniel Kruger, graphic by Peter Santilli/ THE WALL STREET JOURNAL



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Electric ROEs Slightly Lower, Gas ROEs Higher in 2017

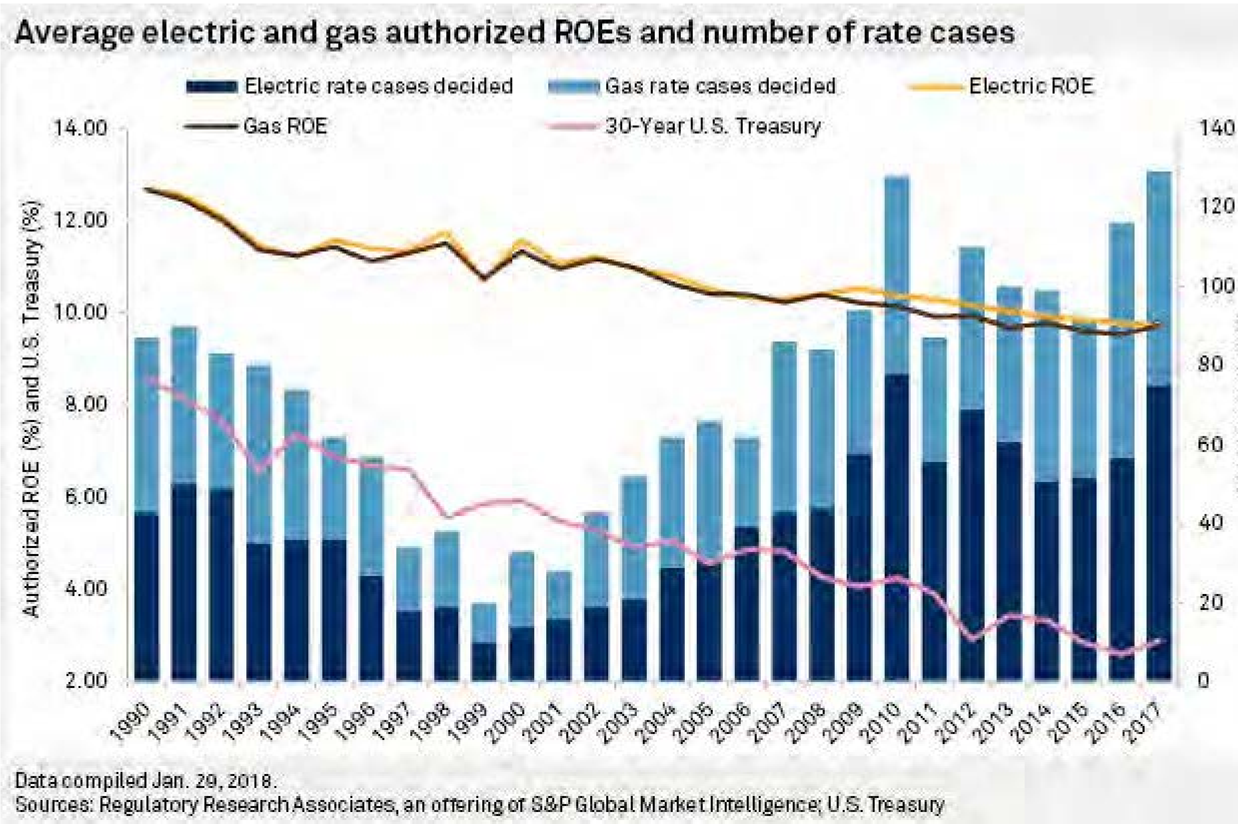
by Lisa Fontanella – Regulatory Research Associates (RRA)
An offering of S&P Global Market Intelligence – Jan. 31, 2018

Rate case activity was brisk in 2017. The average ROE authorized electric utilities was 9.74% in rate cases decided in 2017, a record low, albeit marginally below 9.77% in 2016. There were 53 electric ROE determinations in 2017, versus 42 in 2016.

This data includes several **limited issue rider cases**; **excluding these** cases from the data, the **average authorized ROE was 9.68% in rate cases decided in 2017**, **marginally up from 9.6% in 2016**. The differential in electric authorized ROEs is largely driven by **Virginia statutes** that **authorize** the **State Corporation Commission** to **approve ROE premiums of up to 200 basis points for certain generation projects**

For vertically-integrated electric utilities, the average ROE authorized was 9.8% in 2017, versus 9.77% in 2016. For electric distribution utilities, the average ROE authorized was 9.43% in 2017, versus 9.31% in 2016.

The average ROE authorized gas utilities was 9.72% in 2017 versus 9.54% in 2016. There were 24 gas cases that included an ROE determination in 2017, versus 26 in 2016. RRA notes that the 2017 data includes an 11.88% ROE determination for an Alaska utility. **Absent** this "**outlier**," the **2017 gas ROE average** is **9.63%**.



In **2017**, the **<u>median</u> authorized ROE** for **all electric** utilities was **9.6%, versus 9.75% in 2016**. For **gas** utilities, the **<u>median</u> authorized ROE** in 2017 was **9.6%, versus 9.5% in 2016**.

Over the past several years, the persistently low interest rate environment has put a downward pressure on authorized ROEs. As shown in the graph to the left, the **annual average ROE has generally declined since 1990** and has been below 10% for electrics since 2014, and below 10% for gas utilities since 2011. In addition, after reaching a low in 1999, the number of rate case decisions for energy companies has generally increased over the last several years, peaking in 2010 and again in 2017.

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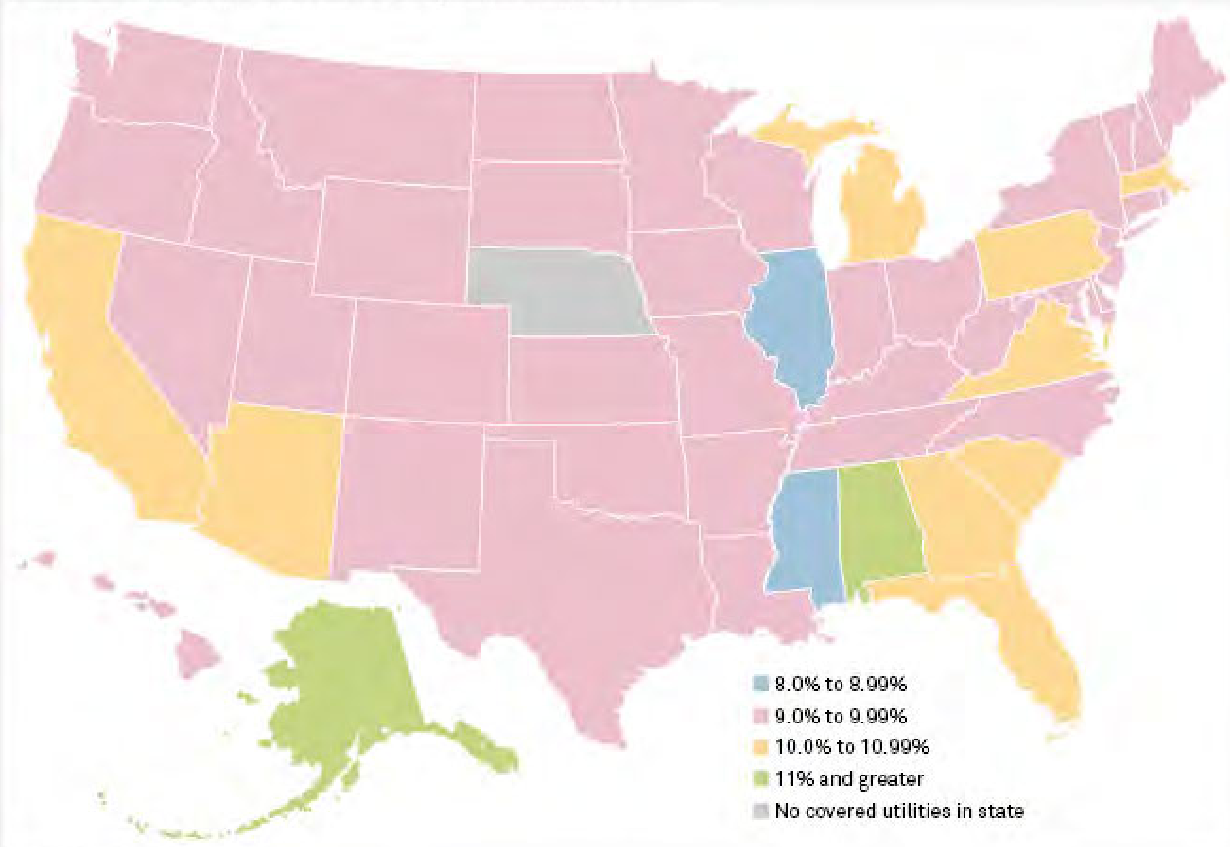
As Rate Case Activity Rises, Focus Will Remain on Authorized ROEs

by Lisa Fontanella – Regulatory Research Associates (RRA)
an Offering of S&P Global Market Intelligence – Feb. 23, 2018

Rate case activity has been robust over the last several years driven by the need to address capital investment for infrastructure upgrades and expansion and new generation to replace retiring facilities, costs associated with reliability initiatives such as vegetation management, environmental compliance and renewable resource and energy efficiency mandates and increased O&M expenses. These factors have been exacerbated by slow demand growth due to the impact of conservation and distributed resources. These issues will remain prevalent for the foreseeable future and when the need to address the impacts of the 2017 federal Tax Cuts and Jobs Act is added to the mix, there is little doubt that rate case activity will be on the rise as well.

Last electric ROE authorized by commission*



Data as of Feb. 20, 2018.
* Based on covered companies in rate case data base.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence
Map credit: Cat Weeks

During 2017, there were 129 electric and gas rate cases in which a commission decision was rendered and two cases were withdrawn with no commission action in in the 53 jurisdictions covered by Regulatory Research Associates, an offering of S&P

Global Market Intelligence. As of Feb. 20, 2018, 10 cases have been decided in 2018, with an additional roughly 90 cases pending. With this level of rate case activity comes an increasing focus on authorized ROEs and how they might be impacted by such **factors** as the **evolving interest rate environment**, the recent **changes in federal tax law** and the **regulators'/customers' tolerance for** a **continuous string of rate changes**. While it is too soon to predict how these competing forces will ultimately impact authorized ROEs going forward, it is instructive to examine how the returns approved by the various jurisdictions in recent years have compared to prevailing national averages

With the exception of a handful of states including Alabama, most of the jurisdictions followed by RRA have issued orders establishing new electric and/or gas ROEs since 2012. The **Alabama** Public Service Commission has not set a definitive ROE for the state's three major energy utilities in several years. Instead, the PSC has utilized ROE ranges and rate-setting adjustment points under **Rate Stabilization and Equalization**, or **RSE**, **frameworks**. These ROEs have been **above** the **average of ROEs** approved for energy utilities in cases decided nationwide during the effective periods. RSE frameworks have been in place for Alabama Power Co. and Alabama Gas since 1982 and 1983, respectively.

In 2013, Alabama Power's RSE framework was modified to utilize a "weighted cost of equity" metric, the product of the ROE and common equity ratio, with an authorized range of 5.75% to 6.21%; the embedded ROE and equity ratio were not separately identified. In 2014, the RSE framework for Alabama Gas began utilizing an ROE range of 10.5% to 10.95%. An RSE mechanism was implemented for Mobile Gas Service Corp., or MGS, in 2002; beginning in 2013, MGS's authorized ROE range was set at 10.45% to 10.95%. Alabama Power is a subsidiary of Southern Co., and Alabama Gas and MGS are subsidiaries of Spire Inc.

There are 27 public utility commissions that last issued an electric ROE determination in 2017. For gas utilities, there are 20 jurisdictions that last issued a gas ROE determination in 2017.

As of Feb. 20, 2018, there were four recent ROE determinations in Iowa, Kentucky, Mississippi, Oklahoma and Virginia for electric utilities and one determination in Illinois for a gas utility.

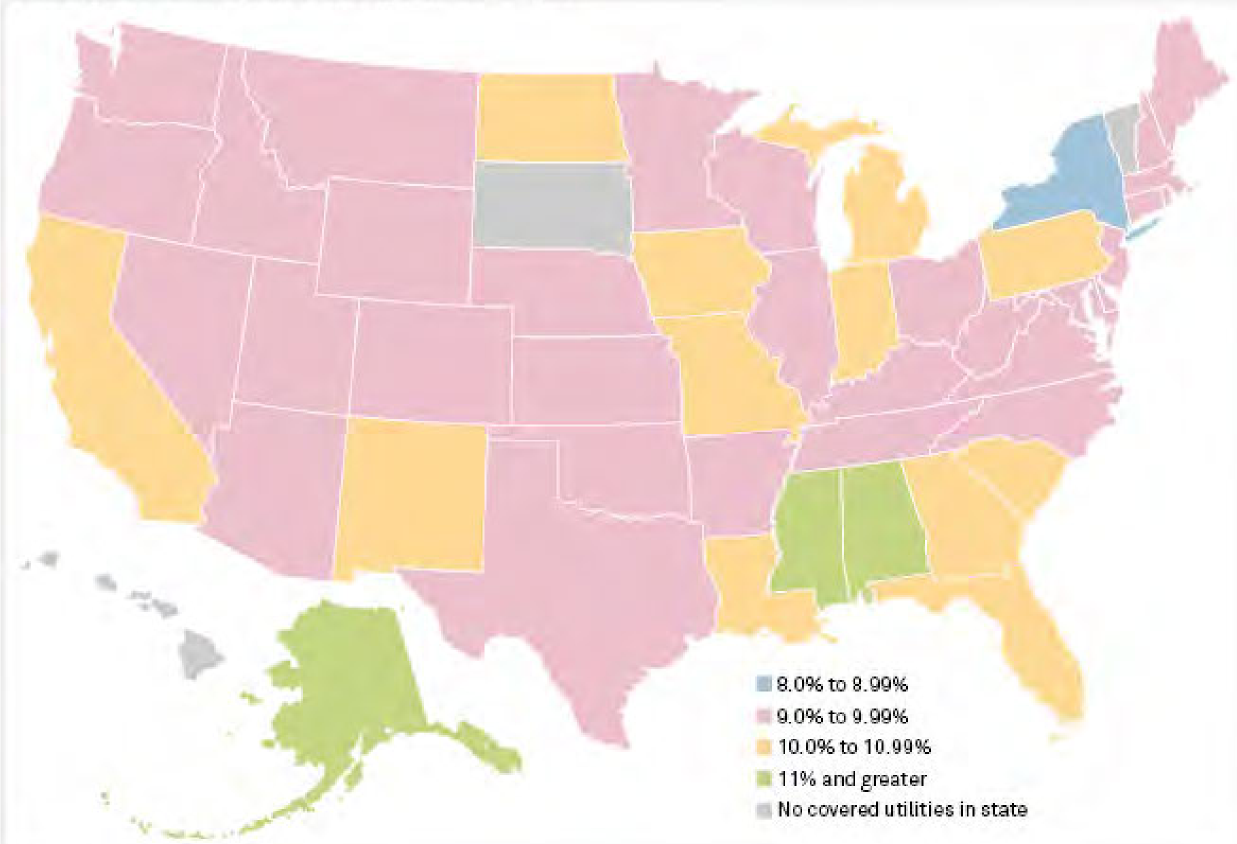
As noted in the maps, the bulk of the most recent electric and gas ROEs authorized by state public utility commissions have ranged from 9% to 9.99%.

The average allowed ROEs for electric and gas utilities have fallen steadily over the past years. This trend has been driven by a declining interest rate environment and the proliferation of expedited recovery mechanisms that reduce business risk.

The average ROE authorized electric utilities was 9.74% in rate cases decided in 2017, a record low, albeit marginally below 9.77% in 2016. The 2017 authorized ROEs fell within a range of 8.4% to 11.95%, with a median of 9.6%.

These figures include several **limited issue rider** cases; **excluding** these cases from the data, the **average authorized ROE** was **9.68%** in **electric rate cases** decided in **2017**, up marginally from 9.6% in 2016. The differential in electric authorized ROEs is largely driven by **incentive ROEs** that have been approved in various generation-related limited-issue rider proceedings in **Virginia**, where statutes authorize the State Corporation Commission to approve ROE premiums of **up to 200 basis points for certain generation projects**.

Last gas ROE authorized by commission*



Data as of Feb. 20, 2018.
* Based on covered companies in rate case data base.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence
Map credit: Cat Weeks

The **average ROE authorized gas utilities was 9.72%** in cases decided during 2017 versus 9.54% in 2016. The authorized ROEs were in a range of 8.7% to 11.98%, with a **median of 9.6%.**

As noted in the accompanying table, for those commissions in which the last ROE determination was rendered in 2017, the **highest electric and gas ROEs, at 11.95% and 11.88%, respectively**, were **authorized by the Regulatory Commission of Alaska**. Authorized returns in Alaska have been above national averages and reflect the unique challenges faced by utilities in the state.

Last authorized ROE by commission*

		Electric			Gas		
Jurisdiction	Commission	Year of last ROE specified in state	Last ROE specified in state	Prior 12-month national average ROE	Year of last ROE specified in state	Last ROE specified in state	Prior 12-month national average ROE
Alabama	Alabama Public Service Commission	--	--	--	--	--	--
Alaska	Regulatory Commission of Alaska	2017	11.95	9.73	2017	11.88	9.59
Arizona	Arizona Corporation Commission	2017	10.00	9.68	2017	9.50	9.56
Arkansas	Arkansas Public Service Commission	2017	9.50	9.69	2016	9.50	9.55
California	California Public Utilities Commission	2017	10.30	9.68	2017	10.05	9.71
Colorado	Colorado Public Utilities Commission	2016	9.37	9.79	2016	9.50	9.60
Connecticut	Connecticut Public Utilities Regulatory Authority	2016	9.10	9.79	2017	9.25	9.69
Delaware	Delaware Public Service Commission	2017	9.70	9.68	2017	9.70	9.51
District of Columbia	District of Columbia Public Service Commission	2017	9.50	9.69	2017	9.25	9.58
Florida	Florida Public Service Commission	2017	10.25	9.71	2009	10.85	10.19
Georgia	Georgia Public Service Commission	2013	10.95	10.07	2017	10.55	9.52
Hawaii	Hawaii Public Utilities Commission	2013	9.00	10.07	--	--	--
Idaho	Idaho Public Utilities Commission	2017	9.50	9.75	2017	9.50	9.73
Illinois	Illinois Commerce Commission	2017	8.40	9.75	2018	9.80	9.75
Indiana	Indiana Utility Regulatory Commission	2016	9.98	9.80	2008	10.20	10.20
Iowa	Iowa Utilities Board	2018	9.98	9.74	2012	10.00	9.81
Kansas	Kansas Corporation Commission	2015	9.30	9.93	2014	9.10	9.73
Kentucky	Kentucky Public Service Commission	2018	9.70	9.74	2017	9.70	9.56
Louisiana	Louisiana Public Service Commission	2013	9.95	10.07	2005	10.50	10.52
Louisiana	New Orleans City Council	2014	9.95	10.00	2009	10.75	10.37
Maine	Maine Public Utilities Commission	2016	9.00	9.79	2016	9.55	9.58
Maryland	Maryland Public Service Commission	2017	9.50	9.69	2017	9.70	9.59
Massachusetts	Massachusetts Department of Public Utilities	2017	10.00	9.75	2016	9.80	9.59
Michigan	Michigan Public Service Commission	2017	10.10	9.79	2017	10.10	9.57
Minnesota	Minnesota Public Utilities Commission	2017	9.20	9.70	2016	9.11	9.55
Mississippi	Mississippi Public Service Commission	2018	8.58	9.75	--	--	--
Missouri	Missouri Public Service Commission	2017	9.50	9.70	2014	10.00	9.77
Montana	Montana Public Service Commission	2014	9.80	9.95	2017	9.55	9.57
Nebraska	Nebraska Public Service Commission**	--	--	--	2012	9.60	9.73
Nevada	Public Utilities Commission of Nevada	2017	9.40	9.75	2016	9.50	9.54
New Hampshire	New Hampshire Public Utilities Commission	2017	9.50	9.71	2014	9.50	9.66
New Jersey	New Jersey Board of Public Utilities	2017	9.60	9.68	2017	9.60	9.70
New Mexico	New Mexico Public Regulation Commission	2017	9.58	9.76	2012	10.00	9.76
New York	New York Public Service Commission	2017	9.00	9.74	2017	8.70	9.56
North Carolina	North Carolina Utilities Commission	2016	9.90	9.76	2016	9.70	9.58
North Dakota	North Dakota Public Service Commission	2017	9.65	9.70	2013	10.00	9.66
Ohio	Public Utilities Commission of Ohio	2013	9.84	10.06	2013	9.84	9.92
Oklahoma	Oklahoma Corporation Commission	2018	9.30	9.76	2016	9.50	9.60
Oregon	Oregon Public Utility Commission	2017	9.50	9.75	2017	9.40	9.59
Pennsylvania	Pennsylvania Public Utility Commission	2012	10.40	10.18	2007	10.40	10.33
Rhode Island	Rhode Island Public Utilities Commission	2012	9.50	10.16	2012	9.50	9.92
South Carolina	Public Service Commission of South Carolina	2016	10.10	9.77	2017	10.20	9.67
South Dakota	South Dakota Public Utilities Commission	2012	9.25	10.40	--	--	--
Tennessee	Tennessee Public Utility Commission	2016	9.85	9.81	2015	9.80	9.85
Texas	Public Utility Commission of Texas	2017	9.65	9.74	--	--	--
Texas	Railroad Commission of Texas**	--	--	--	2017	9.60	9.51
Utah	Public Service Commission of Utah	2014	9.80	9.97	2014	9.85	9.64
Vermont	Vermont Public Utility Commission	2017	9.10	9.76	--	--	--
Virginia	Virginia State Corporation Commission	2018	10.20	9.73	2017	9.50	9.71
Washington	Washington Utilities and Transportation Commission	2017	9.50	9.76	2017	9.50	9.71
West Virginia	Public Service Commission of West Virginia	2015	9.75	9.97	2015	9.75	9.84
Wisconsin	Public Service Commission of Wisconsin	2017	9.80	9.74	2017	9.80	9.70
Wyoming	Wyoming Public Service Commission	2017	9.45	9.75	2014	9.90	9.72

Data as of Feb. 20, 2018.
* Covered companies in rate case data base. If multiple ROEs are authorized on a given date, then highest authorized ROE is specified.
** Commission does not regulate electric.
-- = not applicable
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

For those commissions in which a gas ROE determination was last rendered in 2017, the second highest return, at 10.55%, was issued by the Georgia Public Service Commission.

The **lowest electric ROE authorized in 2017 was 8.4%**, **approved** by the **Illinois Commerce Commission**, or ICC. In Illinois, the electric utilities do not own generation facilities and the state's major electric utilities operate under **formula rate plans**, or **FRPs**, whereby the ROE is re-set annually and calculated using a formula that is tied to long-term Treasury bond rates. In recent years, the formula has typically yielded ROEs that are below prevailing industry averages. The FRP proceedings are being conducted under state law that requires the companies to invest specific amounts in their transmission and distribution systems over the years 2012 through 2021, with recovery of these investments to occur in the context of annual FRP proceedings, subject to ICC approval.

For those commissions, in which an **electric** ROE determination was last rendered in 2017, the **second highest return, at 10.3%,** was **issued by** the **California Public Utilities Commission**. The PUC's ROE determinations for California's largest utilities have typically occurred outside of general rate cases in proceedings involving automatic cost-of-capital adjustment mechanisms. Over the last several years, ROEs approved in this process have generally been above the prevailing industry averages at the time established.

On the **gas** side, the **lowest ROE determination in 2017, at 8.7%,** was awarded by the **New York Public Service Commission**. The **PSC** has **consistently authorized ROEs** that have been **substantially below other states**. In traditional fully litigated rate cases, the **New York PSC relies on** a **combination** of the **discounted cash flow,** or **DCF**, approach **and** the **capital asset pricing model**, or **CAPM**, to set the authorized ROE, with a **weighting** of t**wo-thirds DCF** and **one-third CAPM**. In the context of orders predicated on multi-year rate settlements, the **PSC** has generally **authorized ROEs** that included a slight **premium** – typically about **30 basis points** – **to account for investor risk associated with the multi-year plan**. These plans have typically included ROE-based company/ratepayer revenue sharing mechanisms for earnings in excess of the authorized return. Recent multi-year plans have provided a specific authorized return that is below the initial threshold for sharing.

In the cases decided **thus far in 2018**, the **ROEs** authorized for the **electric** utilities have ranged from **8.58%,** approved by the **Mississippi Public Service Commission**, **to 10.2%** approved by the **Virginia State Corporation Commission** in a limited-issue rider case; the ROE **included** a **100-basis-point incentive**. Of the three gas cases decided so far in 2018, only one specified the authorized ROE, and that was a 9.8% ROE approved by the ICC.

Can We Be Brutally Honest About Investment Returns?

by Jason Zweig – WSJ – Jan. 19, 2018

Pension funds have fantastical expectations of the market.

With **U.S. stocks at all-time highs**, it's more important than ever that investors be brutally realistic about future returns.

Some of the most purportedly sophisticated investors in the world, the managers of giant pension funds for state and local government employees, might not have absorbed that lesson yet. You can learn a lot from these folks — if you listen to them and then do the opposite.

A new study by finance professors Aleksandar Andonov of Erasmus University Rotterdam and Joshua Rauh of Stanford University looks at expected returns among more than 230 public pension plans with more than $2.8 trillion in combined assets.

For their portfolios, generally consisting of cash, U.S. and international bonds and stocks, real estate, hedge funds and private-equity or buyout funds, these **pension plans report** that **they will earn** an **average** of **7.6% annually over** the **long term**. (That's **4.8% after** their estimates of **inflation**.) These funds often **define** "**long term**" as **between 10 and 30 years**.

Based on how they divvy up their money, how much are these pension funds assuming specific assets will earn?

They expect cash to **return** an **average of 3.2% annually over the long run**; **bonds**, **4.9%;** such "real assets" as **commodities** and **real estate**, **7.7%; hedge** funds, **6.9%; publicly traded stocks**, **8.7%; private**-**equity funds**, **10.3%.**

Let's put all that in perspective.

Take **cash** first. **Three-month U.S. Treasury bills yield 1.4%**. The **highest**-returning **institutional money-market funds yield 1.5%**, according to Crane Data.

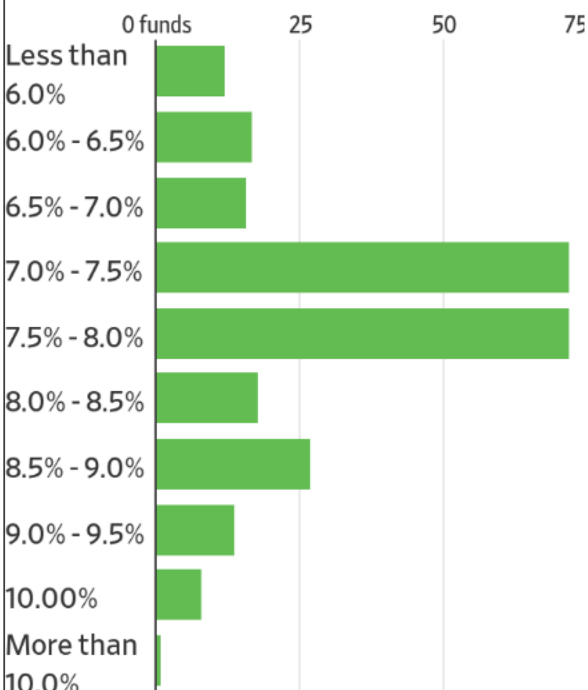
How could cash earn more than twice that rate of return over the long run?

To be fair, **Treasury bills over the past half-century** have **returned** an **average** of **4.8% annually**, according to the Federal Reserve. **But short-term interest rates would have to rise sharply** for cash **to earn close to that**.

Great Expectations

More than a quarter of large public pension plans expect to earn at least 8% annually on their investments.

Number of funds by expected rate of return



Note: Expected long-term rates of compound annual return

Source: Disclosures, based on "building-block method," from 257 pension portfolios collected by Aleksandar Andonov, Erasmus University, and Joshua Rauh, Stanford University

Next, consider **bonds** – The simplest reliable indicator of how much you will earn from a portfolio of bonds in the future is their **yield to maturity in** the **present.** With **10-year Treasurys yielding 2.6%** and **investment-grade corporate bonds averaging under 3.7%,** it would take a near-miracle today to get anything close to 4% out of a high-quality fixed-income portfolio.

Yet the pension plans are expecting their bonds to earn 4.9%.

That isn't impossible, either, if they throw safety to the winds and buy boatloads of high-yield "junk" bonds and other risky debt. The **whole point of a pension fund**, however, is **not to take excessive risks**.

How realistic is the expectation that **stocks** will return an average of 8.7% annually into the distant future?

That's **below** the **U.S. average of 10.2% annually over** the **past 90 years**. **But stocks were far cheaper** over most of that period **than** they are **today**, **so** their **returns** were **naturally higher**.

The blogger "Jesse Livermore," who writes thoughtfully about financial markets at PhilosophicalEconomics.com, pointed out in a recent post that **stocks aren't likely to earn more than** an **average of 5.9% annually over** the **long run from today's lofty prices**.

Stocks could do better than that **if** the **cost of living shoots up**, investors become willing to pay much more for shares, earnings grow at an unprecedented pace or companies buy back vastly more of their own stock.

Among those, the least implausible scenario is **higher inflation**. So the pension funds could hit their 8.7% stock return that way — but such a surge in the cost of living would crimp their bond returns. What they would **gain on** their **stocks** they would **lose on** their **bonds**.

Finally, consider how the pension plans estimate the future returns on **private-equity** funds.

Put some alcohol into anyone in the buyout business and you will get an earful about how competitive and overvalued that market is — and how difficult it will be for future returns to match those of the past.

But the new study of estimated returns finds that the older a pension fund's holdings of private equity are, the more likely its officials are to extrapolate those returns — as if the good times of the early 2000s, when deals abounded and buyouts were cheaper, were still rolling.

What's more, says Prof. Rauh of Stanford, the **less experience a pension plan has with private equity**, the **more likely** it is to make an **aggressive estimate of future returns from buyout funds**.

In other words, **those with the least expertise in private equity think they can earn** the **most from it**.

Why do expectations among **pension plans run so high? Because** they **have to**, the chief investment officer of a large public pension plan tells me. State laws guarantee generous retirement benefits for millions of current and former government employees. To appear as if they can meet those obligations, the pension plans have no choice but to set their expected returns higher than reality is likely to deliver.

That's the exact opposite of what the rest of us should do. **Sooner or later**, **investors who build** their **expectations on hope rather than** on **arithmetic end up sorry.**

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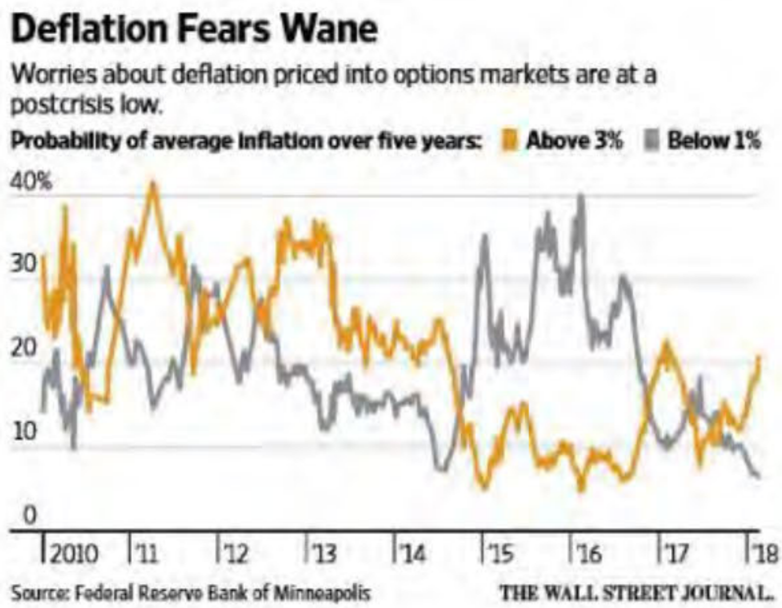
A Crowd around the Bond Story

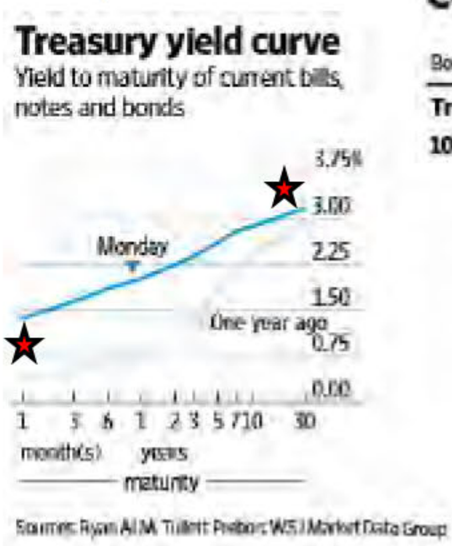
by James Mackintosh – WSJ Streetwise Column – Feb. 27, 2018

The **reality of inflation and growth** has **shifted only a little in** the **past few months**. **Beliefs about inflation and growth, however,** have **moved a lot**, and investors hoping they will rise fast could be in trouble if reality doesn't catch up soon.



This is most obvious in the bond market. Last summer, gloom about the prospects for inflation prevailed, with hedge funds having more bets on bond yields falling than rising. No longer. The narrative has shifted, and fast money has shifted with it, making some of the biggest bets ever on yields rising.

The risk for investors is that the **move from worrying about deflation to worrying about inflation** won't happen smoothly. In other words, reality might once again disappoint the market. Yes, bond yields should go up – over time. But they have soared this year, to the point that the fall in bond prices, which go down when yields go up, is as quick as it has been only four other times since the end of the recession in 2009. Each of those times prices fell too fast and popped back up.



Corporate Borrowing Rates and Yields

Bond total return index	Close	Yield (%) Last	Yield (%) Week ago	52-Week High	52-Week Low	Total Return (%) 52-wk	Total Return (%) 3-yr
Treasury Ryan ALM	1424.247	**2.669**	2.671	2.736	1.818	**-0.777**	0.191
10-yr Treasury, Ryan ALM	1667.791	**2.862**	2.877	2.943	2.058	**0.063**	-0.604

"Cyclically, everyone's very excited," said Chris Watling, founder of consulting firm Longview Economics. "Every asset allocator you talk to seems to be short the 10-year" Treasury.

Many of the biggest recent swings in bond yields have come **when investors** were **crowded into wrong-way bets**. In April 2010, futures traders had what was then a record bet on rising yields, reflecting a consensus that the economy was in a normal post-recession rebound. Suffice to say it wasn't, and those bets were quickly reversed. The same happened at the end of 2016, when postelection excitement about rising yields led to a record bet, but again proved wildly overdone.

The opposite happened in May 2013 and last summer, when investors had some of their biggest post-crisis bets using futures and options on bond yields falling. In both cases, 10-year yields subsequently jumped by close to a percentage point. This month the net bet on rising 10-year Treasury yields reached the second biggest, behind only the rise after the election, while the number of futures only bets on rising yields hit a record.

This **isn't to say** that the **new consensus is wrong**. Global economic growth brings with it a tighter jobs market and more demand, which ought to be inflationary. The worry is that it **doesn't arrive quickly** enough to confirm investors in their new belief and disappointment sets in.

Leveraged funds with large positions would then look **exposed**, something that often prompts them to **close out** their **bets** and would **push down bond yields**. With tens of billions of dollars of outstanding bets against bond futures, such a rush to cover short positions could have a big effect.

The **new market story** is of **synchronized global growth, tighter monetary policy** and **higher wages and inflation**. The **short-term issue isn't** so much **whether** it is **right or wrong**, **but whether everyone yet believes in it**. If there are more investors out there who haven't been converted, then economic data supporting the story could push up bond yields further still. If everyone and his dog is already betting on growth and inflation, then the very same data might disappoint those hoping for more.

In Europe, there are already signs of disappointment. Economic data have been coming in below forecasts, pushing Citigroup Inc.'s measure of "economic surprise" negative for the first time since September 2016. Again, this suggests not that the euro-zone is in trouble, but merely that economists upgraded their forecasts too enthusiastically.

Now, I'm a natural contrarian and may again be overestimating how far the story has to run. After the U.S. election I thought it was right that bond yields should rise, but that they had gone up far too quickly given the uncertainties about Donald Trump's policies. I was too early, and 10-year Treasury yields rose another 0.3 percentage point – a fall of almost 3% in price – before the market began to share my concerns about how long it would take to implement tax cuts and infrastructure spending.

A repeat is possible. Fund manager sentiment toward bonds is very negative, but not as negative as it was after the election or during the 2013 taper tantrum. Bond yields have risen fast, but not as fast as they did after the election. Bets on inflation over the next five years being above 3% – derived from inflation options – are still below where they stood after the election, too. All these measures could run further, and hedge funds and others could pile on even bigger bets on rising yields.

Yet, the balance of risks has shifted. Wage growth that would have been a positive surprise last summer would today be a damp squib for investors who are expecting a continuation of last month's fireworks. U.S. Treasurys may still look unattractive at a 10year yield of just under 2.9%, but remember that it has only been above 3% for two days since July 2011. The **market is adopting a new narrative**, but it would be **normal to have plot twists as the story works out**.

BlackRock CEO to Companies: Pay Attention To 'Societal Impact'

by Sarah Krouse – Jan. 16, 2018

Left: **Laurence Fink** called on CEOs of companies in which BlackRock invests to articulate long-term plans and how their organizations contribute to society.

The boss of the world's largest money manager told corporate chiefs to prepare for **BlackRock** Inc. **to become a more assertive shareholder.**

Laurence Fink in his annual letter to chief executives of companies in which BlackRock invests called on them to better articulate their long-term plans and how their organizations contribute to society, and said the New York money manager will have **more frequent and in-depth conversations** with them. He has made similar appeals to CEOs in past letters.

BlackRock's assets have swelled to $6.3 trillion as investors have plowed hundreds of billions of dollars into index-tracking funds. That has given large index-fund managers like BlackRock **increasing clout** on important **corporate decisions** such as **takeovers** and the **fates of chief executives**.

"The time has come for a **new model of shareholder engagement** — one that strengthens and deepens communication between shareholders and the companies that they own," Mr. Fink wrote.

BlackRock and rivals Vanguard Group and **State Street** Global Advisors are **increasingly among** the **largest shareholders in many S&P 500 companies**. But unlike Wall Street's traditional stock pickers, **index-fund managers** are **unable** to **sell companies whose actions they disagree with**, **because** those money managers must own shares in the **companies** that **comprise** a **given benchmark**.

That leaves **proxy voting and talks with** the **company** as the **main avenues index-fund managers can use to press for changes**.

"The growth of indexing demands that we now take this function to a new level," Mr. Fink wrote of the firm's corporate governance efforts.

The **three largest index-fund providers owned 18.5% of the S&P 500** at the end of the third quarter, **compared with 14.7% five years earlier**, according to research by Lazard Ltd.

BlackRock plans over the next three years to **double** the **size** of the **team** that **engages with companies** in which the firm's funds invest, **to more than 60 people**, he said.

Michelle Edkins, the executive who leads those efforts, will now report to Barbara Novick, a co-founder of BlackRock who leads its government relations and public policy work. “As the objectives of investment stewardship and public policy often intersect,” Mr. Fink told employees in a memo Tuesday, Ms. Novick will lead both groups though they will operate separately.

In the annual letter, Mr. Fink reiterated his call for companies to articulate long-term strategic plans and said board members should be able to describe how they oversee those efforts. This year, for example, he said companies should tell shareholders how changes to the U.S. tax law will impact their long-term plans.

Corporate strategies should cover financial metrics, he wrote, but to achieve those “you must also understand the societal impact of your business, as well as the ways that broad structural trends — from slow wage growth to rising automation to climate change—affect your potential for growth.”

This year, BlackRock and Vanguard supported a **successful shareholder proposal at Exxon Mobil** Corp. that called for the company to share more information about how **climate change** and regulations could impact its operations.

BlackRock also cast votes over the past year against directors at some companies due to concerns that they sit on too many boards.

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How Much New Investor Cash Did BlackRock Attract in 2017? $1 Billion a Day

by Sarah Krouse – WSJ – Jan. 12, 2018

Investment firm says it saw record net inflows for the year of $367 billion.

The **world’s largest asset manager** reached a new milestone during 2017: the equivalent of $1 billion of new client cash every day.

The **annual net inflow of $367.3 billion helped BlackRock** Inc. **pass $6 trillion** in **assets** for the first time, **up more than $1 trillion from the end of 2016**. The record haul during 2017 amounted to more than **$698,000 a minute**.

Most of BlackRock’s new money, or 67%, went to its iShares exchange-traded fund business as investors continue to embrace lower-cost products tied to indexes. The iShares unit finished 2017 with more assets than BlackRock’s actively managed products for the first time.

The pace of new investor cash into BlackRock puts it in the same league as **rival Vanguard** Group, which **attracted a net $369.3 billion in new money last year**. The **two managers now oversee a combined $11.2 trillion**, higher than the gross domestic product of China in 2016.

"They're neck and neck," said Kyle Sanders, an analyst at Edward Jones, of BlackRock and Vanguard, which ended 2017 with $4.9 trillion in assets. "It's those two and then it's everyone else fighting for scraps."

Both firms are benefiting from a confluence of factors working in their favor: a stock market boom, recent regulatory changes and a growing investor preference for cheaper ETFs, which are funds for all types of investors that trade on exchanges.

"It's hard for me to see active flows being as strong as what we predict for ETF flows" in the next two years, BlackRock Chief Executive Laurence Fink said in an interview. He cited ongoing regulatory changes in the U.S. and Europe that have led to broader adoption of the funds.

Mr. Fink told employees in the firm's town hall earnings meeting that BlackRock had proven it can compete with Vanguard while making money for shareholders, people familiar with the matter said.

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At BlackRock, Vanguard and State Street 'Engagement' Has Different Meanings

by Sarah Krouse – WSJ – Jan. 20-, 2018

Less aggressive than activists, biggest passive money managers use their heft to influence portfolio companies.

Left: **BlackRock CEO Laurence Fink has said the firm would be more assertive with the companies in which it invests while ensuring they make the right decisions over time for long-term shareholders**.

The **biggest passive money managers all** like to **use** some version of the **word** "**engage**" when describing how they hold their portfolio companies accountable behind the scenes. They **differ** on **how** that **engagement** is **measured**.

BlackRock Chief Executive Laurence Fink cited the strategy this week **in** his **annual letter** to other CEOs. He used the words "**engage**" or "**engagement**" **15 times to describe how BlackRock would be more assertive** with the companies in which it invests while ensuring they make the right decisions over time for long-term shareholders.

BlackRock had 1,603 "**engagements**" **with companies in** which it invests during 2017. That is more than the **954 engagements** counted **by rival Vanguard** Group and **676 from State Street** Corp.'s money management unit **last year**.

How those engagements are defined and disclosed varies from firm to firm, making it **difficult** to **assess how aggressively** these big U.S. shareholders are **wielding** their growing **clout**.

BlackRock's engagements, according to the company, **can be** "**basic**," "**moderate**" or "**extensive**." **Basic** can be **one conversation** on a "routine matter"; **moderate** "generally involves **more than one meeting**," while **extensive** can be "**numerous meetings over** a **longer time frame**."

For **Vanguard** and **State Street each phone call or meeting counts as an** "**engagement**". **State Street** typically also **sends hundreds** of **letters** to its portfolio companies that **it** also **classifies as** "**engagements**," **though** they **aren't included in** the **firm's count of 676 engagements**.

The **three managers collectively oversee more than $13 trillion in assets**, **bigger than the size of China's economy**, the world's second-largest. They have ramped up efforts to interact with their portfolio companies as their **assets and stakes in major companies have swelled**. **Those the firms ownered 18.5% of the S&P 500** at the **end** of the **third quarter**, **up from 14.7% five years earlier**, according to research by Lazard Ltd.

BlackRock, Vanguard and State Street **say they prefer not to use** their **heft to make immediate demands such as putting a specific individual on the board or divesting business units**, in contrast to more aggressive dictates from activist investors.

Instead they say they **like to work behind the scenes** and **talk** with their portfolio companies **routinely** about their policies and plans.

BlackRock, for example, plans **to write** to about **300 companies in** the **Russell 1000 that have fewer than two women on the board** to ask them to disclose their approach to boardroom and employee diversity, BlackRock governance head Michelle Edkins said Thursday at a Santa Clara University event in California. The firm plans to **ask them to set a time frame** in which they will **improve** their **diversity**. **State Street also pressed** its portfolio companies to improve their **boardroom diversity in 2017**.

"It is a conversation and **we have an agenda** and we have several things we want to discuss," Ms. Edkins said of the firm's meetings with companies. "It is absolutely not a thing that we do over bottles of wine. If they're lucky, they get a really nasty cup of BlackRock coffee."

BlackRock has more **staff dedicated to these discussions** and other investment stewardship tasks than Vanguard or State Street. It plans to double that group to 60 in the next three years.

"The growth of indexing demands that we now take this function to a new level," Mr. Fink said of shareholder engagement in his annual letter earlier this week.

Unlike traditional stock pickers, **index funds managers can't sell a stock if they are disappointed** by a company's performance or disagree with its strategy. **They do, however, have other ways** they can **express** their **opinions beyond engagement**.

All use shareholder votes to oppose or support the appointment of board members or management resolutions as well as proposals from fellow shareholders. **What they decide is increasingly determining the outcome of these shareholder votes**. The **support of BlackRock and Vanguard**, for example, **helped** a **shareholder proposal pass** in **2017** at **Exxon Mobil** Corp.'s **annual meeting** that called for the company to share more information about how **climate change** and **regulations** could affect its operations.

At times, the **three** big passive owners **come to differing conclusions**. **Vanguard**, **Procter & Gamble** Co.'s **biggest shareholder**, **sided with management** in the **company's battle last year with Nelson Peltz**, the Journal reported, while **BlackRock** and **State Street voted with Mr. Peltz's Trian Fund** Management. Mr. **Peltz narrowly won** a **seat on** the **board**.

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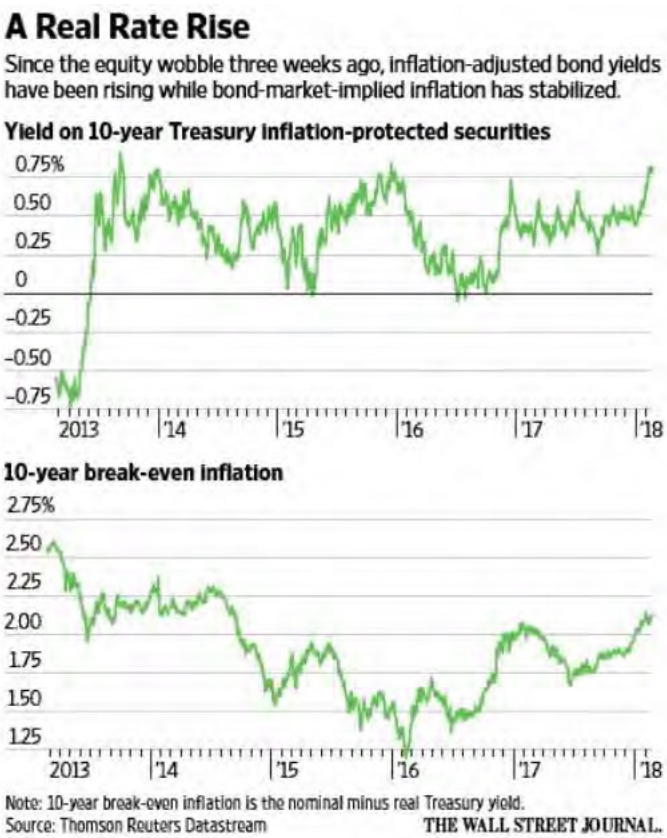
Bonus in Higher Bond Yields

by James Mackintosh – WSJ Streetwise Column – Feb. 23, 2018



Little matters more to shareholders now than interpreting the message from the bond markets. After the scare at the start of the month that knocked 10% off U.S. stocks, there are indications of possible good news hidden in rising bond yields. Yet, the danger remains that massive tax cuts will push up yields to the point where they become bad for shares – and identifying that point is one of the big challenges for investors.

Start with the potential good news: Bond investors seem finally to be anticipating stronger growth in the real economy and a better long-term outlook, a sharp change from the previous assumption that the main effect of U.S. tax cuts would be to boost inflation.

Investors have pushed up real 10-year Treasury yields this month, while inflation expectations finally stopped rising. Bond markets appear to be anticipating more productivity- boosting investment, which would make the tight jobs market less likely to spark inflation.

Even better, real yields on 30-year Treasury inflation protected securities, the longest- dated U.S. bonds, have also been rising, reversing a decline that set in last summer. Investors are pricing in a better long-term outlook, which would make higher Federal Reserve interest rates possible without damaging the economy – or stock prices.

This **good news comes with caveats**. It is **never** a **good idea** to **read too much into** a **three-week move**, even one that has pushed 30-year yields almost all the way back up to where they stood in July. The bond market believing in a better economy doesn't make it so, either. Finally, the move can be interpreted a different way, as a reward for rising uncertainty about where long-run interest rates will eventually land. If rising yields reflect doubts about **secular stagnation**, that isn't nearly as good for stocks as the belief that the post-crisis **economic torpor** is **finally in** the **past**.

Certainly **economists** are **treating White House forecasts of a productivity renaissance with skepticism**. **Nathan Sheets**, **chief economist at PGIM Fixed Income and a former Treasury official**, **expects** the **Trump tax cuts** to **boost economic growth by 0.5 percentage point** or a little more for each of the **next two years**. **But** he predicts **only** an **annual 0.1 point extra on long-run potential growth**, resulting **from higher corporate investment**.

The huge federal deficits likely to be incurred in the latest U.S. budget come at a time when the jobs market is already tight and there are signs that wage rises may finally be accelerating.

The tax cuts add fiscal fuel only poured in this amount into a late-cycle economy twice since World War II, according to Gerard Minack, of Sydney-based Minack Advisors: the Vietnam War spending of the late 1960s and the 1986 Reagan tax cut. In both periods, bond yields rose sharply as inflation picked up, while stocks soared, plunged and then soared again before the eventual recession.

Break-even rates suggest investors' inflation expectations have generally risen since the start of the year.

Ten-year break-even inflation rate*

The problem for shareholders watching the bond market is that rising inflation expectations are good for stocks until they are bad. One theory for why is simple enough: **When investors** are **worried about deflation**, **higher inflation reduces** the **danger** and so **helps stocks even as** it **pushes up bond yields**. Deflation fears have now gone away, so the question is at what point **inflation fears** will take over, **and rising bond yields** will be **bad for stocks**.

One answer is **when yields reach** the **point** that they anticipate the **Fed actively trying** to **slow** the **economy**. **Higher yields will no longer mean higher profits**, leaving nothing to offset the **hit to**

valuations that **comes with** a **higher discount rate**.

In economic terms this means bonds being priced for an interest rate above the so-called neutral rate, either because inflation is getting out of hand or because the Fed has made a mistake; either would be bad for both shares and bonds. Fed policy makers estimate the **long-run neutral fed-funds rate is 2.8%,** about where the 10year currently stands, but bonds typically offer extra yield to compensate for uncertainty over their term.

Credit Suisse's chief U.S. equity strategist, Jonathan Golub, thinks the **switch happens at** a **10-year yield of 3.5%, above which further rises** start to be **progressively worse for stocks**. He derives the number by looking at how stocks performed just on days when yields rose, with a strong relationship since 2014 showing stocks gained less the higher yields were.

In the past the **number** was **much higher, averaging above 7% since 1980**, but Mr. **Golub says** it has **dropped because** investors, like the **Fed**, **think** a **weaker economy can't cope with** such **high rates as** it **once could**.

Bank of America Merrill Lynch analysts say the "**sweet spot**" **for shares** is a **10-year Treasury yield between 1% and 3%**, with stocks more likely to fret about rises above that.

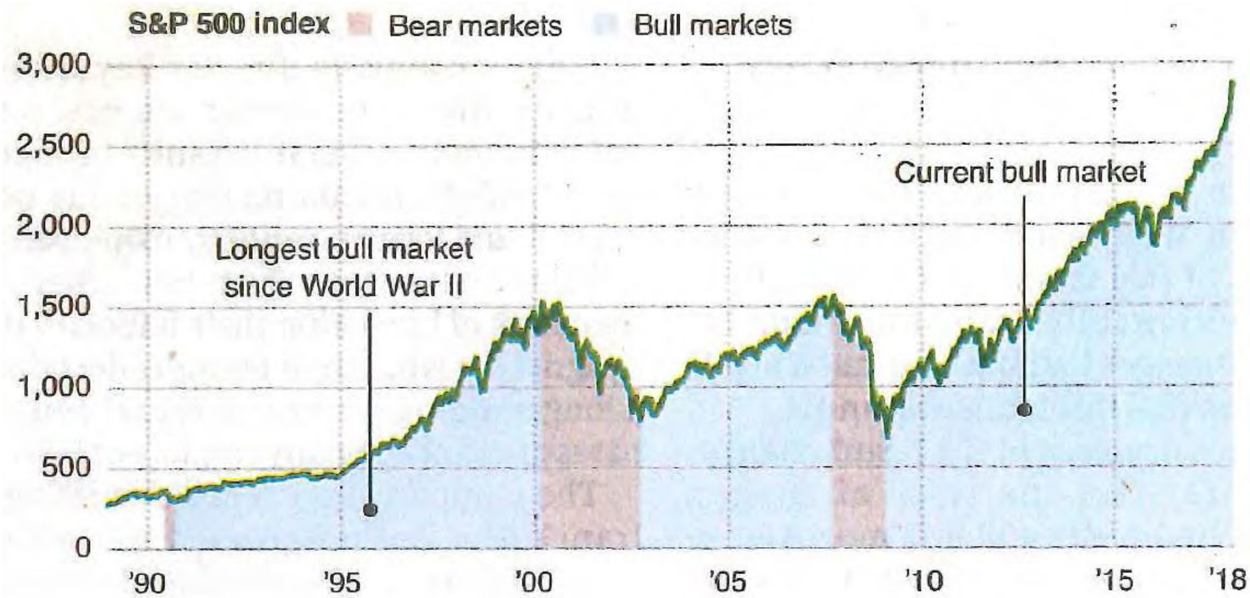
Investors shouldn't get hung up on any precise number, as the **turning point** is **inherently uncertain** and **shifts with changing beliefs about** the **economy**.

What is more certain is that there is a regime shift under way. **In the past few years**, **investors justified buying shares at very high valuations because bonds looked even worse. As Treasury yields rise, expensive shares will look less attractive** – so companies will need the prospect of big rises in profits to maintain their appeal. The more it is real rather than nominal bond yields rising, the better for shareholders.

Bull Market Birthday

by Ken Sweet and J. Paschke, AP –The Oregonian – Mar 9, 2018
Source FactSet

If the current bull market lasts until August, It will be the longest since World War II.



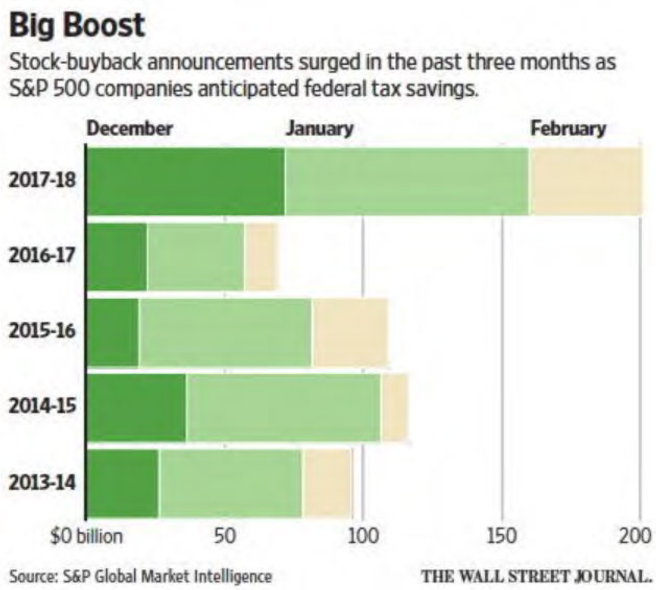
Happy 9th birthday, 2nd longest **Bull** market since World War II. The stock market's near decade-long climb upward since the depths of the Great Recession turns nine years old Friday. On March 9, 2009, the Standard & Poor hit a cycle low of 676.53, and now is up more than 300 percent since that date, according to Howard Silverbtatt at S&P Global.

The stock market has had several corrections since March 9, 2009, which is when an index like the S&P 500 falls 10 percent or more from a recent high, most recently in February. But the stock market has not fallen 20 percent or more from a recent high, which is when a bull market becomes a **Bear** market. At its current level, the S&P 500 would have to fall roughly 600 points in order to enter a bear market.

If the current bull market. If the current bull market lasts until August 21, it will be the longest bull market in U.S. since World War II, exceeding the bull market that started October 1990 and lasted until March 2000.

Buybacks Surge in Wake of Tax Cuts

by Akane Otani, Richard Rubin and Theo Francis – WSJ – Mar. 2, 2018



U.S. companies are **buying back their shares** at an **aggressive pace**, stirring questions in Washington and on Wall Street about the way that the new corporate tax cuts are being used.

Share buybacks announced by large U.S. companies have **exceeded $200 billion in** the **past three months**, **more than double the prior year**, according to a Wall Street Journal analysis of data for S& P 500 companies.

Among the biggest: Cisco Systems Inc. at $25 billion, Wells Fargo & Co. at about $21 billion, PepsiCo Inc. at $15 billion, AbbVie Inc. and Amgen Inc. at $10 billion apiece, and Alphabet Inc. at $8.6 billion.

Announced buybacks surged in December and continued at a robust pace in January and February. Near the end of the year lawmakers in Washington finished writing a bill to cut U.S. taxes by $1.5 trillion over a decade. It was signed by President Donald Trump shortly before Christmas.

“Companies are feeling some pressure not to just spend their savings on buybacks,” said Joseph Amato, president and chief investment officer for equities at Neuberger Berman Group LLC. “But at a time when we’re already seeing double-digit earnings growth around the world, they can’t hurt.”

The tax overhaul cut the tax rate on large corporations from 35% to 21%. It also included a low one-time tax on profits stockpiled abroad to encourage companies to repatriate more than $2 trillion held in overseas subsidiaries, and it included incentives for investment.

The moves are spurring a debate about **how companies** are **using** the **savings from** the **tax cut**; the **full answer won’t be** fully **understood for months or years** as the new money moves through the economy.

The **corporate rate cuts**, combined with investment incentives in the new law, are **meant** to **boost business spending** and **broader economic growth**, and increase wages over time. **Some** of the **money** is also being returned directly to investors in the form of **bigger dividends** and **buybacks**. And some companies have announced one-time bonuses for employees.

Kevin Hassett, chairman of Mr. Trump's Council of Economic Advisers, said at a White House briefing that the buyback boom is being driven by companies encouraged to repatriate funds from overseas.

Of the companies in the S& P 500, about 44% have said they plan to reinvest some portion of their tax gains into capital expenditures or wages, while 28% said they would use them to increase shareholder returns, Morgan Stanley found in an analysis of earnings transcripts.

Its own analysts expect companies to spend about 43% of their savings on buybacks and dividends, and 30% on capital expenditures and labor.

Cisco last month said it would bring back $67 billion of its foreign cash holdings to the U.S. this quarter and would spend much of it on buybacks and dividends. Amgen added $10 billion to its buyback program and said it would also spend $300 million on a new U.S. manufacturing plant in response to the tax changes. Hewlett Packard Enterprise Co. said last week it would return $7 billion to shareholders through buybacks and dividends by the end of fiscal 2019, as well as increasing its match to employees' 401 (k) contributions. Chief Executive Antonio Neri cited the tax-law change related to offshore cash.

A surge in share repurchases could give the bull market a boost at a time when many investors are concerned about how much longer it will last. By buying back shares, companies reduce the amount of shares held by the public and thus boost their per-share earnings.

S& P 500 firms are on track to post their sixth consecutive quarter of earnings growth. If companies spend $500 billion – about a fifth of what they are estimated to hold in earnings overseas – on buybacks, per share earnings in the S& P 500 this year could go up an additional $3 a share, or 2 percentage points, according to an analysis by Goldman Sachs Group.

Still the **practice is controversial** on Wall Street. Some critics say **companies** are **better off funneling cash into** spending on **research**, **upgrading equipment** and **raising wages**.

Companies that buy back **shares** don't always see their stocks outperform the broader market. The PowerShares Buy-Back Achievers Portfolio, an exchange- traded fund that includes shares of companies that have reduced their number of shares outstanding by at least 5% over the past 12 months, has fallen 1.3% so far this year, trailing the S& P 500's 0.2% advance. Last year, it rose 17%, while the S& P 500 gained 19%.

It is a hot-button issue in Washington too. Democrats have pointed to buyback announcements as proof that the tax law's benefits are tilted to high-income households. Tens of millions of households have stock investments, but some 84% of stocks are held by the wealthiest 10% of households.

Republicans have highlighted the one-time employee bonuses announced by dozens of large companies, typically around $1,000 for full-time employees, as evidence that tax cuts are reaching a broad base.

Washington's buybacks vs. bonuses fight has been raging as the parties position themselves for the 2018 midterms.

House Minority Leader Nancy Pelosi (D., Calif.) has labeled bonuses "crumbs" compared with the size of the corporate tax cuts. Treasury Secretary Steven Mnuchin said buybacks are helping the broader economy. "Even if people buy back stock, that is money that goes back into the economy that lets investors take that money and allocate it to other things. It's a complete system," Mr. Mnuchin said Tuesday at the U.S. Chamber of Commerce.

The **long-run economic case for the corporate tax cut** was that the rate reduction and incentives for business investment would **give companies more reasons to invest in the U.S.,** because projects that didn't make financial sense would become profitable.

Economists generally agree that such changes may happen, though they **differ about** the **scale** and **pace** of the **change** and **how broadly** the **benefits** are **distributed**.

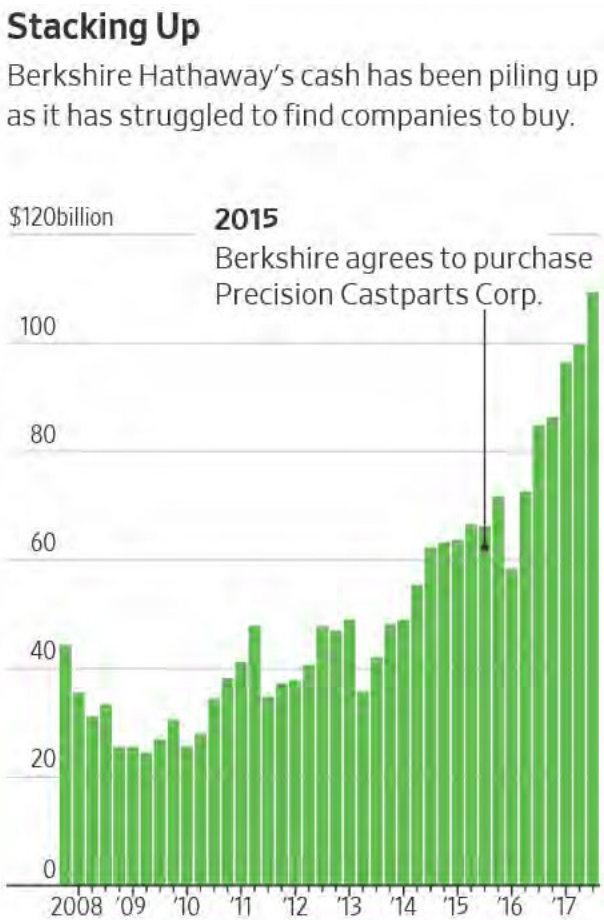
"It's February, folks," said Douglas Holtz-Eakin, an economist and former Congressional Budget Office director who has advised Republicans. "Deep breath. It will take a little time."

Playing With $100 Billion, Warren Buffett Is Giant Trader of U.S. Treasury Bills

by Nicole Friedman and Daniel Kruger – WSJ – Feb. 23, 2018

Berkshire Hathaway now one of world's largest owners of Treasury bills; cash pile soars as it struggles to find acquisitions

Left: Warren Buffett has long resisted using cash to pay a dividend, partly because of the tax consequences for shareholders. He prefers to keep Berkshire Hathaway's cash invested in U.S. Treasurys, rather than higher-yielding corporate debt, because that provides more liquidity during a market downturn.



Berkshire Hathaway Inc. shareholders will look to Warren Buffett's annual letter on Saturday for new clues of what the conglomerate plans to do with more than $100 billion in cash.

There is little mystery about who is getting that money meanwhile: Uncle Sam.

Berkshire has used its mounting cash pile to become one of the world's largest owners of U.S. Treasury bills after **struggling** to **find big companies to buy** in recent years.

It held **$109 billion in cash** as of **Sept. 30**, up from $86 billion at the end of 2016 and more than double what it had at the end of 2006. **Nearly all** of that was **invested in short-term bills**, according to Mr. Buffett.

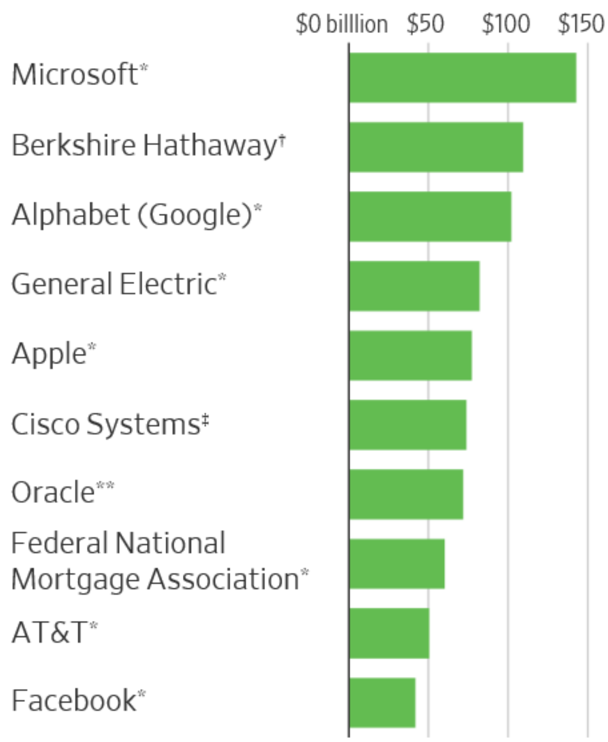
Berkshire has an **outsize presence** in the **$2 trillion market for Treasury bills**, a type of **government debt that matures in a year or less**. It **held more bills** around the **end** of the **third quarter than** large countries such as **China** and the **U.K.** It also had more at that time than the $13.5 billion held collectively by a group of 23 primary bond dealers that are obligated to underwrite U.S. government debt sales.

Berkshire's holdings are big enough that when bond dealers need bills for a specific date, they will come to Berkshire and arrange a trade, Mr. Buffett said.

"We're the ones they call. We've got the best inventory," Mr. Buffett said in a 2017 interview with The Wall Street Journal. "That's a new sideline for us here."

Shortages of Treasury bills have been a particular problem for bond dealers and investors at recent points. When the U.S. government approached its debt ceiling in recent years, the government was sometimes forced to sell fewer bills, making them scarce in the market. A recent budget deal pushed back the next debt-ceiling showdown until March 2019.

The Omaha, Neb., billionaire uses his widely read annual shareholder letter to recap Berkshire's results and discuss broader financial themes. He typically says little about where he could turn next for an acquisition, although he has acknowledged in other settings that pressure is mounting for Berkshire to find better uses for its massive cash holdings.



*As of Dec. 29, 2017 †As of Sept. 29, 2017
‡As of Jan. 31, 2018 **As of Nov. 30, 2017
Note: Apple's total does not include long-term marketable securities

Source: FactSet

Left: Among large corporations, only Microsoft has more cash than Berkshire.

Those holdings grew by an additional $3.3 billion last week when Phillips 66 repurchased 35 million of its shares from Berkshire.

"There's no way I can come back here three years from now and tell you that we hold $150 billion or so in cash or more, and we think we're doing something brilliant by doing it," he said at Berkshire's annual meeting last May. "I would say that history is on our side, but it would be more fun if the phone would ring."

Berkshire hasn't made a major buy since it agreed to acquire aerospace manufacturer Precision Castparts Corp. in 2015 for more than $32 billion, its biggest deal ever. A **deal last year to buy** Texas power-transmission company **Oncor** for $9 billion in cash was **terminated after** Oncor's parent company got a **higher offer**.

Mr. **Buffett** has long resisted using cash to pay a dividend, partly because of the tax consequences for shareholders. He has **said** the **company would buy back stock if its price falls below 120% of book value**. **Both classes of Berkshire stock traded Thursday** at **165% of book value**.

"He's aware that [Berkshire's cash] is not earning a high rate of return for shareholders," said David Kass, a professor at the University of Maryland's Robert H. Smith School of Business and a Berkshire shareholder. "Paying out a special cash dividend, a one-time dividend at the discretion of management, makes some sense."

Berkshire earns revenue from holding and trading its Treasury bills, but the profit is minimal relative to its overall business operations. Berkshire's head trader, Mark Millard, declined to comment.

Other corporations with large cash holdings tend to invest in higher-yielding assets such as corporate bonds. But Berkshire prefers to hold Treasury bills because they would provide more liquidity during a market downturn, Mr. Buffett said on CNBC last month. Mr. Buffett used Berkshire's financial strength during the financial crisis to throw lifelines to companies including Goldman Sachs Group Inc. and General Electric Co. in 2008.

"I believe at some point in the future, they'll be rewarded, [and] we'll be rewarded as shareholders, for having all that cash," said Trip Miller, managing partner of Gullane Capital Partners LLC in Memphis, Tenn. "They'll be sitting there **ready to pounce**."

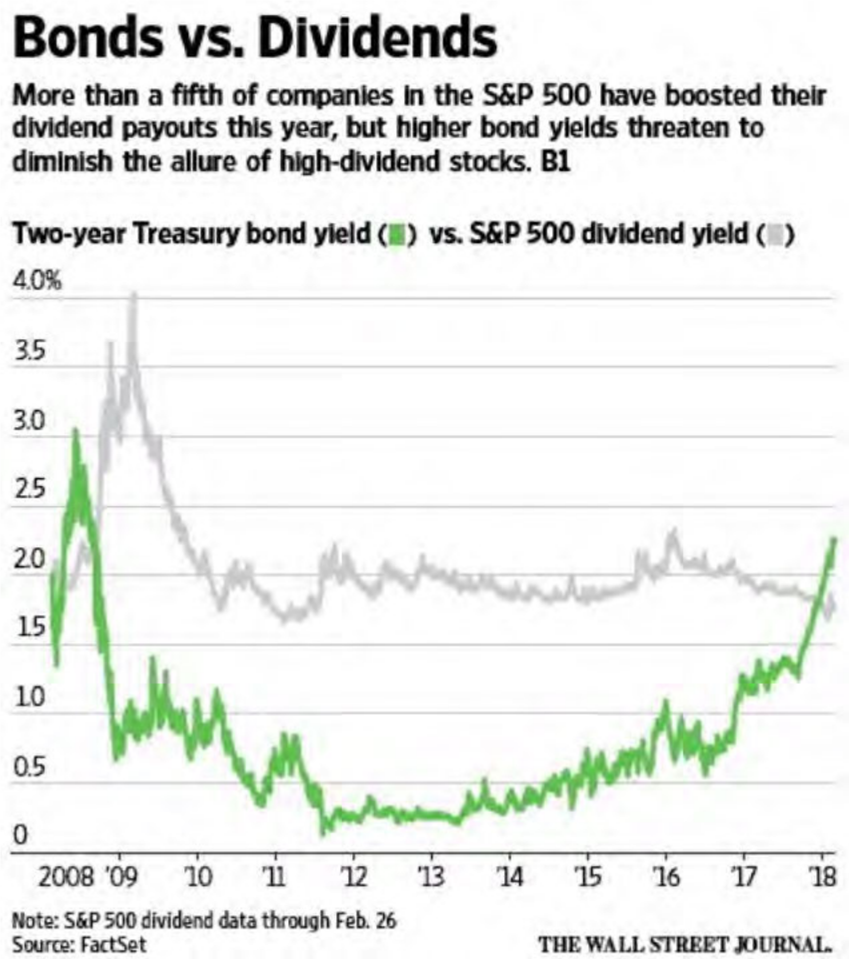
Mr. **Buffett's current involvement** in the **Treasury market** is **less stressful than** one in the early 1990s. Mr. **Buffett stepped in as chairman of Salomon** Inc. in **1991 after** a **rogue trader** was **caught trying to corner the market in two-year government debt by manipulating the auction process to buy more bonds than allowed**.

Berkshire typically buys about **$4 billion in Treasury bills every Monday** at government auctions, or **less than 4% of what the Treasury is selling**, Mr. Buffett said on CNBC in January. He joked: "We're **very careful about how many we bid for**."

Companies Sweeten Dividends

by Michael Wursthorn – Feb. 28, 2018

Over one-fifth of S& P 500 lift payouts and none cut them; bonds prove tough rival.



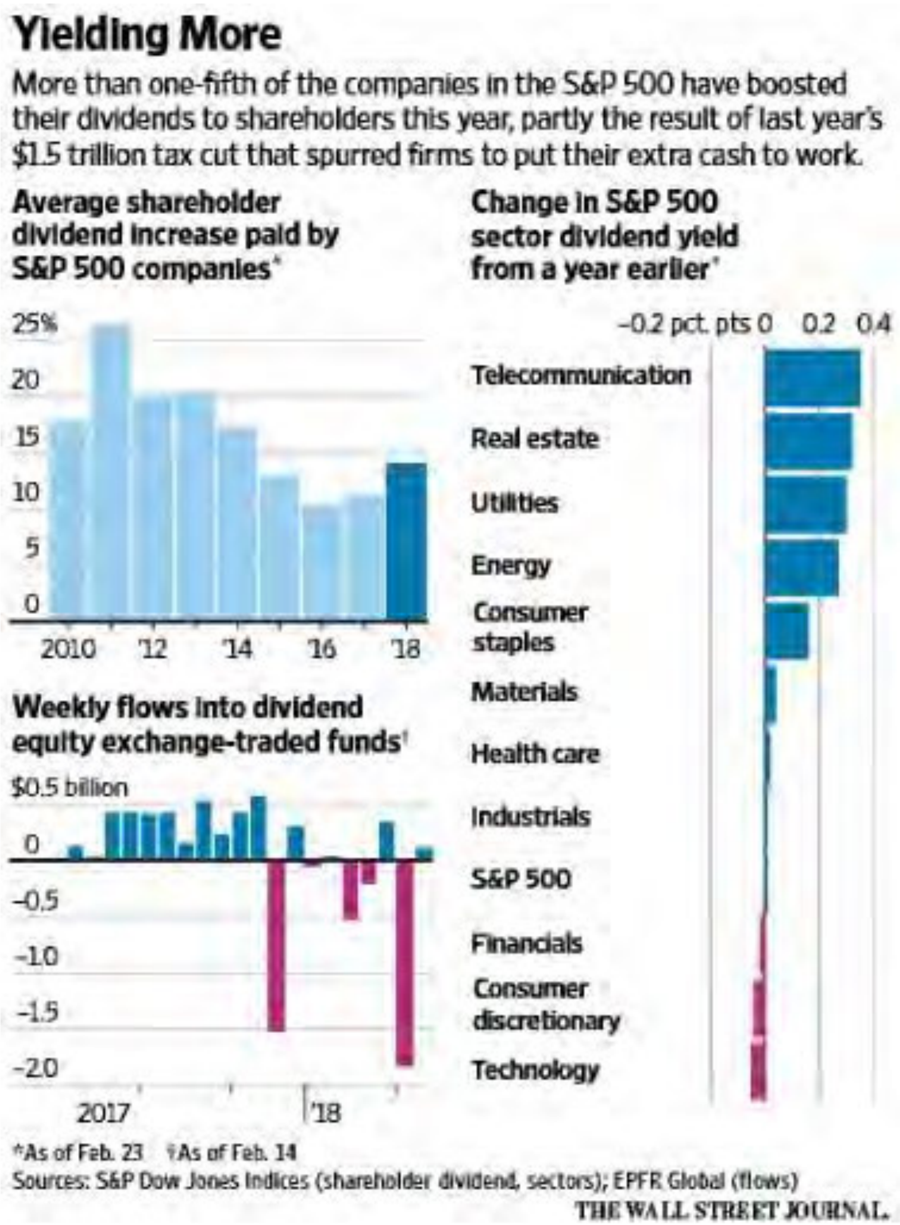
Dividends are on the **rise at a time investors have fewer reasons to buy** the **stocks that pay them** out.

More than one-fifth of the **companies in** the **S&P 500** have **boosted** their **dividends** to shareholders **so far this year**, while no firms have slashed their payouts, a first since 2011, according to S& P Dow Jones Indices.

The increases – from an array of companies including cable-giant Comcast Corp., asset-management firm T. Rowe Price Group and consumer- products company Kimberly-Clark Corp. – are getting bigger, too, with companies on **average raising** their **payouts by 14%**, the biggest jump since 2014.

The dividend boosts, which come as companies report some of their best earnings and sales in years, **partly result from last year's $1.5 trillion tax cut** that spurred corporations to put their extra cash to work. But they **also coincide with** a **rise in bond yields that threatens** to **diminish** the **allure of stocks**.

Bond yields have flirted with multiyear highs this month amid signs that long dormant **inflation** could be picking up enough to force the Federal Reserve to speed up the pace of interest-rate increases.



Those jitters sent stocks sputtering in early February, pushing the S& P 500 into correction territory for the first time in two years. Although stocks have regained much of their footing since then, with the broad index off just 4.5% from its all-time highs, **increased volatility** has kept investors on edge.

Bonds are relatively more attractive than they have been in years, and **high-dividend stocks like utilities** and real-estate companies are **among the worst performers in the S&P 500 this year**.

The **yield** on the **two-year U.S. Treasury** note **surpassed** the **income** investors could earn **from dividends on** the **S&P 500 in December** **for** the **first time since** the throes of the **financial crisis in September 2008**. The spread between the two has continued to widen this year with two-year bonds touching a high of 2.27% in February, nearly half a percentage point greater than what the S& P 500 had been yielding.

But bond yields are still relatively low and would have to move higher, with the benchmark 10-year U.S. Treasury yield at least above 3%, to spark a bigger rotation out of equities and into bonds, money managers say.

“Now that rates are higher, bonds are more attractive enough to start some sort of shift,” said Jay Jacobs, director of research at exchange, Global Management Co. “But the case for keeping equity payers in a portfolio is still very strong.”

14% Average increase in dividends among S&P 500 this year.

Utilities and real-estate companies **in** the **S&P 500 tend to pay bigger dividends relative to their share price than most other sectors** and **continue to offer better yields than short-term bonds as well as** the **10-year Treasury note**, whose yield rose Tuesday to 2.910%.

But those stocks have been struggling since November as bond yields ticked higher, drawing investors on the hunt for yield.

About $2.1 billion has flowed out of dividend-heavy exchange-traded funds over the five-week period ended Feb. 14, up from the $648.6 million in redemptions for the prior five-week period, according to data provider EPFR Global.

The pace of those redemptions appeared to be slowing, however. About $118 million flowed into those funds in the most recent week, according to EPFR's data.

"Now that rates are going higher, it's going to make bonds a lot more attractive," said Mr. Jacobs. "What's probably at the most risk right now is those lower- yielding stocks."

Eight of the 11 major S&P 500 sectors are generating a higher dividend yield than last year, including energy, consumer staples and healthcare companies.

Energy firms are seeing some of the biggest dividend increases, with three companies – Anadarko Petroleum Corp., Pioneer Natural Resources Co. and Cimarex Energy – at least doubling their payouts this month.

In total, four companies in the S& P 500 have at least doubled their dividends to shareholders this year, matching the number for all of last year.

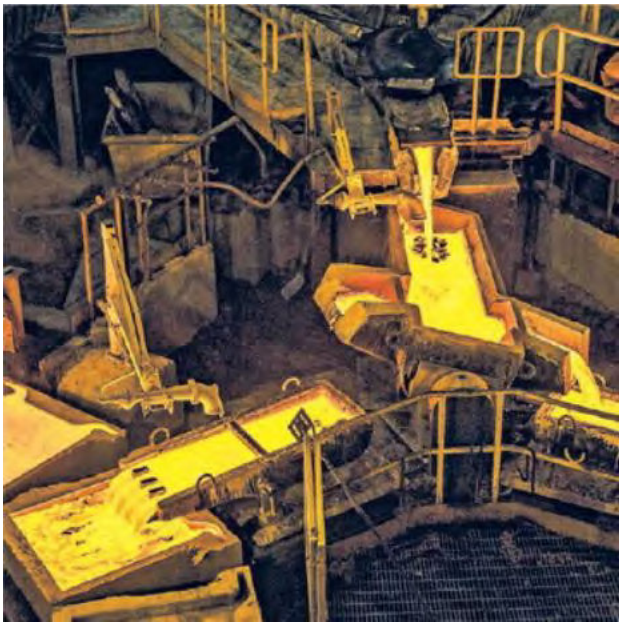
February is typically the busiest month for dividends as companies roll out their annual results and reward shareholders ahead of their annual meetings.

Historically, more than half of the companies in the S&P 500 increase their dividends each year, and in recent years, 60% or more of the index boosted their payouts, according to S& P Dow Jones Indices.

"It's a function of the **strong economic backdrop** coupled with the **changes to the tax code**," said Mike Allison, a portfolio manager with Eaton Vance. "A healthy earnings backdrop and lack of anything better to do with capital other than to return it to shareholders is something we like."

Copper Prices Decline on Strong Dollar, China Weakness

by Ira Iosebashvili and David Hodari – WSJ – Mar. 1, 2018



Left: Molten copper pours into ceramic molds to form plates in Peru.

Copper prices slid Wednesday, pressured by a **rising dollar** and weaker-than**-expected data from China**, the **world's largest buyer of the metal**.

Copper for May delivery **fell** 1.7% at **$3.1325 a pound on** the **Comex** division of the New York Mercantile Exchange. Prices for **aluminum**, **nickel** and **other industrial metals also declined**.

The dollar delivered its first monthly gain against a basket of currencies since October, driven by expectations that stronger growth in the U.S. may push the Federal Reserve to raise rates at a faster than- expected pace. A **rising dollar tends to weigh on prices for copper**, which is **denominated in** the **U.S. currency** and becomes **less affordable to foreign investors when** the **dollar appreciates**.

The Chinese manufacturing purchasing managers index came in at its weakest since July 2016. **China accounts for roughly 45% of global copper demand**.

Chinese investors were also digesting Communist Party plans to remove term limits on the country's presidency at its national congress, to begin March 5.

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Corporate Bonds Beg to Differ with Their Equity Brethren

by John Lonski, Chief Economist
Moody's Capital Markets Research, Inc. – Feb. 8, 2018

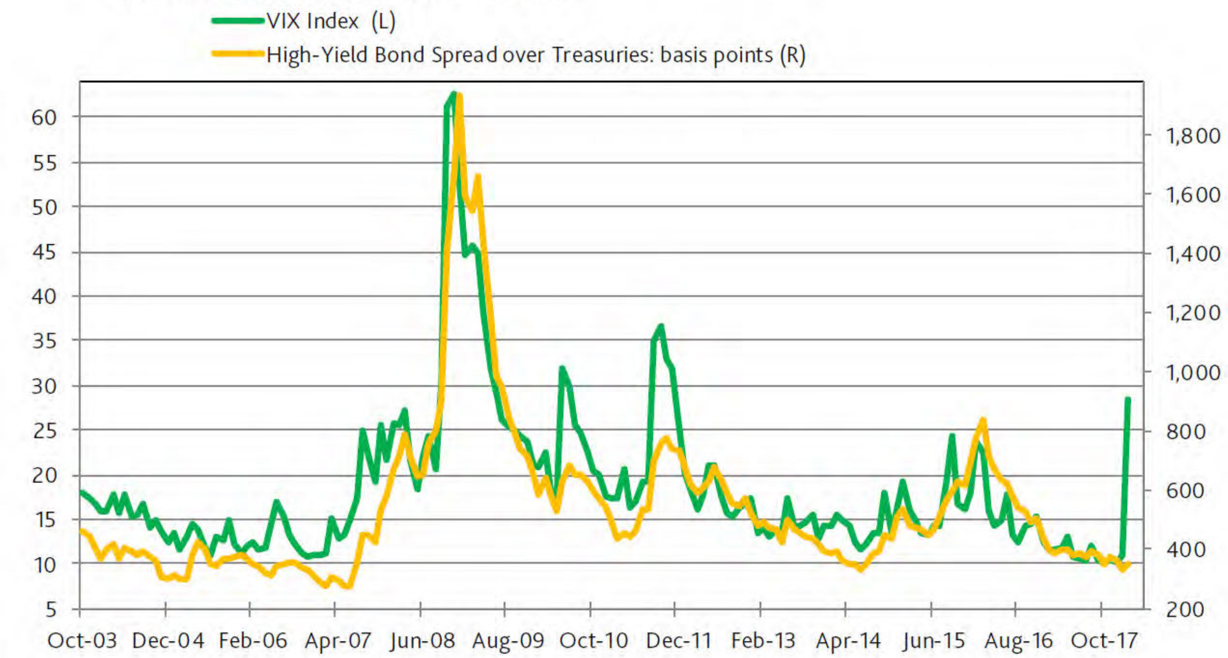
Thus far, the corporate credit market has been relatively steady amid equity market turmoil. Corporate credit's comparative calm stems from expectations of continued profit growth that underpins a still likely slide by the high-yield default rate. The record shows that 90% of the year-to-year declines by the default rate were joined by year-to-year growth for the market value of U.S. common stock.

Today's positive outlooks for business sales and operating profits suggest that equities will recover once issues pertaining to interest rates are sufficiently resolved. For now, equities may be paying dearly for having been more richly priced vis-a-vis fundamentals when compared to corporate bonds.

Since the VIX index's current estimation methodology took effect in **September 2003**, the **high-yield bond spread** has **generated** a **strong correlation of 0.90 with** the **VIX index**. **However**, for now that **ordinarily tight relationship** has **broken down**. **Never before** has the **high-yield bond spread been so unresponsive to a skyrocketing VIX index**.

The VIX index's 28.5-point average of February-to-date has been statistically associated with an 832-basis-point midpoint for the high-yield bond spread. Instead, the high-yield bond spread recently approximated 353 bp. Thus, **the high-yield spread predicted by the VIX index now exceeds the actual spread by a record 479 bp**.

Figure 1: Elevated VIX Index Now Favors a High-Yield Bond Spread that More Than Doubles Recent 353 bp *(correlation = 0.90)*
sources: CBOE, Moody's Capital Markets



The old record high gap was the 364 bp of October 2008, or when the actual spread of 1,398 bp would eventually surpass the 1,762 bp predicted by the VIX index. Not long thereafter, the actual high-yield spread would peak at the 1,932 bp of December 2008.

More recently, or during the euro zone crisis of 2011, the 1,018 bp high-yield spread predicted by the VIX index was as much as 323 bp above August 2011's actual spread of 695 bp. After eventually peaking at October 2011's 775 bp, the spread narrowed to 590 bp by August 2012.

What transpired following August 2011 and October 2008 warns against being too quick to dismiss the possibility of at least a 100 bp widening by the latest high-yield spread. Nevertheless, high-yield spreads would be significantly thinner one year after the gap between the predicted and actual spreads peaked For example, by August

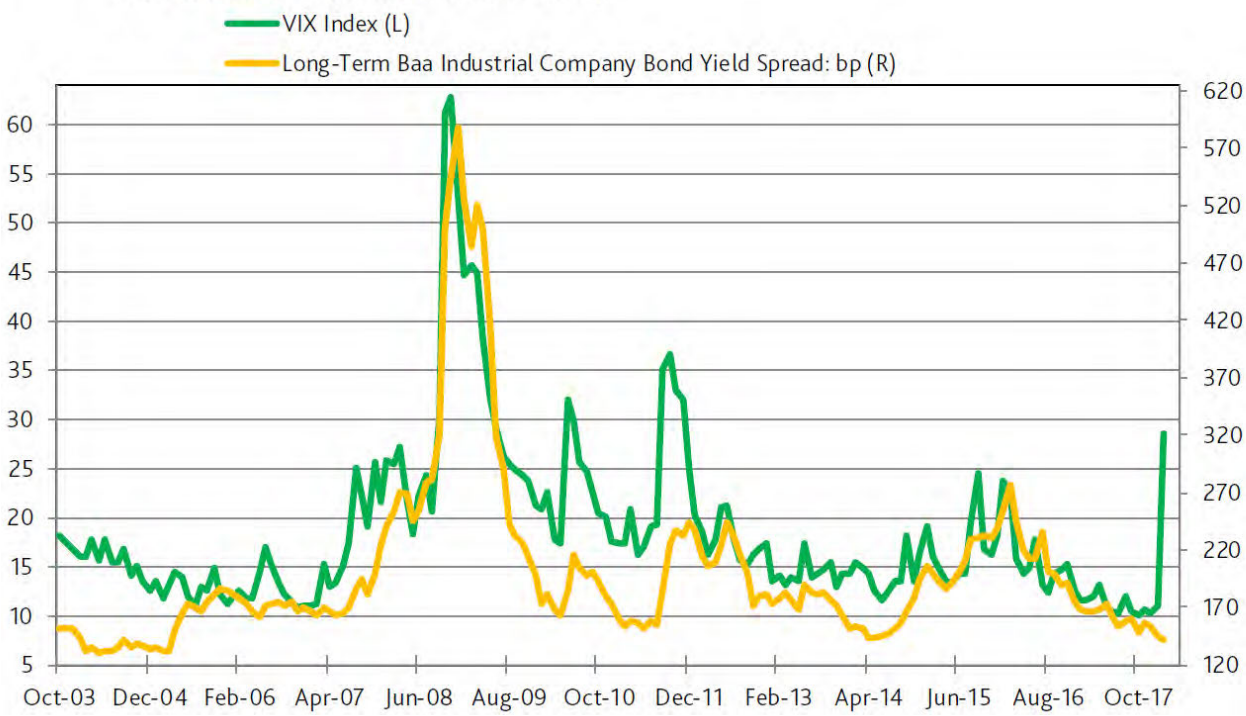
2012, the high-yield spread had narrowed to 590 bp, while the spread had thinned to 737 bp by October 2009.

Baa Spread Remains Very Thin Despite Well-Above-Average VIX Index

In addition, the recent VIX index favors a much wider spread for Baa-grade corporate bonds. The **VIX index now favors** a **279 bp yield spread for Moody's long-term Baa industrial company bond yield**, which was a very wide **137 bp greater than** the **actual spread** of **142 bp**.

The latest gap between the predicted and actual Baa spread was second only to the 146 bp of August 2011, or when the predicted Baa spread of 330 bp exceeded the actual 184 bp. The actual long-term Baa industrial company bond spread would eventually peak at December 2011's 244 bp and would still be a relatively wide 216 bp as of August 2012.

Figure 2: Baa Industrial Company Bond Yield Spread Shrugs Off Now Elevated VIX Index *(correlation = 0.85)*



The comparatively unperturbed and still atypically thin corporate bond yield spreads suggest that the **latest sell-off of equities is overblown from the perspective of fundamentals**. Perhaps the high-yield bond spread correctly senses that Treasury bond yields are not about to remain at levels that suppress interest-sensitive business activity.

However, the failure of Treasury yields to drop sharply in response to deep equity market sell-offs increases the risk of a climb by interest rates that curbs interest-sensitive spending. Thus, the upcoming peak spring selling season for housing may have much to say about where both interest rates and share prices are headed. A subdued pace for home sales might well establish a top for 2018's 10-year Treasury yield.

The 10% drop by the PHLX index of housing-sector share prices since January 26 may be warning of a disappointing pace for home sales. The possible combination of softer home sales and fewer auto sales would favor a less-than-3% peak for the 10-year Treasury yield.

Heavy Supply of Treasuries and Inflation Risks Boost Bond Yields

The U.S. Treasury bond market is now being hit hard by the combination of a surge in the supply of tradable Treasury bonds and the possibility that forthcoming fiscal stimulus amid a comparatively low unemployment rate may give rise to persistently rapid price inflation. More specifically, investor aversion to U.S. Treasury debt stems from (i) the increase in the federal budget deficit stemming from forthcoming tax cuts, (ii) the increase in the supply of tradable Treasury coupon securities stemming from scheduled reductions in Fed holdings of Treasury debt, (iii) a widely anticipated hiking of fed funds' midpoint from a current 1.375% to 2.125% by year's end, and (iv) worry over a possibly extended upswing by consumer price inflation. If PCE price index inflation shows signs of remaining well above 2%, fed funds' midpoint could finish 2018 at 2.375%.

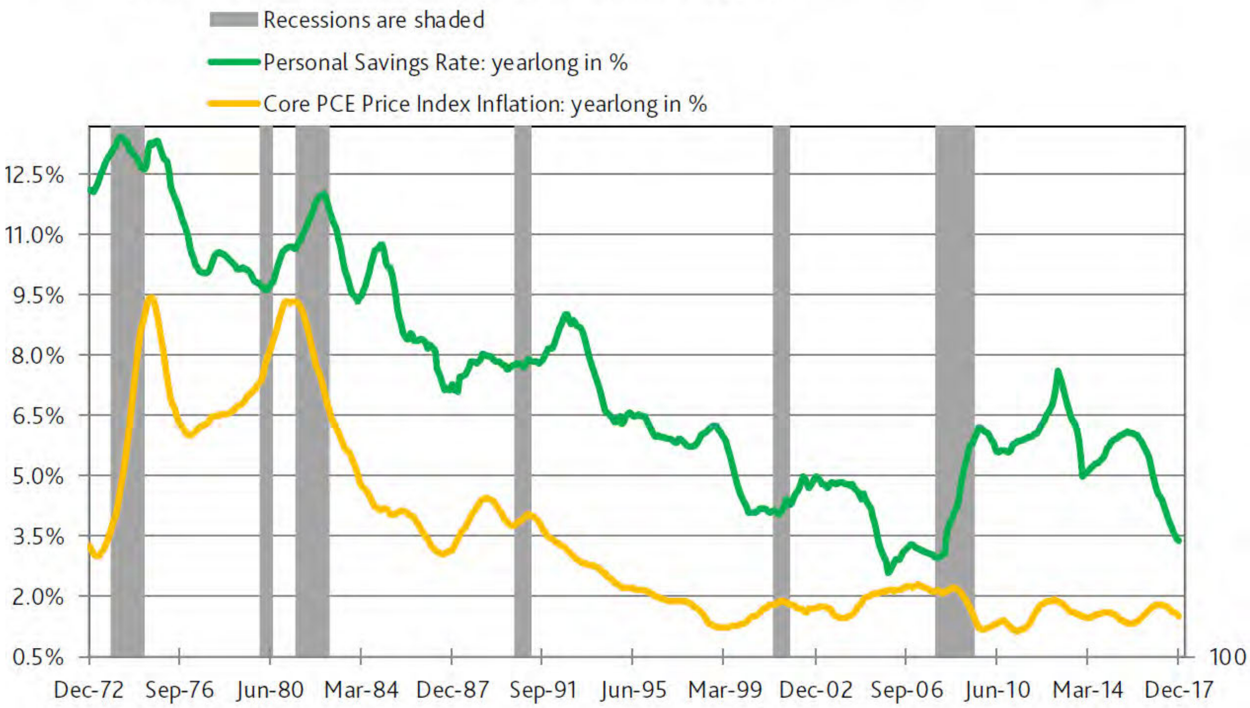
Mostly because of costlier energy products, the annual rate of PCE price index inflation should break above 2% in March. However, it's still problematic as to whether PCE price index inflation's annual rate will reach August-September 2011's current recovery high of 2.9%.

Low Personal Savings Rate Saps Business Pricing Power

In addition, fiscal stimulus may not supply much of a lift to demand-driven consumer price inflation. In view of the relatively low personal savings rates of the past several years, an unexpectedly large share of personal income tax cuts may be saved and not spent. Moreover, the low personal savings rate questions whether consumers are able to afford a broadly distributed and recurring acceleration of consumer prices. The more consumers reduce real spending in response to faster consumer price inflation, the more likely it is that price hikes will be rescinded.

For a sample that begins in 1972, the **moving year-long rate of core PCE price inflation reveals a strong correlation of 0.82 with the moving year-long personal savings rate**, or the percent of disposable personal income that is saved. When the personal savings rate averaged 11.35% during the 10-years-ended 1982, the accompanying annualized rates of inflation were 7.1% for the PCE price index and 7.7% for the core PCE price index. Far slower were the average annualized rates of growth of 1.7% for the core PCE price index and 1.8% for the PCE price index during the 10-years-ended 2017, or when the personal savings rate averaged a much lower 4.9%.

Figure 3: Core PCE Price Index Inflation's Trend Moves in Direction Taken by the Personal Savings Rate
sources: Bureau of Economic Analysis, Moody's Analytics

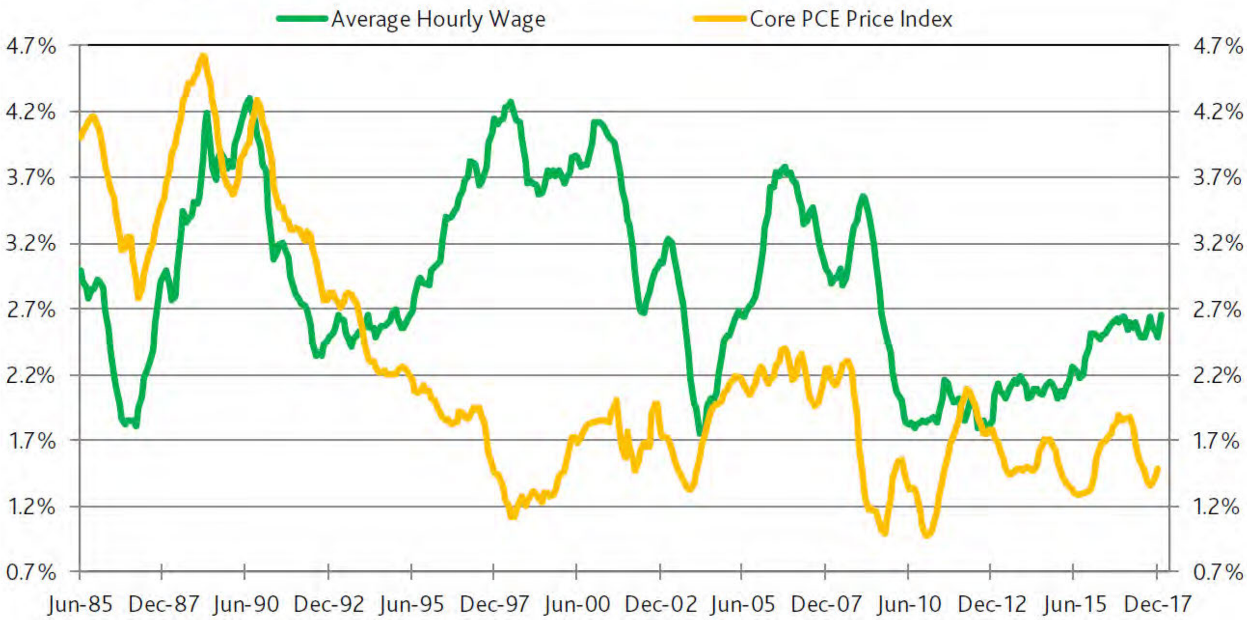


Faster Wage Growth Is Not a Trustworthy Indicator of Core Inflation

The **average hourly wage has not been** a **trustworthy leading indicator of consumer price inflation's underlying pace**. For example, despite how the year-over-year growth rate of the average hourly wage accelerated from Q3-1992's 2.3% to Q4-1997's 4.2%, the annual rate of core PCE price index inflation slowed from 2.9% to 1.5%, respectively. The **slight 0.21 correlation between core PCE price index inflation and the growth by the average hourly wage implies faster wage growth does not assure** a **faster rate of core PCE price index inflation**.

The record shows that **slower wage growth does a better job of signaling a deceleration by core PCE price index inflation compared to faster wage growth's ability to indicate faster core inflation**. Since June 1986, the average hourly wage's annual increase accelerated over a 12-month span on 225 occasions. For only 111, or 49%, of those accelerations by the hourly wage did the annual rate of core PCE price index inflation also increase. **By contrast, the annual rate of core PCE price index inflation decelerated from 12 months earlier for 103, or 67%, of the months showing a slower annual increase by the average hourly wage**.

Figure 4: Core PCE Price Index Inflation Often Slows When the Average Hourly Wage Accelerates *(correlation = 0.21)*
yy % change of moving 3-month averages
source: Moody's Analytics



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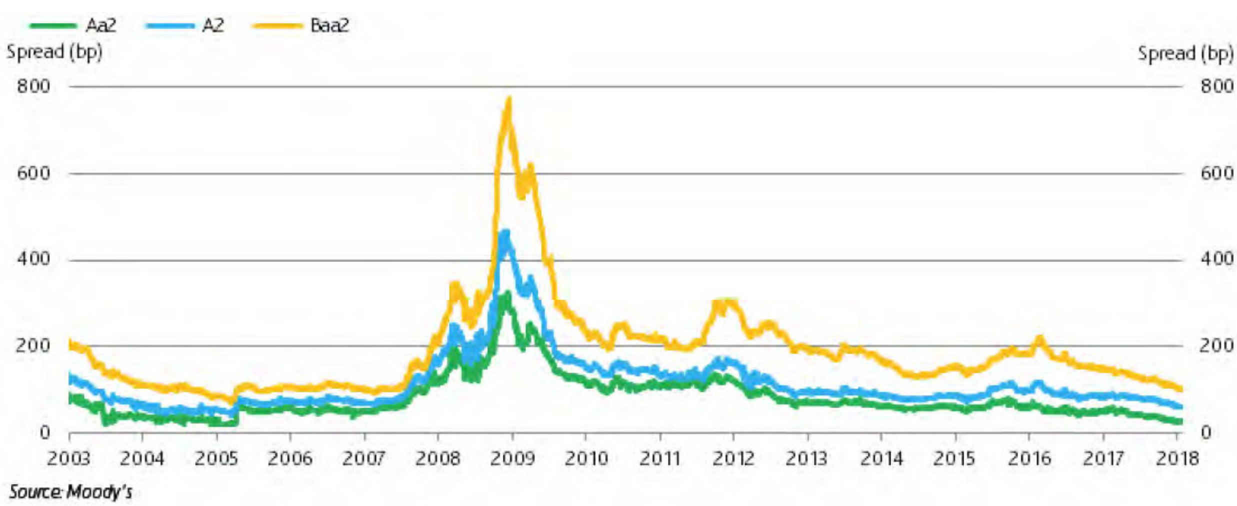
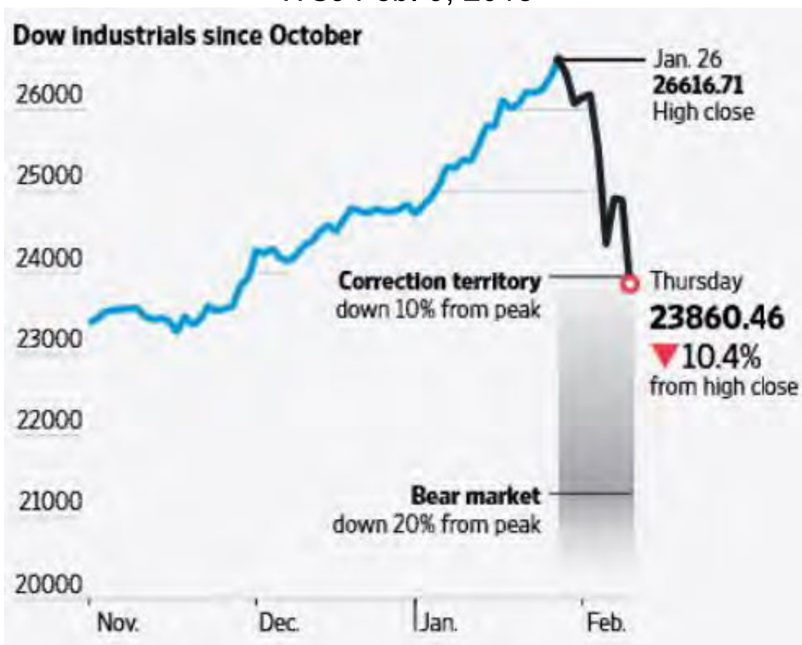
5-Year Median Spreads (High Grade)

Moody's Data Analytics Jan. 25, 2018



DOW Drops Over 10% – Entering Correction Territory
WSJ Feb. 9, 2018



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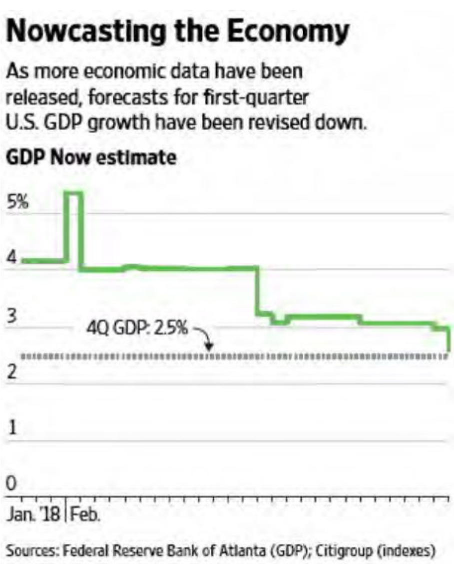
Economic Growth Weaker than Thought

by Sara Chaney – Mar. 1, 2018
Josh Mitchell contributed to this article.



U.S. economic growth was slightly **weaker than initially thought during** the **fourth quarter** and **may be cooling** a bit in the **first quarter as well**.

Gross domestic product, a broad measure of the goods and services produced across the U.S., **rose** at a **2.5% seasonally** and **inflation-adjusted annual rate in** the **fourth quarter**, the **Commerce Department said** Wednesday. The agency in January estimated last quarter's growth rate at 2.6%.

The **government's estimate of output** was **reduced** because companies drew more from their inventories than previously estimated, meaning they had less to produce. **Business**

investment also was slightly **weaker than initially reported**, growing at a **6.6% rate last quarter** versus an originally reported 6.8%.

The inventory drawdown could fuel restocking later in the year that leads to more production. Still some analysts have moved down their forecasts for first-quarter growth in recent weeks after reports showing sluggish retail sales and durable-goods business orders.

The **Federal Reserve Bank of Atlanta**, for example, has **shifted its forecast** for **first-quarter growth** from 5.4% growth **down** to 2.6% since Feb. 1. Forecasting firm Macroeconomic Advisers projects a first-quarter growth rate of 1.8% as of Wednesday. That would be slower than growth rates exceeding 3% in the middle of last year. Joel Prakken, Macroeconomic Advisers' chief U.S. economist, said its first-quarter growth projections are soft because it is factoring in un-usually high snowfall in recent weeks, which is associated with restrained economic growth. Its estimate also takes into account the tendency for first-quarter growth to be weaker than other quarters. "We're looking for much firmer growth in the middle part of the year and the last half of the year," he said. Weather has affected restaurant chain Potbelly Corp., which saw same-store sales decrease 2.4% in the fourth quarter from the same period a year earlier. "The early [2018] trends are not as strong as fourth-quarter trends," said Michael W. Coyne, Potbelly's chief financial officer, in a call with analysts on Friday. "What wasn't planned for was that we had substantially worse weather this year than last." U.S. policy makers and many analysts remain optimistic about the full-year outlook, which is bolstered by tax cuts at home and stronger conditions overseas.

Edison International Sells $550M of Senior Notes

by Nephele Kirong – *S&P Global Market Intelligence* – Mar. 9, 2018

Edison International **sold $550 million** of its **4.125% senior notes due** March 15, **2028**, according to a March 8 free writing prospectus.

The company plans to use proceeds to repay term loan agreement and commercial paper borrowings, as well as for general corporate purposes.

Interest on the notes is payable every March 15 and Sept. 15, beginning Sept. 15. The notes have a **spread to benchmark U.S. Treasury** of **128 basis points** and were expected to be rated **A3** by **Moody's**, **BBB** by **S&P** Global Ratings and A- by Fitch Ratings.

Barclays Capital Inc., J.P. Morgan Securities LLC, Wells Fargo Securities LLC, Morgan Stanley & Co. LLC and TD Securities (USA) LLC acted as joint book-running managers.

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Southwestern Electric Power Sells $450M of Senior Notes

by Saad A. Sulehri – S&P Global Market Intelligence – Jan. 19, 2018
S&P Global Ratings and S&P Global Market Intelligence
are both owned by S&P Global Inc.

Southwestern Electric Power Co. sold **$450 million** of its **3.85%** series L **senior unsecured notes due Feb. 1, 2048,** according to a Jan. 18 free writing prospectus.

Interest on the notes is payable semiannually on Feb. 1 and Aug. 1 of each year, starting Aug. 1. The notes have a **spread to benchmark Treasury** of **97 basis points** and were expected to be **rated Baa2** by **Moody's** and **A-** by **S&P** Global Ratings.

The **A**merican **E**lectric **P**ower Co. Inc. **subsidiary** plans **to use** net **proceeds** to fund the **repayment** of its $300 million of 5.875% series F senior **notes** due March 1 and $81.7 million of the Sabine River Authority of Texas pollution control revenue refunding **bonds**, series 2006, and for general corporate purposes. Pending such use, the company may **temporarily invest** them in **short-term, interest-bearing obligations.** At Dec. 31, 2017, the company had $118.7 million in advances from affiliates outstanding.

Merrill Lynch Pierce Fenner & Smith Inc., **Barclays** Capital Inc., **KeyBanc** Capital Markets Inc. and **UBS** Securities LLC acted as joint book-running managers.

Mizuho Securities USA LLC, **BOK Financial** Securities Inc., **Huntington Investment** Co., C.L. **King** & Associates Inc., **Loop Capital** Markets LLC and **Samuel** A. **Ramirez** & Co. Inc. served as co-managers.

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Otter Tail Issues 4.07% Senior Unsecured Notes Due Feb. 7, 2048

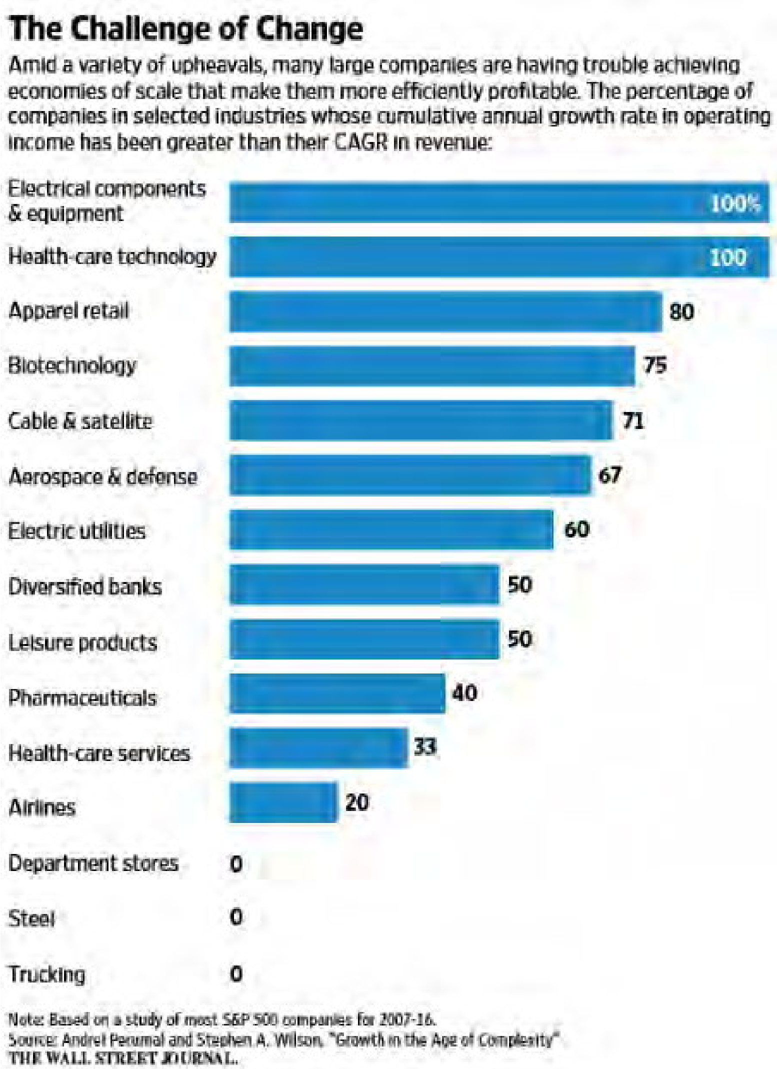
Transaction Profile – S&P Global Market Intelligence – Feb. 7, 2018

Otter Tail Power Co. on Feb. 7 sold **$100 million** of **4.07%** series 2018A **senior unsecured** notes **due** Feb. 7, **2048** in **private placement**, to refinance existing debt under the company's revolving credit facilities.

The issuing currency is USD. The Gross Amount Offered including Overallotment was $100,000,000.

For CEOs, Strong Growth—and Turmoil

by Sharon Terlep – WSJ – Jan. 22. 2018



After a decade of slow growth, corporate chieftains have good reason to feel buoyant.

In the U.S., the economy grew 3% in the third quarter and Federal Reserve officials in December increased their forecast for 2018 growth to 2.5%, up from 2.1% in September. Bulls on Wall Street boosted the market cap for S& P 500 companies last year by 18%, unemployment stood at a 17-year low, and a big tax cut and regulatory rollbacks portend more gains.

Europe, meanwhile, is also bouncing back after an all-but-lost decade. Asia's continued growth makes it a rare moment — after the extended hangover of the downturn — when **the world's major economies are all pointing up**.

Yet plenty of **anxiety lingers** — also with good reason. CEOs continue to grapple with the ever-accelerating pace of technology change. Meanwhile, they face growing pressure from investors and boards, and greater scrutiny from customers and even their own employees in the age of social media. Consumer habits and tastes continue to shift drastically. While a GOP-led Washington has been generally more favorable to business, political turmoil, and the risks it brings, has only increased, at times drawing executives into debates they'd just as soon avoid.

Change all around

"In my 37 years at General Motors, the amount of technology is changing more than ever," Chief Executive Mary Barra says, discussing GM's efforts to bring to market fully electric vehicles and cars that drive themselves. "We've made **cultural changes**,

we've changed where we do business, we're developing **transformative technologies**," says Ms. Barra.

Left: GE Wind Turbine Plant in France.

Whether it's GM trying to take the **shape** of a tech **company**, **General Electric** Co. **considering** a **breakup**, or PepsiCo Inc. struggling to sell soda, corporate mainstays are trying to right themselves after becoming vulnerable to market forces they once ably navigated. **CEOs** are **overhauling business models**, **forging unexpected alliances** and **giving concessions to activist shareholders who criticize how their companies are being run**.

CVS Health Corp., the largest U.S. drugstore chain, will spend much of this year trying to cement its acquisition of insurance giant Aetna Inc, a deal that creates an almost unprecedented health-care enterprise. **Procter & Gamble** Co., the maker of Tide and Pampers, has said it **will admit activist investor Nelson Peltz to** the board in **March after spending** at least **$60 million trying** to **stop him and his strategy for overhauling the company**. P& G agreed to add Mr. **Peltz** to the board after **winning** a **shareholder vote by a historically narrow margin**.

AT& T Inc. and Time Warner Inc. are prepared to fight at least until June a Justice Department lawsuit trying to stop a merger that would turn the phone company into a media giant. Big food companies, meanwhile, continue to grapple with dramatic shifts in what people eat and where they shop, as retailers scramble to reinvent a business model decimated by Amazon.com Inc.

"Some say that it's **more change in the last three years than in the last 10 or 20 years,**" Home Depot CEO Craig Menear says of the changing retail landscape and his company's plans to upend an online- sales strategy laid out just five years ago. "It's imperative that we address these evolving needs with increased speed," says Mr. Menear.

Kurt Simon, JPMorgan Chase & Co. global chairman of mergers and acquisitions, worked on deals last year including Walt Disney Co.'s agreement to acquire most of 21st Century Fox Inc. for $52 billion. "How and who companies compete with are rapidly changing in a number of industries due to technology and the emergence of disruptive new entrants," Mr. Simon says. "For incumbents, you have the opportunity to either be disrupted or go on the offensive."

<u>No longer is size synonymous with growth and profitability</u>. **Some of the world's biggest corporations** are **hemmed in by** their **own size**, **incapable** of

moving quickly enough to adapt to fast changing markets and consumer tastes. **GE**, which last year **saw** its **shares drop by one-third** amid a reset of long-term financial projections, **embodies the dilemma**. The industrial giant is refocusing on three core business lines — the aviation, power and health-care divisions — while exiting most of its other business. CEO John Flannery, who took over last summer, this month said that GE is evaluating carving out its major divisions into separately traded units.

About 40% of companies in the S& P 500 are becoming less profitable as they grow, says Stephen Wilson, managing partner of advisory firm Wilson Perumal & Co., whose analysis measured revenue growth and operating income at the top companies. **A company whose operating income grew more slowly than its revenue, according to the analysis, experienced so-called diseconomies of scale, as opposed to leveraging desirable economies of scale**.

"**In the industrial age**, the **biggest company was the most competitive**," Mr. Wilson says. "Today, companies are trying to get bigger to get economies of scale, but to get bigger they are becoming more fractured, and that means less economies of scale. Companies are realizing that they can't just add new products and grow, that they can't just go into more countries and grow."

Crossing industry lines

Adding to all of this turbulence, companies are increasingly transparent, giving investors and consumers greater ability to look under the hood and compare operations, even as new technologies continue to transform such economic fundamentals as how people get around and shop.

This changing business landscape in turn is altering the nature of how companies produce goods and deliver services, and is **affecting everything from human-resources departments to the supply chain**.

A need for radical action will likely lead to more deals that cross industry lines, like the CVS-Aetna deal or Amazon's $13.7 billion deal in June to acquire Whole Foods Market Inc.

"**Earlier** rounds of **M&A were simply competitors buying each other and getting the synergies out of a deal**," says Frank Aquila, a partner at law firm Sullivan & Cromwell LLP. "While that's **still** an **important** part of M& A, we're going to see many more combinations going forward that may not be what people expect."

Despite a recognition that change — **often radical change**—is **needed**, perhaps the **trickiest part** will be **where to be radical** and **where** to be more **cautious**.

"The hardest thing for chief executives is to figure out where to make changes and how radical to be in different parts of the business," says Andy Eversbusch, a managing director at consulting firm AlixPartners LLP. Ideally, Mr. Eversbusch says, a company can pull off a "healthy turnaround" in which it overhauls itself before crisis strikes.

"The **leaders** that I see who are very **good at this**," he says, "are ones who routinely invest themselves in **questioning every aspect of their business**."

Forces That Could Revive Inflation Are Lurking

by Greg Ip – WSJ Capital Account Column – Mar. 1, 2018

Inflation is going to head up this year– on that there isn't much debate. The real debate is over whether it will be a **nonevent or** something more **ominous**.

The **Federal Reserve** and **most of Wall Street think** it will be a **nonevent**. But there is a plausible scenario in which it marks a new, dangerous trend. Even if you think it unlikely, you need to give this scenario serious thought because trillions of dollars of investments are geared to inflation being dead.

Unemployment in the last year has sunk to a 17-year low, yet inflation continues to run below the Fed's 2% target. Abroad, it is the same story: In Germany and Japan unemployment is at multi-decade lows but inflation remains stuck below 2%.

This disconnect is one reason Fed officials devoted much of their late January meeting to discussing what drives inflation.

Ironically, wage and price data firmed soon after. The "core" consumer-price index excluding food and energy rose 1.8% in January from a year earlier and should soon top 2% as favorable readings from a year ago drop out of the 12-month calculation. The Fed focuses on a different gauge which is running lower, at 1.5%. But some economists think it, too, could hit 2% this year.

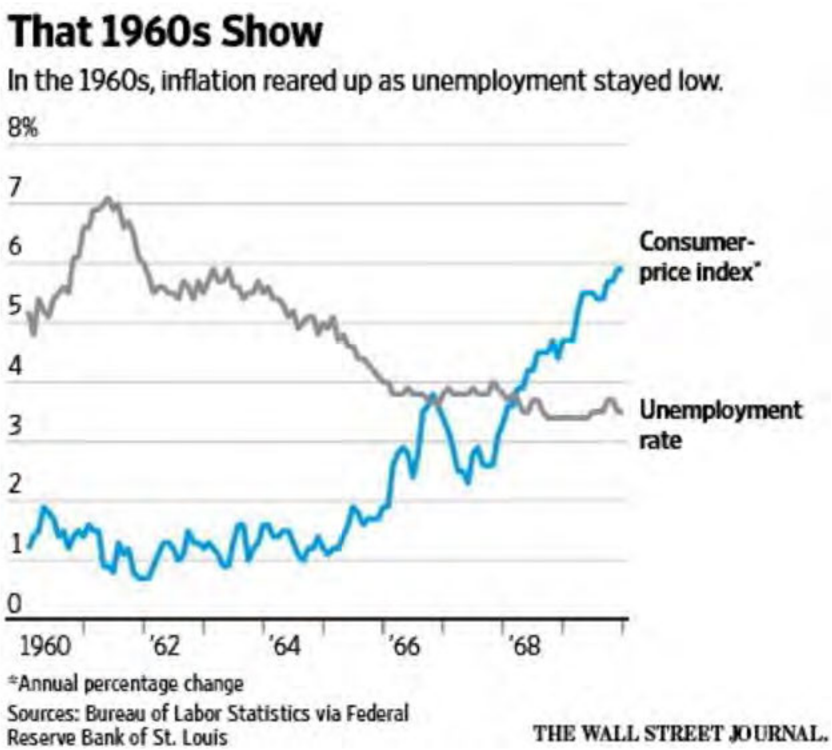
The consensus is that inflation will then level off, in great part because the **public has come to expect 2% inflation** and should set prices and wages accordingly. This is a sound and persuasive base case. But multiple forces are now at work that could, together, keep it going up. The most important is that unemployment at today's low levels has over the postwar period typically coincided with rising price pressure. Second, a big tax cut and a federal-spending boost are about to juice the economy and potentially push unemployment even lower. A falling dollar and rising oil prices are feeding through to other costs.

On top of these short-term factors, **several structural forces are at work**, as a recent report from BCA Research, a Montreal-based investment advisory, shows.

One is **protectionism**. Global trade rose faster than global output from the early 1980s until the global financial crisis. Trade held down prices and wages by exposing American workers and firms to intense foreign competition. Globalization has since gone into reverse, and protectionist pressures are mounting: **Americans can expect to pay more** for washing machines and softwood lumber and perhaps soon anything containing steel or aluminum be-cause of tariffs imposed by President Donald Trump.

Productivity growth the usual antidote to rising costs, is tepid and could stay that way.

If **inflation** turns up, economists have long assumed it would do so slowly, giving the Fed plenty of time to respond. But **Michael Feroli of J.P. Morgan** notes this assumption is built on models in which the world behaves in a predictable, linear way. In fact, he says, the world isn't linear and inflation can change suddenly: It "is **sluggish and slow-moving**, **until it isn't**."



A case in point: **In 1966**, **inflation**, which **had run below 2% for nearly a decade**, **suddenly accelerated to over 3%**. **Some** of the **circumstances echo** the **present**: unemployment had slid to 4%, taxes had been cut and federal spending for the Vietnam War and Lyndon Johnson's "Great Society" programs was surging. Deutsche Bank economists note the budget deficit jumped by more than 2% of gross domestic product between 1965 and 1968, similar to what they project between 2016 and 2019. Except in recessions, stimulus of this size "is unprecedented outside of these two episodes."

The effect of an overheating economy was then compounded by policy errors. Fed Chairmen William McChesney Martin Jr. and Arthur Burns were too optimistic about how low unemployment could go without pushing prices higher, and succumbed to pressure from Mr. Johnson and then Richard Nixon to keep interest rates low. From 1966 to 1981, inflation and interest rates climbed to double digits, decimating stock and bond values.

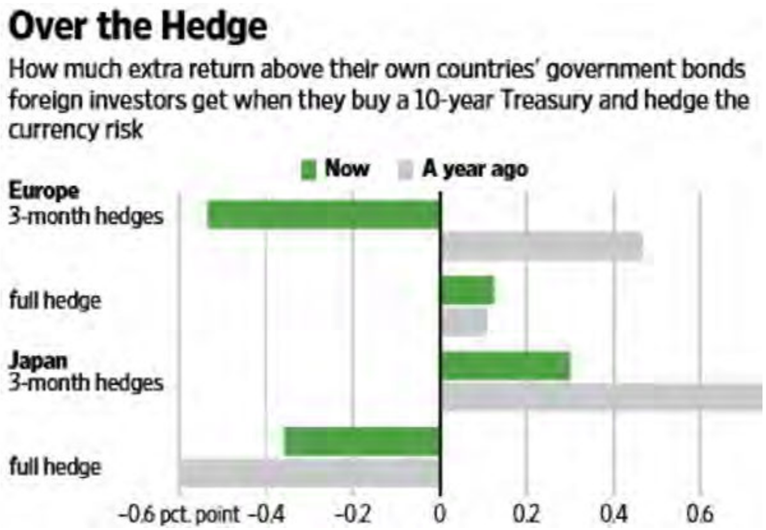
Some on Wall Street worry Mr. Trump, who treats the stock market as a report card on his presidency, will similarly pressure Fed Chairman Jerome Powell. So far, this seems unlikely: Mr. Trump and his officials have asserted the Fed's independence, and no central banker, including Mr. Powell, is about to relinquish it.

Yet even without politics, the Fed faces clamor to replace or relax its 2% inflation target. Advocates say higher inflation and thus higher interest rates provide more room to cut when the next recession hits. But inflation doesn't have to top 4%, much less 10%, to wreak havoc: a world in which inflation risks persistently point up instead of down would drive bond yields higher and kick the support out from under stock and property values.

This scenario seems remote. But if you had given **inflation** up for dead, it is **prudent** to **consider** the **consequences if it** turns out to have **only** been **sleeping**.

Foreign Investors Eschew U.S. Debt

by Jon Sindreu – WSJ – Mar. 1, 2018



The **rise** in **Treasury yields should make U.S. debt more attractive to international investors** still **struggling with low returns at home, yet few are buying**.

The **rising costs** of **currency hedges means** it **often isn't worth it**.

Yields on **10-year U.S. government bonds** have jumped to **2.9% from 2.1%** a **year ago**, near levels last seen in early 2014. In Europe, a **10-year German government bond yields 0.66%,** while in **Japan** the **same maturity returns 0.05%**. **Yields move inversely to prices**. **Last year**, **buying Treasurys** and **swapping** the **proceeds back into euros provided European investors** with a **higher return than buying German** sovereign **bonds**. Now, **hedging costs** have **increased so much** that this **trade** is **no longer profitable**.

That could **sap** an **important source** of **demand for Treasurys**. I t is **also making** it **more expensive** for foreign investors to buy U.S. corporate debt.

"We've been very wary about what optically appears like a very wide difference [in yields] between Europe and the U.S., because of funding and hedging costs," said Charlie Diebel, a London-based fund manager at Aviva Investors, who is now looking to buy in other bond markets like Canada.

The **European Central Bank estimates** that **since 2015, euro-zone investors** have **accounted for more than half** of **foreign purchases of U.S. debt securities**.

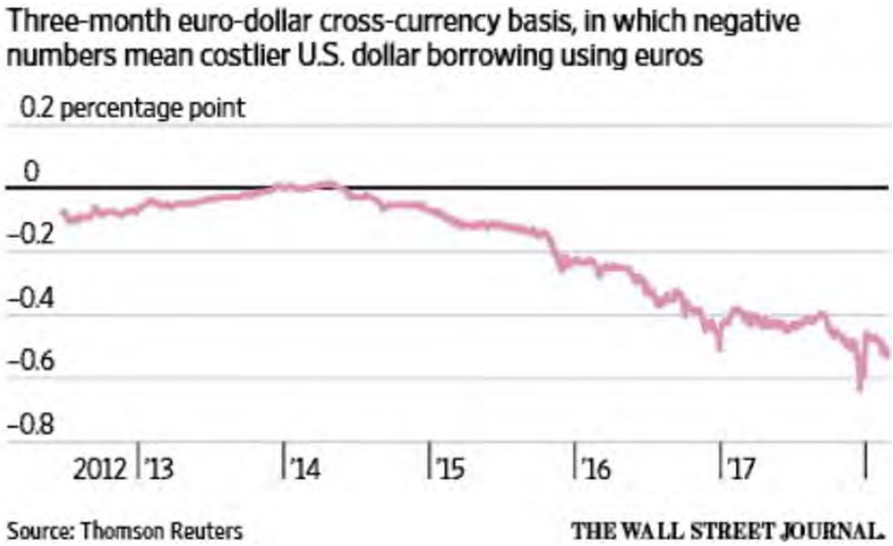
But in **2017**, **euro-zone investors** were **consistent net sellers** of **Treasurys**, according to official U.S. data.

International investors usually **hedge** their **holdings** of **foreign bonds using derivatives**, which allow them to **borrow** a **foreign currency in exchange for their own**, and **lock in** a **future rate** at which they will **reverse** the **transaction**.

On the surface, there is still a case for buying Treasurys and hedging the currency risk. Buying a 10-year Treasury and buying a hedge in euros for that same maturity will still earn an investor a small pickup of about 0.1 percentage point over what they would get buying a German government bond. A year ago, the reward was similar.

But the problem for the Treasury market is that few big investors hedge it for anywhere near that time, analysts say.

"**Most investors prefer** to **roll over three-month currency hedges** because it's a **more liquid** market," said Chris Iggo, chief fixed-income investment officer at AXA Investment Managers.



Holding long-term Treasurys and hedging the currency risk for three months means **taking** a **hit every time** the **Fed**eral Reserve **nudges up short-term borrowing costs**, which it has done three times over the past year. On Tuesday, Fed Chairman Jerome Powell indicated that the central bank is on track to keep gradually lifting interest rates and perhaps even pick up the pace this year.

The greenback has also just become harder to source for investors using currency derivatives, as rules designed to make finance safer have made banks more reluctant to lend dollars in the short term. Adding to this, the Fed is now sucking dollars out of the financial system as it rolls back its monetary stimulus, making the currency even scarcer.

A year ago, investors were getting about 0.5 percentage point extra for buying a 10-year Treasury and hedging the currency risk every three months, instead of purchasing a German government bond, according to The Wall Street Journal's calculations. They are now losing 0.5 percentage point, a multiyear low.

Yields on long-term bonds like the 10-year Treasury will have to go up much more if they are to attract fresh overseas buyers, Mr. Iggo said. On Wednesday, the yield on the 10-year Treasury note settled at 2.870%.

Typically, government debt trades in line with where investors believe central banks will set interest rates in the future. Investors currently think borrowing costs will be increased to cool burgeoning inflation pressures, with Mr. Powell cementing that belief on Tuesday.

But Fed data suggests that rate expectations account for only one-third of the selloff in 10-year Treasurys this year. The rest of the selling has been influenced by a rise in that bond's "term premium," the extra compensation investors get for holding longer-term debt, which is more sensitive to a fall in demand.

The rising cost of currency hedges also is affecting U.S. corporate bonds, investors say, making them less attractive compared with their euro-denominated counterparts.

Over the past month, yields on corporate debt have risen further in the U.S. than Europe, according to indexes complied by Bank of America Merrill Lynch.

Japanese investors can still get a 0.3-percentage-point pickup over their own debt by buying Treasurys with three-month currency hedges.

But Commerzbank AG analysts noted that they will find much better opportunities in Europe, where they now get an extra 0.8 percentage point to hold German sovereign bonds and swap the proceeds back into yen every three months.

Since 2014, Japanese asset managers have been steadily reducing their holdings of U.S. debt, data from Japan's Investment Trusts Association show, and that trend continued into last year.

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'Success Theater' Masked Rot at GE

by Thomas Grytya, Joann S. Lublin and David Benoit – WSJ – Feb. 22, 2018
Ted Mann contributed to this Article.

Left: **Under Immelt, disdain for bad news led to overoptimistic forecasts, botched strategies**.

Jeffrey Immelt, the longtime boss at General Electric Co., was a polished presenter who held court each year at a waterfront resort off Sarasota, Fla., where industrial executives and Wall Street listened for his outlook on the conglomerate.

"This is a strong, very strong company," Mr. Immelt said at the event last May.

On that Wednesday morning, he looked shaky to some people in attendance, quickly going through highlights of 27 slides in the ballroom of the Resort at Longboat Key Club. He defended his long-held 2018 profit goal, an optimistic benchmark Wall Street had long abandoned.

"It's not crap. It's pretty good really," he told the skeptical room, referring to GE's recent financial performance. "Today, when I think about where the stock is compared to what the company is, it's a mismatch."

GE's $10 billion deal for a **turbine rival closed just as that market was cooling.**

It was a mismatch. On that day, GE shares were trading near $28. They would go on to collapse over the next six months while the stock market set fresh records. Today, they trade below $15.

GE's precipitous fall, following years of treading water while the overall economy grew, was exacerbated, some insiders say, by what they call "**success theater**." **Mr. Immelt and his top deputies projected** an **optimism about GE**'s business and its future **that didn't** always **match** the **reality of its operations or** its **markets**, according to more than a dozen current and former executives, investors and people close to the company.

This culture of confidence trickled down the ranks and even affected how those gunning to succeed Mr. Immelt ran their business units, some of these people said, with consequences that included **unreachable financial targets**, **mistimed bets on markets and** sometimes poor decisions on **how to deploy cash**.

"The **history of GE** is to **selectively only provide positive information**," **said Deutsche Bank** analyst John Inch, who has a "sell" rating on the stock. "There is a **credibility gap** between what they say **and** the **reality** of what is to come."

Within weeks of the May meeting, **Mr. Immelt** announced his **retirement**. By year-end, GE under a **new leader** had **cut its dividend in half** and **triggered a restructuring** that is **expected to eliminate thousands of jobs and cast off more than $20 billion of assets**. Today, **federal regulators are examining GE's accounting** for certain transactions, and **new CEO John Flannery** is **considering breaking up the 125-year-old company**.

The tumble is stark for a company that embodied the managerial success of American business and its industrial power.

Few knew just how badly ailing it was. Even GE's board didn't realize the depth of problems in the biggest division, GE Power, until months after directors had replaced Mr. Immelt. For the fourth quarter, GE reported lower revenue and, after a charge related to a review of its insurance business, a loss of nearly $10 billion.

"Many of us are in some level of shock," said a former director. Investigations are under way inside GE seeking to find out how it all happened.

mistic," said Mr. Sherin.

Costly Buybacks:

But Mr. Immelt didn't like hearing bad news, said several executives who worked with him, and didn't like delivering bad news, either. He wanted people to make their sales and financial targets and thought he could make the numbers, too, they said.

The optimism was evident in how he and the board used cash. Over the **past three years**, **GE spent more than $29 billion on share repurchases**, at an **average price of almost $30, twice the current level**. That included **billions** of dollars **spent** less than a year **before GE** suddenly found itself **strapped for cash** last fall.

Trian Fund Management LP, which invested $2.5 billion in GE in 2015, wanted it to buy back even more stock. The **activist investor** urged the company to borrow $20 billion for repurchases (which it didn't do), based on a belief that the profits Mr. Immelt was promising would send the stock soaring when they arrived.

Instead, at Mr. Immelt's retirement in August the stock was below its level when he took over 16 years earlier. Including dividends, GE gained 8% with Mr. Immelt at the helm, while the S& P 500 rose 214%. Since he stepped down, the stock has lost about 43%, erasing almost $94 billion in market value. The relationship with Trian deteriorated and the firm successfully pushed for a board seat.

Mr. Immelt's successor, Mr. Flannery, in November **slashed 2018 financial targets**. Instead of $2 a share, GE projected $1 to $1.07; it now expects to be at the lower end of that range. **Gone now are most of Mr. Immelt's team**. "GE's customers, investors and employees want us to focus on the future. We are building a stronger, simpler GE," Mr. Flannery said in a statement. "In the last decade, the GE team built a number of excellent businesses."

Several directors discussed in November whether the entire board should be fired, according to people familiar with the meeting. Instead, what had been an 18-person board will lose half its members but add three new directors in coming months.

Mr. Immelt's predecessor, Jack Welch, delivered steady profit growth in the 1980s and '90s. He **built a huge lending business called GE Capital** that generated **outsize profits** – **but nearly sank** the **company during** the **financial crisis on Mr. Immelt's watch**.

When **GE later sold most of GE Capital**, Mr. Immelt laid out a strategy in which industrial businesses would grow enough to offset the lost cash flow from the financial unit, so that long-term financial projections and the dividend were sustainable. Instead, **free cash flow wasn't enough to cover dividends for years**.

Mr. Immelt ramped up research spending and hired thousands of programmers to develop software for GE machinery. Results were strong at aviation and health care. But sales and profits slumped at the oil and power units.

Acquiring companies that help drillers pump and transport fuel, **GE spent** more than $14 billion over 10 years, most of it **based on higher oil prices than today's**.

GE's $10 billion deal for a **turbine rival closed just as that market was cooling**. This was a **2014** agreement to **acquire Alstom SA's power business**. Mr. Flannery favored the deal, in 2014 calling the power sector core to GE's future. Now the new CEO says the price was too high. The acquisition suffered in part because of an **18-month regulatory review in Europe**. **GE had to safeguard French jobs and shed certain assets**.

Some in the leadership at GE wondered if it should drop the deal. Mr. Immelt and power division leaders were determined to close the transaction, people familiar with the decision said.

Defenders of the deal say it gave GE a much larger base of customers for its services and provided technology to produce a more efficient gas turbine. While the timing wasn't ideal, said one person close to the transaction, the company couldn't control when such assets became available.

"When the EU delayed the deal, GE should have walked away," said Scott Davis, an analyst at Melius Research. "The fatal move, however, was how GE acted after the deal closed."

Rather than using his unit's greater size to raise prices, **GE Power's then-CEO Steve Bolze moved to gain market share, undercutting rivals such as Siemens** AG **to win sales for GE's biggest gas turbines**, analysts say.

At the time, Mr. **Bolze** was among those **competing** to **be the next head of GE.** He was bullish on the power unit's prospects in March 2017 but warned of possible volatility. "I am not naive on the market," Mr. Bolze said at an investor meeting that month, predicting a flat market for the biggest turbines. In June, days after losing out for GE's top job, Mr. Bolze said he would leave.

It wasn't until a meeting in September that the board learned the depths of the problems at the division, which accounts for 30% of GE's approximately $122 billion in annual revenue. **GE Power was sitting on** too much **unsold inventory** and was **discounting** deals **to hit sales projections**.

Mr. **Immelt**'s optimism was part of the problem, according to some people close to the situation. They said he **told** the **board** that management had identified **risks in** the **power business**, **yet downplayed them**. The probability and risk were way off, one said.

Mr. Immelt's spokesman said the board and executive team were informed of the company performance and were involved in setting financial targets.

Orders in the **power division dropped 25%** in the **fourth quarter of 2017** from a year earlier, and the unit's **profits** for the full year **fell by nearly half to $2.8 billion**. In December, GE said it would **cut 12,000 jobs** in the power business, or **nearly 18% of the division's workforce**, and it has **replaced much of** the **management of** the **unit**.

Lisa Davis, the U.S. chief **of Siemens**, said the German company's executives "have **seen** this **decline coming** for the last several years." So Siemens had **reduced** its **capacity in** its **power business**, she said, **while GE bought more**.

GE also had been selling **upgrades** to **make existing gas turbines run more efficiently**. As recently as July, it was **telling investors** it would sell as many as **165** so-called **advanced gas path**, or **AGP**, **upgrades** in **2017**. In October, the company **cut** that **target in half**, and it said it expects to sell **just 40 upgrades in 2018**.

"I led GE through multiple industry cycles, 9/11, recessions, and the global financial crisis. My leadership team always focused on the task at hand," Mr. Immelt, 62 years old, said in a written statement. "Because we had a culture of debate and external competitiveness, GE built a set of industrial businesses that lead in their markets."

At a conference in November, Mr. Immelt said he was "fully confident that this company is going to thrive in the future."

A spokesman for the former CEO pointed to his decision to purchase $8 million worth of GE shares in 2016 and 2017. That included 100,000 shares in mid-May at a price roughly twice today's.

Former GE Chief Financial Officer Keith Sherin said Mr. Immelt would methodically approach a problem with his team, consider multiple viewpoints and communicate regularly with the board. "I never found him to be overly optimistic," said Mr. Sherin.

Some analysts have expressed concern GE's accounting for the upgrades masked pressure on the division. Ac-cording to former executives, the upgrades meant lower service fees for customers, in exchange for one-time upgrade costs, meaning that **future sales were being pulled forward**.

SEC Inquiry

GE disclosed last month that the **Securities and Exchange Commission** is **examining** its **revenue recognition practices around** such **contracts**. The agency **also** is seeking information about a **recent GE review** of its **insurance business** that **prompted a $6.2 billion fourth-quarter charge** and a **plan** to **set aside $15 billion over seven years** to **bolster in-surance reserves** at the **now-shrunken GE Capital** unit.

GE said it is cooperating with the inquiries. The SEC declined to comment. It's clear more changes are in store, for both employees and investors. Last month, Mr. Flannery said he was examining whether to separate some of GE's core units. That was a sharp contrast to one of Mr. Immelt's last predictions. "I view 2017 as the last big restructuring year in the company," Mr. Immelt said at the conference in Sarasota in May. "So this noise is going to kind of come out of the system."

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Harvard, Hawaii Gambled on Market Calm—Then Everything Changed

by Gregory Zuckerman, Gunjan Banerji and Heather Gillers – WSJ – Feb. 14, 2018

Harvard, Hawaii and others, pressed to improve returns, made risky bets that depended on low stock-market volatility.

Left: Traders at NYSE, Feb 8, 2018.

A **decade** of **low bond yields pushed some** of the most **stability-minded investors to dabble in risky investments that depended on markets being orderly**. **Now**, **those bets are looking problematic**.

In the past, pension funds, endowments and family offices pursued relatively safe investments. After interest rates collapsed on the heels of the financial crisis, they ran into challenges paying pensioners and filling university budgets, and added riskier bets on hedge funds and venture capital in the hopes of winning better returns.

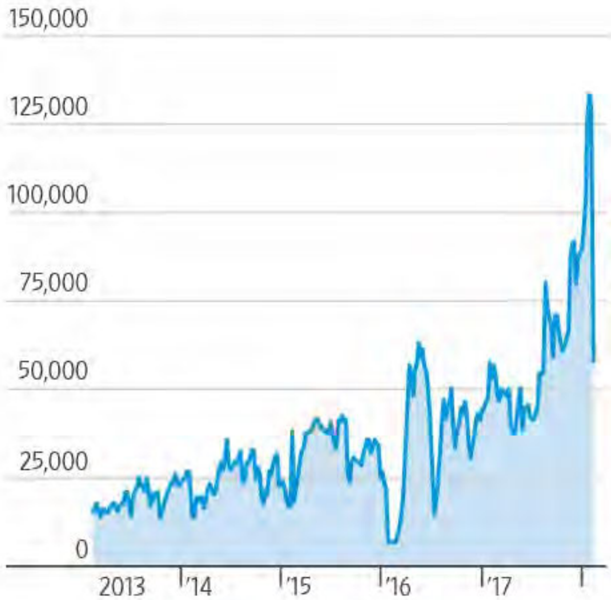
More recently, some of these investors also made **big, unpublicized wagers** seeking to benefit from what had been an unusually long period of low volatility, according to pension-fund consultants and others who deal with these institutions. The strategies, often involving the writing of complicated options contracts, were **for years** a source of **easy money**. Markets hadn't been so calm since the 1950s.

Among those making such bets were **Harvard University's endowment**, the **Employees' Retirement System of the State of Hawaii** and the **Illinois State Universities Retirement System**.

Yet volatility has now returned to markets, with a vengeance. When the Dow Jones Industrial Average lost more than 2,400 points in a week, intraday market swings also surged. The **Cboe Volatility Index**, or **VIX**, a measure of expected swings in the S&P 500, closed at its highest level last week since August 2015, **recording** its **biggest one-day jump ever** on **Feb. 5** as it surged to 37.32 from 17.31 the prior day.

Betting Against Fear

The number of bets against volatility, as measured by the Cboe Volatility Index, held by asset managers, including pensions, endowments and others



Note: Includes futures and options

Source: FactSet

The **$16.9 billion Hawaii fund in 2016 began** earning money **selling** "**put**" **options**—essentially a **bet** that **markets would stay calm or rise**. When markets fall, **Hawaii is on** the **hook to pay out**.

"We've taken some losses that you'd expect with these sharp moves," said Vijoy Chattergy, the fund's chief investment officer, on Feb. 8. He also said "they're within expectations."

For now, investors express confidence these strategies will work out. Others in the market, however, worry that any additional turmoil could spur institutions to quit their "**low-vol**" **strategies**. "Our fear is when these strategies unwind," said Alberto Gallo, a portfolio manager at Algebris Investments in London.

Mr. Gallo estimates more than $500 billion of investment strategies globally are dependent on volatility remaining low. These trades include funds that target or sell volatility by using various derivatives.

The rise of low-volatility bets is among the reasons this downturn is different, investors say, and difficult to predict. Some trades are hard to track. It's also challenging to quantify how much money is in investments betting against volatility or dependent on placid markets. One thing seems certain: with central banks gradually withdrawing their support for the market, the **subdued calm of recent years is unlikely to return**.

Wagers on low volatility vary by investor. In one popular move, investors bought two exchange-traded products that bet on continued stability for stocks—the ProShares

Short VIX Short-Term Futures exchange-traded fund and the VelocityShares Daily Inverse VIX Short-Term exchange-traded note. These were a wager that the key volatility index would fall and stay low.

Together, these funds managed $4 billion until the recent market turbulence, with much of that money coming from the likes of big investors such as **Harvard University. Harvard's endowment**, Harvard Management Co., **owned over 100,000 shares of the ProShares Short VIX fund** as of the **end of** the **third quarter of 2017**, filings with the Securities and Exchange Commission show. Its fourth-quarter filing indicate it **sold** the **position**, though Harvard's current holdings are unclear.

Left: Harry Elkins Widener Memorial Library in Harvard Yard in Cambridge, Mass.

"There's a tsunami of money going into" these types of strategies, said Don Dale, a managing member of consultant Equity Risk Control Group. The firm advises large pension funds and endowments.

Pension funds, endowments and family offices took other steps, including selling VIX futures and options, selling options on the S&P 500 or other indexes and selling options on individual shares or other indexes.

"The **low-return environment** pushes **people into investments** they **wouldn't have made eight to 10 years ago**," said David Morehead, Senior Director of Investments at Baylor University's endowment. "While institutions may not be explicitly trading volatility, more have been pushed into assets with lower quality, higher leverage, and more illiquidity."

Donald Pierce, the chief investment officer of the $9.3 billion San Bernardino County Employees' Retirement Association, has been trading volatility for about six years, most recently by buying options on stock indexes, often with trades equivalent to about $300 million of risk for the plan.

Sometimes, Mr. Pierce buys products betting on rising volatility. Other times he sells these products, depending on his view of where U.S., Japanese, Russian, Brazilian and other markets are headed. Mr. Pierce says his trading has saved the county millions recently and that he will continue to make volatility trades.

"We take an opportunistic approach," he said. "For us, it's a substitute for equities."

Other pensions take more one-way bets, including the Hawaii pension system. The put options it began selling in 2016 give holders the right, but not the obligation, to sell stocks at a certain level. When markets are calm, Hawaii receives a check each month from whoever is buying a put option. If markets fall, whoever bought the put can collect.

The fund's Mr. Chattergy, while worried about an extended downturn, says Hawaii has taken steps to mitigate losses. He said Hawaii will continue to sell these put contracts, convinced the income will offset market turbulence. "We're continuing to trade the strategy."

The **low-vol trade** has **worked** every year **since** markets began rebounding in early **2009**. **Until last Monday**, the **S&P 500 had enjoyed 404 consecutive trading days without a 5% correction, the longest such streak since September 1959**, according to Bianco Research LLC. The average close of the Cboe Volatility Index was 11.09 last year, the lowest average on record going back to 1990.

Many **big investors** who flocked to these products have been **under unique pressures to generate returns**. **Pension funds across** the **U.S. typically need to earn 7% to 8% each year to meet obligations**. In the **past decade**, they have **struggled** to **meet** that **target**, while their **total assets have fallen as retirement payouts** have **increased**.

As a **result**, **many** have lowered their bond holdings and **turned to** real estate, commodities, hedge funds and private-equity holdings. These so-called **alternative investments** rose to 26% of holdings at about 150 of the biggest U.S. funds in 2016, compared with 7% more than a decade earlier, according to the Public Plans Database, which is run by a group of nonprofits.

Bond holdings by major public pension plans fell to 21.09% in December 2017 from 25.32% in December 2007, according to Wilshire Trust Universe Comparison Service.

More recently, the **army of consulting firms** that advise pension funds, such as Wilshire Consulting, has **recommended** some **public**-**pension**-**fund clients write put contracts**. As recently as 2013, hardly any public pension funds used this strategy, according to Wilshire Consulting President Andrew Junkin. He estimated more than 60 of the nation's more than 6,000 pension funds now do.

A growing number of Wall Street firms have been selling volatility-related strategies to pension funds and other big investors. Neuberger Berman's U.S. Equity Index PutWrite Strategy sells puts on stock indexes. Part of the value of a put relates to the volatility of underlying stocks. By selling the puts, the fund aims to generate steady income in stable markets.

In a document prepared for an Illinois pension, the firm argued that behavioral biases in financial markets mean investors "ultimately overpay for protection." The Neuberger Berman options products have attracted about $3 billion over the past two years.

But the **strategy suffers losses when stocks fall**. So far this month, the fund has lost 4.37%, through Feb 12, though that tops a loss of 4.52% for its benchmark, a mix of puts on stock indexes and compares with a 5.90% loss for the S&P 500 through that date.

The Neuberger Berman products have outperformed their benchmarks in recent years and the firm notes the price for the puts rises when markets tumble, making the fund a lower-risk way to invest in stocks.

"The efficacy of these strategies manifests itself over months and quarters," said Doug Kramer, who oversees the strategy at Neuberger. "Everything's functioning as designed. We're happy to have higher volatility and be able to underwrite higher option premiums."

Public pension plans including the Illinois State Universities Retirement System have invested in these products. Illinois SURS declined to be interviewed for this article.

The market's rebound over the past few days has sparked a new round of investments in some of the riskiest of the volatility trades. The **ProShares Short VIX fund, which posted a 97% drop in net asset value last week** from its high price in January, has since rebounded — even though volatility indexes such as the one the fund is designed to track can have outsize moves, and likely would see heavy losses and face possible liquidation if volatility spikes again.

On Tuesday, it closed at $11.29, up from a low of $9.58 on Feb. 8, and its market value is now nearly $800 million, up from $300 million just last week.

“**People are jumping back into this product again**,” said Pav Sethi, chief investment officer of Gladius Capital Management, an investment firm focused on volatility strategies, “**despite the clear structural risks**.”

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Bond Yields Hurt High-Dividend Stocks

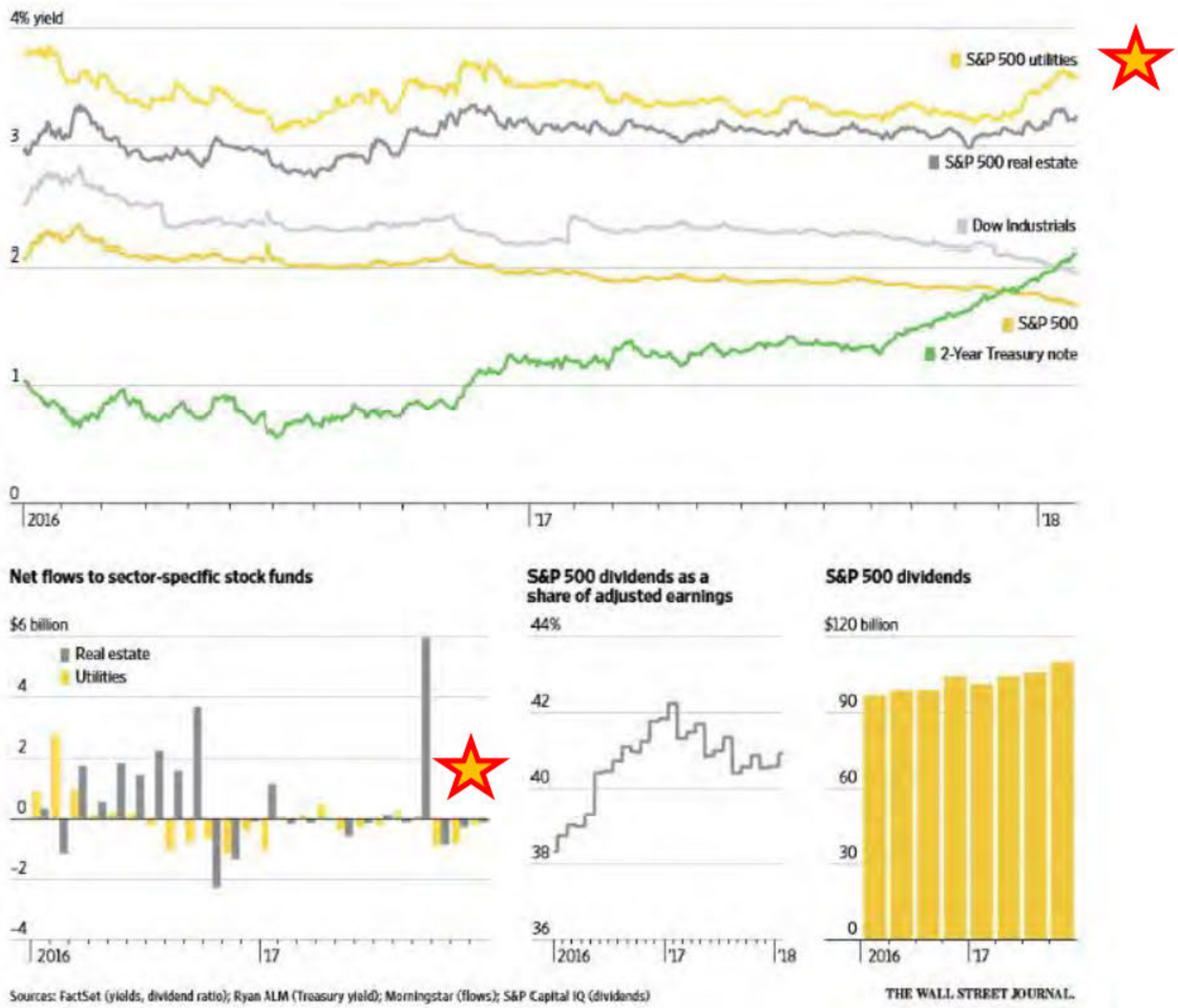
by Ben Eisen – WSJ – Jan. 31, 2018

Fed’s course change is pushing many investors out of shares that benefit from low rates, such as utilities and real-estate firms.

Rising bond yields are **starting** to **compete with stocks that pay** some of the **biggest dividends**, **leaving these companies behind** even **as** the **stock market** has **rallied** to **new highs**.

The **S& P utilities sector** is **down** about **10% since** the **end** of **November** and the real-estate sector has fallen 4.9%, **sharply underperforming the S& P 500’s 6.6% rise**. Companies in both groupings typically pay out big dividends relative to their stock prices, giving them high dividend yields.

For years, **investors poured money into high**-**dividend stocks** as they **sought** investment **income that outpaced super low yields in** the **bond market**, which were held down by the Federal Reserve’s low-rate policy. **But** the **central bank** is **reversing course**, **leading to** a **rise** in **bond yields** that has **accelerated** in **recent days**.



The **two-year U.S. Treasury note yield**, which **rose to a nine-year high of 2.124%** on Tuesday, **now** offers **more compensation than** the **S&P 500 dividend yield, which was at 1.69% this week**, or the Dow Jones Industrial Average's dividend yield, at 1.97%.

That bond yield, a benchmark for short-term debt, **still trails the average dividend yields offered by S& P utilities** and real-estate companies, but investors say rising rates are playing a key role in driving money out of riskier income plays and into the bond market.

"A lot of investors would be very content investing in the two-year Treasury given that they're getting over 2% now," said Andrew Pace, a vice president at Performance Trust Capital Partners LLC, a fixed income trading firm.

Rising yields stand to make it more expensive for a wide swath of borrowers, from corporations to homeowners, and traders say they were a big reason why stocks fell Tuesday.

The S&P 500 slid 1.1% Tuesday, its worst day since August. Investors have turned more cautious on stocks in recent days after a strong start to the year. Dividend stocks were mixed Tuesday. The utilities sector rose 0.2%, while the real-estate grouping fell 0.5%.

The **Fed** has penciled in three increases to its benchmark policy rate this year, but some investors believe the pace could speed up if inflation, long missing from the economic recovery, starts to rise. For much of the past five years, consumer prices have increased at less than 2% a year, the central bank's target, but have recently shown signs of picking up. Now, traders in the federal-funds futures market see a nearly 25% probability of at least four rate increases this year, according to CME Group data. That is **pushing many investors out of stocks that benefit from low rates**, and **into those expected to benefit from faster inflation and economic growth**.

Wall Street strategists, including those at **Bank of America Merrill Lynch, recently recommended investors have a smaller allocation to utilities** and real estate than their benchmarks.

"As a group of companies, dividend-yielding stocks are likely to underperform," said Anik Sen, global head of equities for PineBridge Investments. The firm has been underweight the broad real estate and utilities sectors for a few years, though it believes some individual names could continue to perform well.

Meanwhile, investors say they are chasing sectors most likely to see a profit boost from the recent corporate-tax overhaul, which lowers the corporate tax rate to 21% from 35%. Big banks and other financial institutions, for example, have said they expect to become more profitable over time due partly to the lower tax rate. They are also set to bring back cash they currently hold overseas, which they may use, in part, to increase dividends and share repurchases. The S& P 500 financial sector is up 8.2% since the end of November.

While utilities and real estate aren't likely to benefit as much from the new tax law, the shift out of those sectors has been slow. Investors pulled money from mutual funds and exchange-traded funds that invest in utilities stocks for seven out of 12 months last year, with net outflows totaling nearly $3 billion. They withdrew money from real-estate funds in nine of the months in 2017, but a large inflow in September pushed net flows positive, according to Morningstar data.

Over the past year, Matt Quinlan, portfolio manager of the Franklin Equity Income Fund, has reduced his exposure to some sectors that already offer high dividends while investing in stocks such as industrial and financial companies whose fundamental growth could reward shareholders with higher dividends down the road. "We're focused on companies growing their dividends," he said.

Higher Yields and Lower Equities Might Yet Swell Credit Risk

by John Lonski, Chief Economist, Moody's Capital Markets Research, Inc.
Feb. 1, 2018

It has been a volatile week for financial markets. After shrugging off an earlier ascent by the 10-year Treasury yield from year-end 2017's 2.41% to January 26's 2.66% and advancing by 7.1%, the market value of U.S. common stock has since sunk by 1.6% in reaction to a climb by the 10-year Treasury yield to 2.77%.

The deeper post-January 26 drop of 3.7% by the interest-sensitive PHLX index of housing-sector share prices underscores the importance of higher Treasury bond yields to the latest retreat by equities. Earlier, or from year-end 2017 through January 26, the index of housing sector share prices was up by 4.9%, which trailed the accompanying advance by the overall equity market.

Unlike equities, the dollar-denominated corporate bond market has been reasonably well behaved. Most investment-grade bond yield spreads narrowed during last week's equity sell-off.

The recent 141 basis points spread of Moody's Investors Service's long-term Baa industrial company bond yield average was less than each of its prior month-long averages going back to the 132 bp of February 2005, or just before the breakout of troubling developments pertaining to Detroit's big three automakers. Nevertheless, January 2018's estimated $141 billion of dollar-denominated investment-grade bond issuance was down by 27% from January 2017's pace.

Though the yield spreads of dollar-denominated high-yield bonds widened somewhat from their January 26 close, the latest 329 bp spread of a high-yield composite was thinner than each of its previous month long averages going back to the 277 bp of June 2007. However, since January 26, only three dollar denominated high-yield bonds have been issued raising $2.1 billion. The latter two measures are disproportionately small compared January 2018's 81 new high-yield bond offerings that secured $44.0 billion. Still, January 2018's month-long dollar amount of high-yield bond offerings shot up by nearly 21% from January 2017's tally.

The near disappearance of high-yield bond offerings amid the equity market turmoil of late January warns of diminished systemic liquidity if any forthcoming climb by interest rates roils earnings-sensitive financial markets.

Capital Spending Will Determine the Efficacy of Tax Reform Measures

Supply-side economics will be put to the test over the next couple of years. **Seldom, if ever before, have policy changes gone to such great lengths to spur business capital spending with the ultimate intent of rejuvenating labor productivity**.

Taken together, the drop in the top corporate income tax rate to 21%, the **immediate expensing of capital outlays**, and **new tax incentives aimed at repatriating overseas cash may keep real capital spending's 10-year average annual growth rate above its long-term average of 4% indefinitely**.

Not only is the recent top **corporate income tax rate** of **21%** the **lowest since 1939**, but **never before** has the corporate income tax rate been immediately **cut** be something **as deep as** the **14 percentage point drop from the 35% rate that held** from **1993 through 2017**.

Figure 1: Drop in Top Corporate Income Tax Rate to 21%, Immediate Expensing of Capital Outlays, and Repatriation of Overseas Cash May Keep Real Capital Spending's 10-year Average Annual Growth Rate Above Long-Term Average of 4%
source: Bureau of Economic Analysis

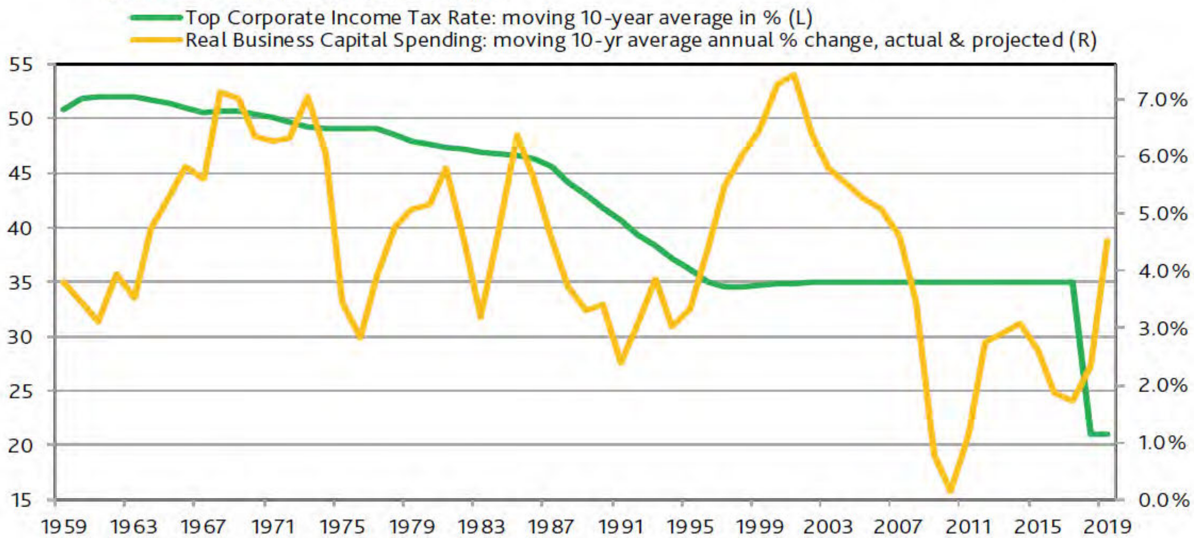
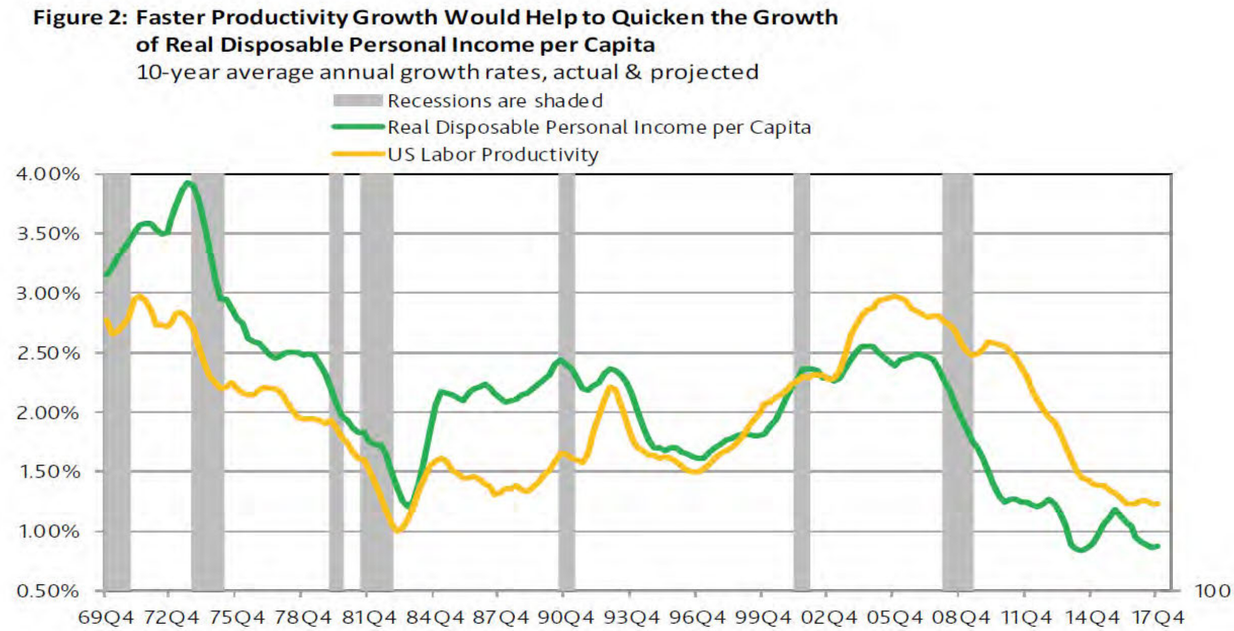
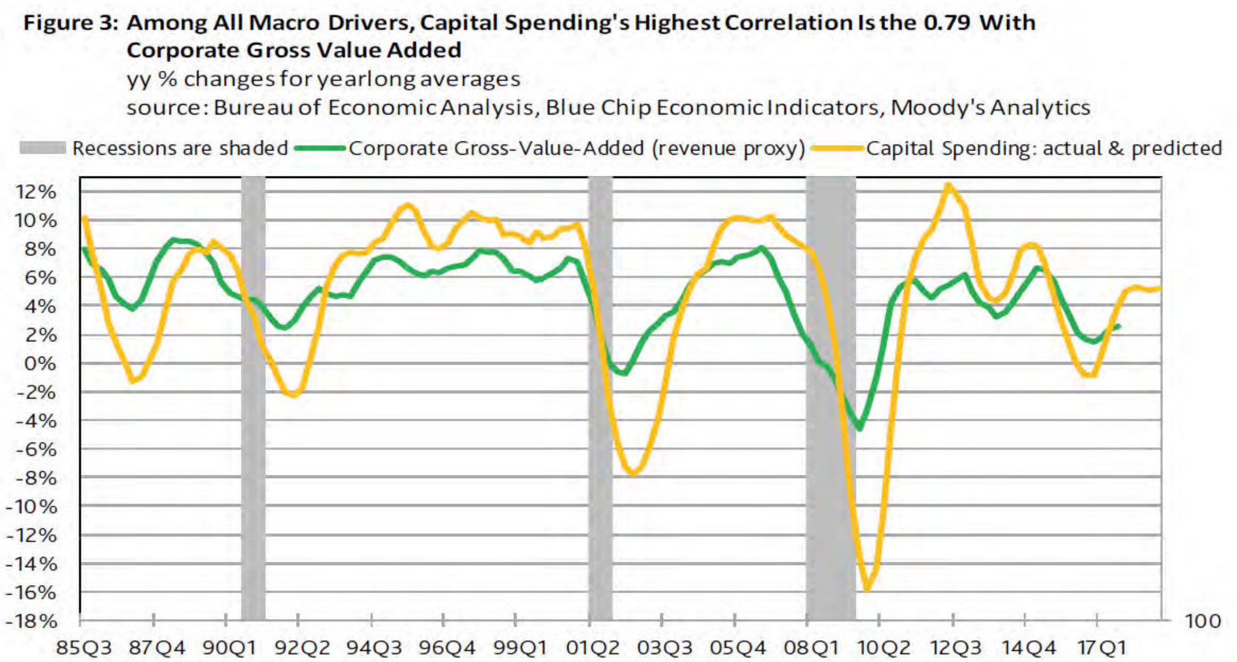


Figure 1 shows how the cutting of the corporate income tax rate from **1986's 46% to 1988's 34% ultimately helped supply a major lift to the trend rate of growth of real business investment spending**, which in turn **quickened labor productivity's 10-year average annualized rate of growth from the 1.0% of 1983 to the 2.2% of 1992**. More recently, a slowdown by productivity's 10-year average annual growth rate from 2007's 2.8% to 2017's 1.2% was joined by a deceleration for the comparably measured growth rate of real disposable personal income per capita from 2.4% to 0.9%, respectively.



Revenue Outlooks Will Influence the Composition of Capital Outlays

However, the record indicates that an extended and substantial upturn by capital expenditures **requires firmly held expectations of sufficiently rapid growth by corporate revenues**. The record shows that the **growth of corporate gross value added, or corporate revenues net of materials, generates the strongest correlation with the growth of capital outlays among all conceivable macroeconomic drivers**. **To the degree businesses** are **unsure of future revenues**, increases in capital expenditures are likely to be directed more toward **cost-cutting and** enhanced **product quality**, as opposed to an expansion of production capabilities.



The Supply of Tradable Treasury Debt Is About to Soar

Thus far, 2018 has brought attention to the **upward pressure** that will be put on **Treasury bond yields** by both a forthcoming increase in **fiscal stimulus and** a scheduled **reduction** in the **Federal Reserve's holdings of U.S. Treasury notes and bonds**.

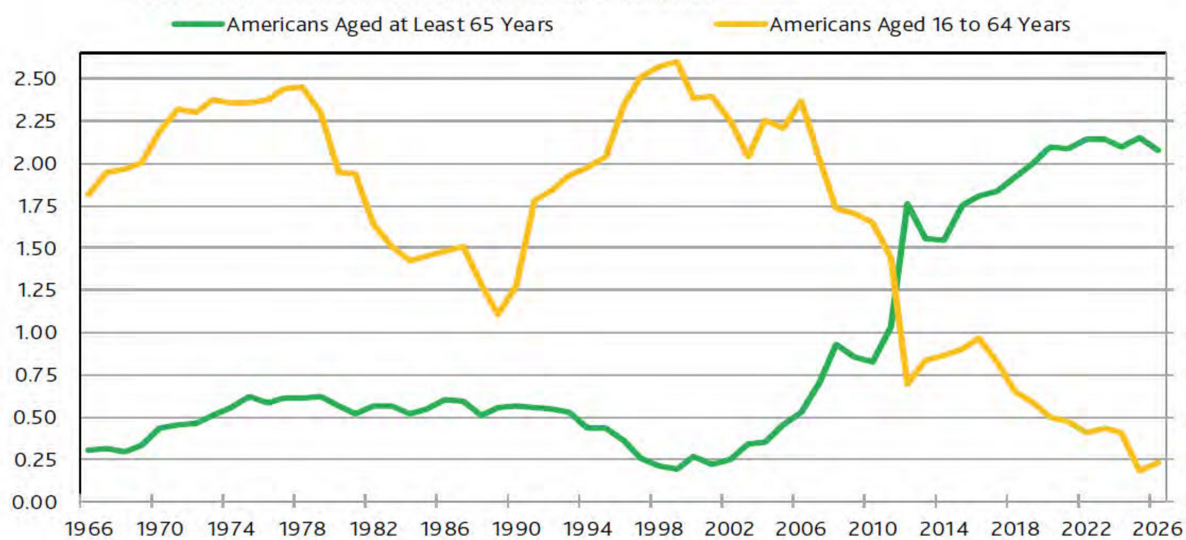
According to one estimate, the **increase in marketable treasury securities** will more than **double** from just under **$500 billion in fiscal-year 2017** to **nearly $1.2 trillion in FY 2018**. Perhaps not since the Second World War has the supply of tradable U.S. Treasury debt increased by so great of an amount relative to GDP in the context of well-established economic recovery. **Conceivably**, if the recent and possibly forthcoming climb by Treasury yields destabilizes the equity and corporate bond markets or shrinks interest-sensitive activity, the **Fed might be compelled to downsize** the **planned reduction** of its **Treasury bond holdings**.

Even before the recently enacted tax cuts, a record increase in the **number of retirees** was expected to widen the federal budget deficit via an increase in mandatory outlays on Social Security and Medicare.

Unprecedented demographic change will influence financial markets and business activity during the next 10 years. The average annual increase in the number of Americans aged at least 65 years is expected to soar from the **351,000 per annum** of the **10-years-ended 2007 to 1.8 million per annum** for the **next 10-years**.

Adding to the difficulty of funding the retirement of so many individuals is the accompanying **plunge in** the **average annual increase in the number of people aged 16 to 64 years** (or the **working-age population**) from the **2.3 million of the 10-years-ended 2007 to** the **416,000 of the 10-years-ended 2027**.

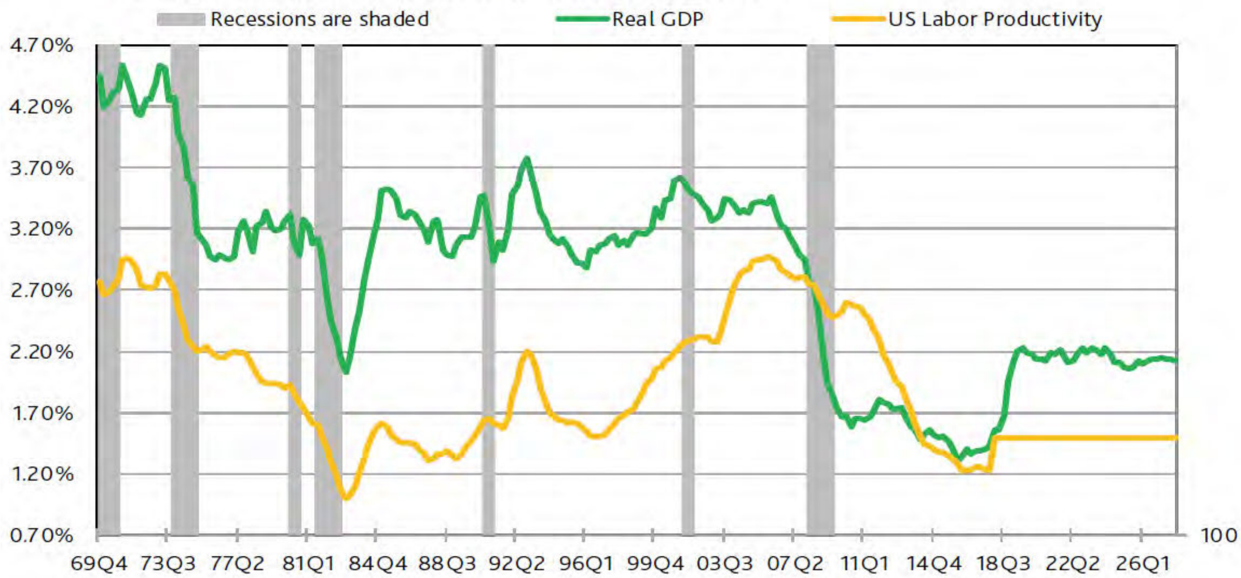
Figure 4: Profound Shift in Age Distribution of US Population May Influence Markets and Business Activity for Years to Come
actual & predicted annual change in millions of people
sources: US Bureau of the Census, Moody's Analytics



Productivity Growth is Key to the Future Pace of Business Activity

In view of how the **labor force is expected to grow no faster than 0.5% annually, on average, through 2027**, the return of **3% real GDP growth on a recurring basis requires the attainment of a 2.5% average annual rate of growth for labor productivity**. Though difficult to achieve, the good news is that the 10- year average annualized growth rate for labor productivity was at least 2.5% from 2003 through 2010 and from 1957 through 1973. Supply-side economics will emerge triumphant if productivity again grows by at least 2.5% annually on a recurring basis.

Figure 5: Real GDP's 10-year Average Annual Growth Rate Could Return to 3% if Productivity Grows by 2.5% on a Recurring Basis
10-year average annual growth rates, actual & projected



An Extended Sell-Off of Equities Amid Rising Treasury Bond Yields Will Eventually Swell Corporate Bond Yield Spreads.

By John Lonski, Chief Economist, Moody's Capital Markets Research Group
Jan. 25, 2018

Credit Spreads

As measured by Moody's long-term average corporate bond yield, the recent **investment grade corporate bond yield spread of 98 bp is far under its 122-point mean of the two previous economic recoveries**. This spread is **more likely** to be **wider**, as opposed to narrower, a year from now.

The recent high-yield bond spread of 329 bp is less than what is inferred from the spread's macroeconomic drivers and the high-yield EDF metric. The adverse implications for liquidity of possibly significantly higher interest rates merit consideration.

Defaults

After setting its current cycle high at January 2017's 5.8%, the US high-yield default rate has since eased to the 3.3% of December 2017. Moody's Default and

Ratings Analytics team expects the default rate will average 2.4% in Q4-2018. A deeper slide to its 1.85% average of the 18-months-ended June 2015 is unlikely for now.

US Corporate Bond Issuance

Yearlong 2017's US$-denominated bond issuance rose by 6.8% annually for IG, to $1.508 trillion and soared by 33.0% to $453 billion for high yield. Across broad rating categories, 2017's newly rated bank loan programs from high-yield issuers sank by 26.2% to $72 billion for Baa, advanced by 50.6% to $319 billion for Ba, soared by 56.0% to $293 billion for programs graded single B, and increased by 28.1% to $25.5 billion for new loans rated Caa.

Fourth-quarter 2016's worldwide offerings of corporate bonds showed annual percent changes of -10.2% for IG and +24.9% for high-yield, wherein US$-denominated offerings fell by 8.5% for IG and advanced by 24.9% for high yield.

First-quarter 2017's worldwide offerings of corporate bonds showed annual percent increases of 7.7% for IG and 110.6% for high-yield, wherein US$-denominated offerings advanced by 17.1% for IG and by 98.3% for high yield.

Second-quarter 2017's worldwide offerings of corporate bonds showed an annual percent decline of 6.3% for IG and an increase of 8.3% for high-yield, wherein US$-denominated offerings fell by 6.4% for IG and grew by 5.8% for high yield.

Third-quarter 2017's worldwide offerings of corporate bonds showed an annual percent decline of 1.6% for IG and an increase of 6.6% for high-yield, wherein US$-denominated offerings dipped by 0.7% for IG and grew by 4.3% for high yield.

Fourth-quarter 2017 revealed year-over-year advances for worldwide offerings of corporate bonds of 17.6% for IG and 77.5% for high-yield, wherein US$-denominated offerings posted increases of 21.0% for IG and 56.7% for high yield.

For yearlong 2016, worldwide corporate bond offerings rose by 2.3% annually for IG (to $2.402 trillion) and sank by 7.8% for high yield (to $426 billion). For yearlong 2017 have worldwide corporate bond offerings increasing by 4.0% annually (to $2.499 trillion) for IG and advanced by 41.2% for high yield (to $602 billion).

The worldwide corporate bond offerings of 2018 are expected to show annual increases of 3.5% for IG and 2% for high yield.

The financing of acquisitions and shareholder compensation will stand out among 2016's uses of funds obtained via bond issues and newly-rated bank loan programs. **Companies will resort to acquisitions and divestitures in order to better cope with the US's subpar recovery**. **To the degree companies fear significantly higher bond yields, pre-fundings will rise**.

US Economic Outlook

The consensus expects that the mid-point for the federal funds rate should finish 2018 at 2.125%. In view of the considerable underutilization of the world's productive resources, low inflation should help to rein in Treasury bond yields. **As long as the global economy operates below trend, the 10-year Treasury yield**

may not remain above 2.7% for long. A fundamentally excessive climb by Treasury bond yields and a pronounced slowing by expenditures in dynamic emerging market countries are among the biggest threats to the adequacy of economic growth and credit spreads going forward.

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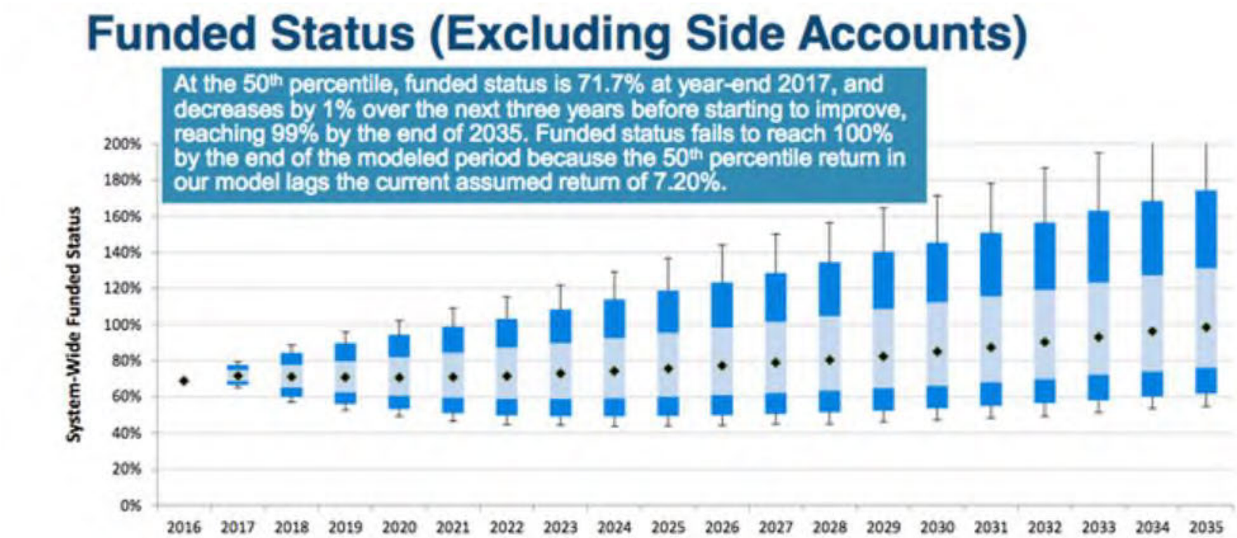
PERS Investment Returns Surged 15.3% in 2017, More than Twice Expectations

by Tec Sickinger – The Oregonian – Feb. 1, 2018

Thanks to a **red-hot stock market**, **Oregon's public pension system investment portfolio generated a 15.3 percent return last year**, more than double what was expected and **sufficient to lop $3 billion** or so **off** the **system's $25 billion unfunded liability**.

But it **wasn't enough** to head off another painful round of pension cost increases slated to hit government budgets in 2019.



		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
95th	–	68.7%	79.4%	88.6%	95.9%	102.2%	109.1%	115.4%	121.7%	129.3%	136.6%	144.1%	150.1%	156.3%	164.7%	171.3%	178.3%	186.8%	195.0%	204.6%	211.6%
90th		68.7%	77.6%	84.5%	89.6%	94.3%	99.0%	103.3%	108.2%	114.0%	118.8%	123.4%	128.7%	134.7%	140.2%	145.3%	150.8%	156.4%	163.1%	168.5%	174.3%
75th		68.7%	74.7%	77.6%	79.8%	82.0%	84.3%	87.2%	89.7%	92.5%	95.3%	98.3%	101.6%	104.8%	108.6%	112.3%	115.7%	119.2%	123.1%	127.4%	131.0%
50th	•	68.7%	71.7%	71.1%	70.8%	70.6%	70.9%	71.4%	72.9%	74.3%	75.6%	77.4%	79.0%	80.4%	82.4%	85.0%	87.5%	90.2%	93.1%	96.3%	98.6%
25th		68.7%	68.9%	65.3%	62.7%	60.7%	59.6%	59.0%	59.1%	59.5%	60.2%	61.1%	62.2%	63.6%	65.0%	66.1%	68.1%	69.9%	72.2%	74.3%	76.3%
10th		68.7%	66.6%	59.9%	56.1%	53.2%	51.0%	49.7%	49.0%	49.1%	49.3%	49.9%	50.6%	51.5%	52.4%	53.6%	54.9%	56.6%	58.0%	60.1%	61.7%
5th	–	68.7%	65.2%	57.1%	52.5%	49.3%	46.6%	44.6%	44.2%	43.8%	44.0%	44.0%	45.0%	45.1%	46.1%	47.2%	48.1%	49.3%	51.4%	53.7%	54.6%

Milliman

The Legislature will probably delay any serious conversation about changes to benefits, as it has for the past three years. **Gov. Kate Brown**, for one, says she's not ready to talk about the main benefit reform idea in circulation – reinstituting some level of employee contributions to the pension fund -- until 2019.

In the meantime, she has another plan, or **two plans** actually. The first would **redirect a slice of state revenues to offset the pension costs of K-12 schools, community colleges and universities**. The **second** involves **enticing** the 900 or so **public employers** who participate in the system to **shake** their **sofa cushions**, **identify** reserve **resources** and **deposit them** in **accounts at PERS**. In the process, they would be **gambling** that the **pension fund's investments** will **generate higher returns than** the **low** and **largely risk-free returns** those **dollars earn today** in the **short**- and **medium-term funds managed by the Oregon Treasury**.

Historically, that's been a **good bet**. **But** it's **no sure thing**.

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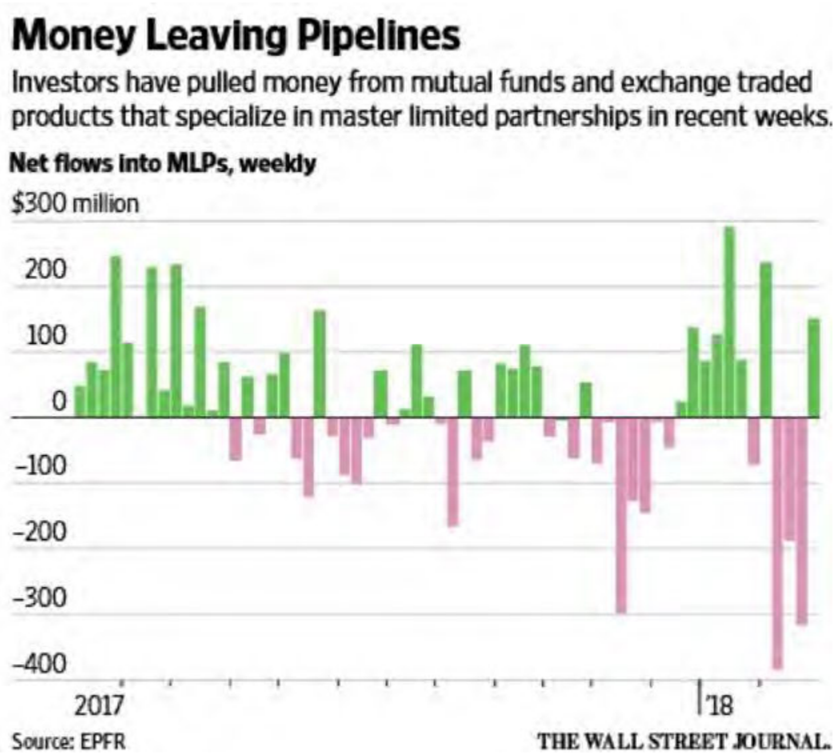
Pipeline Firms Are Dealt Tax Blow

by Alison Sider and Christopher M. Mathews – Mar. 16, 2018



Federal regulators eliminate certain allowances for master limited partnerships.

A **federal tax ruling dealt** a **new blow** to a **group of pipeline firms** that had **helped finance** a **massive build-out of energy infrastructure**, intensifying questions on Wall Street about the sector's survival.

The **decision** Thursday by the **F**ederal **E**nergy **R**egulatory **C**ommission to **disallow certain income**-**tax allowances** could hasten the demise of many socalled master limited partnerships, which were already on a lengthy losing streak.

The stocks of several pipeline- partnership companies plummeted after the announcement. Shares of Enbridge Energy Partners LP fell 17%, Spectra Energy Partners LP shares dropped 10%, while Williams Cos. and Energy Transfer Equity shares were down more than 10% before rebounding.

Once the **darlings** of the **energy sector because** they **essentially pay no corporate tax**, **such pipeline companies**, or **MLP**s, have lost luster as they have struggled to keep up with demand for growing payouts to investors and their parent companies. In response, some pipeline companies have begun converting older partnerships into traditional corporate structures.

The regulator's decision will chip away at some of the tax benefits that made these partnerships attractive in the first place. **FERC voted** to **reverse** a **longstanding policy** that **allowed interstate natural gas** and **oil pipelines configured as pass-through companies to collect corporate income-tax expenses from customers**.

The **FERC policy** has been **litigated for years** because **customers claim** it **allowed pipeline owners** to **essentially recover income-tax costs twice because regulators already allow partnerships** to **structure rates** to **ensure** a **sufficient after- tax return**. A **federal appeals court agreed with customers** in **2016** and **told FERC** to **examine** the **policy**.

Several big partnerships, including Enterprise Products Partners LP, Energy Transfer Partners LP, and Magellan Midstream Partners LP, said the change won't impact their bottom lines or the rates they charge. Analysts expect companies to appeal the decision.

Still, FERC's decision was the latest blow for a group of companies that investors had started to sour on.

"The sentiment in the group is terrible and this does not help," said Ethan Bellamy, an analyst at Robert W. Baird & Co.

Some analysts said the reaction by investors was overblown. Many newer pipelines have negotiated rates with customers that won't be affected by the change and a handful companies that own pipelines but aren't structured as partnerships also will be unaffected. The **majority of pipeline companies** are **MLPs**, with a **total market capitalization** of about **$350 billion**.

The firms' tax-advantaged structure and promises of large payouts helped draw billions of dollars of investment in pipelines and other energy infrastructure that was needed at the height of the shale boom, when companies were racing to bring the output from new oil and gas fields to market.

But the tide has started to shift.

The partnerships were marketed as the toll roads of the energy industry, and investors expected that their payouts would be insulated from volatile commodity prices.

It didn't work out that way. **Partnerships slashed their dividend**- like payouts during the oil rout that began in 2014. Investors who owned a portfolio of MLPs in 2014 would have had their distributions cut by a third since then, said Mr. Bellamy.

Retail investors who bought MLPs in the boom times are “fed up,” said Tyler Rosenlicht, who manages a portfolio of MLPs and infrastructure investments at Cohen & Steers, an investment firm.

Oil prices have stabilized at above $60 a barrel and companies are getting back to work drilling new wells, creating a need for more pipes. But the partnerships have languished. The Alerian MLP Index was one of the worst-performing assets last year – losing 6.5% on a total return basis compared with the nearly 22% that the S& P 500 returned.

Investors have pulled more than $500 million from funds and exchange-traded products that specialize in energy partnerships in recent weeks.

Thursday’s decision by FERC is likely to force many older pipelines to lower rates, say analysts, potentially making it more difficult to fund hundreds of billions in planned infrastructure projects.

Some companies, including Kinder Morgan Inc. and Oneok Inc. have done away with their partnerships converting them to traditional corporations.

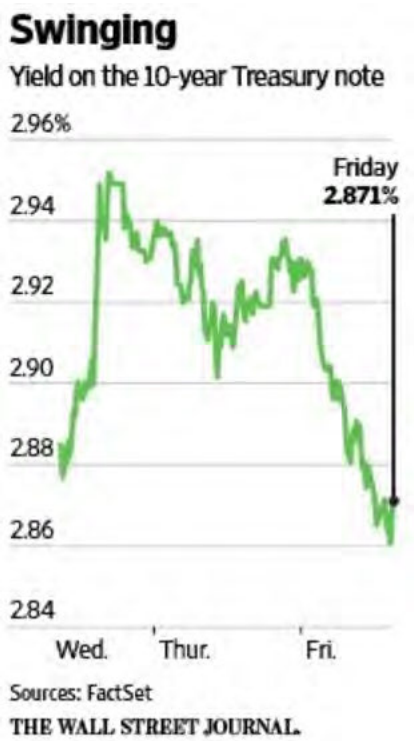
The **FERC decision will accelerate** the **conversion** of **older partnerships into traditional corporations**, according to Height Securities analyst Katie Bays. “No question about it, for older MLPs you’re going to see a more fast-paced transition,” she said.

Others say that even if retail investors maintain their chilly stance, the MLP structure isn’t going anywhere. More MLPs can now live within their means without infusions of cash from equity markets. Institutional investors and private equity backers have funneled money into the space.

“I don’t think the model is going away. I still think it’s an effective way to build critical infrastructure,” said Rob Thummel, who manages a portfolio of MLPs and other energy investments at Tortoise Capital Advisors. “If you have more production, you need more pipelines.”

Prices of Treasurys Advance

by Gunjan Banerji – WSJ – Feb 24, 2018



Government-bond prices strengthened Friday, capping off a **turbulent week**.

The yield on the benchmark 10-year Treasury note slipped for the second straight day to 2.871% from 2.917% Thursday. Yields fall as bond prices rise. The yield on the 10-year note hit a multiyear high earlier in the week before receding. Higher domestic yields alongside improvement in some European bonds may have led investors to buy U.S. government debt later in the week, analysts said.

"People are taking advantage of the higher yields that we haven't seen up here in" several years, said Brian Rehling, co-head of global fixed income strategy at Wells Fargo Investment Institute.

Investors also will be watching for more clues on interest- rate policy at Federal Reserve Chairman Jerome Powell's congressional testimony in the coming week.

Recent interest-rate volatility has spurred swings across asset classes, analysts say. The **Fed** released **minutes** from a January meeting this past week, **triggering swings in both stocks and bonds**.

The Treasury market could be tested again in coming weeks, Mr. Rehling said.

Treasury yields have risen in February as **solid economic and inflation data** have **led investors to sell government bonds**. **Inflation** is a **primary threat** to **Treasurys because** it **weakens** the **purchasing power of their fixed payments**.

Fed officials signaled growing confidence in the U.S. economy when they met in January. They supported the Fed's current rate path and could be a precursor to a more aggressive plan.

Investors also have built up a large amount of bearish bets on Treasury futures, according to Bank of America Merrill Lynch. Investors can tap Treasury futures to make directional bets or hedge other parts of their portfolios.

"**Extreme positions can be vulnerable to a rapid unwind**, which in this case could aggravate a rate rally," wrote **Bank of America Merrill Lynch** analysts in a Feb. 23 note.

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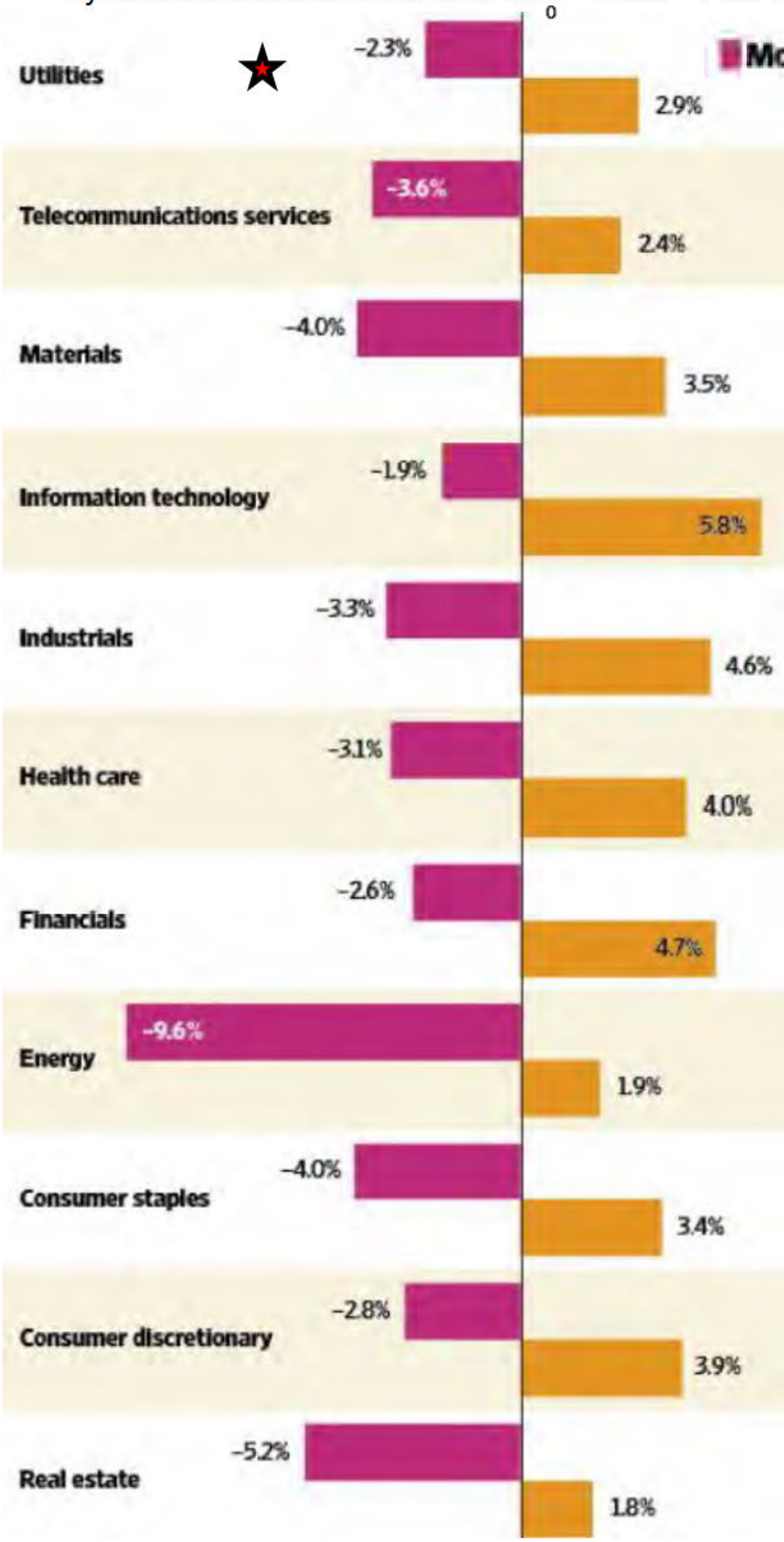
S&P 500 Notches Best Week since 2013

by Michael Wursthorn and Riva Gold – WSJ – Feb. 20, 2013



Financial markets stumbled in early February, raising fears the nine year old bull market for stocks was ending. This week brought a respite, stocks and oil rose, volatility fell and treasury yields were subdued. While the 11 sectors within the S&P 500 are still all down so far this month, the past week brought gains that were widespread with technology stocks leading the charge.

Source: FactSet, WSJ.

The Dow Jones Industrial Average and S&P 500 edged higher Friday to extend their rebounds as stocks showed firm signs of regaining their footing after tumbling earlier this month.

The blue-chip index gained 4.3% over the past five trading days to notch its best week since President Donald Trump's election, while the S& P 500's 4.3% move upward was its biggest weekly jump since 2013.

The indexes were on pace for an even bigger rally, but they pared gains – and the Nasdaq Composite turned lower – Friday afternoon when a Russian organization and several individuals were charged with interfering in the U.S. electoral process.

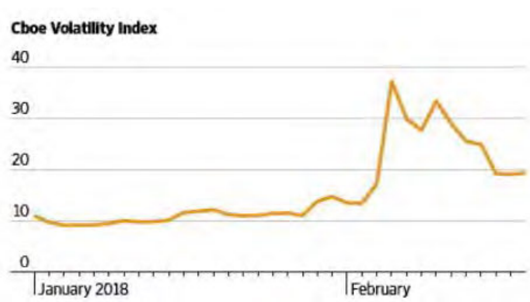
Still, the Nasdaq had risen enough earlier in the week to add 5.3%, its biggest weekly gain in seven years.

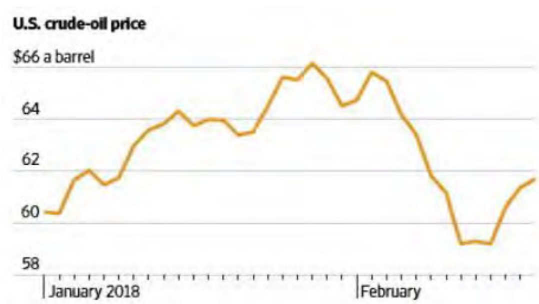
Jitters about the threat of faster inflation subsided this past week, as many investors said strong economic growth and robust corporate profits should support major indexes' move higher, similar to the sentiment for much of last year.

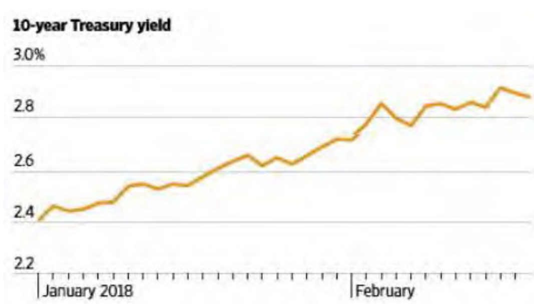
"With all the strong indicators, data points and earnings out there, **investors thought** it made sense that this should be a **buying opportunity**," said Joe Heider, president of Cirrus Wealth Management. Clients of the Cleveland-based firm have been buying small-cap stocks and adding international equities to their holdings, while largely avoiding any deep selling, he added.

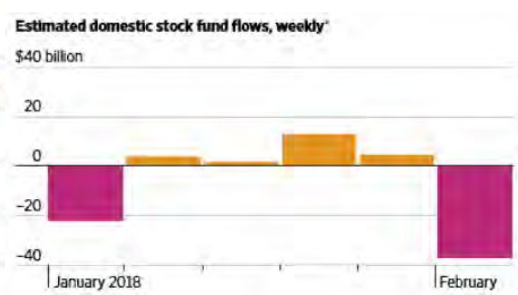
The Dow industrials added 19.01 points, or less than 0.1%, on Friday to 25219.38, after being up as much as 232 points earlier in the day. The S& P 500 gained 1.02 points, or less than 0.1%, to 2732.22, while the Nasdaq declined 16.96 points, or 0.2%, to 7239.47.

Earlier this month, stocks fell dramatically, pushing the Dow and the S& P 500 into correction territory after strong wage figures in the monthly U.S. jobs report suggested inflation had picked up. New data this past week further showed inflation is firming, with U.S. producer prices









Stocks and Spreads May Transcend Higher Treasury Yields

by John Lonski, Chief Economist
Moody's Capital Markets Research, Inc. – Jan. 11, 2018

Markets now focus on early 2018's climb by Treasury bond yields to heights last observed in March 2017. Though the 10-year U.S. Treasury yield climbed from year-end 2017's 2.41% to a recent 2.55%, the latter resembles the 2.6% average predicted for 2018's first quarter by the Blue Chip Financial consensus of late December 2017. Moreover, the 10-year Treasury yield still lags its 2.74% average of the six-months ended March 2014 that coincided with the taper tantrum.

During the height of the taper tantrum of late 2013 and early 2014, the 10-year Treasury yield rose to nearly 3%. Notwithstanding a jump by the average 10-year Treasury yield from the 1.81% of the six months-ended March 2013 to the 2.74% of the six-months-ended March 2014, the market value of U.S. common equity still advanced by 24.7% year over year. Moreover, the high-yield bond spread's moving six-month average narrowed from the 515 basis points of the six-months-ended March 2013 to the 398 bp of the six-months-ended March 2014. Thus, the prices of earnings-sensitive securities need not collapse if the 10-year Treasury yield again remains above 2.7%.

Richly Priced Shares Heighten Equities' Vulnerability to Higher Yields

However, there are some important differences between the six-months-ended March 2014 and today. First, today's equity market is more richly priced than that of the taper tantrum. During the six-months ended March 2014, the market value of U.S. common stock approximated 12.3 times after-tax profits. By contrast, the market value of equity was recently 16.0 times the value of after-tax profits. Intuitively, **the more richly priced equities are relative to profits, the greater is the risk of a drop by share prices in response to a climb by interest rates**.

Nevertheless, U.S. equities are now more reasonably priced compared to what held when 1998-2000's equity bubble began to deflate in March 2000. As of 2000's first quarter, the market value of common equity was valued at a stratospheric 24.5 times after-tax profits. Thus, first-quarter 2000's 150 bp year-over-year spike by the 10-year Treasury yield to 6.48% was all the more capable of bursting a grossly inflated equity bubble. And, after the bubble burst, a very long wait of nearly seven years would pass before equities returned to their March 2000 highs in December 2006.

By comparison, 1994's interest-rate inspired sell-off of equities was far milder. For one thing, the market value of U.S. common stock would quickly return to its peak of January 1994 by February 1995. Moreover, in terms of month-long averages, 1994's top-to-bottom drop by the market value of common stock was a relatively shallow 5.3% compared to the 42.8% peak-to-trough plummet of March 2000 through October 2002.

In a manner that warns against being too cavalier about the equity market's ability to withstand significantly higher interest rates, U.S. equities were valued at 13.2 times profits just prior to the start of 1994's sell-off, which was more attractive than the recent 16.0:1 ratio. **That** being **said**, provided higher interest rates do not adversely affect outlooks for profits and credit quality, **any forthcoming sell-off of equities is likely to be mild and short-lived**.

Sell-Off of 2015-2016 Was More Severe than 1994's Retreat

In all likelihood, an equity market correction that is primarily interest-rate driven will lack the severity of 2015-2016's market drop that was the offshoot of a contraction by profits and a jump by the expected default rate. After peaking in May 2015, the month-long average of common equity's market value then sank by a cumulative 12.9% until bottoming in February 2016. By August 2016, the market value of common stock had returned to its high of May 2015. Without question, 2015-2016's earnings and credit quality inspired sell-off was more severe than the interest-rate inspired reversal of 1994. Of special importance was how the ballooning of the high-yield bond spread from a May 2015 average of 451 bp to February 2016's peak of 836 bp differed radically from a decline by the high-yield spread's calendar average from 1993's 452 bp to 1994's 368 bp. Thus, **both** the **equity and corporate bond markets should survive largely intact if** the **10-year Treasury yield rises no higher than** the **2.9%** projected by the consensus **for 2018's final quarter.**

Moreover, if share prices are driven sharply lower by higher interest rates, chances are that the sell-off of equities will eventually help to steer interest rates lower. The current business cycle upturn shows 91 months in which the yearly change of the market value of common stock resides within the ongoing recovery. In only nine of the 91 months has the market value of equity declined from a year earlier, wherein seven of the nine months contained a yearly decline by the 10-year Treasury yield.

Wider Spreads Would Question the Durability of a Climb by Treasury Yields

After narrowing in each of the first six trading days of 2018, a composite high yield bond spread widened by 10 bp on January 10 in response to worry over a possible future diminution of systemic liquidity stemming from an extended climb by benchmark bond yields. An extended widening by corporate bond yield spreads would eventually help to reverse any climb by Treasury bond yields.

Meanwhile, the average expected default frequency metric of U.S./Canadian high-yield issuers set a new 32-month low of 3.41% on January 10. The latter was down from the 3.83% of three-months earlier and the 3.83% of a year earlier. The now declining trend of the average high-yield EDF metric complements expectations of a lower high-yield default rate. January-to-date's average high-yield EDF and its accompanying three-month decline favor a 451 bp midpoint for the high-yield bond spread, which is well above the actual 340 bp.

An ultra-low VIX index helps to explain why the actual high-yield spread is far narrower than what might be inferred from the average high-yield EDF metric. The VIX index's 9.54-point average of January-to date favors an exceptionally thin spread of 292 bp for the high-yield bond composite.

The composite high-yield bond spread now posts its narrowest readings since July 2014. It was in June 2014 that the high-yield spread's month-long average recorded its current cycle low of 331 bp. June 2014 also was home to month-long averages of

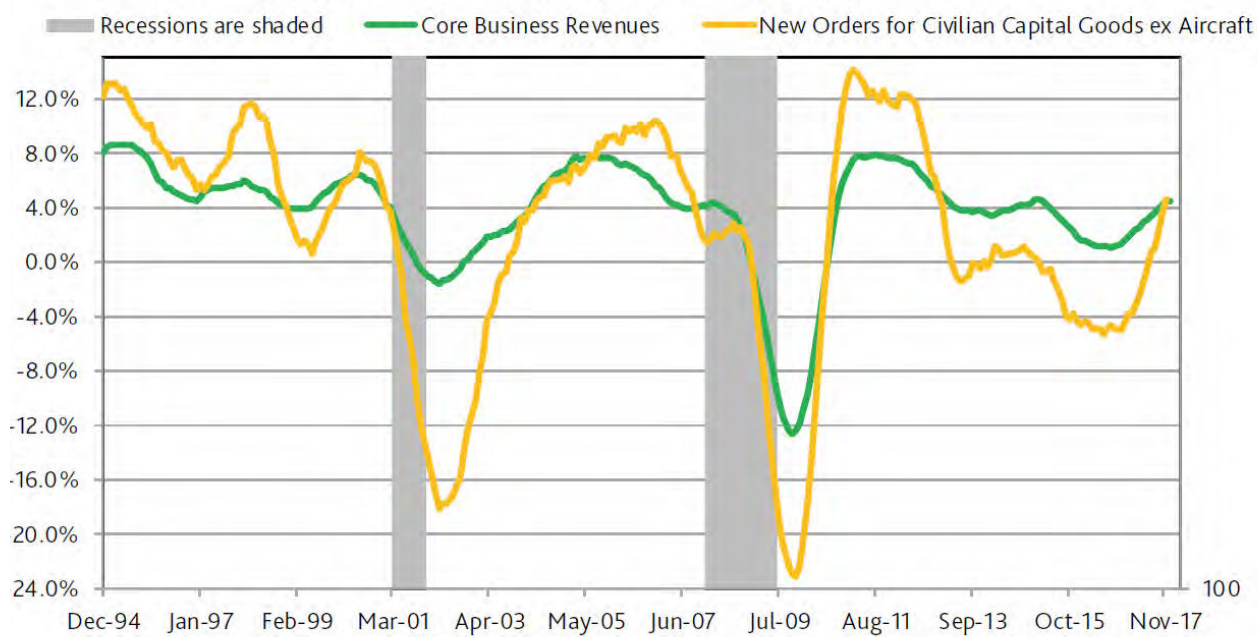
2.15% for the average high-yield EDF metric, 0.25% for the median high-yield EDF metric, and 11.5 points for the VIX index.

Livelier Business Sales Reinforce Capital Spending's Upbeat Outlook

The final quarter of 2017 is likely to reveal an unexpectedly brisk pace for core business revenues, where the latter excludes identifiable sales of energy products. Earlier, the annual increase of core business revenues had slowed from year-long 2014's 4.3% to 2015's 1.9% and 2016's 1.6%. Subsequently, the year-over-year growth of core business revenues accelerated to the 4.2% of both 2017's first and second quarters, the 4.3% of the third quarter, and the 5.5% of October-November 2017.

Accordingly, Q4-2017 should post the fastest yearly advance by core business revenues since the 5.2% of Q3-2014. In addition to the cutting of the top corporate income tax rate and the immediate expensing of capital outlays, the rejuvenation of core business revenues strengthens the case favoring a pronounced upturn by 2018's business capital expenditures. The record shows a strong correlation of 0.90 between the annual increases of new orders for nondefense capital goods and core business revenues.

Figure 1: Acceleration by Core Business Revenues Stokes Growth by New Orders for Nondefense Capital Goods ex Aircraft
yy % changes of moving 12-month averages whose correlation = 0.90
source: Bureau of the Census, Moody's Capital Markets Research Group



The faster pace of business sales also applies to small businesses. According to a December survey conducted by the National Federation of Independent Business, the net percent of small businesses reporting an increase in sales volume over the last three months jumped up to +9.0 percentage points for the best such score since the

+9.3 points of May 2006. Nevertheless, the sales-volume index's +1.6 points average of Q4-2017 was well under its +6.6 points average of Q2-2006.

The net percent of surveyed small businesses claiming a three-month increase by sales volume averaged +1.7 percentage points for all of 2017. In each of the 10 previous years, or 2007 through 2016, the sales volume index's annual average was less than zero, implying the percent of small businesses reporting a drop by sales volume exceeded the percent reporting an increase. Still, 2017's yearlong average for the sales volume index fell considerably short of its prior cycle highs which were 1988's record +11.5 points, the +6.8 points of both 1998 and 1999, and the +7.7 points of 2004.

Business Outlook Is Not Without Downside Risk

In conclusion, **business activity has improved** by **enough to improve outlooks** for profits and corporate credit quality. **However**, as long as expenditures drive the U.S.' rates of resource utilization higher, the **prudent investor should expect** a **rise** by **inflation** risks and **higher interest rates**.

Nevertheless, December's smaller than expected 148,000 new payroll jobs, the 6.8% increase by the initial state unemployment claims comparing the four-weeks ended January 6, 2018 to the contiguous four-weeks ended December 9, 2017, and November 2017's fewest job openings since May 2017 show that the **business outlook is not without downside risk**.

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Stocks Are Probably Overpriced, but Don't Be Too Sure

by Jason Zweig – WSJ Intelligent Investor Column – Feb 23, 2018

The more overvalued stocks have gotten, the better they have performed. That might not be over yet.

For years now, market strategists – and financial columnists, for that matter – have been warning investors to expect low returns. Nevertheless, stocks have delivered great results.

Over the **five years** through Thursday, the **S&P 500** has **earned** an **average** of **14.6% annually**, **including dividends**; in the **last 12 months**, it's **up 16.7%.** The louder the warnings became, the better stocks have performed.

In their latest survey of global investment returns, released this week, financial researchers Elroy Dimson of Cambridge Judge Business School, and Paul Marsh and Mike Staunton of London Business School explore why.

For starters, investors are human.

The shock and fear set off by the financial crisis, when stocks worldwide lost 58% after inflation from October 2007 through March 2009, left many investors traumatized.

The harder the fall, the harder it becomes to visualize a large and lasting recovery. Security analysts persistently underestimated how well the stock market would do after 2009 (see chart), pension funds cut their exposure to stocks and many individual investors turned pessimistic or sold outright.

The result was a **consensus** that we were **in for a long period of poor investment returns**.

Imagine the stock market as a hobgoblin bent on tormenting all those who blunder into his lair and try to make sense of him. By going way up, the market hobgoblin made fools out of the maximum number of people.

More importantly, **stocks did surprisingly well because interest rates went, and stayed, shockingly low**. **Until recently**, **rates across** the **world have been** at their **lowest levels in decades**, **often centuries**.

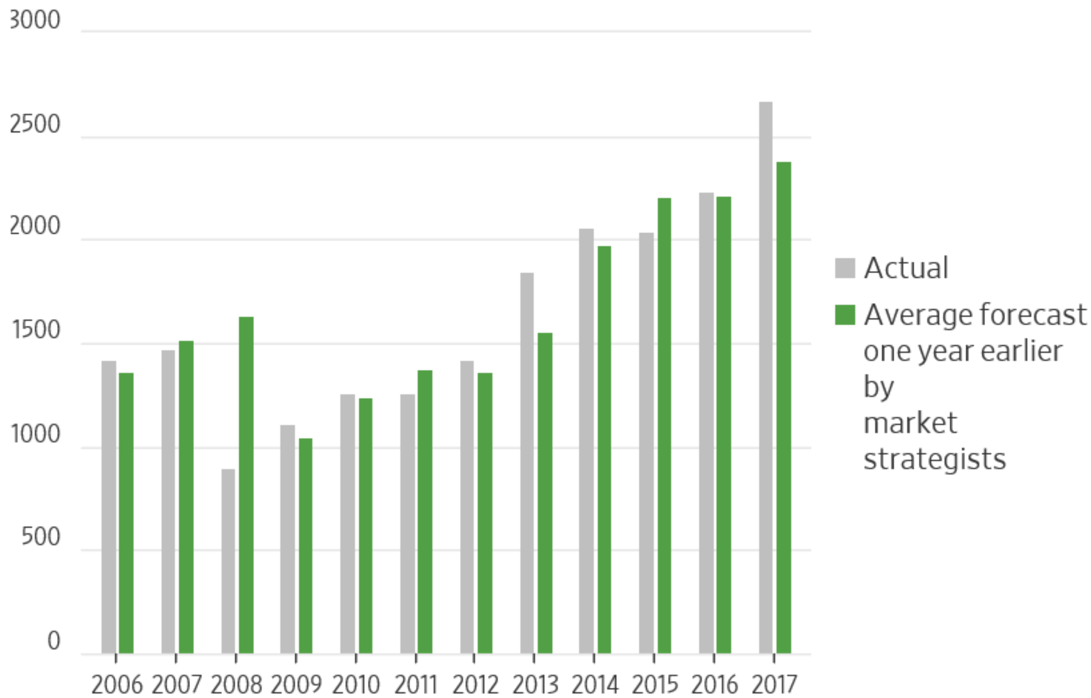
As interest rates fell, the cash that stocks would generate in the long-term future became more valuable than usual. Investors bid up stocks, bonds, real estate and almost all financial assets – even though most were already expensive by historical standards.

Now that interest rates have **begun** to **go up**, "**one cannot discount** the **possibility** that the **stock market might be overpriced**," Prof. Marsh says dryly.

Especially in the U.S., expectations of more good times are on the rise. Between Dec. 31 and Feb. 21, analysts' estimates for earnings on all the companies in the S&P 500 rose 7.1%, according to FactSet analyst John Butters – by far the biggest increase so early in the year for more than two decades.

Some of that may be a rational response to the change in corporate tax rates, which, as Warren Buffett said in a recent television interview, will effectively boost after-tax earnings by about 20%.

S&P 500 Year-End Index Level



Advisor Perspectives, a research and publishing firm in Lexington, Mass., recently conducted a survey of expected returns among investment advisers. Among the 505 who provided estimates, more than half expect large U.S. stocks to earn an average of at least 5% annually over the next decade. More than an eighth of these advisers expect stocks to return at least 8% annually. Even after adjusting for their average estimate of 2.7% inflation; that seems aggressive. (To be fair, many officials overseeing multi-billion-dollar pension funds make these folks look conservative.)

Unfortunately, there is no precision tool for predicting exactly when investors have lost their heads.

The **London Business School and Cambridge** researchers **studied** the **returns on stocks in 21 countries from 1900 through 2017**. You might expect unusually good years to be followed by patches of bad performance, and vice versa. Under realistic assumptions, however, **investors who bought after returns were high didn't do markedly worse in the long run than those who bought after returns were low**.

That's puzzling, but the puzzle is extremely old.

A new book by financial historian William Deringer of the Massachusetts Institute of Technology, "Calculated Values," shows that the tools for estimating what assets are worth had already assumed their modern form at least 300 years ago.

European and British investors and speculators in the early 1700s knew "how to value a share of future profits more or less the same" as financial analysts do today, Prof. Deringer says in an interview. The idea, then as now, was to **eliminate as much uncertainty as possible from** the **calculations**.

No formula, however, can subtract all surprises from the future. "There's only so much uncertainty any valuation measure can control," says Prof. Deringer, himself a former financial analyst. "You're always left with imprecise, qualitative assessments of something, and it's often the very thing that makes all the difference."

One reason stocks tend to **have high returns over** the **long term is to compensate investors for** the **risk of losing 50% or more in** the **short term**. **Another** is that there never has been, and probably **never** will be, a **foolproof way** of **telling exactly when that risk might materialize**.

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Stocks Are Moving in Tandem. That Can Be Scary

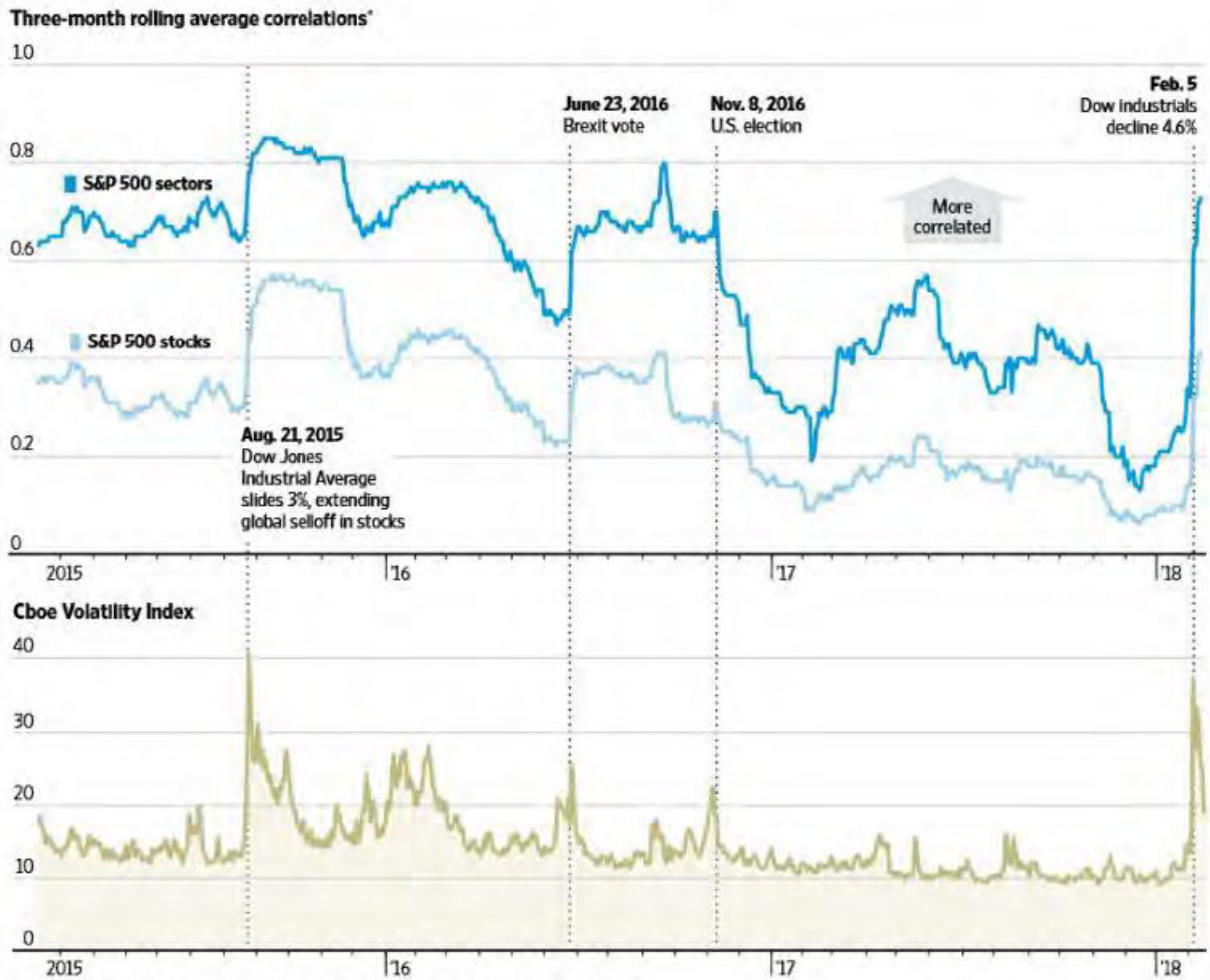
by Akane Otani – WSJ – Feb. 15, 2018

Correlations among the S&P 500's 11 sectors recently hit highest level since 2016 U.S. presidential election.

Left: S&P Climbed 4.6% over the past four sessions, rising each day since falling into correction territory.

Shares of **everything** from **manufacturers** to **banks** to **oil-production companies** are **rebounding together after tumbling in unison earlier this month**, a phenomenon that **could lead to more turbulence ahead**.

Correlations among the **S&P 500's 11 sectors**, a **measure of how different stock groups move in relation to one another**, **spiked** as the index suffered its first correction in two years last week and further increased when stocks began bouncing



*A correlation of 1 indicates assets are moving in perfect lockstep. Correlation data are through Feb. 12.
Sources: Goldman Sachs Group (correlation); WSJ Market Data Group (VIX)
THE WALL STREET JOURNAL.

back from those lows. They recently hit the highest level since the U.S. presidential election in 2016, according to a Goldman Sachs analysis.

In other words: **S&P 500 sectors** are **moving together** more than they have in quite some time. For some investors, that **raises red flags**.

Rising correlations can create more violent downturns when stocks do fall, as factors such as individual companies' earnings potential or financial records tend to become less important than the broader fears driving selling in the stock market.

"**People end up throwing the good out with the bad**," especially if they are primarily invested in the stock market through broad exchange-traded funds tracking major indexes, said Art Hogan, chief market strategist at investment bank B. Riley FBR. The **popularity of ETFs** in recent years has likely **helped push correlations higher**, Mr. Hogan added, as investors in **index-tracking funds** who want to increase or decrease their exposure to stocks during market swings can **buy or sell only broadly** — **not pick and choose shares**.

"What we saw was **when** the **stock market** is **selling off**, it **didn't matter what** your **business does or what sector** you fall in – you were **for sale because** you were **part of** the **S&P 500,"** Mr. Hogan said.

Tough Task on Trade

by Paul Wiseman and J. Paschke, AP – The Oregonian – Mar. 10, 2018
Source: U.S. Commerce Department

It is one thing to complain about America's huge trade deficits. It's quite another to do something about them.

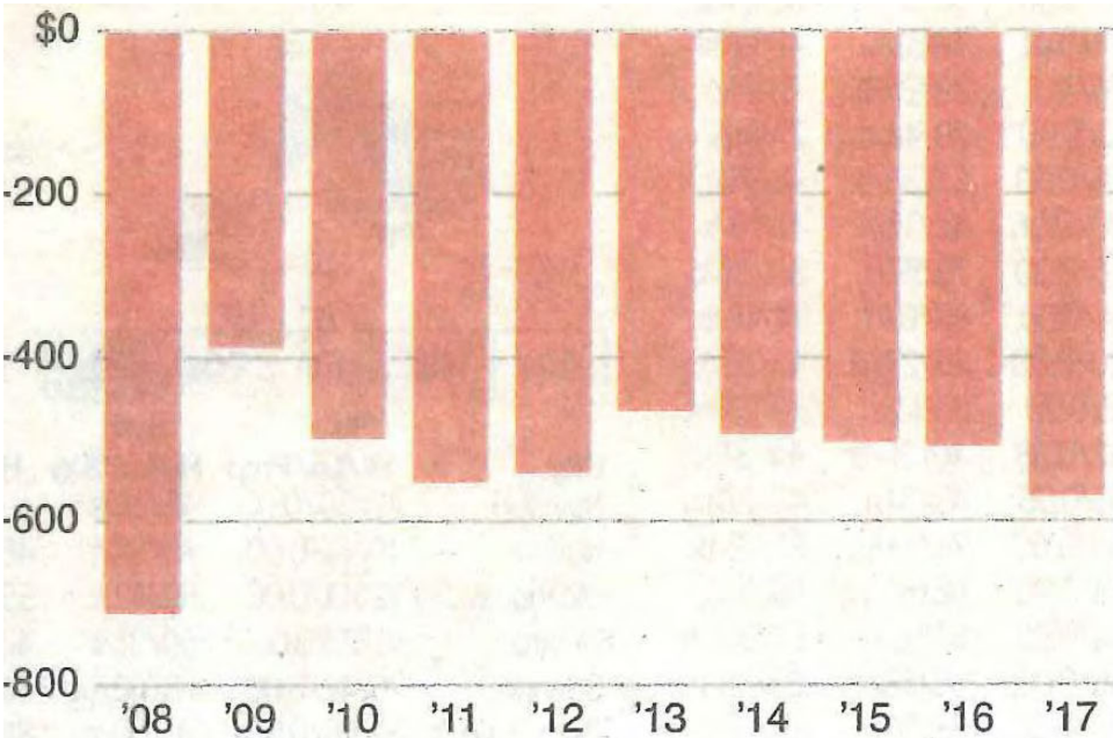
President Donald Trump has promised to reduce the gap between what the United States sells and what it buys from abroad. He blames the deficit on bad trade deals and cheating by U.S. Trading partners. He has begun to renegotiate a trade pact with Canada and Mexico, imposing taxes on imported solar panels and washing machines, and threatening big taxes on foreign steel and aluminum.

So far his **efforts haven't dented the trade deficit**. Last year's trade gap came to $566 billion, highest since 2008. The deficit in the trade of goods with China was a record $375 billion. The trend continued into 2018: The trade deficit for January rose to $56.6 billion, highest since October 2008.

The main culprit: A strong economy gives Americans the appetite, confidence and financial wherewithal to buy imported products. And economists say persistent trade deficits reflect a big economic force that is hard to change: Americans spend more than they produce, and imports make up the difference.

Making a dent? Despite President Trump's promises, the trade deficit remains stubbornly impervious to efforts to reduce it.

Trade Deficit, in $ Billions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Toys R Us's Baby Problem is Everybody's Baby Problem

by Andrew Van Dam – Washington Post – The Oregonian – Mar. 15, 2018

There are endless reasons a big-box toy store would collapse during a retail apocalypse — and Toys R Us acknowledged a number of them in its most recent annual filing: the teetering tower of debt incurred by its private-equity owners, competition from Amazon, Walmart and Target.

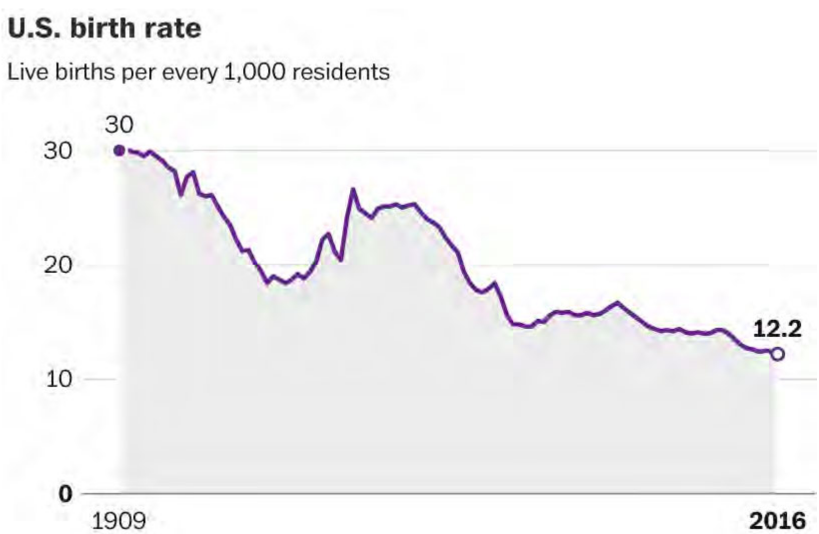
They even wrung their hands about app stores, labor costs and potential tariffs raising the costs of the imported goods they sell.

But one risk stood out. Toys R Us said there just **weren't enough babies** (emphasis ours):

The decrease of birthrates in countries where we operate could negatively affect our business. Most of our end-customers are newborns and children and, as a result, **our revenue are dependent on the birthrates in countries where we operate**. In recent years, many countries' birthrates have dropped or stagnated as their population ages, and education and income levels increase. A continued and significant decline in the number of newborns and children in these countries could have a material adverse effect on our operating results.

It may not have been the biggest existential threat confronting Geoffrey the Giraffe (the store's mascot), but it's the one with the broadest implications outside of the worlds of toys and malls.

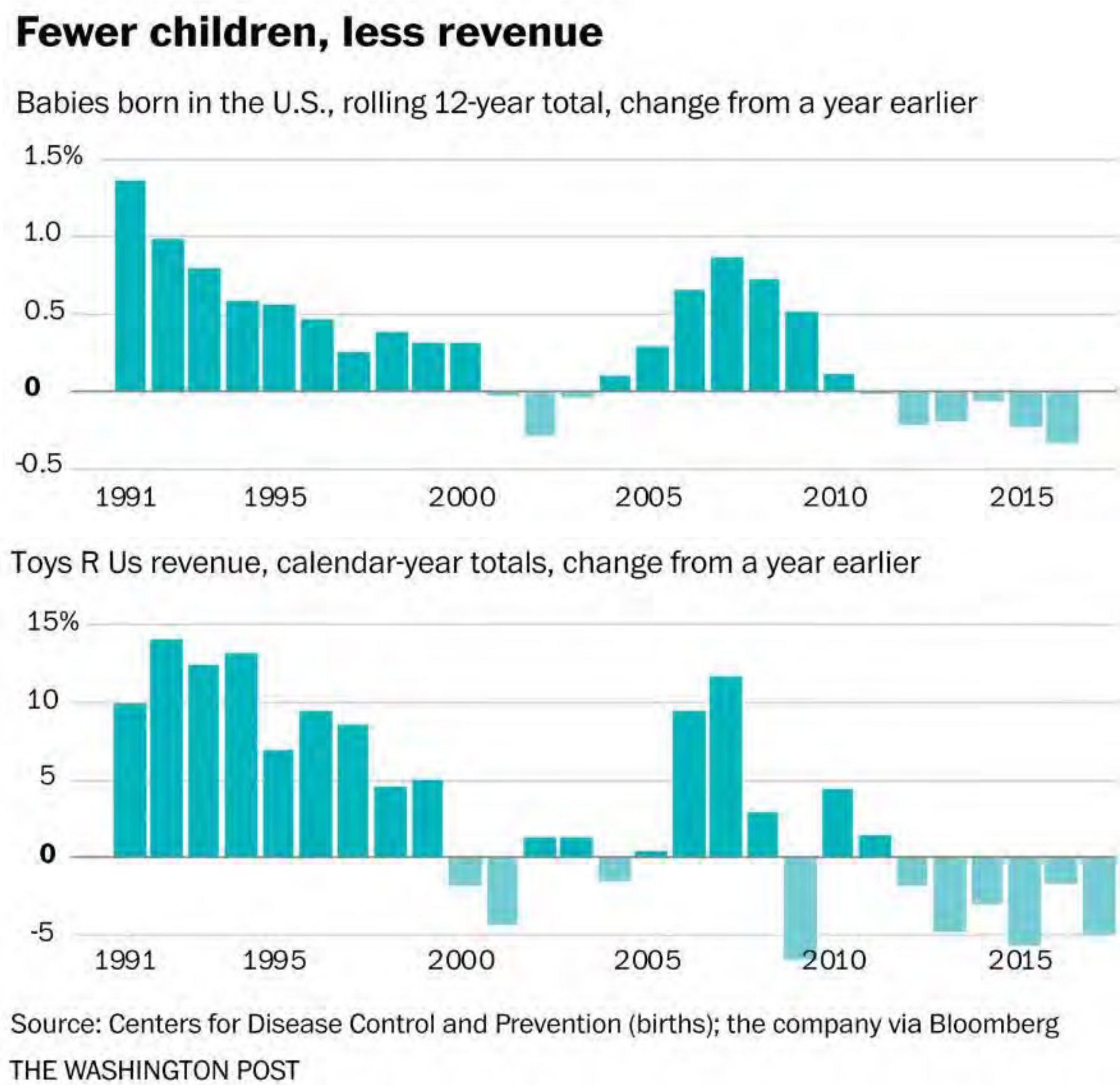
Measured as a share of overall population, U.S. births have fallen steadily since the Great Recession. They **hit their lowest point on record in 2016** – the most recent year for which the Centers for Disease Control and Prevention has comparable data.



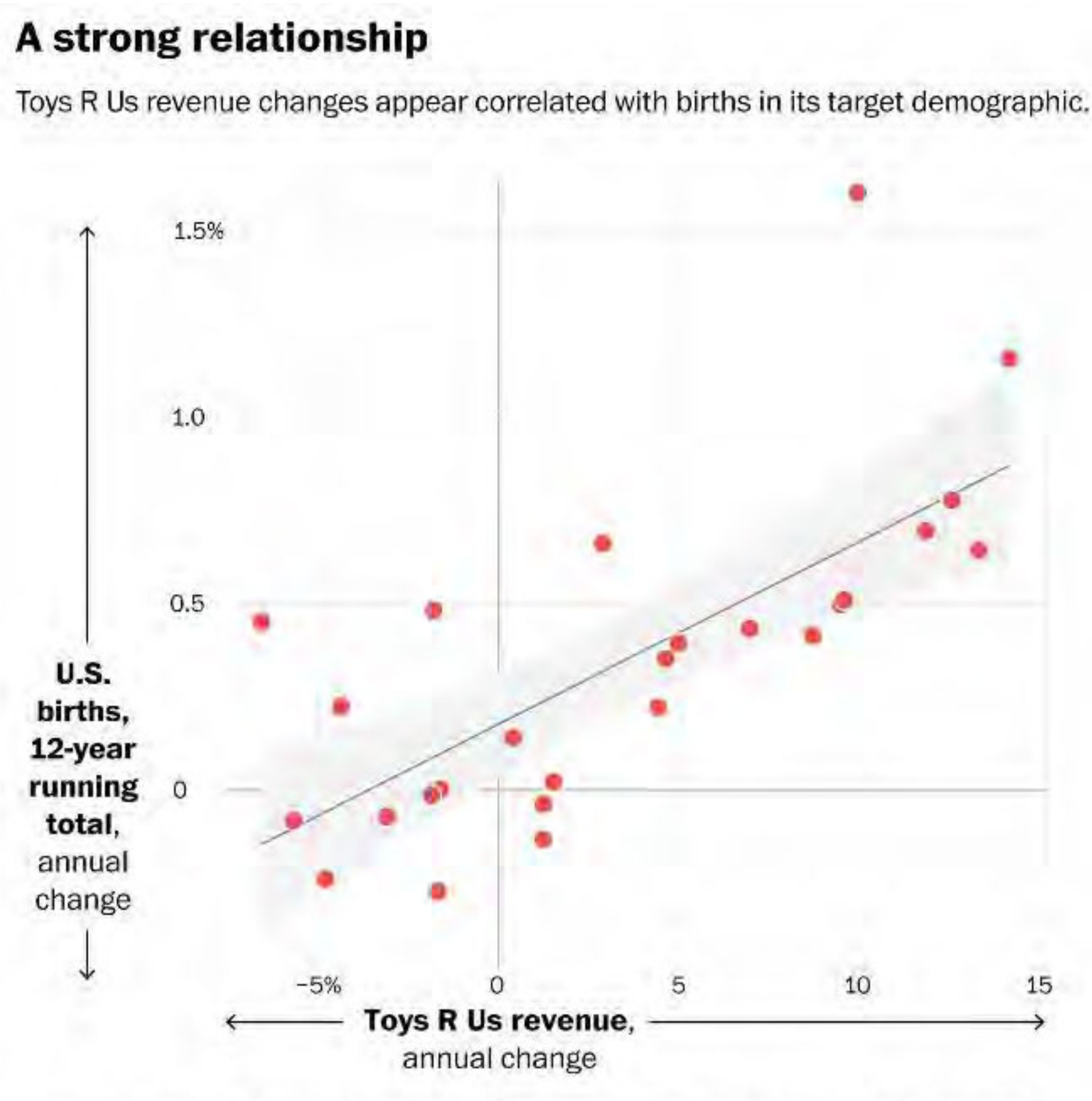
Even adjusted for the aging population and declining share of women of childbearing age, U.**S. fertility rates are at all-time lows**.

That's problematic for Toys R Us, which also operates the Babies R Us stores. The company claims in its annual report that its income is linked to birthrates, and it appears to be right.

The change in the number of children born in the previous 12 years (and thus sitting right within the Toys R Us demographic), tracks closely with the company's changing annual revenue.



There are, to be sure, numerous other factors at play. The same economic forces that encourage people to have children may also encourage them to splurge on toys, for example.



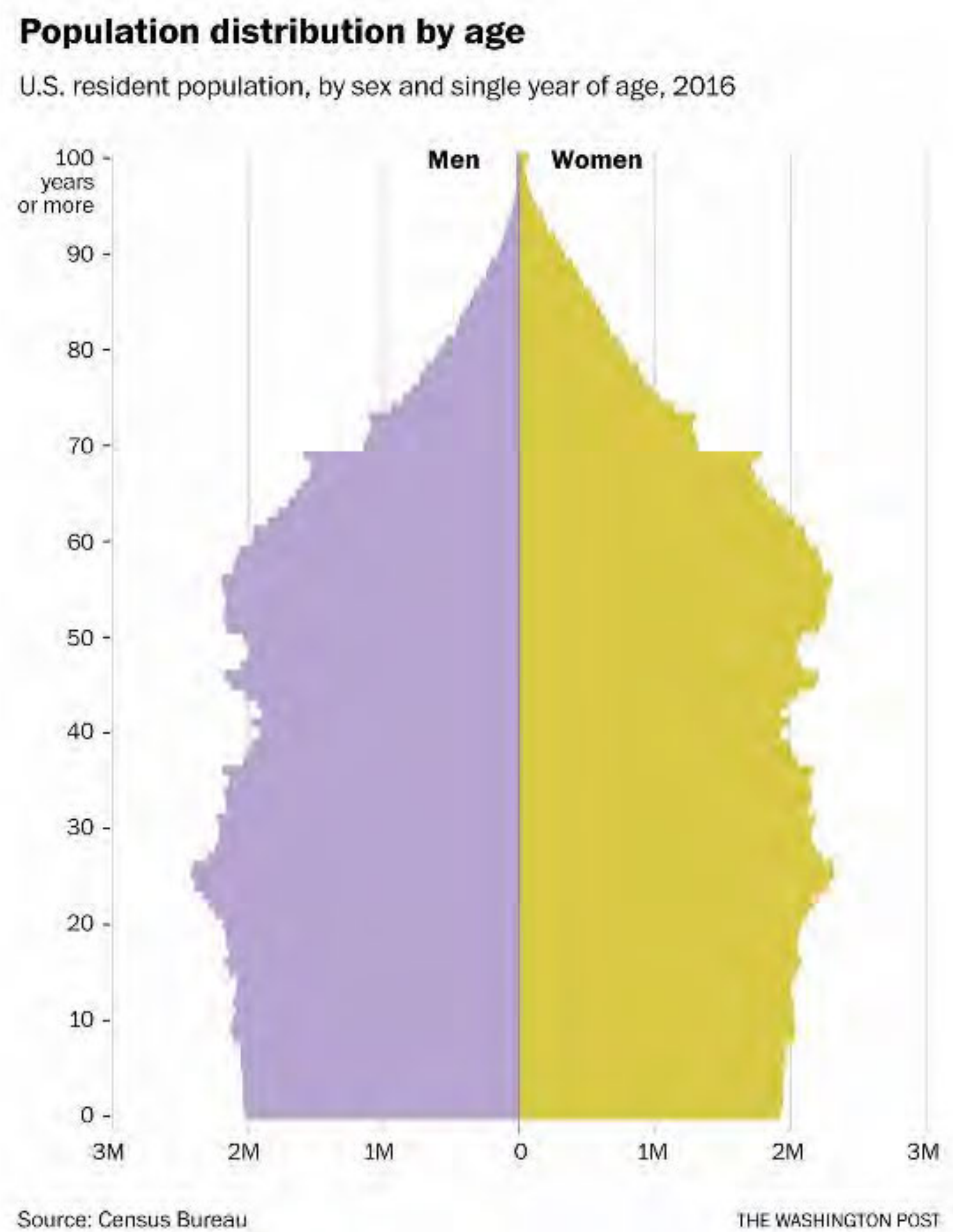
Sources: Centers for Disease Control and Prevention (births); the company via Bloomberg
THE WASHINGTON POST

But it's nonetheless apparent that Toys R Us's **fortunes rise and fall with the population** of its target market.

And that's why the company's demise should worry the rest of us. Toys R Us focuses on kids, so it's feeling the crunch from declining birthrates long before the rest of the economy. But it's **just a matter of time before the trends that toppled the troubled toy maker put the squeeze on businesses that cater to consumers of all ages**.

The **smaller generation of children** whose lackluster toy consumption brought down Geoffrey the Giraffe **will be adults soon**. They'll become the prime-age consumer spenders that drive U.S. economic growth.

And the **generation after them** will be **smaller still**, after accounting for a slight bump from the generational fallout of the baby boom.



Eventually, **unless** the **country does something significant** to **encourage larger families or immigration**, that **narrowing base** of the **population pyramid will crawl upward.**

In the end, Toys R Us will just have been the first of many businesses of all descriptions facing the same hard demographic truth: **Economic growth** is **extremely difficult without population growth**.

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As Boomers Go Gray, Even 2% Growth Will Be Hard to Sustain

by Jason Furman – WSJ **OPINION** – Feb. 15, 2018

Mr. Furman, a professor of practice at the Harvard Kennedy School, was chairman of the White House Council of Economic Advisers, 2013-17

Hoping for **3% GDP growth** or more is folly. The **fundamentals** – **people and productivity** – **seem unlikely to provide it.**

Most of what was good in the American economy last year was unsustainable, and most of what was sustainable was not good. A decade after the financial crisis, there is still no sign the economy can generate the consistent growth of 3% a year many continue to hope for. The **growth rate for 2017** was **just 2.5%,** and even that seems unlikely to last. Is this the new normal?

Not exactly. Instead it's a return to the old normal, a reversion that was widely expected after baby boomers began to retire. While policy makers should do what they can to increase the economy's long-run growth rate, they also need to avoid making decisions based on **unrealistic expectations**.

Economic growth comes from **two sources**. **First** is a **cyclical rebound in demand** as the economy gets closer to full capacity (or even proceeds beyond it). **Second** is an increase in the economy's underlying potential output—also called the **supply side**— driven by **growth in** either the **workforce or productivity**.

The trouble is that **more than half** of **last year's economic growth came from** the **cyclical factors**, which have **little left to contribute given** that we're at or **near full employment**. What this means is that absent much bigger productivity improvements, it will be a challenge for the U.S. to achieve sustained economic growth of even 2%.

The stock market's recent travails provide a vivid illustration of unsustainable growth. Last year the market went up 19%, which boosted consumer spending through a wealth effect. This surge in consumption probably accounted for about 0.75 percentage point of the growth in gross domestic product. For four straight years, consumer spending has risen faster than GDP, causing the personal- savings rate to drop to 2.4% – nearly the lowest on record.

Now a market correction has happened, and even with their recent rebound stocks are still 6% off their highs, as of close on Wednesday. Whatever may happen in the market, it's sobering to listen to the people arguing that stocks are correctly valued. The theory that today's high price/earnings ratios are justified – meaning it simply has become more expensive to buy a given return – implies lower earnings going forward. That, too, would undercut the consumption-fueled growth the U.S. has been enjoying, leaving households vulnerable after the past several years in which they took on increased debt and reduced their personal savings.

Another unsustainable boost to the economy has been the falling dollar. Last year the dollar's effective exchange rate – a measure that compares the dollar against a basket of currencies weighted by trade volume – fell 7%. Although the U.S. pursued a de facto strong-dollar policy through higher interest rates and larger budget deficits, this was more than offset by unexpectedly strong global growth. The weak dollar helped roughly stabilize the trade deficit, meaning net exports only subtracted 0.1 percentage point from GDP growth in 2017, compared with an average of 0.5 point a year from 2013-16.

The momentum in GDP growth could continue into 2018, especially given that tax cuts and the recent spending bill will provide about $250 billion in new demand-side fiscal stimulus this year. The unemployment rate, now 4.1%, could fall into the 3% range, a welcome development. Lagging benefits from the weakening of the dollar may arrive. **Beyond 2018**, however, these factors will begin to lose their force, especially since the Federal Reserve is sure to raise interest rates to offset any additional fiscal stimulus. More important, while predictions about markets are uncertain, it is a mathematical fact that the unemployment rate cannot indefinitely fall by 0.6 percentage point a year, as it did in 2017.

Growth will therefore **have to come from** the **supply side**. **But** a **bigger workforce** is an **unlikely** candidate. Assuming that current immigration rates continue and that employment rates by age are stable, the workforce will expand by 0.5 percentage point a year over the next decade. It is theoretically possible that people out of the workforce today could return. **Betting on this**, though, would be **imprudent**, given the steady decline in labor-force participation for men since the 1950s and for women since around 2000.

That **leaves productivity growth**, which is even less certain. The statistics usually reported exclude farms and the government, meaning they cover only a faster-growing subset of businesses. Instead let's look at economy wide productivity, which is what's relevant for predicting overall economic growth. In **2017** economy-wide **productivity increased 0.9%**, **slightly below** its **1% annual pace over** the **past decade**. If that average rate continues, overall economic growth in coming years will average only 1.5%.

But maybe the productivity figure for 2007-17 is too pessimistic, reflecting a combination of fallout from the global financial crisis and bad luck. In that case we might look to the average economy-wide productivity growth of the past 50 years, 1.6%. That would push the baseline for overall growth to 2.1%. Actual growth over the next five or 10 years could vary from this range of 1.5% to 2.1%, but there is lit-tle basis for a forecast that diverges significantly.

As an analogy, imagine you're asked to predict the high temperature in Boston on Christmas Day. You might say 43 degrees (the average over the past decade) or 40 degrees (the average over the past 50 years). It could well end up being 20 degrees or 60 degrees, but those would be foolish predictions.

Slower growth is less the fault of **President Trump** than of his generation. Mr. Trump**, born in 1946**, was in the **first wave of boomers**. **Forty percent** of the **people born that year have left** the **workforce**. This was **predictable**, which is **why in 2005** the **Social Security Trustees** projected that the **economy would grow 1.8% a year from 2020-30**. If anything, **additional data since** then **would lead us to revise that forecast down**. Americans simply have for-gotten this **basic reality**. To the degree that policy and business **decisions** are **based on false hopes for much higher growth**, the **result** can only be **dashed expectations**.

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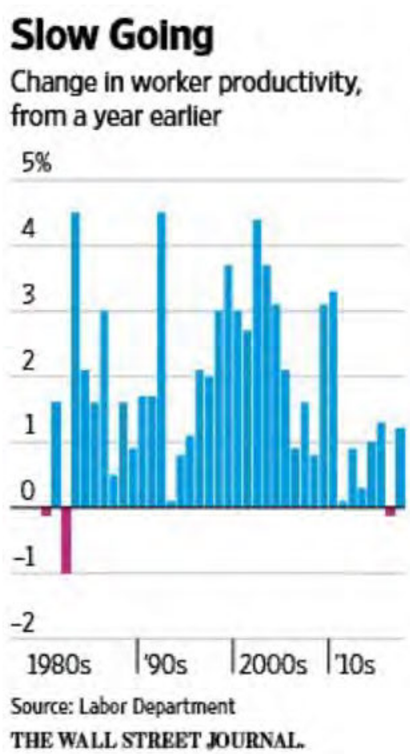
Worker Productivity Remained Sluggish in 2017

by Eric Morath, Josh Miutchell – WSJ – Feb. 2, 2018

U.S. worker productivity grew below its long-run average for the seventh straight year in **2017**.

Nonfarm business-sector productivity, measured as the goods and services produced per hour worked, **advanced 1.2%** last year from 2016, the Labor Department said Thursday. That **matched** the **average rate recorded from 2007 through 2017**, and is **well below the 2.1% annual rate averaged since 1947**.

Productivity hasn't topped its long-run average since 2010, when the economy was first emerging from a deep recession.



In the **fourth quarter, productivity decreased** at a 0.1% seasonally adjusted annual rate. The first quarterly decline since early 2016 offset what had been solid gains in the middle of the year. **Americans worked more hours** in the final three months of 2017, while the **pace of output gains cooled**.

Soft productivity gains is an impediment to stronger wage gains, and ultimately better economic growth.

When workers don't become much more productive, it may be difficult for businesses to justify larger raises for workers. Firms may instead opt to add more employees rather than increase pay for current staff. That is consistent with recent solid hiring and sluggish wage gains.

Stronger productivity gains are likely **needed** to **reach President Donald Trump's** goal of sustaining better than a **3% economic growth rate**. The recent period of **sluggish productivity coincides with** about **2% average growth in gross domestic product since the recession ended**.

Output gains in recent years have largely been supported by firms adding more workers to increase production. But with the unemployment rate trending at a 17year low and **older Americans retiring in larger numbers**, it is unlikely that the labor force will grow more quickly in coming years. That puts the **burden on existing workers to produce more**. **New tax laws** passed last year are **intended to boost business investment**. That **could spark better productivity gains**.

"With a very investment friendly tax reform coming on stream, I would expect business investment to surge and productivity growth to pick up further, approaching what we think of as historically normal levels," said Stephen Stanley, chief economist at Amherst Pierpont Securities.

Productivity for the third quarter was revised down Thursday to an annualized pace of 2.7% growth from an earlier estimate of up 3%. Still, the gain was the best pace since early 2015. Economic growth during the quarter, 3.2%, matched the best rate since 2014. Last quarter, gross domestic product expanded at a 2.6% annual rate.

Investment Fuels Factory Momentum:

U.S. factories maintained momentum in January, buoyed by **rising demand for equipment**, in the latest sign **companies are stepping up investment spending**. The Institute for Supply Management on Thursday said its index of factory activity settled at 59.1, down slightly from 59.3 in December but still ranking as the third highest since 2011. Any mark above

50 indicates expanding activity, as measured by factors such as product sales, raw-materials prices and industry employment.

One factor driving the latest growth: **Higher demand for business equipment**. **Sales of such long-lasting goods** indicates **companies** are **investing to expand their production capacity**. The lead time for filling those orders rose 8% over the month because **factories** are being **flooded with new orders**, said Tim Fiore, head of the ISM survey.

”We’re still accelerating,” Mr. Fiore said of the overall manufacturing outlook. “There are a lot of strong feelings 2018 is going to be a good year.”

A measure of overall sales of goods, known as new orders, slipped from December but remained a robust 65.4. Production also held at a high level. Employment continued to grow, but more slowly.

Prices for raw materials hit the highest level since 2011, indicating higher inflation pressures. Mr. Fiore said that was a sign of healthy demand rather than an overheating economy.

The factory sector has expanded for **most of this decade**, largely because of **steady but slow economic growth in the U.S**. **Now**, the sector appears to be **picking up above recent trends**, largely because of firming **global growth** and **higher spending by businesses**.

Thursday’s report showed unit labor costs at nonfarm businesses rose at a 2% rate in the fourth quarter, primarily because of an increase in hourly compensation. **Unit labor costs are the ratio of hourly pay to productivity**. Unit labor costs rose 0.2% for the full year.

Productivity for manufacturing firms rose at a 5.7% pace in the **fourth quarter** from the third. That was the **best quarterly gain since 2010**. **But for the full year, manufacturing productivity advanced just 0.7%**.

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Troubles Push GE to Consider a Breakup

by Thomas Gryta – WSJ – Jan. 16, 2018
Leslie Scism contributed to this article

Major problems in GE Capital are prompting a re-evaluation of strategy

General Electric Co.'s chief executive said the company is **considering breaking apart** the American icon after it disclosed **more problems buried in one of its major units**.

John Flannery, who took over as CEO last summer, said the Boston conglomerate is re-evaluating its strategy and structure, including splitting its major divisions into separately traded units.

"We are looking aggressively at the best structure or structures for our portfolio to maximize the potential of our businesses," Mr. Flannery said on a conference call Tuesday, promising to update investors in the Spring. "Our results, over the past several years, including 2017 and the insurance charge, only further my belief that we need to continue to move with purpose to reshape GE."

GE spent decades striking deals that once made it the most valuable U.S. company, with a financial-services arm that rivaled the biggest banks and a media empire that included NBC. But since the financial crisis the company has shrunk its operations to focus on its core industrial divisions. It also **made big bets on oil and coal** markets that have depressed its recent results.

A breakup would come just a few months after Mr. Flannery unveiled his plan to turnaround the struggling giant by focusing on its **three core units**—**aviation**, **power** and **health care**. **In November**, Mr. Flannery **slashed the dividend by half** and said he would divest $20 billion of assets, though he stopped short of the more dramatic structural changes he raised on Tuesday.

GE has been struggling to increase its profits and is under pressure from investors, including activist Trian Fund Management, to cut costs and revamp its operations. Last year, executives **blamed overcapacity in its big power business for a shortfall in** profits and cash flow. In December, GE said it would **cut 12,000 jobs in the unit, which makes turbines used in power plants** around the world.

On Tuesday, GE said it **would book** a **$6.2 billion charge** in its **fourth quarter and** would **have to set aside $15 billion over seven years to bolster insurance reserves at** its **GE Capital** unit, **surprising investors** with deeper-than-expected problems in a business many thought the company had left behind.

The charge follows a reassessment of the conglomerate's remaining insurance business. Although GE sold much of its financial-services operations after the 2008 financial crisis, it kept on its books billions of dollars of coverage for long-term-care policies that had been sold by other insurers to consumers. Those policies promise to pay for nursing homes and other care for individuals.

Although GE hasn't covered new policies since 2006, it and other insurers have begun to reckon with what are emerging as deep shortfalls. Over the past several years, many insurers have sought regulatory approval from state insurance departments to increase rates, with partial success, saying they aren't collecting enough in premiums to offset the claims as those individuals age.

GE discovered last year that its reinsurance coverage was operating at a deficit, prompting the company to review all of its assumptions, according to a person familiar with the matter.

The upshot is that the **GE Capital unit**, which had been paying dividends in recent years to the parent company, **won't pay dividends to GE for the foreseeable future**. GE had suspended the GE Capital dividend last year and slashed its payout to shareholders by half.

Mr. Flannery has been working to streamline the once far-reaching GE Capital unit and focus it on providing financing for GE's industrial operations, such as jet engines and MRI machines. He expressed frustration at the review's results while saying the actions would restore GE Capital ratios to appropriate levels.

"At a time when we are moving forward as a company, a charge of this magnitude from a legacy insurance portfolio in run-off for more than a decade is deeply disappointing," he said.

GE shares slid 3% in early trading Tuesday, to just above $18. Wall Street was braced for the charge, which GE had said would exceed $3 billion. The company is slated to report its fourth-quarter financial results next week.

GE's looming charge is one of the biggest yet in a corner of the insurance industry that has reeled from pricing miscalculations made decades ago. About 7.3 million of the policies are in consumers' hands, some with generous lifetime benefits.

Insurers have taken $10.5 billion in pretax charges against their earnings in recent years to boost reserves for future claims, according to analysts at investment bank Evercore ISI.

Genworth Financial Inc., which was spun off from GE in 2004, has tallied losses from its older long-term-care policies of $2.5 billion since 2006.

Long-term-care insurance took off in the early 1990s. The policies had strong appeal to older people, and many insurers thought they had the perfect product to profit from people's concerns about becoming unable to care for themselves and outliving their savings.

In general, the policies pay for nursing homes, assisted-living facilities or health-care aides in people's private residences. Such care generally isn't paid by the Medicare health-insurance program for older people, while the federal-state Medicaid program is for the poor.

But by the mid 2000s, many insurers were rapidly ratcheting back the benefits, concluding they had badly miscalculated how many people would file claims and how long they would draw benefits before dying, among other things.

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Trump Infrastructure Plan Could Ease Wave of New Energy Projects

by Molly Christian – SNL Financial LC – Feb. 26, 2018

Ashleigh Cotting contributed to this article.

President Donald Trump's **new infrastructure plan** seeks federal **support** for **new hydroelectric generation and rural power projects** while **proposing broad permitting reforms** that could affect other energy resources, including natural gas pipelines.

The plan **calls for $1.5 trillion** in **new investment over** the **next 10 years** in **U.S. roads, bridges, ports,** the **electric grid and other infrastructure**. The **federal government** would **provide $200 billion** in funding, with **state, local** and **private parties kicking in** the **rest** of the $1.5 trillion.

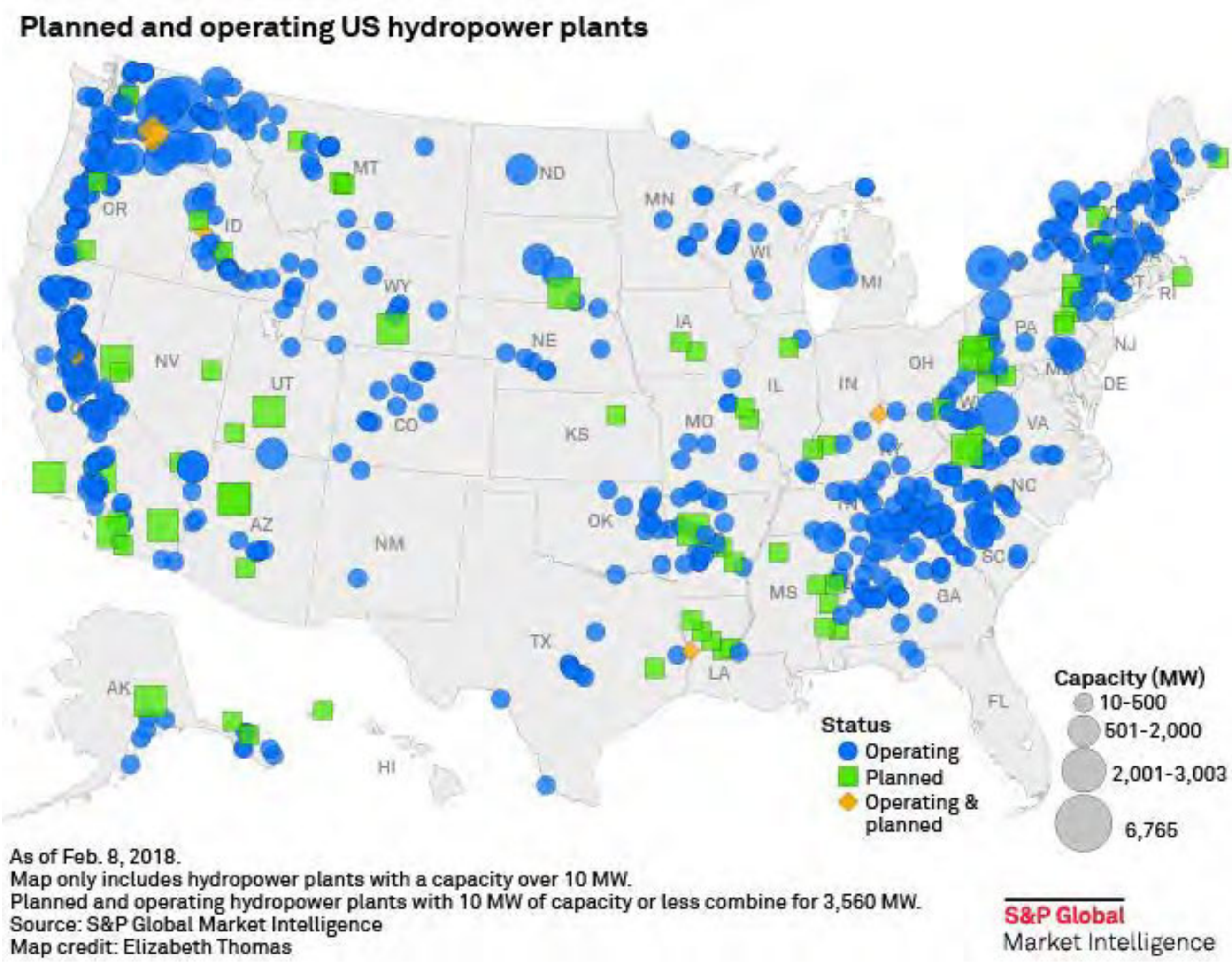
Most pipeline developers and power generation and distribution owners do not rely on direct federal funding for infrastructure projects. But the White House's outline, released Feb. 12, would set aside federal funds for rural energy projects, provide incentives for hydroelectric generation, and **streamline** the **federal permitting process for all energy projects regardless** of **whether** they are **publicly or privately operated**.

Hydropower

The proposal would provide **$100 billion in federal support to encourage state, local and private infrastructure investment**. The **incentives**, which federal agencies would distribute **in** the **form of grants**, would **apply** to "**governmental infrastructure**" **projects**, including **airports**, **passenger rail**, **ports waterways**, and **hydropower**.

Trump's plan would also **broaden** the **use of tax-exempt private activity bonds** to **include new** construction of **hydroelectric generation**, and **authorize** the **secretary** of the **Army to allow commercial operation** and **maintenance of Corps-owned hydropower facilities**.

According to data from S&P Global Market Intelligence, operating **U.S. hydropower capacity totals 98,906 MW, with another 22,710 MW planned** for construction. Of that amount, **28,031 MW** of **operating** capacity and **3,396 MW** of **planned** generation **are** owned by **municipal**, **state** or **federal** entities **and electric cooperatives**.



Rural electric projects

Energy projects in rural areas would also get a lift. The plan would provide **$50 billion in federal money for** a **rural infrastructure program**, **80%** of which would go **to state governors to distribute** and **20% to rural performance grants**.

Rural electric generation, transmission and distribution facilities would be **eligible to receive that money**. The **U.S. has 20,303 MW of planned government** or **cooperative**-**owned power projects**. Those entities also have 1,**568 miles of new transmission planned along existing lines** and **1,696 miles of totally new capacity** in the works.

Rural utilities are "**delighted**" **with** the **White House's focus on their infrastructure**, **said** Kirk Johnson, senior vice president of government relations with the **National Rural Electric Cooperative Association**. Johnson said plenty of areas could use the $50 billion set aside for rural infrastructure, particularly development of high-speed internet and broadband in remote areas.

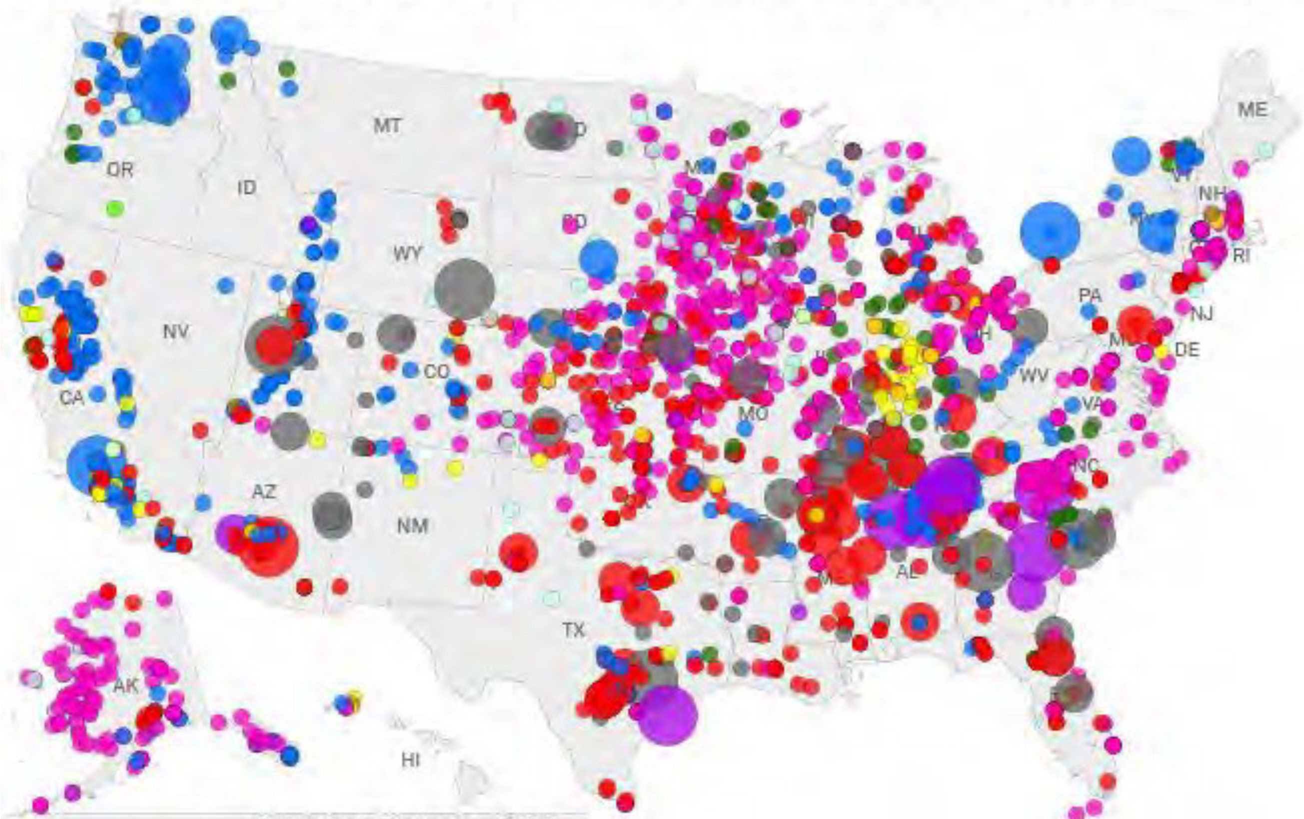
But funding for electric generating and transmission assets may be less of a priority for rural utilities. Johnson noted the U.S. Department of Agriculture's Rural Utilities Service, or RUS, already has a loan program for energy infrastructure. And to the extent rural electric utilities may seek to tap the $50 billion program, Johnson said he would like to see changes in how the money is distributed.

Rather than having the money go to states, some of which are not set up to award federal cash for energy projects, Johnson said the money could be administered by an entity such as the RUS. The White House's proposed block grant formula for funding rural projects "works for some areas of infrastructure but it doesn't really work for others," he said.

NRECA also **wants** the Trump administration to "**drop** this **foolish idea**" of **privatizing** certain federally owned transmission assets, including those overseen by the **Bonneville Power Administration**, **Southwestern Power Administration** and **Western Area Power Administration**. In its budget requests for fiscal years 2018 and 2019, the White House **proposed selling** the **three federal power marketing administrations' transmission lines to private entities**. For fiscal year 2019, Trump also proposed to sell the **Tennessee Valley Authority's transmission** infrastructure.

Public power groups blasted the move, saying the sale would raise power prices for consumers and that federal power marketers recover all their costs through customer payments, avoiding impacts on taxpayers. Johnson said he has "yet to find that person" in Congress who supports privatizing the assets. Lawmakers would need to approve the sale, **but both** the **U.S. House of Representatives** and **U.S. Senate excluded** the **proposed divestitures from recent spending bills**.

Power generation assets owned by municipal, cooperative, state and federal entities



	Operating	Planned	Total
Cooperative	60,828	6,151	66,979
Municipal	49,013	2,825	51,838
Federal	34,917	4,104	39,021
Political subdivision	29,533	5,598	35,131
State	20,604	1,103	21,707
Municipal marketing authority	8,537	522	9,059
Total:	203,431	20,303	223,735

Fuel type
- Biomass
- Coal
- Gas
- Geothermal
- Nuclear
- Oil
- Other nonrenewable
- Solar
- Hydro
- Wind

Owned capacity (MW)*
- 0-700
- 701-1,450
- 1,451-3,401

As of Feb. 8, 2018.
Includes operating and planned power plants owned by companies with an EIA ownership structure of municipal, municipal marketing authority, cooperative, state, political subdivision, or federal.
*Only includes capacity owned by municipal, cooperative, state, and/or federal owners.
Source: S&P Global Market Intelligence
Map credit: Elizabeth Thomas

S&P Global
Market Intelligence

Pipelines

Trump has made **lifting barriers** to oil and gas **pipeline development** a key part of his energy agenda. In March 2017, the president granted a presidential permit for TransCanada Corp.'s Keystone XL oil pipeline, reversing the Obama administration's decision in November 2015 to deny the permit in response to widespread environmental opposition to the project.

Trump's support of pipeline development extended to his recently introduced infrastructure plan, which asked Congress to clarify how much time states have to grant or deny water quality certifications under Section 401 of the Clean Water Act. Oil and gas shippers have complained that states, including New York, have used the Section 401 process to hamper pipeline projects.

"It is incumbent on the administration and Congress to establish greater accountability in the Section 401 process," the Interstate Natural Gas Association of America said after the release of the infrastructure plan.

The urge for **permitting reforms** comes as developers are planning a wave of new pipelines in the coming years. For natural gas alone, a combined 10,354 miles of new pipeline capacity totaling roughly 84.6 million dekatherms is announced or under development, according to S&P Global Market Intelligence data. Those numbers apply to pipeline projects with a start and end point within the U.S.

In addition to proposed Clean Water Act changes, the infrastructure plan would **allow** the **Secretary of Interior** to **directly authorize pipeline construction** on **National Park Service lands, rather than first seek approval from Congress as currently required**.

US natural gas pipeline projects by development status, in-service year

	Announced		Early development		Advanced development		Under construction		Total	
In-service year	Capacity (Dth)	Mileage	Capacity (Dth)	Mileage	Capacity (Dth)	Mileage	Capacity (Dth)	Mileage	Capacity (Dth)	Mileage
2018	828,000	90	2,584,581	212	3,955,401	313	19,231,771	2,140	26,599,753	2,756
2019	8,208,286	1,256	5,649,578	416	2,873,000	781	1,888,997	234	18,619,861	2,687
2020	1,947,420	470	1,970,000	15	2,057,326	234	0	0	5,974,746	719
2021+	5,805,405	1,814	17,386,164	797	106,660	13	1,800,000	165	25,098,229	2,789
NA	584,226	139	3,213,242	870	3,761,260	153	713,174	241	8,271,902	1,403
Total	17,373,337	3,769	30,803,565	2,310	12,753,647	1,494	23,633,942	2,781	84,564,491	10,354

As of Feb. 14, 2018.
S&P Global Market Intelligence guarantees coverage on natural gas pipeline projects longer than 10 miles.
NA = not available
Includes pipeline projects with both a start and end point located in a U.S. state.
Source: S&P Global Market Intelligence

Permit Changes for All

The potentially most **far-reaching** changes for energy under Trump's plan stem from its **permitting reforms**.

The president called for **limiting** the **National Environmental Policy Act review process for new infrastructure projects to two years** and **consolidating authority for those reviews with a lead federal agency to cut down on duplicative analyses and speed up permitting times**.

The proposal would also reduce the U.S. Environmental Protection Agency's participation in certain project reviews and **revoke** the **EPA's authority to veto Section 404 Clean Water Act permits granted by the U.S. Army Corps of Engineers**. In addition, Trump proposed shortening to **150 days the time limit to file lawsuits**

against federal permitting decisions. The statute of limitations for filing such suits **currently** is **six years** for many projects.

The **permitting proposals drew applause from power industry groups**.

"It is critical that existing statutes impacting permitting and siting are improved, simplified, and streamlined so that companies can site and permit critical energy infrastructure," Edison Electric Institute President Tom Kuhn said. He added that EEI has worked with its members to identify "administrative and legislative recommendations that will help to modernize federal laws and streamline their implementation," ideas the group will likely take to Capitol Hill as lawmakers consider an eventual infrastructure bill.

Cloudy Outlook

A government-led infrastructure program will **require approval from Congress**, whose tight calendar for the rest of 2018 could make forming comprehensive legislation difficult.

"The further into an even-number year you get the harder it is to get things done," Johnson said in reference to the upcoming 2018 mid-term elections. But he added that **NRECA would like to see something done this year**.

In addition to time constraints, lawmakers are divided on how much federal money to authorize for infrastructure development and which types of projects to prioritize.

Leading Democrats have **said** the proposed **$200 billion in direct federal funding** falls **far short** of the American Society of Civil Engineers' recommended **$2.0 trillion** above current spending to get **U.S. infrastructure back to good condition**. Democrats have also criticized the plan's reliance on private investors, who they said could impose large new tolls and user fees on infrastructure.

"The president's ... proposal would do very little to make our ailing infrastructure better, but would put unsustainable burdens on our local government and lead to Trump tolls all over the country," Senate Democratic Leader Chuck Schumer said.

Proposals to ease permitting for new projects will also be a tough sell. A sweeping rollback in permitting regulations "is not something that's going to get buy-in from Democrats," Sierra Club legislative director Melinda Pierce said.

A group of lawmakers met with Trump on Feb. 14 to discuss a way forward on infrastructure legislation, but Congress appears to be far from ready to introduce a bill. "I think members are still in discussion about what a broad infrastructure package would look like," said Nicole Daigle, a spokesperson for Senate Energy and Natural Resources Committee Chairman Lisa Murkowski, R-Alaska. "I know there are **lots of ideas** floating around, but there is **no bill yet**, at least not to my knowledge."

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Trump Orders Aluminum and Steel Tariffs on National Security Grounds

by Evan Fallor – S&P Global Market Intelligence – Mar. 8, 2018

President Donald Trump signed orders enacting tariffs of 25% on global steel imports and 10% on aluminum, pledging to boost American production and security.

The move by Trump on March 8 was hailed by some U.S. steel producers but also left some industries and Republican lawmakers concerned about adverse effects on U.S. companies that rely on imported steel and aluminum that could lead to job losses.

Trump, flanked by top administration officials as well as American steel and aluminum workers brought in for the announcement, said the **tariffs** will **go into effect in 15 days**. Trump said they are a measure of economic and national security interest, as the U.S. now relies too heavily on imports of steel and aluminum for military production. He urged companies in other countries to bring production to the U.S.

"There's no tax in the USA so if you don't want to pay the tax, bring your plant to the USA," Trump said. "There's no tax."

As noted by a senior administration official speaking on background earlier March 8, a **temporary exemption** will be **given to Canada and Mexico while** the U.S. **renegotiates** the **North American Free Trade Agreement**, or **NAFTA**, with the two countries. The three countries just concluded the seventh round of talks for the 24-year-old trade deal March 5.

"We're going to hold off the tariff on those two countries to see if we're able to make the **deal on NAFTA**," Trump said, **without** specifying a **time frame or deadline**. "If we do, there **won't be** any **tariffs on Canada** and there won't be any tariffs on **Mexico**. I have a feeling we're gonna make a deal."

Trump followed through with the tariffs he first proposed March 1, despite push-back and opposition from many within the Republican party, as well as from global trading partners and U.S. industries that could be targeted by retaliatory tariff measures. The European Union has threatened retaliatory tariffs of 25% against several U.S. exports, including peanut butter, cranberries, shirts, Levi Strauss & Co. jeans and Harley-Davidson Inc. motorcycles.

The president said that U.S. Trade Representative Robert Lighthizer will conduct talks with individual countries hoping to be removed from the tariff list, saying that he is showing "great flexibility and cooperation" toward those countries that are "friends of ours" on trade.

"America will remain open to modifying or removing the tariffs for individual nations as long as we can agree on a way to ensure that their product no longer threatens our security," Trump said.

The proclamations drew immediate concern from Republicans and the retail industry.

“Simply put: This is a tax hike on American manufacturers, workers and consumers. Slapping aluminum and steel imports with tariffs of this magnitude is misguided," Senate Finance Committee Chairman Orrin Hatch, R-Utah, said in a statement. "We share a common goal of making trade work for all Americans and it’s unfortunate that this decision will have harmful implications for American businesses, workers and consumers who rely on these products."

The National Retail Federation said the tariffs will raise the cost of certain types of consumer products and could offset benefits of Republican-passed tax reform.

"Consumers are just beginning to see more money in their paychecks following tax reform, but those gains will soon be offset by higher prices for products ranging from canned goods to cars to electronics," NRF President and CEO Matthew Shay said in a statement. "The retail industry is extremely concerned by the administration’s apparent desire to ignite a trade war, where the net losers will be the very people the president wants to help."

The U.S. Fashion Industry Association also voiced concern, warning in a statement that the tariffs will be "catastrophic for the U.S. economy and jobs."

Trump, however, said the tariffs would bring back jobs and production to U.S. steel and aluminum mills. He hinted at introducing a reciprocal tax aimed at mirror taxes on imports and exports between the U.S. and trading partners.

"I think companies are going to be very happy in the end," Trump said. "Many of the countries who treat us the worst on trade and military are our allies. We just want fairness."

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Trump’s Tariff Vow Rattles Markets

by Jacob M. Schlesinger, Peter Nicholas, and Louise Radnofsky –
Bob Tita, William Mauldin and Andrew Tangel contributed to this article.
WSJ – Mar. 2, 2018

Planned duties on steel and aluminum anger trade partners

President Donald Trump's pledge Thursday to impose stiff **tariffs on steel and aluminum imports** sparked worries of a global trade war, sending stocks tumbling, drawing protests from a swath of American industries and prompting threats of retaliation. Mr. Trump told a meeting of industry executives the U.S. would slap **25% tariffs on steel** imports and **10% on aluminum** imports, steps meant to revive domestic manufacturing and **fulfill a campaign promise** that helped him capture the Midwest in the 2016 election. "You're going to see a lot of good things happen. You're going to see expansion of the companies," the president said.

President Donald Trump told a meeting of steel and aluminum industry executives, 'You're going to see a lot of good things happen.'

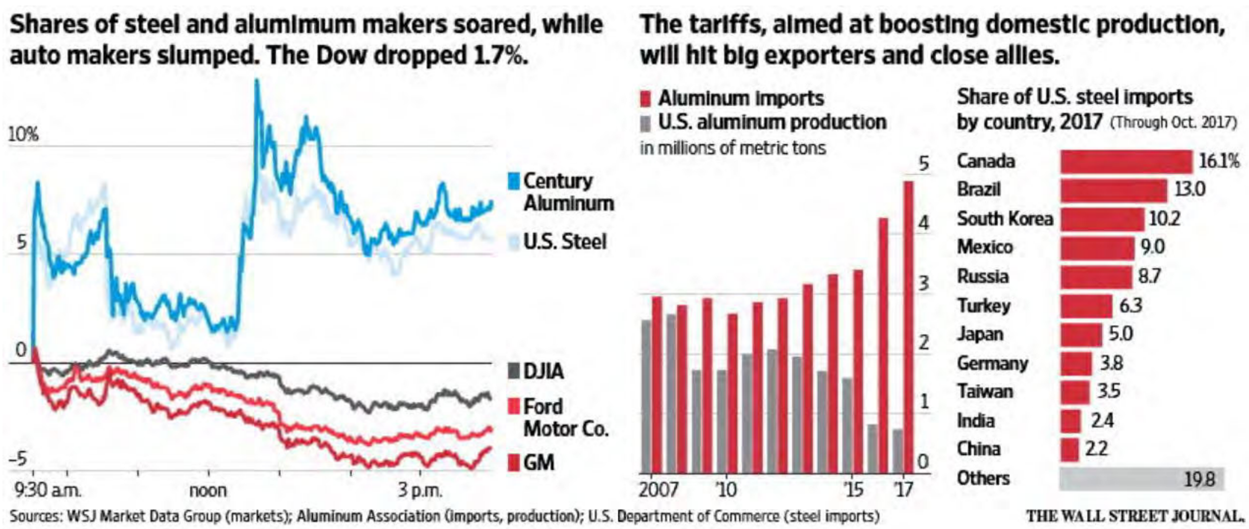
But the impact on companies that use steel was swift. The Dow Jones Industrial Average fell more than 500 points, or 2%, initially after the announcement, as shares of big steel users, including auto makers Ford Motor Co. and General Motors Co., dropped even more. The losses continued in Asia early Friday. At midday in Tokyo, Japan's Nikkei Stock Average was down 2.9%.

The moves were quickly denounced by industry trade groups, including beer and boat makers worried about costlier aluminum and manufacturers of chemicals, air conditioners and oil pipelines all concerned about pricier steel inputs.

"It's going to be expensive," said Ed Bolas, chief financial officer at DyCast Specialties Corp., a Minnesota maker of parts for products including cutting tools and engines. "All of it will impact the consumer."

Mr. Trump's announcement marks his biggest move to date to carry out his "America First" trade policy aimed at upending decades of U.S. leadership fostering globalization. The swift backlash underscores the dramatic ways that system may now be changing.

The decision was controversial inside his own administration, coming over the objections of some top advisers and surprising many in the White House who first learned of the plans from news reports Wednesday night. Mr. Trump's Defense Department had weighed in against the move, with a memo cautioning against harm to "our key allies" such as Canada and Japan.



"These U.S. measures will have a negative impact on trans-Atlantic relations and on global markets," warned Europe's trade commissioner, Cecilia Malmstrom.

The president justified the tariffs by invoking a little-used **Cold War-era law** that **gives presidents broad discretion to curb imports deemed a threat to** "**national security**." The announcement was based on **studies** conducted by the **Commerce Department**, made public **last month**, which **concluded metals imports** had **eroded** the **country's ability** to **make its own weapons**, **tanks** and **aircraft**.

As a sign of how eager the president was to take action, he chose the toughest of the three options presented by the Commerce Department, which had also outlined a more-targeted approach aimed only at certain countries.

Mr. Trump also felt such urgency to announce the decision that he did so providing no further details beyond the broad numbers, saying the concrete policies wouldn't be presented until next week.

The new tariffs underscore Mr. Trump's pivot in his second year in office to reorient decades of American policies aimed at expanding free trade and globalization. Thursday's move comes about a month after the White House unveiled similar tariffs and quotas on solar panels and washing machines, invoking a different, little- used 1974 trade law allowing U.S. industries to seek sweeping protection if they can show significant injury from a sudden surge in foreign competition.

Trump aides are also weighing a broad package of trade and investment penalties against China, as they complete a detailed study accusing Beijing of widespread theft and expropriation of American intellectual property. Thursday's decision is aimed in particular at China, whose steel overcapacity has fueled a global glut hampering American producers.

Mr. Trump's announcement appeared to be a diplomatic jab at Chinese President Xi Jinping, coming the same day his top economic adviser was meeting at the White House with the Trump economic team to try to ease trade tensions.

The new tariffs seem to reflect the rising power inside the Trump administration of his economic nationalist aides, who have tangled over the past year with his more free-trade oriented advisers. The infighting was evident Wednesday night, with some officials insisting a decision was imminent and others saying it was still being deliberated.

Mr. Trump has repeatedly said his campaign pledge for greater steel protection won him the presidency, and his U.S. trade representative, Robert Lighthizer, talks of tougher policies creating a "new coalition" in support of trade, by winning over Democrats who have grown increasingly hostile to globalization over the past quarter-century. Mr. Trump is hoping to solidify his political base in advance of midterm congressional elections this year, and the announcement comes ahead of a March 13 special House contest in Pennsylvania steel country.

Indeed, many congressional Democrats and labor unions joined the metals executives in cheering the new policy, which they had long advocated. "This welcome action is long overdue for closed steel plants across Ohio," said Ohio Democratic Sen.

Sherrod Brown, who has been working closely with Mr. Trump and his trade team to craft such new policies.

But the decision also is likely to open a rift between the White House and traditional free-trade Republicans in Congress, who have become increasingly vocal in recent weeks in urging Mr. Trump to avoid taking such action.

Even Sen. Pat Toomey, a Re-publican representing Pennsylvania, blasted the move, saying that “invoking national security as a means of imposing new, huge tariffs on all kinds of imported steel is a big mistake that will increase costs on American consumers, cost our country jobs, and invite retaliation from other countries.” The move also drew complaints from allies and trading partners, who have warned that they could retaliate. Canadian Foreign Minister Chrystia Freeland said that, “Should restrictions be imposed on Canadian steel and aluminum products, Canada will take responsive measures to defend its trade interests and workers.” A Chinese foreign-ministry spokeswoman said, “The U.S. has overused trade remedies” adding that “China will take proper measures to safeguard its interests.”

Corporate Borrowing Rates and Yields

Bond total return index	Close	Yield (%) Last	Yield (%) Week ago	52-Week High	52-Week Low	Total Return (%) 52-wk	Total Return (%) 3-yr
Treasury Ryan ALM	1430.722	**2.624**	2.712	2.736	1.818	**0.548**	0.301
10-yr Treasury, Ryan ALM	1676.851	**2.802**	2.917	2.943	2.058	**1.676**	−0.467

U.S. government bonds rallied after President Donald Trump announced he would impose tariffs on imports of steel and aluminum, which investors said could curb economic growth. The **yield on the benchmark 10-year U.S. Treasury note** posted its **biggest one-day decline since Sept. 5** – **0.067 percentage** point – **to 2.802%** from 2.870% Wednesday. Yields fall as bond prices rise.

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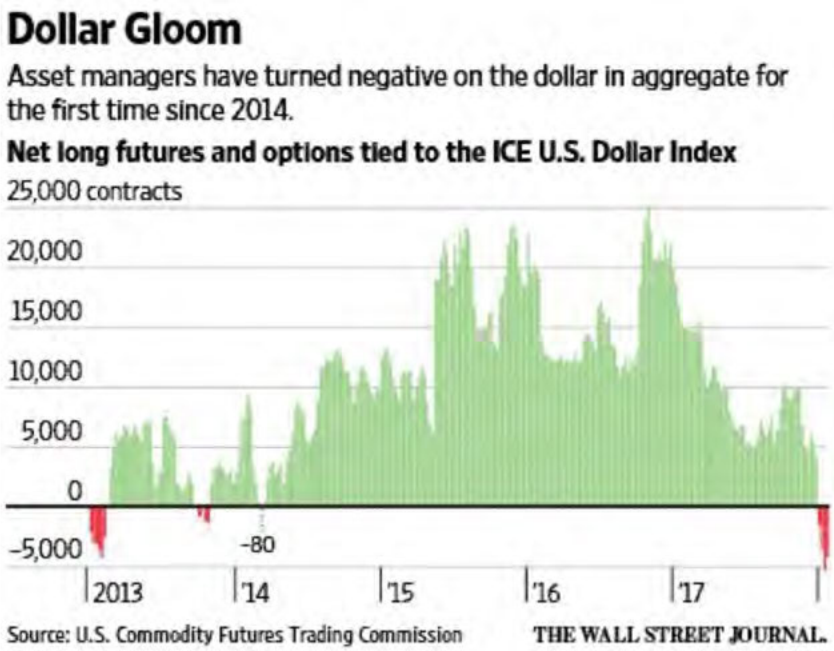
Dollar Sentiment Turns Bearish

by Saumya Vaishampayan – WSJ – Jan. 31, 2018

The dollar just can’t catch a break: **Long-term investors have collectively turned negative on the U.S. currency this year for the first time since 2014**. Asset managers now hold more bearish futures and options contracts tied to the ICE U.S. Dollar Index than bullish ones, and they have done so all year, according to data from the U.S. Commodity Futures Trading Commission.



Put another way, these **investors, who control hundreds of billions of dollars of investment money**, are **now betting the dollar will get weaker**.

The last time these investors held a negative view on the greenback was nearly four years ago, but it only lasted a week and the net number of bearish contracts they held was negligible.

The market data are the latest sign that strong economic growth around the world, not just in the U.S., has boosted the relative appeal of stocks, bonds and currencies in places like Europe and emerging markets. Big investors' decision to **rotate money out of U.S. markets and into other regions** has helped drive the dollar lower over the past year, analysts say.

The bearish view held by asset managers contrasts with the current collective stance of hedge funds and other leveraged investors, who started betting on a stronger dollar after President Donald Trump signed the tax-overhaul bill into law in late December. Hedge funds had been negative on the dollar for much of the second half of 2017.

"Near-term, leveraged fund positioning tends to correlate with price action for currencies, while asset managers' money is more sticky," said Khoon Goh, head of Asia research at Australia & New Zealand Banking Group in Singapore, who tracks CFTC data for both asset managers and hedge funds.

Mr. Goh estimates these asset managers are the most net bearish on the U.S. dollar on record when measured against the euro, yen and other major currencies

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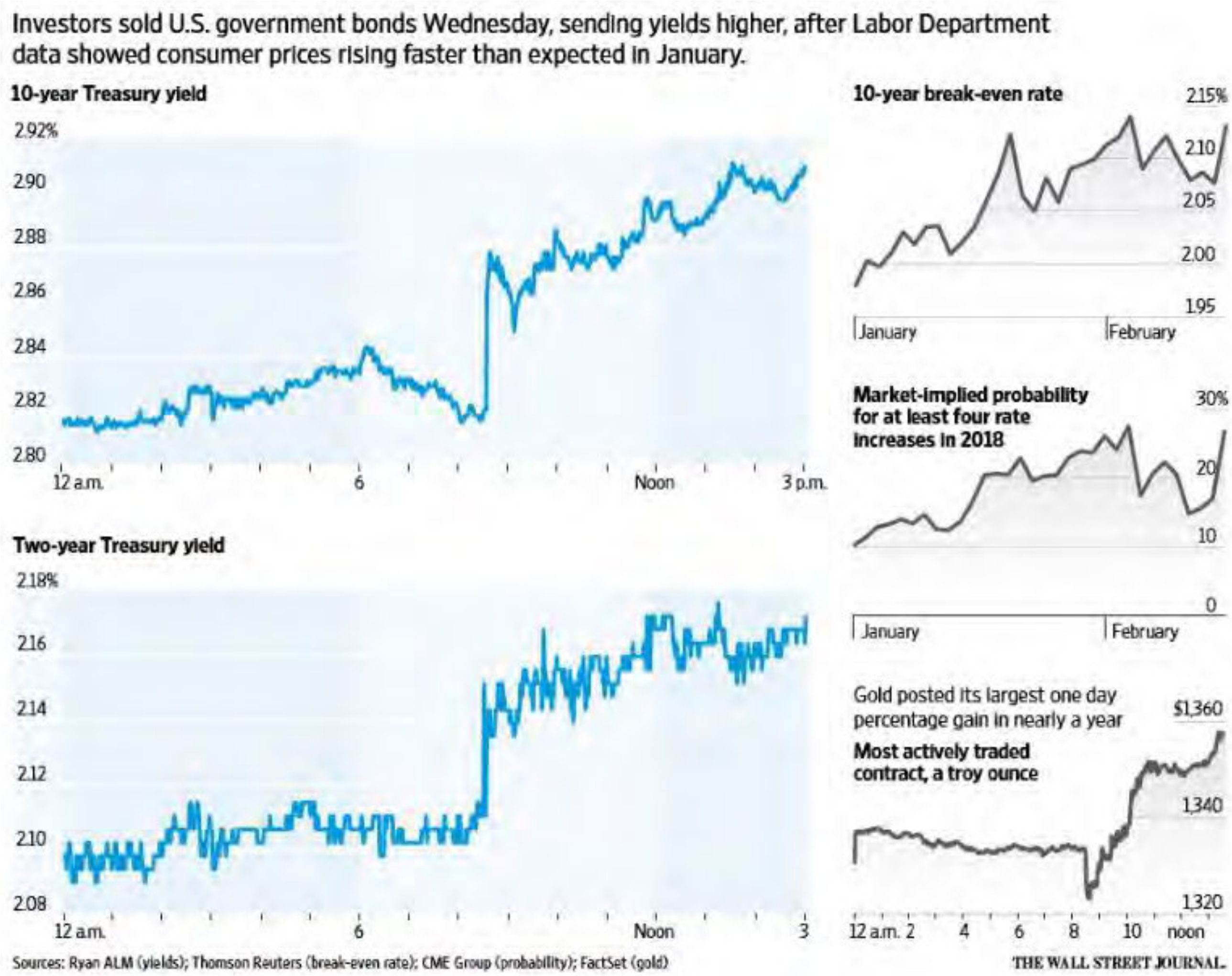
U.S. Treasurys Weaken after Price Data

by Akane Otani – WSJ – Feb. 15, 2018
Daniel Kruger contributed to this article.

The yield on the benchmark 10-year U.S. Treasury note, which affects everything from mortgage rates to corporate loans, rose to four-year highs Wednesday after consumer price data showed inflation continuing to firm.

Increases in consumer prices in recent months have fed concerns among investors that long-dormant inflation could be accelerating. At the same time, some investors worry an expanding federal budget deficit could lead to an oversupply of bonds in the market.



That backdrop made Wednesday's data on **consumer prices** particularly **important for traders**, many of whom feared an unexpectedly strong reading that leads bond yields to jump could send global markets reeling again. **Inflation poses a threat to bond prices because it chips away at the value of the securities' fixed payments.**

In recent weeks, such **fears caused investors** to **sell bonds**, which **led yields** to **rise**, **pressuring shares** from New York to Tokyo.

"Much of the 2017 market environment rested on a number of assumptions which are now being repeatedly **challenged** — in this case, the **assumption** that **inflation** was '**dead**,' " said James Athey, senior investment manager at Aberdeen Standard Investments.

Yields rose early **Wednesday after** the **Labor Department said** its **consumer-price index**, a measure of what Americans pay for everything from theater tickets to breakfast cereal, **rose 0.5% in January**, **while** so-called **core prices**—which **exclude** the **volatile food** and **energy categories**— **rose 0.3%.**

Economists surveyed by The Wall Street Journal had **expected CPI to rise by 0.4%** and **core** prices to increase **by 0.2%**.

The **stronger-than-expected pickup in prices sent bond yields to multiyear highs**, with the 10-year Treasury note climbing to 2.913%, the highest closing level since Jan. 9, 2014, compared with 2.837% Tuesday.

Yet the reaction in other markets was more sanguine, a contrast to two weeks ago, when a leap in bond yields sent asset prices around the world tumbling.

U.S. stocks rebounded, further chipping away at the losses that had sent them into correction territory earlier this month. Meanwhile gold, which typically suffers when investors expect higher rates and inflation, notched its biggest oneday percentage gain since March.

The U.S. dollar, which tends to rise with inflation expectations, headed for its fourth consecutive decline, deepening its losses for the year.

However, the extra yield investors demand for holding junk-rated debt remains near multiyear lows, even after ticking higher lately.

Some analysts said the relative calm in other markets partly reflected skepticism about whether

January's figures pointed to a longer-term pickup in inflation, as opposed to transitory gains in prices. For instance, apparel prices rose at the fastest pace since 1990 in January, which some analysts blamed on cold weather across the U.S., while gasoline prices — which have since retreated from earlier highs — also helped drive inflation higher.

"We're **not talking about runaway inflation**," said Putri Pascualy, portfolio manager and senior credit strategist at Pacific Alternative Asset Management Co. Rather, **investors are seeing** the **latest uptick in prices as having come from** "a **context where inflation was nonexistent**."

The Federal Reserve's preferred measure of inflation, the price index for personal-consumption expenditures, has largely undershot the central bank's 2% target, suggesting there is still room for prices to rise.

Some investors also said the relatively gradual pace of bond yield increases in recent sessions appeared to be keeping pressure off other markets. The yield on the

10-year note, for instance, posted a bigger one day move on Feb. 7, a day before U.S. stocks fell into correction territory.

Treasury yields have yet to reach levels that many say could mark the start of a more severe bond selloff. **Many investors and analysts have said** a **yield** of **3% or higher on** the **10-year Treasury** would mark the **point at which bonds could pose** a **threat to stocks**. For years, those have looked attractive to yield-seeking investors because of ultralow interest rates around the world.

The last time the yield on the 10-year note closed above the 3% level was the end of 2013.

Still, others remain concerned that a faster-than-expected pickup in prices could hurt bonds by pushing the Federal Reserve to pick up its pace of interest-rate increases. After the Labor Department's report, federal-funds futures, used by traders to place bets on the course of interest rates, showed a slightly higher chance of the Fed accelerating its pace of rate increases in 2018. The **market on Wednesday priced in** a **roughly 26% chance of at least four interest-rate increases by year-end**, according to data from CME Group, **compared with 17% one day earlier**. That put pressure on bonds carrying shorter maturities, sending yields higher. The yield on the two-year Treasury note, which tends to be highly sensitive to the path of the Federal Reserve's interest rates, jumped to 2.173%, compared with 2.104% Tuesday, settling at the highest level since Sept. 12, 2008. Meanwhile, the yield on the five-year Treasury note rose to 2.640%, its highest close since April 6, 2010.

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A Value Proposition for Value over Growth

by Steven Russolillo – WSJ – Feb 16, 2018

A **little volatility might be what value stocks need** to get their mojo back.

Such stocks, which tend to have **slow but steady earnings growth** and **cheap valuations**, **vastly underperformed** their **pricier growth counterparts globally last year**, compounding a gap that has persisted since the end of the financial crisis. Just **think** of the surging shares in sectors such as tech, led by the likes of **Facebook** Inc. and **Tencent** Holdings Ltd., **compared with** relative underperformers such as **utilities** stocks.

Last summer, Goldman Sachs Group Inc. even **questioned whether** the **markets** were **witnessing** the **death of value investing**.

Left: Growth Stocks like Tencent, which has joined with lego to promote online safety, have outperformed value shares, which some say are poised to shine.

But if the recent market swoon world-wide is any indication, **value stocks could be poised for** a **comeback**, according to an analysis by Morgan Stanley.

Value stocks have **historically** tended to **outperform growth in high-volatility environments**, **as investors seek** what are perceived as **safer** and **steadier stocks**. **Morgan Stanley** defines **high volatility** as being when the **Cboe Volatility Index**, or **VIX**, rises **over 30**. The **VIX surged 116%** on **Feb. 5**, its **biggest one-day gain ever**, **finishing** that day at **37.3,** its highest since August 2015. On **Thursday**, the **VIX fell** 0.7%, to **19.13**, **near** its **long-term average**.

"We find **high-volatility** regimes tend to **favor** a **rotation into value**," says Steven Ye, a quantitative analyst at **Morgan Stanley** in Hong Kong. In previous instances when the VIX rose to what he called extreme levels, as in 1987, 1998, 2008, 2010 and 2015, it has tended to remain elevated for several months.

"It is important to distinguish the current correction as a valuation-driven one, since macro and earnings trends remain positive," Mr. Ye said. "In such a correction, we would look for value with cash flows and **avoid both expensive growth stocks**" and **bondlike stocks that pay high dividends**.

Morgan Stanley's positive call on value stocks hasn't fully come to fruition, although the gap between the performance of value and growth stocks appears to be narrowing.

In Asia, an index of value stocks provided by MSCI Inc. is roughly unchanged in 2018, compared with a 1.4% gain for a rival growth-stocks index. Last year, growth stocks outperformed value in Asia by 20 percentage points.

A similar trend holds true in the U.S. The Russell 1000 Growth Index is up 2.7% this year, compared with a 1.1% drop for its value counterpart. Growth stocks rose 28% last year, compared with an 11% increase for value stocks.

Moreover, markets have calmed in recent days. Most Asian stock indexes rose Thursday after strong overnight gains in the U.S. and Europe. That comes after several indexes around the world, including Japan's Nikkei Stock Average, Hong Kong's Hang Seng Index and the S& P 500 in the U.S. all fell into correction territory last week, down at least 10% from a recent high.


Out of Favor
Value stocks in Asia have lagged behind growth shares even as volatility has risen this year.*
Growth
Value
Growth stocks beat value in Asia last year.*
Growth stocks have beaten value stocks in the U.S. since the start of 2017.†
*Benchmarks are MSCI EM Asia Value Index and MSCI EM Asia Growth Index †Benchmarks are Russell 1000 Growth Index and Russell 1000 Value Index
Source: FactSet
THE WALL STREET JOURNAL.

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Wild Ride
The dollar swung sharply this week as U.S. officials spoke at Davos about its value. But other factors had an impact in foreign-exchange trading, as several large Asian countries have bought dollars in a bid to weaken their currencies to keep exports competitive.
Dollar's performance vs. Asian currencies
Chinese Yuan
Korean Won
New Taiwan Dollar
Thai Baht
Foreign-exchange reserves (excluding gold)
China
Hong Kong, Korea, Singapore, Taiwan
Indonesia, Malaysia, Philippines, Thailand
Monthly change in the People's Bank of China's foreign reserves
Sources: Council on Foreign Relations (reserves); WSJ Market Data Group (currencies)
THE WALL STREET JOURNAL.

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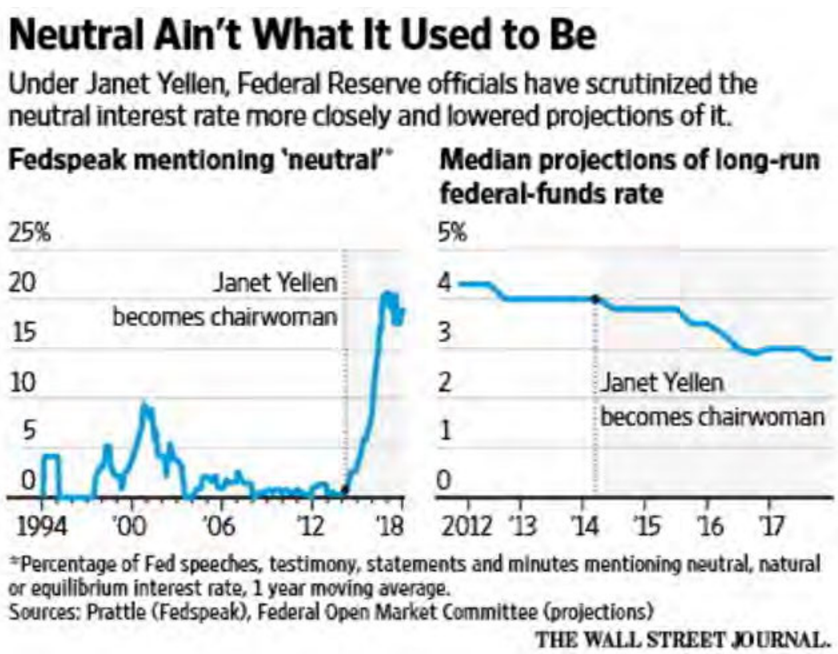
Yellen Bequeaths a New Normal for Rates

by Greg Ip – WSJ – Capital Account Column – Feb. 1, 2018

Janet Yellen leaves a huge and largely unappreciated imprint on interest rates that will reverberate long after her last Federal Reserve policy meeting Wednesday.

This isn't because of the rate increases the Federal Reserve chairwoman engineered over the past four years. Rather, it is because she persuaded her colleagues and the broader public to change their views radically on where interest rates should be in the long run.



When Ms. Yellen took office in February 2014, her colleagues generally believed short-term rates, then zero, would eventually return to their precrisis average of 4% (or 2%, after inflation). The notion of where rates will settle in the long run is also called the equilibrium, natural or neutral rate: low enough to keep the economy growing and unemployment low but high enough to maintain stable inflation. Over the course of Ms. Yellen's term, thanks to her persuasion, Fed officials ratcheted down their estimates of neutral to 2.8% (0.8% after inflation).

The decline in neutral, in turn, plays a key and largely unappreciated role in how the Fed has, and will continue to, set interest rates. Just as distance to the runway determines how soon and how rapidly an aircraft descends, the distance to neutral determines when the Fed raises rates and how quickly. By convincing her colleagues the neutral rate had fallen, Ms. Yellen has anchored the Fed's entire rate path, justifying the glacial pace of increases Ms. Yellen pursued and her successor, Jerome Powell, plans to continue.

The Swedish economist Knut Wicksell first described the neutral rate more than a century ago. Think of a market in which savers supply and borrowers demand funds. At the neutral rate, the supply and demand for funds is in balance. It can't be directly observed, but it can be inferred. If the economy is overheating, then rates are probably below neutral, fueling excess borrowing and spending. If inflation is

dropping, **rates** are **probably above neutral**; there is **too little borrowing and spending**.

For years, central banks paid little attention to neutral. It had been pegged to around 4% in the early 1990s and didn't seem to have moved much since. The term, and its variants, appeared in barely 1% of Fed speeches and statements before 2014. Shortly after Ms. Yellen took office, neutral began to occupy the Fed's attention. By 2017, it was cropping up in nearly 20% of Fed speeches and statements, according to an analysis by Prattle Analytics LLC, which quantifies market-moving language from companies and central banks.

After her first full meeting as chairwoman, Ms. Yellen had the accompanying statement hint that neutral had dropped, at least for the time being. More dovish colleagues began making the case in public, and by that summer, most were marking down their estimates.

Initially, Ms. Yellen was looking for an explanation for why such low rates were generating only modest growth. She blamed temporary headwinds, such as the need to pay down crisis-era debts. As the crisis receded, economists such as **Harvard University's Larry Summers argued** there was more to it: The **world** had **entered** a **low-rate era**. **Aging populations and low productivity growth sapped** the **demand** for funds, while high saving in the likes of China and investor hunger for safety buoyed the supply.

The **implication**: The **U.S. economy simply couldn't tolerate rates as high as in the past**. If the Fed ignored the lesson, it **could trigger a new recession**. "My colleagues and I began to realize, Gee, the new normal was very different," Ms. Yellen recalled last year, which "led to a big rethink about how much we would actually need to raise" interest rates.

Ms. Yellen faced resistance from insiders and outside critics, who thought scrapping longstanding estimates of neutral risked inflation, asset bubbles and lost credibility for the Fed. But the majority sided with her. A **low neutral rate** is **likely** to **remain the consensus within** the **Fed** for **some time** after Ms. Yellen leaves.

The risk for Mr. Powell, as Mr. Wicksell noted a century ago and Ms. Yellen has more recently, is that neutral is uncertain, and it changes. The forces holding back growth and borrowing may in fact be temporary.

Ms. Yellen's bet on a low neutral rate has served the economy well so far. If Mr. Powell has to undo the bet, his term promises to be a lot rockier

CASE: UG 344
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 212

Staff CAPM Results
(Capital Asset Pricing Model)

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff's Representative CAPM Modeling Results

2.87%	Risk Free Rate as Wall Street Journal (WSJ) Feb. 28, 2018 effective 10 Yr US Treasury (UST) Yield
3.14%	Risk Free Rate as WSJ Feb. 28, 2018 effective 30 Yr UST Yield
4.50%	Ibbotson Market Risk Premium (Since 1980 — My Adult Lifetime)
6.00%	Morningstar in Stocks, Bonds, Bills and Inflation 2015 Classic Yearbook (Very Long Run since 1926)

$R_{AVA} = R_f + Beta*MRP$

	#	Abbreviated Utility	UG 344 Company	UG 344 Staff	Ticker	VL 2/24/2018 Beta	Ibbotson's Modern Adult Lifetime Perspective: 10-Yr Forward UST CAPM w VL Beta	Ibbotson's Modern Adult Lifetime Perspective: 30-Yr Forward UST CAPM w VL Beta	Morningstar Very Long Historical Perspective: 10-Yr Forward UST CAPM w VL Beta	Morningstar Very Long Historical Perspective: 30-Yr Forward UST CAPM w VL Beta
1	1	Atmos	Yes	Yes	ATO	0.70	6.02%	6.29%	7.07%	7.34%
2	2	Chesapeake	Yes	No	CPK	0.70	6.02%	6.29%	7.07%	7.34%
3	3	New Jersey	Yes	No	NJR	0.80	6.47%	6.74%	7.67%	7.94%
4	5	Northwest Natural	Yes	Yes	NWN	0.70	6.02%	6.29%	7.07%	7.34%
5	6	ONE Gas	Yes	Yes	OGS	0.70	6.02%	6.29%	7.07%	7.34%
6	7	South Jersey	Yes	No	SJI	0.85	6.69%	6.96%	7.97%	8.24%
7	8	Southwest Gas	Yes	Yes	SWX	0.80	6.47%	6.74%	7.67%	7.94%
8	9	Spire	Yes	Yes	SR	0.70	6.02%	6.29%	7.07%	7.34%
9	11	WGL	Yes	No	WGL	0.80	6.47%	6.74%	7.67%	7.94%
		TOTAL PEERS	9 all	5		Mean	6.11%	6.38%	7.19%	7.46%
			6 w/o M&A	80% Mid Cap			6.24%	6.51%	7.37%	7.64%
							6.09%	6.36%	7.17%	7.44%

Mean rows: Staff Gas Screen; Company Peer Screen; Company Peer Screen - w/o M&A

Individual Utility Minimum ROE: 6.02%

Individual Utility Maximum ROE: 8.24%

Minimum Mean of Peer Groups	6.09%
Hamada Adjusted	6.48%
Maximum Mean of Peer Groups	7.64%
Hamada Adjusted	7.96%
Point CAPM ROE	7.22%

CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

April 20, 2018

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

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street S.E., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I present Staff findings in the general categories of utility plant and pensions and propose related staff adjustments.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/302, Proposed Gross Plant Adjustments

Exhibit Staff/303, Major Project List

Exhibit Staff/304, Distribution Expense Adjustment

Exhibit Staff/305, Construction Overhead Adjustment (confidential)

Exhibit Staff/306, Stock Based Compensation

Exhibit Staff/307, Pension Expense

Exhibit Staff/308, Other Post Retirement Benefits Expense

Exhibit Staff/309, Data Request Responses

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Regarding plant asset additions, what was the earliest month of data included in Company's work papers filed with this case?

A. The starting point in the Company's model is December 31, 2016.[1]

Q. What was the last full calendar year of costs included in the Company's previous general rate case UG 221?

A. The base year for UG 221 was 2011 with rates effective November 1, 2012.

Q. Please describe the methods used by Staff to review plant additions in the years between 2012 and 2017.

A. Staff obtained lists of individual assets placed into service system-wide between 2012 and 2017.[2] Staff compared these lists to plant investment as reported on the FERC Form 2 filed annually under Docket No. RG 37, the lists of projects not yet completed as of the effective date of rates under UG 221,[3] and projects discussed in the opening testimony and work papers of the current case.[4]

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[1] UG 344 200 wp7 - Gross Plant and Accum Deprec.
[2] 2017 Plant Audit OPUC-AIR 45 and OPUC-AIR 47.
[3] Staff/309, NW Natural Response to Staff DR 200.
[4] Staff/309, NW Natural Response to Staff DR 198.

Q. What was the volume and dollar value of assets placed into service between 2012 and 2017?

A. Approximately 85,000 assets valued at $763.5 million.

Q. **What was your strategy for reviewing that much data?**

A. We focused on asking questions about significant additions and account changes that were not discussed in testimony.[5] In response, the Company provided over 100 files containing over 2,800 pages of documentation and data.

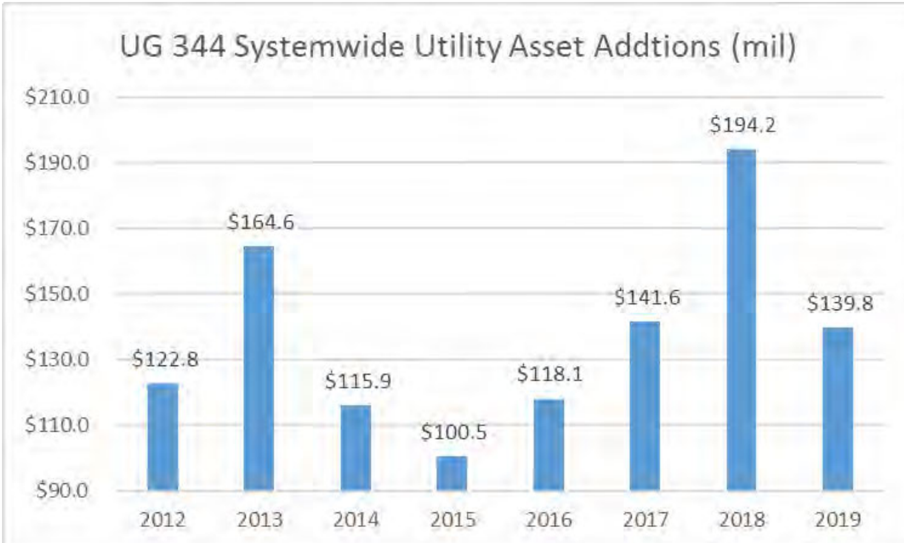
Q. What other information did you review?

A. We obtained copies of annual capital budgets, selected project budgets and documents, work in process, and information about the application of construction overhead and AFUDC to certain projects.

Q. Regarding gross plant additions, is there an overarching issue in this case?

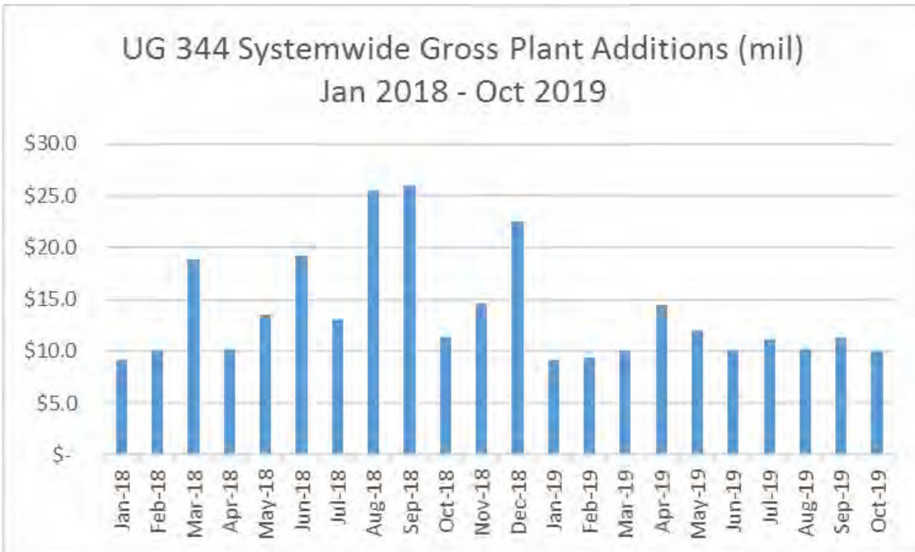
A. Yes, the amount of plant investment projected in 2018 is abnormally high as illustrated in the following chart:

[5] Staff/309, NWN Responses to Staff DRs 122, 195-217, 251-258, 264, 266, 366, 403.



Furthermore, when major projects[6] are removed, the average level of spending from 2012-2015 is less than $100 million per year and $113 million and $122 million for 2016 and 2017, respectively. Accordingly, the magnitude of additions projected for 2018 is even more unusual. The following chart shows projected gross plant additions by month from January 2018 through the end of the test year:

[6] Major projects: Mid-Willamette Valley Feeder, Corvallis Reinforcement, South of Monmouth Bare Steel Replacement, Sherwood Facility, Salem Retrofit, Improvements at the Portland and Newport LNG Plants, and a few others.



Q. Did the Company provide lists of specific assets to be added during the projected months?

A. Yes, in the Company's response to Staff DR 264. However, the assets identified are 30-50% of the projected gross plant additions. This is discussed further in my testimony regarding issues and proposed adjustments below.

Q. Are you proposing any adjustments?

A. Yes, Staff is questioning the prudence of two large projects, the Mid-Willamette Valley Feeder and Corvallis Loop.[7] We are also proposing additional gross plant adjustments as discussed in the remainder of my testimony.

Q. Is there additional information not involving proposed financial adjustments that Staff believes should be on the record as part of this rate case?

[7] Opening Testimony of Lance Kaufman Staff/700, Kaufman/3-25 and 26-36.

A. Yes, review of the Company's annual capital budgets indicate that the Company's investment in bare steel replacement, leakage reconstruction, and distribution integrity declined following the sunset of the Safety Improvement Program.[8]

UG 344 OPUC DR 197	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual
	$	$	$	$	$	$
2. REPLACEMENTS SUPPORTED BY REVENUES	9,331,985	21,762,042	17,147,487	6,000,000	-	-
TOTAL BARE STEEL	2,921,159	16,004,549	11,704,825	5,450,603	582,586	358,628
BARE STEEL-MAINS-119	2,473,633	15,579,141	11,172,767	3,937,421	117,345	294,418
BARE STEEL-SERVICES 319	447,526	425,408	532,058	1,513,182	465,241	64,210
TOTAL LEAKAGE	1,083,145	1,954,297	2,684,136	1,818,447	506,514	676,638
LEAKAGE RECONSTRUCTION - MAINS	967,772	1,743,320	2,362,562	1,539,474	328,549	348,762
LEAKAGE RECONSTRUCT - SERVICES	115,373	210,978	321,574	278,973	177,966	327,876
LESS: UNALLOWED LEAKAGE/BARE STEEL	(3,000,000)	(3,750,000)	(3,750,000)			
DISTRIBUTION INTEGRITY - MAINS (DIMP)	1,564,351	791,351	410,279	87,306	154,177	510,603
DISTRIBUTION INTEGRITY - SERVICES (DIMP)	658,731	1,350,562	1,223,500	735,004	360,739	314,014
TRANSMISSION INTEGRITY (TIMP)	6,354,599	5,661,282	5,124,748	4,460,286	3,749,325	4,385,889
GUARDPOST PLACEMENT					65,078	146,039
LESS: UNALLOWED DIMP & TIMP	(250,000)	(250,000)	(250,000)	(6,551,646)	(5,418,418)	(6,391,812)

Q. Why is the decrease in spending significant?

A. Opening testimony indicates the Company's intent to apply for a safety cost recovery mechanism under Commission Order No. 17-084 after the current rate case.[9] Accordingly, the fluctuation in spending patterns may be relevant in future proceedings.

Q. Regarding pension costs, is there an overarching issue in this case?

A. Yes, the amount of pension cost included in rates has been limited to approximately $3.8 million per year since 2003.[10] A balancing account was

[8] *See In The Matter of Northwest Natural Gas Company dba NW Natural, Application for an Accounting Order*, Docket No. UM 1406, Order No. 09-067 (Mar 01, 2009), and *In The Matter of Northwest Natural Gas Company dba NW Natural, Motion to Amend Order Approving Stipulation and Application Regarding Accounting Treatment of System Integrity Program*, Docket No. UM 1406, Order No. 11-337 (Aug 30, 2011).
[9] NW Natural/100, Anderson/13-14; NW Natural/800, Karney/50-51.
[10] *See In The Matter of Northwest Natural Gas Company, Application for a General Rate Revision Advice No. 02-19*, Docket No. UG 152, Order No. 03-507 (Aug 22, 2003).

established in 2011 for Company contributions in excess of that amount.[11] The amounts recorded in the balancing account have significantly diverged from the estimates prepared in 2011.

[11] *See In The Matter of Northwest Natural Gas Company dba NW Natural, Application to Defer Pension Costs*, Docket No. UM 1475, Order No. 11-051 (Feb 10, 2011).

ISSUE 1. TEST YEAR PLANT ADDITIONS (NOV 2018 TO OCT 2019)

Q. Please briefly describe the purpose of this adjustment.

A. The purpose is to remove plant additions after the effective date of rates in this case pursuant to the provisions of ORS 757.355 and Commission policy.

Q. What is the Company's proposed gross utility plant in service?

A. The proposed gross utility plant in service is $2,844,623,408.[12], [13]

Q. Does Staff propose an adjustment for test year plant additions?

A. Yes, Staff removes $68,419,992[14] of additions scheduled to occur on or after November 1, 2018, the effective date of rates in this case.

Q. Does your adjustment remove predictable distribution type expenses?

A. Yes, however, Staff adds back a portion of those expenses as discussed in Issue 5. Recovery of Predictable Distribution Type Expenses in Rate Base.

Q. Why is Staff proposing that property additions during the test year be removed?

A. ORS 757.355 provides that "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

[12] NW Natural/200, McVay/201, line 16, 202, line 18, and 210, line 1.
[13] Details regarding how the $2,844m figure is derived are found in 200 wp7 - Gross Plant and Accum Deprec.
[14] Staff/302, Fox/1.

Under this statute, the cost of plant that is scheduled to come on-line until after the rate effective date of November 1, 2018, should not be included in rate base.

Q. How did Staff determine the amount of the adjustment removing investment in plant scheduled to come on-line after the rate effective date?

A. We changed the input assumptions in the model provided by the Company.[15]

Q. What calculation steps occur in the model provided by the Company?

A. In summary, the model follows these steps:

- Gross plant, including additions, is forecasted by month at the FERC account level.
- FERC accounts are grouped into the following categories:
    - Intangible – Software
    - Intangible Other
    - Production
    - Transmission
    - Distribution
    - General
    - Storage and Storage Transmission
    - Land & Structures
    - CNG/LNG

[15] UG 344 200 wp7 - Gross Plant and Accum Deprec.

- Oregon plant balances in the following categories are included in the calculated rate base for each month: Intangible – Other, Production, Transmission, and Distribution.
- System-wide plant balances in the following categories are allocated[16] between Oregon and Washington: Intangible – Software, General, Storage and Storage Transmission, Land & Structures, and CNG/LNG.
- The test year plant is the average of the following monthly rate bases:
  - One half of the October 2018 balance, plus
  - The eleven months from November 2018 through September 2019, plus
  - One half of the October 2019 balance.

Q. Is the model consistent with how rate base was calculated in the prior rate case UG 221?

A. Yes, beginning with the monthly FERC balances except the CNG/LNG category is new in UG 334.

Q. How did Staff change the input assumptions to determine the amount of plant additions during the test year?

A. We held the October 2018 plant balances by FERC account constant throughout the test year thereby eliminating the test year additions that flowed through the model described above.

[16] Allocation factors are further discussed in Issue 4.

Q. Why does Staff believe this is to be the most fair and reasonable way to calculate the adjustment?

A. Due to the complexity of how the FERC accounts are grouped and allocated between states, this method is holistic and ensures the adjustments flowing through to the rate case are calculated in a way that is consistent with how gross plant is calculated in the rate case as filed. Also, this method creates an objective audit trail that is transparent and easier for a reviewing party to follow.

Q. Did you notice anything unusual within the cell formulas in the Company model?

A. Yes, the first $33 million of Storage and Storage Transmission is allocated directly to Oregon and the remainder is allocated between Oregon and Washington. This is "hard coded" in the cell formulas.

Q. Were you able to determine the nature of the $33 million adjustment from the Company work papers?

A. No, the Company's response to DR 403 indicates the purpose of the adjustment is to specifically allocate $33 million of the total South Mist Pipeline Extension to Oregon as agreed in a prior rate case.[17]

Q. Did the Company provide a list of specific assets projected to be placed into service in the test year?

A. Yes, in the Company's response to Staff DR 264. The list includes $24.9 million of "Major items" planned for Oregon.[18] Staff notes that the listed items

[17] The Company's Direct Testimony in UG 152 (UG 152/NWN/400 Stinson at pages 20 – 22) and NWN Advice No. OPUC 04-11A.
[18] See Staff/303, Fox/3.

are 36 percent of the $68.4 million of projected Oregon gross plant additions in the test year.

Q. Are any of the major items listed by the Company mentioned in the Company's testimony?

A. Yes, portions of the Eugene Retrofit, Sherwood Test Building, SE Eugene Project, Newport Refurbishment, and Mist Reliability. However, there are numerous other projects listed that were not mentioned specifically in the Company's opening testimony.

Q. Are any of the major items included in the proposed rate base of $2,844 million?

A. Yes, all of them.

Q. Is Staff proposing a rate base adjustment for any of the major items?

A. Yes, they are included in the removal of all asset additions in the test year. No additional adjustment is necessary at this time.

ISSUE 2. PLANT ADDITIONS (JUL 2018 TO OCT 2018)

Q. Please briefly describe the purpose of this adjustment.

A. There is an unusually large amount of gross plant additions in 2018, most notably in the months of July through September 2018. The effective date of any rate change stemming from this case is November 1, 2018. Staff concludes there is currently insufficient evidence to show that plant scheduled to come on line on or after July 1, 2018, is reasonably certain to be in service prior to the November 1, 2018 rate effective date.

Q. Is Staff proposing an adjustment for plant additions in the months of July through October 2018?

A. Yes, Staff removes $65,403,801[19] of additions scheduled to occur in those months.

Q. Does your adjustment remove predictable distribution type expenses?

A. Yes, however, Staff adds back a portion of those expenses as discussed in Issue 6. Recovery of Predictable Distribution Type Expenses in Rate Base.

Q. How is the adjustment calculated?

A. We changed the input assumptions in the model provided by the Company.[20]

Q. What is the reasoning underlying this adjustment?

A. The property would be used and useful if placed in service prior to November 1, 2018, the effective date of rates in this case. However, Staff cannot conclude with reasonable certainty that the plant scheduled to come on line in the

[19] Staff/302, Fox/1.
[20] NW Natural workpaper, 200 wp7 - Gross Plant and Accum Deprec.xlsx.

months before the rate effective date will actually be on-line when the rates become effective.

In Docket No. UG 325, the Commission made the following statement regarding inclusion of plant in rate base:

> However, we would remind parties wishing to include plant not yet-in-service as part of the proposed revenue requirement in future rate cases, to be prepared to explain such proposals with particularity and to justify via clear and convincing evidence, the circumstances providing the rationale for their inclusion in their general rate case application.[21]

Based on the rate case schedule established at the prehearing conference February 1, 2018, Staff believes it is unrealistic to anticipate reviewing actual expenditures incurred after June 30, 2018. Accordingly, Staff is proposing an initial adjustment removing all additions in the July 2018 – Oct 2018 time period with the understanding that assets will be added to rate base on a case by case basis as the Company provides clear and convincing evidence and attests that the assets will be used and useful on or before November 1, 2018.

Q. Did the Company provide a list of specific assets projected to be placed into service in the months of July through October 2018?

A. Yes, in the Company's response to DR 264. The list includes $33.1 million of "Major items" placed planned for Oregon.[22] Staff notes that the listed items are 51 percent of the $65.4 million of projected gross plant additions in the months of July through October 2018.

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[21] *See In The Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket No. UG 325, Order No. 17-344 (Sep 13, 2017).
[22] Staff/303, Fox/2.

ISSUE 3. PLANT ADDITIONS (OCT 2017 TO JUL 2018)

Q. Please briefly describe the purpose of this adjustment.

A. This is an adjustment for costs that may be identified by Staff prior the end of the rate case.

Q. Is Staff proposing an adjustment for assets placed into service between October 2017 and June 2018?

A. Not at this time, as noted above Staff expects to review the actual cost and prudence of these assets prior to the end of this rate case.

Q. Can you give an example of why Staff would need to review actual additions rather than simply including the Company estimates in gross plant?

A. Yes. The Company's response to DR 210 indicates that the balance in FERC Acct. 354.5 Deer Island Compressor is a not utility asset. However, the gross plant work paper provided by the Company includes periodic additions to this account beginning in the first estimated month, October 2017, and escalating to a value of $810,467 at the end of the test year in October 2019. In light of the incongruity between Company statements, Staff is not confident that the entirety of the projections are accurate. Accordingly, Staff believes the plant additions between October 2017 and June 2018 require additional scrutiny.

Q. **Does the 2017 base year for this rate case, as filed, include actual expenditure data after September 2017?**

A. No, the last three months of 2017 are forecasted.[23]

[23] NN Natural/200, McVay/5.

Q. What are the additions to Oregon gross plant from October 2017 through June 2018 in this case?

A. The Company's work papers include $111.5 million of Oregon gross plant additions within that time frame.

Q. Did the Company provide a list of specific assets projected to be placed into service in the months of January through June 2018?

A. Yes, in the Company's response to DR 264. The list includes $23.2 million of "Major items" planned for Oregon.[24] Staff notes that the listed items are 22 percent of the $70.6 million of projected gross plant additions between January 2018 and June 2018.

[24] Staff/303, Fox/1.

ISSUE 4. LAND AND BUILDING ALLOCATIONS

Q. Please briefly describe the purpose of this adjustment.

A. I propose an adjustment to more accurately calculate the land and building component of gross plant.

Q. What is the nature of the proposed Staff adjustment to land and building allocations?

A. The Company's response to DR 122[25] indicates they are calculating Oregon allocation factors on a property-by-property basis. The rate case work papers are using an average of these individual factors for both gross plant and accumulated depreciation, which results in an increase in Oregon net plant of $1.4 million.

Staff proposes using the more accurate individual averages for gross plant and accumulated depreciation (91.2 percent and 93.6 percent, respectively) since the Company is already going to the effort of calculating these averages at the more detailed individual asset level.

Q. Did the Company provide an explanation for why it is using the higher factor for the gross plant calculation?

A. Yes, the Company states that the higher percentage is appropriate because it will be applied prospectively to future land and building additions.[26] Staff notes that the majority of the additions in the account have already occurred and are inflated by using the higher percentage. In addition, Staff will have the

[25] Staff/309, NW Natural Response to Staff DR 122 Attachment 2 Structures Alloc - Dec 2016.
[26] Staff/309, NW Natural Response to Staff DR 251.

opportunity to either review the actual costs incurred through June 2018 or management attestation of costs for the months of July-Oct 2018 thereby providing Staff an opportunity to review the Oregon allocation percentage. Therefore, Staff's position is that the Company's use of a higher allocation rate in the model is not justified.

ISSUE 5. RECOVERY OF PREDICTABLE DISTRIBUTION TYPE EXPENSES IN RATE BASE

Q. Please briefly describe the purpose of this adjustment.

A. I propose an adjustment to allow the Company to recover incremental costs associated with predictable distribution plant additions in the test year to match additional customer revenues included in the rate case.

Q. Regarding utility plant, are customer related additions defined in the Company testimony?

A. Yes, the Company defines customer additions as mains, services, and meters.[27] Although regulators are not mentioned specifically, Staff believes they should be included as they are associated with individual customer services.

Q. What is the Commission standard for Staff analysis of "distribution system upgrades"?

A. The Commission has identified six criteria for evaluating system upgrades:[28] Such analyses should provide:

1. a comprehensive cost-benefit analysis of whether and when the investment should be built;
2. evaluation of a range of alternative build dates and the impact on reliability and customer rates;

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[27] NW Natural/200, McVay/22.

[28] *See In Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket No. UG 288, Order No. 16-109 at 13-14 (Mar 15, 2016), *and In Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 221, Order No. 12-437 at 16-17 (Nov 16, 2012).

3. credible evidence on the likelihood of disruptions based on historical experience;
4. evidence on the range of possible reliability incidents;
5. evidence about projected loads and customers in the area; and
6. adequate consideration of alternatives, including the use of interruptability or increased demand-side measures to improve reliability and system resiliency.

Q. Did the Company provide the information necessary for Staff to review and approve distribution system assets in this case?

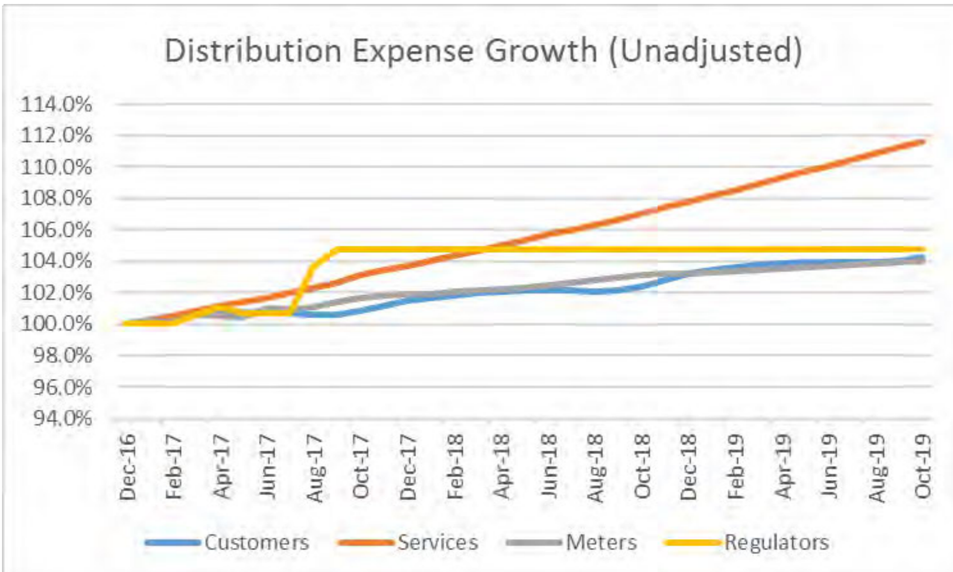
A. With regard to distribution mains, no. Many of these are large projects that should have been fully explained in testimony. With regard to services, meters, and regulators, they are essential for customers connect to the system to receive service and the Commission, in the past, has allowed these additions in rate base proportional to the growth in customers though the test year.

Q. What is Staff's recommendation in this case regarding distribution mains?

A. Staff is proposing an initial adjustment removing all additions from the July 2018 through October 2019 time period (included in adjustments discussed in Issues 1 & 2, above) with the understanding that assets will be added to rate base on a case by case basis as the Company shows and attests that the assets will be used and useful on or before November 1, 2018.

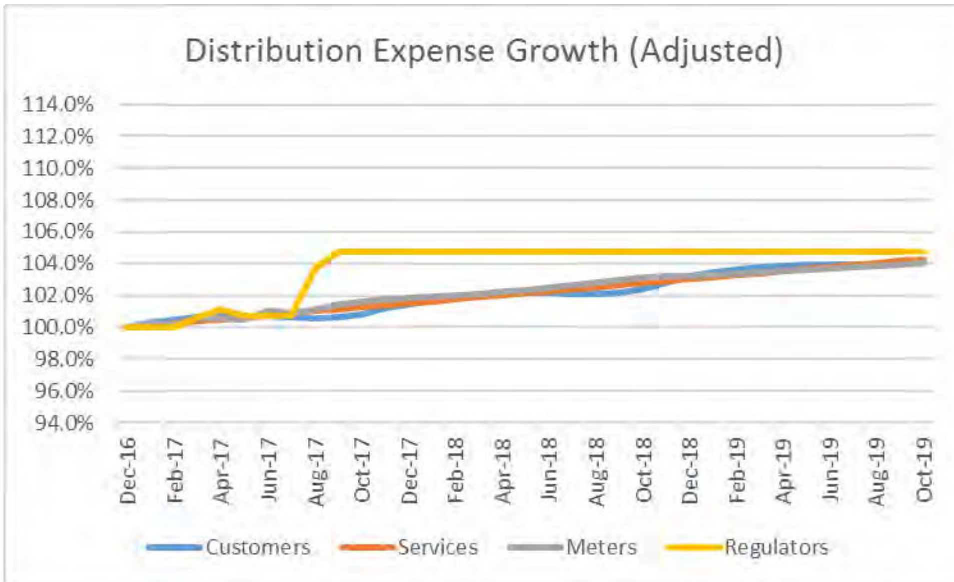
Q. What is Staff's recommendation in this case regarding services, meters, and regulators?

A. Staff is recommending that services, meters, and regulators be added back to gross plant through the end of the test year proportionate to customer growth. The following chart shows the unadjusted rate of growth in services, meters, and regulators:[29]



The following chart shows services, meters, and regulators with service additions limited to the growth in customers.

[29] Customer data from 200 wp2 Rate Case Margin Model. Plant additions derived from Oregon Plant Balances from 200 wp7 Gross Plant and Accum Deprec.



Q. Please elaborate regarding customer growth.

A. Oregon customers are projected to increase from 641,537 in December 2016 to 669,025 in October 2019, an increase of 4.3 percent.[30]

Q. Please elaborate regarding meters.

A. Costs for Oregon meters are projected to increase from $174.1 million in December 2016 to $181.1 million in October 2019, an increase of 4.1 percent. Staff is recommending adding back the portions of Adjustment 1 and 2 that are attributable to test year meter additions ($2.7 million from June 2018 through the end of the test year in October 2019).

Q. Please elaborate regarding regulators.

A. Costs for Oregon regulators are projected to increase from $1.6 million in December 2016 to $1.7 million in October 2019, an increase of 4.7 percent. Regulators were added in batches on or before September 2017, therefore no

[30] Includes Residential and Schedule 3 only. Increases in other customer classes are minimal.

addback is required to achieve the 4.7 percent overall increase. The Company does not track regulators separately.

Q. Please elaborate regarding services.

A. As can be noted from the first graph above, NW Natural's filing includes an almost linear increase in services, which exceeds the rate of customer growth. Oregon services are projected to increase from $670.3 million in December 2016 to $748.3 million in October 2019, an increase of 11.6 percent. Staff is recommending an amount sufficient to achieve a rate of growth in services equal to the increase in customers. Beginning with the June 2018 balance of $708.5 million, Staff recommends an additional reduction of 9.4 million, resulting in a gross plant balance of $699.1 million or 4.3 percent.

Q. If the 11.6 percent increase is based on the "run rate" for service installations why is Staff not recommending the 11.6 percent increase as filed?

A. The Company's filing did not address the rate of growth in excess of the rate of customer growth and subsequent data request responses did not provide enough information for Staff to ascertain if a higher rate of growth would be justified.

ISSUE 7. CONSTRUCTION OVERHEAD

Q. Please briefly describe the purpose of this adjustment.

A. Construction overhead has been increasing much faster than the associated project value of projects thereby causing ratepayers to bear costs that otherwise would have been absorbed by the Company during the years between general rate cases. I propose a downward adjustment to decrease the amount of construction overhead included in rate base.

Q. Please summarize the overall growth in construction overhead.

A. The Company's response to DR 258[31] shows that construction overhead increased from [redacted] in 2009 to [redacted] in 2017, and increase of [redacted] Additionally, the Company's response to DR 197[32] shows budgeted construction overhead of [redacted] in 2019, which is an overall increase of [redacted] since 2009.

Q. The base year for the previous general rate case was 2011. How much has construction overhead increased since 2012?

A. Actual construction overhead in 2012 was [redacted]. The increase through 2017 and the projected increase through 2019 are [redacted] and [redacted] respectively.

Q. What are the comparable increases in project volume since 2012?

---

[31] Staff/309, NW Natural Response to Staff DR 258 CONF Attachment 1.
[32] Staff/309, NW Natural Response to Staff DR 197 CONF Attachment 8 2019 Capital Forecast.

A. Project volume (excluding North Mist and CNG Development) increased from $138.3 million[33] in 2012 to 163.8 million[34] in 2017 and a projected volume of [redacted] in 2019. The increase through 2017 and the projected increases through 2019 are 18 percent and [redacted] respectively.

Q. Is Staff proposing an adjustment to gross plant to reduce the amount of construction overhead?

A. Yes, given there was already a large increase in construction overhead embedded in the previous rate case [redacted] and given the rate of increase in construction overhead since 2012 is approximately [redacted] higher than the growth in project volume, Staff is proposing a reduction in gross plant of $49,352,451.

Q. How is this adjustment calculated?

A. Staff is proposing to hold the ratio of construction overhead to project cost constant at the 2012 ratio of [redacted] The adjustment removes the excess above this percentage for years 2013 through June 30, 2018. We are proposing this amount be apportioned between states using the general Oregon plant apportionment factor of 89.06 percent.[36]

Q. What are some of the underlying conditions noted by Staff that are driving the increase in construction overhead?

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[33] Staff/309, NW Natural Response to Staff DR 197 Attachment 9 Utility Cap Ex Dec 2012.
[34] Staff/309, NW Natural Response to Staff DR 197 Attachment 14 Utility Cap Ex Dec 2017.
[35] Staff/309, NW Natural Response to Staff DR 197 CONF Attachment 8 2019 Capital Forecast.
[36]UG 344 200 wp7 - Gross Plant and Accum Deprec. and Staff/309, NW Natural Response to Staff DR 264 Attachment 8- Allocation Factors - TTM Sept 2017 OM.

A. Based on the Company's response to DR 258,[37] there has been a disproportionate increase in payroll costs, a large increase in materials cost, and a general increase in other costs, after 2012. In general, there appears to have been an effort, beginning in 2013, to load additional costs into construction overhead.

Also, some distribution type projects have exceptionally high load rates of up to 301 percent when compared to the load rates for other project categories.

Q. Please discuss your Exhibits 306 through 308.

A. Exhibits 306-308 show the amounts reported in the Company financial statements for Stock Based Compensation, Pension Expense, and Other Post Retirement Benefits, respectively. The purpose of the exhibits is to supplement the information provided by the Company in response to data requests and to show that the amount being capitalized increased after 2012. Staff notes that the percentage increase in capitalized stock compensation is larger, which is to be expected because the defined benefit pension and postretirement benefit plans have been closed to new participants.

Also, the amounts shown in Exhibit 306 are higher than the stock based compensation information provided in the Company's response to DR 258.[38]

Q. In the broader context of the entire rate case how would an unadjusted increase in construction overhead affect customer rates?

[37] Including attachments 1-4.
[38] Staff/309, NW Natural Response to Staff DR 258 CONF Attachment 2.

A. The increase in gross plant would be capitalized resulting in higher depreciation costs in future rates. Also, the Company's overall rate of increase in non-capital costs would be understated. Staff notes that in testimony the Company makes an assertion consistent with this expected outcome, specifically, that "O&M levels have grown at a reasonable rate, reflecting good cost management practices within the Company".[39] Finally, cost increases occurring outside of the base year are capitalized when they would not have been included rates had they been recorded as non-capital costs. Almost 80 percent of the proposed reduction in construction overhead occurred prior to 2017, and therefore, would not have been otherwise included in rates.

Q. Should a portion of the increase in construction overhead be allocated to the North Mist project, which is not part of this rate case?

A. No, the amount of construction overhead allocable to the North Mist project is one percent and the Commission recently approved an accounting order requested by the Company that restores this one percent amount to the pool of construction overhead allocable to other Company projects.[40] In other words, after the accounting order, the North Mist project has no impact on the allocation construction overhead.

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[39] NW Natural/600, Jorge Moncayo/13.
[40] *See NORTHWEST NATURAL: (Docket No. UM 1913) Application for an Accounting Order- Rate Schedule 90 Firm Storage Service with No-Notice Withdrawal (PGE North Mist Service)*, Order No. 18-071 (Feb 27, 2018).

ISSUE 8. PENSION BALANCING ACCOUNT

Q. Please briefly describe Staff's concerns regarding this account.

A. Staff believes the balancing account is structurally unsound and not in the best interest of ratepayers.

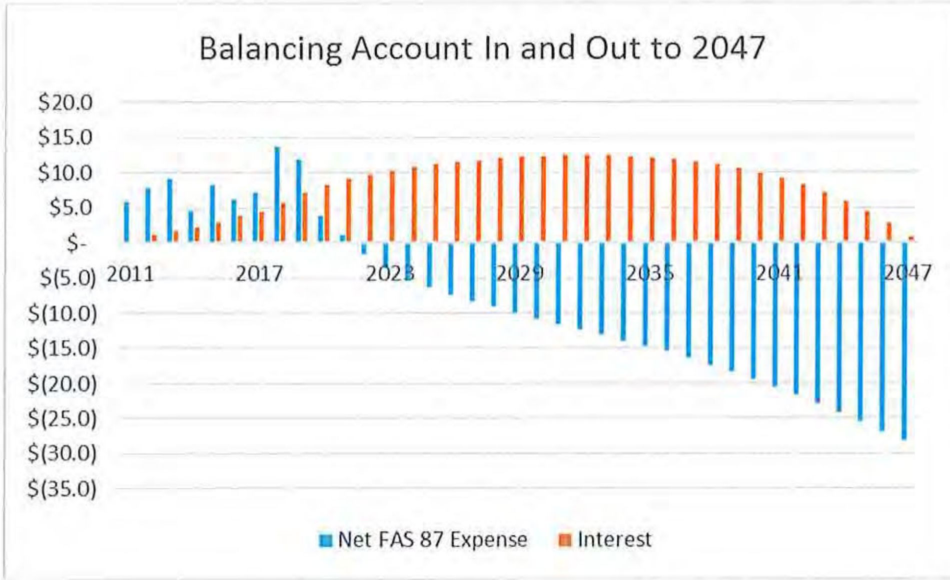
Q. What is the pension balancing account?

A. NW Natural has included approximately $3.8 million of FAS 87 pension expense in rates annually since 2003.[41] A pension balancing account was established in 2011.[42] The balancing account is a mechanism to hold annual contributions in excess of $3.8 million as a regulatory asset with the expectation that FAS 87 expense will become negative in future years offsetting the excess contributions and thereby stabilizing the amount of pension cost included in customer rates.

Q. Why does Staff assert the pension balancing account is not in the best interest of ratepayers?

A. As discussed below, the magnitude and duration of the account are currently projected to far exceed original expectations. This causes the interest component over the life of the account to overwhelmingly exceed the FAS 87 expenses deferred ($302.2 million vs. 79.4 million, respectively). The interest charges alone will exceed $10 million annually for a period of 17 years as illustrated in the following graph:

[41] *See In The Matter of Northwest Natural Gas Company, Application for a General Rate Revision Advice No. 02-19*, Docket No. UG 152, Order No. 03-507 (Aug 22, 2003).
[42] *See In The Matter of Northwest Natural Gas Company dba NW Natural, Application to Defer Pension Costs*, Docket No. UM 1475, Order No. 11-051 (Feb 10, 2011).



Furthermore, the Company's recovery of these interest charges is dependent on the plan being up to 300 percent overfunded. Staff asserts that this assumption is unrealistic.

Q. What was the anticipated maximum balance and duration of the account when it was originally established?

A. The balancing account was originally expected to reach a maximum of [redacted] in [redacted] and decline to a zero balance in [redacted].[43] The duration of the account was expected to be 12 to 13 years.[44]

Q. What is the revised estimate of the anticipated maximum balance and duration of the account most recently provided by the Company?

[43] *See* UM 1475 NW Natural's Redacted Direct Testimony of Stephen P. Feltz / Exhibit 205 (September 20, 2010).
[44] Order No. 11-051, p.3.

A. The balancing account is now expected to reach a maximum of $165.3 million in 2031-32 and decline to a zero balance in 2047.[45]

Q. Do amounts recorded to the balancing account accrue interest?

A. Yes, the balancing account projections provided by the Company show interest calculated at the Company's authorized rate of return.

Q. Does Staff have concerns about the interest calculation?

A. Yes, the original projections (carrying cost) for the account are based on the weighted average cost of capital on cash contributions (less 40 percent tax benefit) in excess of rate recovery. The calculations recently provided by the Company appear to be based on FAS 87 expense instead of cash contributions and do not appear to include an adjustment for the tax benefit. Also, the original calculations do not include compound interest.

Q. Does Staff have concerns about the design of balancing account mechanism itself?

A. Yes, there are two major assumptions underlying the balancing account. First, the projections are based on the difference between the assumed discount rate (4.83 percent) and the expected return on assets (7.50 percent) driving an increase in the funded status of the plan from 64 percent at the end of 2017 to 442 percent in 2050. This increasing funded status is what generates the negative pension expense necessary to bring the balancing account to zero.

[45] Staff/309, NW Natural Response to Staff DR 223 Attachment 1 - Pension Balancing Account Forecast - November 2017 (status quo estimate).

Second, the balancing account projections assume the Company will allow the plan to become overfunded and increase unabated. Staff believes that it is unrealistic to expect the funded status of the plan to significantly exceed 100 percent for a variety of reasons. As one obvious example, the Internal Revenue Code imposes a minimum 20 percent excise tax on employer reversions from a qualified plan.[46]

Q. What is the book value of the pension balancing account at the end of 2017?

A. $60.4 million.[47]

Q. In the event the negative FAS 87 expense is insufficient to bring the balancing account to zero what would be the implication for ratepayers?

A. The Company would need to initiate a Commission proceeding requesting amortization of the balancing account into rates or, alternatively, write off the balance and, consequently, report an extraordinary loss with a potential for adverse outcomes in the debt and equity markets the Company relies on for financing.

Q. Is Staff proposing a pension expense adjustment in the case and/or changes to the balancing account mechanism?

A. Not at this time due to the provisions of Commission Order No. 11-051 pertaining to changes to the pension balancing account. Staff held a workshop

[46] 26 U.S. Code § 4980.
[47] NW Natural 2017 SEC Form 10k, p. 62.

for the parties to Order No. 11-051 on April 4, 2018, in Salem and anticipates further discussions as part of settlement in this case, UG 344. However, in the event no settlement is reached, Staff will continue to pursue a remedy to these issues, though likely not in this rate case.

ISSUE 9. IMPLEMENTATION OF ASU 2017-07

Q. Please briefly describe Staff's concerns regarding the implementation of ASU 2017-07?

A. Staff does not have any concerns per se, however, the implementation of this standard is intertwined with the pension balancing account issue and will alter the value of gross plant additions in the future.

Q. What is ASU 2017-07?

A. ASU 2017-07 is an official accounting standard issued by the Financial Accounting Standards Board (FASB).[48]

Q. Has there been any further guidance specific to the energy industry regarding implementation of the accounting standard?

A. Yes, the Federal Energy Regulatory Commission (FERC) has provided accounting guidance for regulated public utilities.[49] The FERC accounting guidance directs that utilities under FERC jurisdiction may, with respect to capital assets, continue to account for them as they have been previously or may, on an elective basis, apply the provisions of the new accounting standard.

Q. What is the policy of the Oregon Public Utility Commission regarding the inclusion pension and postretirement benefits in rates?

[48] Accounting Standards Update (ASU) No. 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.

[49] *See Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions*, FERC Docket No. AI18-1-000 (Dec 28, 2017).

A. The Commission policy is to include only the actuarially determined FAS 87 expense in rates rather than cash contributions to the plan.[50]

Q. Briefly, what is the impact of the new accounting standard on costs in this rate case?

A. The new accounting standard does not change how overall pension and postretirement benefit "FAS 87" expense is determined. The standard requires a smaller proportion of the overall pension and postretirement benefit to be included in the cost of capital assets and a correspondingly larger portion to be included in periodic operating costs. The standard also changes how overall pension and postretirement benefit are presented in financial statements.

Q. Did the Company elect to apply the new accounting standard?

A. Yes. The Company's 2017 financial statements include the following statement:

> We have elected to adopt the new ASU for FERC regulatory accounting and reporting purposes. We anticipate that this adoption will reduce amounts capitalized to plant. However, this reduction will be largely offset by deferrals to our pension regulatory balancing mechanism, and therefore, we do not expect this standard to materially affect our financial position.[51]

Q. Please discuss how the new standard would change the information reported in Exhibits 307 and 308.

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[50] *See In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Treatment of Pension Costs in Utility Rates,* Docket No. UM 1633, Order No. 15-226 (Aug 03, 2015).
[51] NW Natural SEC Form 10k, p. 64.

A. Exhibit 307 shows that the proportion of pension cost allocated to construction did not decrease when the balancing account was implemented in 2012. Assuming the balancing account arrangement continues, the proportion of costs allocated to construction will decrease and the amount deferred to the balancing account will increase.

Exhibit 308 shows the proportion of other post-retirement benefits allocated to construction and expensed. There is no balancing account for postretirement benefits. Accordingly, the proportion charged to expense will increase as the amount charged to capital decreases. Staff estimates the increase would be around $200,000 per year, the majority of which can be assumed would flow through to capital projects as a part of construction overhead.

Q. Is Staff proposing an adjustment?

A. Not at this time. As noted above, the amount of pension cost included in rates is limited to $3.8 million and the change in postretirement benefit cost is within Staff's proposal to reduce the overall construction overhead charge to [redacted] of project costs.

ISSUE 10. PENSION ACTUARIAL AND INVESTMENT ASSUMPTIONS

Q. Please briefly describe Staff's concerns regarding actuarial assumptions?

A. Actuarial assumptions are customarily reviewed in rate case proceedings. In this case, the assumptions used would not directly affect customer rates due to the pension balancing account arrangement.

Q. Please describe Staff's review of actuarial and investment assumptions.

A. Staff reviewed footnote disclosures in the Company financial statements from 2011-2017. We also compared Company's assumptions with amounts disclosed by a peer group of Gas Local Distribution Companies (LDC).

Q. How did you determine the peer group?

A. We used the same LDCs identified as part of Dr. Villadsen's return on equity analysis.[52]

Q. Are there differences in the timing and format of disclosures for the various companies?

A. Yes, we obtained the information from the most recent SEC 10k filings for calendar year 2017 with the exception of two companies with fiscal years ending September 30. Regarding the disclosure formats, some companies disclose ranges rather than specific percentages and each company has unique categories for plan investments. However, the data can be aggregated at a high level to illustrate how NW Natural's assumptions compare, generally.

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[52] NW Natural/403, Villadsen.

Q. Is Staff proposing rate case adjustments related to actuarial and investment assumptions at this time?

A. No, as noted above, the amount of pension cost included in rates has been limited to approximately $3.8 million per year since 2003.

Q. Please describe the changes in weighted average discount rates used to determine the Company's pension obligation.

A. The Company uses two separate rates. The rate assumption for net periodic benefit cost decreased from 5.49 percent in 2011 to 3.99 percent in 2017. The assumption used for calculating funded status decreased from 4.51 percent to 3.52 percent in the same time frame.

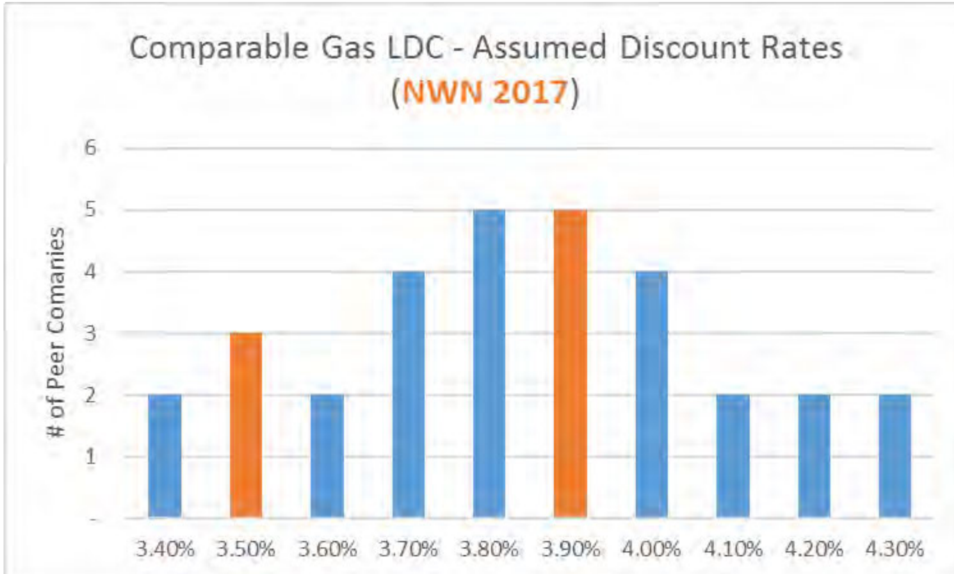
Q. Are there limits to the range of discount rates the Company can use?

A. Yes, the federal government has established interest rate "corridors".[53] The provisions of the law are highly complex but in general are intended to limit increases in tax deductible plan contributions due to declining market interest rates.

Q. How do the Company's weighted average discount rates compare with peers?

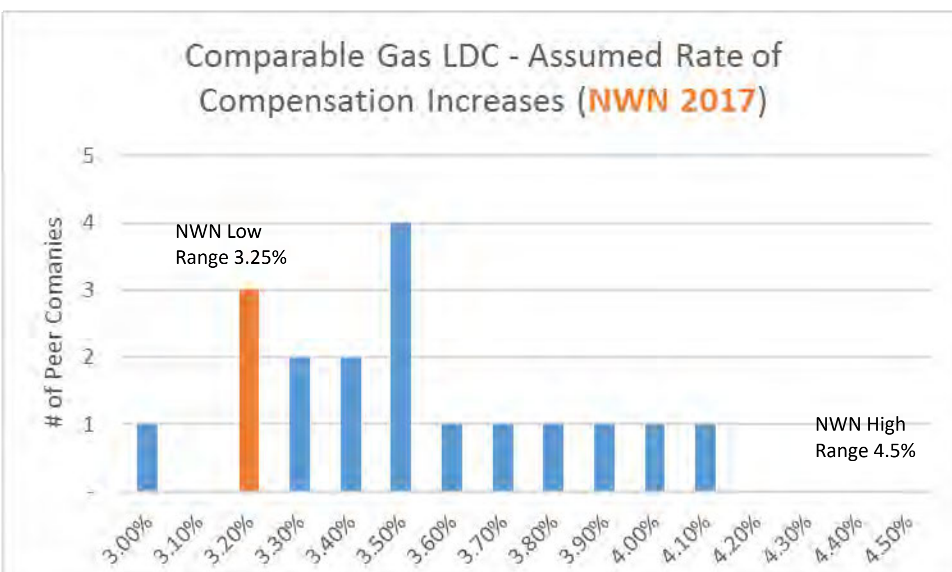
A. The following chart illustrates that there are three other companies using rates in the range of 3.50-3.59 percent and five companies using rates in the range of 3.90-3.99 percent. NW Natural's assumptions are not unusual.

[53] Moving Ahead for Progress in the 21st Century Act ("MAP-21") and Highway and Transportation Funding Act of 2014 ("HATFA").



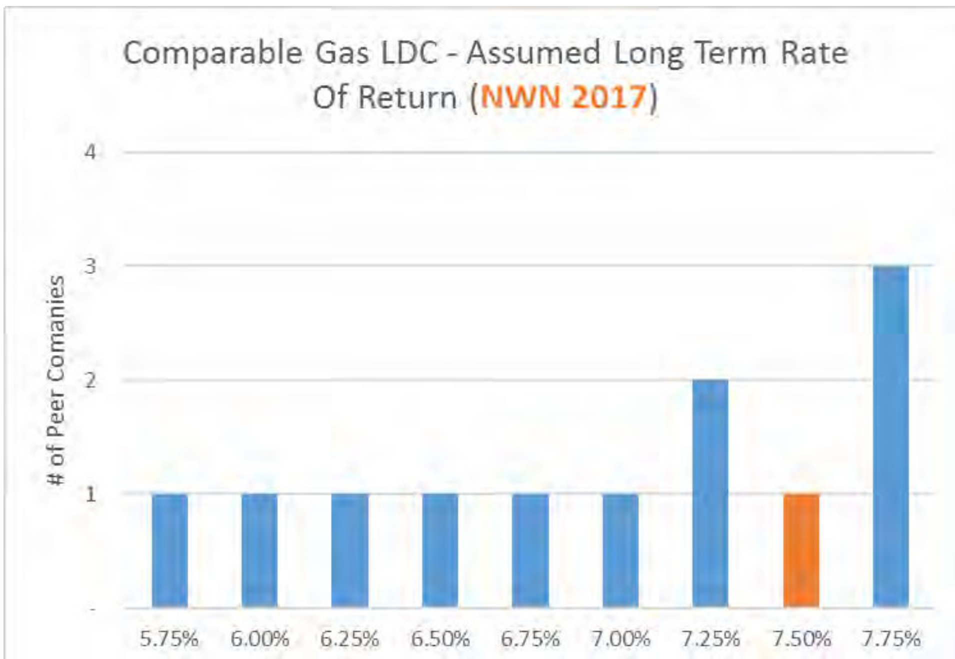
Q. Please describe the changes in the assumed rate of increase in compensation used to determine the Company's pension obligation.

A. The Company uses a range that was 3.25-5 percent in 2011 and decreased to 3.25-4.5 percent in 2017. As shown in the graph below, the lower bound is in the same range as three other companies however the upper bound is 30 basis points higher than assumptions being used by other companies.



Q. Please describe the changes in the expected long-term rate of return used to determine the Company's pension obligation.

A. The Company's expected long term rate of return has declined from 8.25 percent in 2011 to 7.5 percent in 2013 and has remained at 7.5 percent through 2017. As shown in the graph below, this is on the high end of the range of rates being used by peer companies.



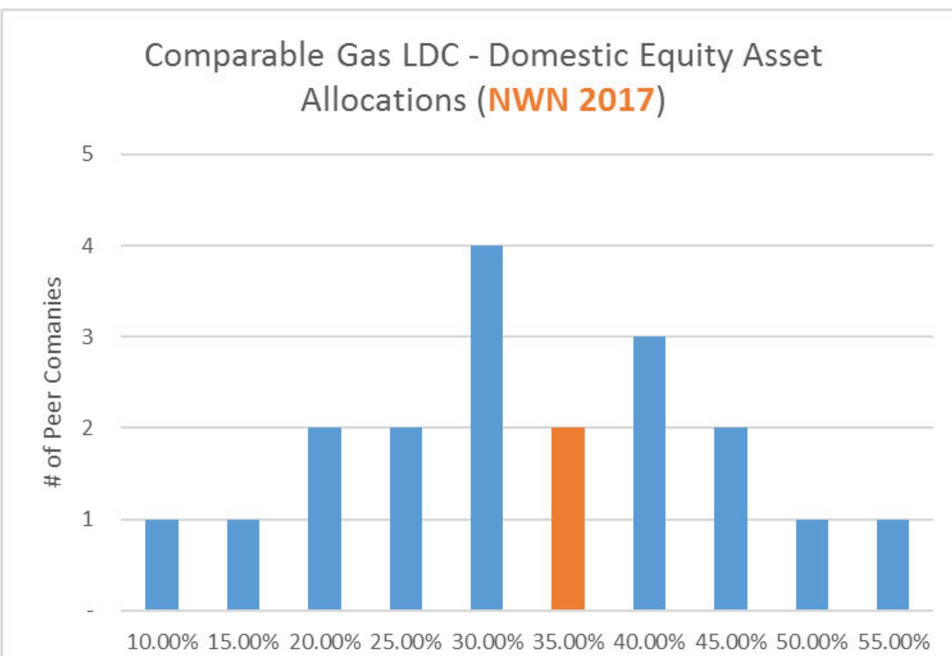
Q. Has there been a change in the Company's disclosed target asset allocation recently?

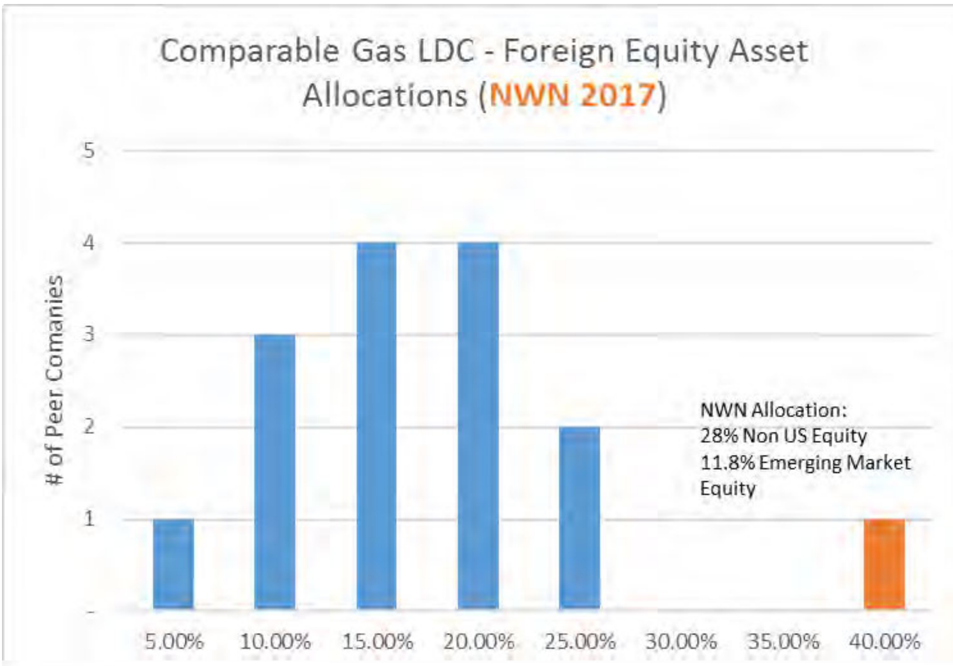
A. Yes, the Company revised the target asset allocations in 2012, 2014, and 2017 as shown in the following table:

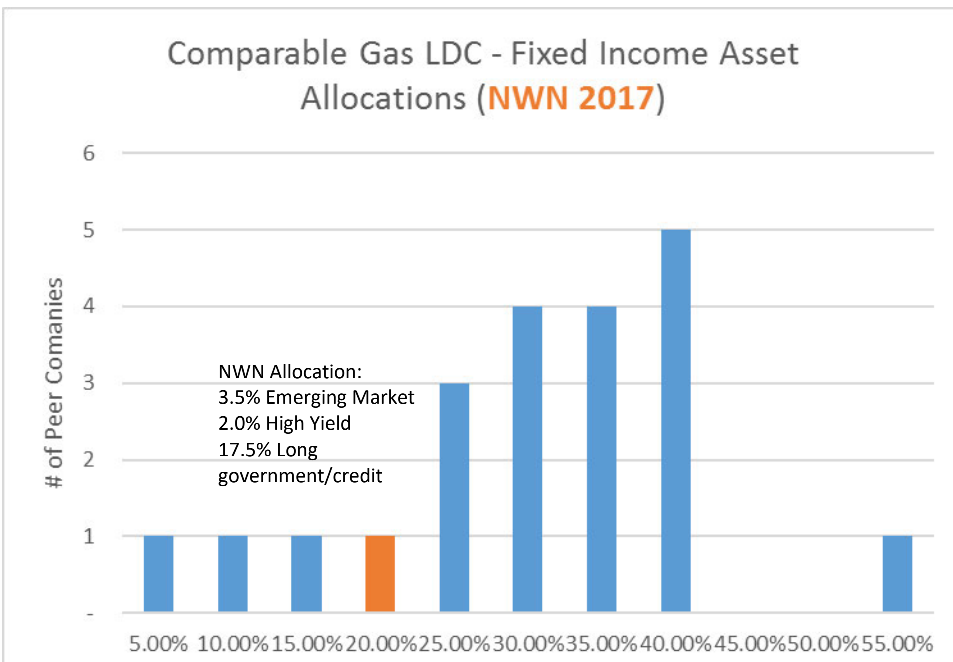
NW Natural Published Pension Fund Asset Allocations							
Target Asset Allocations:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
U.S. large cap equity	15.0%	13.0%	13.0%	18.0%	18.0%	18.0%	29.3%
U.S. small/mid cap equity	10.0%	8.5%	8.5%	10.0%	10.0%	10.0%	6.9%
Non-U.S. equity	14.5%	13.0%	13.0%	18.0%	18.0%	18.0%	28.0%
Emerging markets equity	3.5%	3.5%	3.5%	5.0%	5.0%	5.0%	11.8%
Long government/credit	24.0%	30.0%	30.0%	20.0%	20.0%	20.0%	17.5%
High yield	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	2.0%
Emerging market debt	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	3.5%
Real estate funds	5.8%	6.0%	6.0%	7.0%	7.0%	7.0%	1.0%
Absolute return strategy	12.0%	11.0%	11.0%	12.0%	12.0%	12.0%	
Real return strategy	5.2%	5.0%	5.0%	0.0%	0.0%	0.0%	
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Q. How do these asset allocation compare to those of the peer companies?

A. The Company is in the middle of the pack for domestic equity, significantly higher than average international equity, and lower than average fixed income. As shown in the following tables:







Q. Does Staff have any additional data requests outstanding?

A. Not at this time, due to the amount of pension cost included in rates being limited to approximately $3.8 million as noted above, further analysis will not have an immediate rate impact. However, if the parties were to agree to revisit this limit,[54] Staff would likely issue additional data requests at that time to further clarify the actuarial and investment parameters.

Q. Does this conclude your testimony?

A. Yes.

[54] *See In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Application to Defer Pension Costs,* Docket No. UM 1475, Order No. 11-051 at 3-5 (Feb 10, 2011).

CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	John L. Fox
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010). I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.
EXPERIENCE:	From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work. I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead. I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.

CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 302

PROVIDED IN ELECTRONIC FORMAT ONLY

CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 303

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CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 304

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CASE: UG 344
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 305

IS CONFIDENTIAL

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STAFF EXHIBIT 306

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 306

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STAFF EXHIBIT 307

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 307

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WITNESS: JOHN L. FOX

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STAFF EXHIBIT 308

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 308

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WITNESS: JOHN L. FOX

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OREGON

STAFF EXHIBIT 309

Exhibits in Support
Of Opening Testimony

REDACTED
April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 122

122. Please explain the discrepancy in 2016 year end Oregon situs values reported for the following dockets and accounts:
- UG 344 file 200wp7 FERC account 389 Land $8,796,742
- RG 37(5) FERC Form 2 account 389 Land $9,609,258
- UG 344 file 200wp7 FERC account 390 Structures and Improvements $56,062,951
- RG 37(5) FERC Form 2 account 390 Structures and Improvements $58,238,110

Response:

The values are intentionally different due to the following:

Accounts 389 Land and 390 Structures are unique in terms of how the state allocation methodology has been applied. Land and Structures are more identifiable than other accounts for determining whether they are used in the service of Oregon or Washington customers, or both. For example, a parcel of land or a building in Vancouver, WA could be expected to serve customers in Washington exclusively. The same could be said for land and buildings outside of Portland in the Willamette Valley and along the coast. On the other hand, we know that the Sherwood service center serves both states, even though it is sited in Oregon. For these reasons, a responsive allocation methodology has been adopted.

For 389 Land, an evaluation of the total system (Oregon and Washington) balance at December 31, 2016 was made, with a line item determination of account detail of whether an asset was specific to Oregon, to Washington, or to both. The December 2016 balance displayed on the "Net Plant" tab of file 200wp7 reflects the detailed allocation above, which is also shown on the "Land & Structures" tab of file 200wp7. The pre-allocated balances for December 2016 on the "Land & Structures" tab tie to the RG 37(5) FERC Form 2 balances.

For 390 Structures, a similar exercise was applied to the December 2016 balance to estimate the state allocation factor for the account. The percentage indicated by this analysis was then used to apportion the system amounts to each state for each month of the future period. Again, the allocation was performed on the "Land & Structures" tab of file 200wp7, beginning with balances that tie to the RG 37(5) FERC Form 2 balances for December 2016.

The evaluation of the December 2016 balance for the accounts is contained in the attached excel files, "UG 344 OPUC DR 122 Attachment 1 Land Alloc – Dec 2016" and "UG 344 OPUC DR 122 Attachment 2 Structures Alloc – Dec 2016."

Pages 3 and 4 are confidential and subject to

Modified Protective Order No. 18-002.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 197

197. Please refer to Capital Asset Policy 83.
a. Please provide copies of the annual approved capital budgets and all interim updates to capital budgets for calendar years 2012 through 2019.
b. Please provide the project level budget variance reports for the years 2012 through 2017.

Response:

a. Please see UG 344 OPUC DR 197 Attachments 1-6 and Confidential UG 344 OPUC DR 197 Attachments 7-8.

b. UG 344 OPUC DR 197 Attachments 9-14 includes annual actual to budget variances for the different categories of capital expenditures. In addition to that, we have created a document with actual to budget variances for projects with actual cost over 1 million dollars. UG 344 OPUC DR 197 Attachment 15 includes the list of large projects.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 198

198. Please refer to 600 - Moncayo - Direct Testimony - Operations and Maintenance Capital and 800 - Karney - Direct Testimony - Capital Projects.

a. Please provide in excel format for the following major projects and project components the costs incurred through December 2017, including a list of asset numbers associated with each project by FERC account. Please explain any variances from the cost of each project as stated in testimony.

i. Salem Retrofit Project
1. Structural
2. Seismic
3. Code compliance
4. Change in use
5. Training room
6. Auditorium

ii. Parkrose Retrofit Project
1. Roof
2. Building insulation
3. New windows and doors
4. Restrooms / showers / lockers
5. Lighting
6. HVAC
7. New offices
8. Telephone equipment room
9. Kitchenette
10. Security system
11. Spoils bins
12. Pipe shed
13. Equipment shed
14. Fueling shed
15. Emergency generator
16. Bioswale
17. Fencing
18. Automatic gates
19. Repaving and striping

iii. Eugene Retrofit Project
1. Roof
2. Siding
3. Electrical

4. HVAC
5. Restrooms / showers
6. Reconfigure office space
7. Seismic retrofit
8. Cover spoils bins
9. Cover pipe racks
10. Improve drainage

iv. Coos Bay Retrofit Project
1. Walls
2. Plumbing
3. Lighting
4. HVAC
5. Breakroom
6. Restrooms / showers

v. Sherwood Facility Building A
1. Meter shop
2. Central stores
3. Welding and training facilities
4. Backup gas control
5. Backup resource management
6. Backup emergency operations
7. Emergency generator
8. Backup data center
    a. HVAC
    b. UPS
    c. Server cabinets
    d. Cat 6 and fiber
    e. Network gear
9. Backup emergency call center
10. Business continuity space
    a. Finishes
    b. Data cabling
    c. Electrical work
    d. Furnishings
11. Weld shop ventilation
12. Telemetry
13. Microwave tower

vi. Sherwood Facility Building B
1. Administrative office
2. Automotive repair and maintenance
3. Fire safety shop
4. Carpenter shop
5. Radio/corrosion shop
6. Paint booth
7. Miscellaneous storage

vii. Sherwood Facility Other Improvements

1. Site work
   a. Utilities and infrastructure
   b. Bio swales
   c. Irrigation
   d. Asphalt
   e. Covered spoils bins
   f. Exterior lighting
   g. Parking and striping
   h. Move hazmat shed from Tualatin
2. Fuel shed
3. CNG fueling station
4. Vehicle Shed
5. Weld shop ventilation

viii. Sherwood Facility Materials Testing
1. Test chamber / blast proof panels
2. Pressure testing equipment
3. X-ray testing equipment
4. Sandblasting equipment

ix. North Mist Expansion Project

x. Mid-Willamette Valley Feeder Project
1. Perrydale to Monmouth
2. Rickreall to Monmouth
3. Monmouth reinforcement
4. South of Monmouth

xi. Corvallis Loop Project

xii. SE Eugene Project

xiii. Newport Refurbishment Project
1. Pretreatment upgrade
   a. Molecular sieve system
   b. Compressor upgrades
2. Turbine Modernization
   a. Wet seal upgrade to dry seal
   b. Control system
   c. Starter/fuel gas system
   d. Combustion air inlet
   e. Gas detection/suppression system
3. Vaporizer H-1
4. New control building
5. Plant control system upgrade

xiv. Mist Reliability Program
1. Mist control building project
   a. Structure
   b. Security systems
   c. Control equipment
   d. Data center equipment
2. Mist instrument and controls project

a. Operator controls
b. Fiber optic network

b. Please provide copies all business cases, cost studies, alternative analyses, cost benefit analysis, and or return on investment calculations related to all projects listed above.

Response:

a) Please see UG 344 OPUC DR 198 Attachment 1 for costs through 12/31/2017 for complete projects. The request includes projects that have not been completed yet. Projects that are currently in Construction Work In Progress, and that are not yet In-Service, are not segmented by FERC Plant Account. Total costs for those projects as of 12/31/2017 are:

- Eugene Retrofit: $291,799.79
- Coos Bay Retrofit: $33,054.36
- Sherwood Facility Materials Testing: $435,116.03
- SE Eugene Project: $623,914.92

Note: the North Mist Expansion Project is still in construction and NW Natural is not seeking recovery as part of UG 344. Total costs as of 12/31/2017 is $107,099,031.50

b) Please see UG 344 OPUC DR 198 Attachment 2. Responses related to the Mid-Willamette Valley Feeder will be supplemented with response to UG 344 OPUC DR 239.

Due to the large volume of files associated with the response NW Natural has mailed CD copies containing attachment 1 and attachment 2 to the parties.

Confidential UG 344 OPUC DR 198 Attachments 3-5 have been uploaded to huddle.

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Request No.: UG 344 OPUC DR 199

199. Please refer to 500 - Pipes - Direct Testimony – Facilities / Page 3.
a. Please provide a copy of all work products received by NW Natural as a result of the Parametrix consulting engagement.

Response:

Attached please find a copy of the 2008 Parametrix report attached as UG 344 OPUC DR 199 Attachment 1.

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Request No.: UG 344 OPUC DR 200

200. Please provide in excel format for all projects discussed in Commission Order 12-408 (listed below) for which costs were incurred after December 31, 2011, increases and decreases in each project budget occurring after December 31, 2011, final budget to actual variances for each project, and list of asset numbers associated with each project by FERC account.

a. Corvallis Reinforcement
b. Monmouth Reinforcement
c. Nertec Replacement
d. Tualatin Replacement
e. Westside Transmission Rerate
f. Portland System Optimization Ph 2
g. United Communications Phase 2
h. Tualatin Bioswale
i. Sunset Sheds
j. Coos Bay Retrofit
k. Astoria Retrofit
l. Portland System Optimization Phase 1
m. 2012 Generator Projects
n. Salem Retrofit

Response:

Some of the Projects listed above were either not executed, changed substantially, or were not In-Service as of 12/31/17. As a result, detailed Asset Listings by FERC Plant Account or final Actual to Budget Variances are not available. Those projects are identified below. The detailed Asset listings by FERC Plant Account for the Projects that were In-Service as 12/31/17 are found in UG 344 OPUC DR 200 – Attachment 1. The budget-to-actuals are included in UG 344 OPUC DR 200 Attachment 14. We have also included closeout documents related to the above projects because they provide further insights into changes to project scope and costs over time.

a) **Corvallis Reinforcement (aka Corvallis Loop)**: See UG 344 OPUC DR 200 – Attachment 1; this project is included in the Direct Testimony of Joe Karney – Capital Projects, in the UG 344 rate case. The closeout document associated with this project is attached in UG 344 OPUC DR 200 Attachment 2.

b) **Monmouth Reinforcement (aka South of Monmouth)**: See UG 344 OPUC DR 200 – Attachment 1; this project is included in the Direct Testimony of Joe Karney – Capital Projects, in the UG 344 rate case. The closeout document associated with this project is attached in UG 344 OPUC DR 200 Attachment 3.

c) **Nertec Replacement**: See UG 344 OPUC DR 200 – Attachment 1. NW Natural filed an attestation affirming that this project was used and useful by the rate effective date of our last rate case, UG 221, which is attached as UG 344 OPUC DR 200 – Attachment 1a. The closeout document associated with this project is attached in UG 344 OPUC DR 200 Attachment 4.

d) **Tualatin Replacement (aka Sherwood Facility)**: See UG 344 OPUC DR 200 – Attachment 1; NW Natural filed an attestation affirming that this project was used and useful by the rate effective date of our last rate case, UG 221, which is attached as UG 344 OPUC DR 200 – Attachment 10. Additional investment and improvements have been made to the Sherwood Facility, which are described in the Direct Testimony of Wayne Pipes – Facilities, in the UG 344 rate case. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 5.

e) **Westside Transmission Rerate**: See UG 344 OPUC DR 200 – Attachment 1. This project was also considered a part of the Portland System Optimization Phase 2. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 11 and 12.

f) **Portland System Optimization Phase 2 (Barbur & Slavin Regional Station):** See UG 344 OPUC DR 200 – Attachment 1. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 13.

g) **United Communications Phase 2 (Unified Communications Phase 2):** See UG 344 OPUC DR 200 – Attachment 1. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 6.

h) **Tualatan Bioswale**: This project was cancelled.

i) **Sunset Sheds**: See UG 344 OPUC DR 200 – Attachment 1. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 7.

j) **Coos Bay Retrofit**: This project is ongoing and included in the Direct Testimony of Wayne Pipes – Facilities, in the UG 344 rate case.

k) **Astoria Retrofit**: This project has been changed. It is likely we will relocate our Astoria facility. This project is not included for cost recovery in UG 344.

l) **Portland System Optimization Phase 1**: NW Natural filed an attestation affirming that this project was used and useful by the rate effective date of our last rate case, UG 221, which is attached as UG 344 OPUC DR 200 – Attachment 1a.

m) **2012 Generators Project**: See UG 344 OPUC DR 200 – Attachment 1; NW Natural filed an attestation affirming that this project was used and useful by the rate effective date of our last rate case, UG 221, which is attached as UG 344 OPUC DR 200 – Attachment 1a. This project includes generators at Mt. Scott, Parkrose and Sunset facilities. Closeout documents associated with the Mt. Scott and Sunset facilities are attached as UG 344 OPUC DR 200 – Attachments 8 and 9. The Detailed Asset Listing for Parkrose (Project 200682) was provided in the Response to DR 198.

n) **Salem Retrofit (aka Salem Facilities Retrofit and Salem Remodel)**: See UG 344 OPUC DR 200 – Attachment 1; this project is included in the Direct Testimony of Wayne Pipes – Facilities, in the UG 344 rate case. The closeout document associated with this project is UG 344 OPUC DR 200 Attachment 10.

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Request No.: UG 344 OPUC DR 201

201. Please refer to 200 - McVay Direct Testimony - Revenue of Requirements / Pages 21-22

a. Please provide a list of all standard reports available in the new forecasting tool or model UI Planner.

b. Please provide a narrative summary of the ad hoc reporting capabilities of UI Planner including data base structure, available reporting tools or software, and who in the company is able to query the data and run reports.

Response:

a. Below is a list of reports available in UI Planner:

Financial Statements, Ratio & Metrics

1 Key Assumptions - Board
2 Summary of Results - Board
3 Income Statement - Board
4 Percentage of Margin - Board
5 Growth Rates - Board
6 Balance Sheet Summary - Board
7 Cash Flow Indirect - Board SEC
8 Ratios - Board
9 Common Equity, LT Debt & Qtrly Dividends - Board
10 Capital Expenditures Detail - Board
10a Capital Expenditures Detail - with overheads
11 Interest Report - Board
12 Margins - Board
13 Customer Volumes - Board
EPS - After Tax - Board
EPS - Year over Year -Board
Account Detail
Balance Sheet - Monthly Exec Packet - NEW
Balance Sheet - SEC - NEW
Capital Expenditures
Cash Flow Direct

Cash Flow Indirect - SEC
Credit Metrics Calculations
Deferral and Amortizations Total
EPS
Credit Metrics Entity View
Interest Detail Report
Consolidated Income Statement SEC
Income Statement
Income Statement Annual Totals
System Checks
Income Statement - Year over Year
Income Statement - Year over Year After Tax
Financial Statistics Scenario Report
Statement of Shareholders Equity

O&M

EXP Interstate Storage
EXP NWN O&M and Other Taxes
INP Pension
EXP North Mist Storage
EXP Carbon Solution Programs
EXP CGES
EXP Gain/Loss on Sale of Asset
EXP Pension

Construction & Plant

INP (A) Plant Construction
INP (D) Plant Account
INP (B) Plant Applicant Summary
INP (C) Applicant Allocators to Plant Account
Plant Account - Summary
PLT (F) Applicant Expenditure Summary
CWIP Summary
Net Plant Summary - Utility Plant Comparison
Closings to Plant
Gross Plant Bal Recon
Acc Depr Balance Recon
FIN AFUDC Rate calculation
INP Category 2 Deductible

Financing

INP Treasury - Bonds
FIN Short-Term Rollover & Interest
FIN Automatic Finance
FIN Common Stock
FIN Dividends

- INP Treasury - Ratio Calculation
- INP Treasury - Cash Adjustments
- Bond Summary
- FIN Purchase other company

Income Taxes

- INP (E) Plant Tax Depreciation
- TAX Schedule M List
- TAX Pre-Tax Book Income
- Eff Tax Rate Recon
- Income and Tax by Entity
- TAX State Income Tax
- TAX Federal Income Tax
- TAX State NOL
- TAX Federal NOL
- TAX Non-Utility Income Tax
- INP Tax
- TAX Income Tax Payment
- Tax PTBI Pattern
- TAX Entities to process
- INP Tax reform options
- System Total
- Tax Reform adjustments

Regulatory

- JUR Jurisdiction Allocators
- REG Deferrals & Amortizations
- REG Balances Actuals
- REG Environmental Deferral & Amortization
- REG Goal Seek Revenue
- REG Plant by Function
- JUR Revenue Requirement
- JUR Cost of Capital
- JUR Dynamic Allocators
- REG Data for Jurisdictional Allocation
- JUR Jurisdictional Federal Taxes
- JUR Jurisdictional State Taxes
- JUR Dynamic Interest Rates
- INP Rates/Regulatory Deferrals & Amortizations
- INP Rates/Regulatory
- INP Revenue Requirement Goal Seek
- JUR Earnings Test
- JUR Cost of Capital - Earnings Test
- JUR Federal Taxes Earnings Test
- JUR State Taxes Earnings Test

REG Rates Manager
REG Utility Plant Summary
REG Depreciation Summary
REG Rate Base Net Plant Summary
Income Statement Load Post Processing
General
INP Margin Data
INP General
INP Interest Rate Clearinghouse
INP Biogas
INP Gas Reserves
INP Gas Storage
INP Gill Ranch
INP NNGFC
INP Trail West
INP Interstate Storage
INP NWN
INP Environmental Deferral & Amortization
INP North Mist Storage
INP Carbon Solutions Programs
INP Energy LLC
INP CGES
INP Other Company
Cost of Service
COS North Mist
Line by Entity Reports
Closings to Plant
CWIP Summary
Regulatory Pivot Reports
Pivot Reports
REG Rate Base Net Plant Summary
REG Depreciation Summary
REG Utility Plant Summary

b. UI Planner is a financial and regulatory software application that provides standard financial statements, such as Income Statement, Balance Sheet, Cash Flow, etc., as well as the functionality to build custom reports or views as needed. Within these reports there is the capability to drill down, providing detailed information to the data load level such as the account balance or forecast value for a specific project, and a way to follow data through reports as it is allocated. These reports can be exported to Excel for further analysis offline or for sharing with others. Members of the Financial Planning and Budget department are able to build and run reports, and certain employees within the Tax and Rates and Regulatory departments have access to run reports as well.

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Request No.: UG 344 OPUC DR 202

202. Please provide a list in excel format of all projects included in construction work in process at December 31, 2017. Please include a list of all accounting work orders by project and FERC account. Please identify the date when each project or project component is expected to be placed into service.

Response:

The list of Projects included in Construction Work In Process at December 31, 2017, is included in the attached Excel file, UG 344 OPUC DR 202 – Attachment 1.

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Request No.: UG 344 OPUC DR 203

203. Please refer to work paper 200 wp7 - Gross Plant and Accum Deprec.

a. Please provide an analysis in excel of 2018 and 2019 plant changes for Oregon (cells P6:AM108) and Washington (cells P110:AM142).

b. Please list all planned expenditures by project by FERC account by month.

c. Please cross reference the data to the projects listed in the testimony and exhibits of 600 - Moncayo - Direct Testimony - Operations and Maintenance Capital and 800 - Karney - Direct Testimony - Capital Projects.

d. Please cross reference the data to the projects included in construction work in process at December 31, 2017.

e. Please provide narrative explanation of the changes in plant allocation factors used (cells E177:F185) compared to the factors used in the previous general rate case UG 221.

Response:

a. Please see UG 344 OPUC DR 203 Attachment 1.
b. We do not have a single report that presents expenditure by projects by FERC. Our modeling system allocates expenditures to FERC once the project is placed in service and not while the project is in construction. To fulfill with this request we are providing the following reports:
    i. Projects by applicant by month. An applicant is a category of expenditures (see UG 344 DR 203 Attachment 2)
    ii. Allocations of applicants to FERC Accounts for closed projects (see UG 344 OPUC DR 203 Attachment 3)
    iii. Closings to plant by month projects (see Attachment 1 Rows 145:285)
c. Please refer to UG 344 DR 203 Attachment 2:
    a. Cross reference to 600 – Moncayo Testimony: Cells A303:B307
    b. Cross reference to 800 – Karney Testimony: Column AM
d. Please refer to UG 344 DR 203 Attachment 2 (Column AO)
e. The factor categories are the same as those used to allocate plant in the last rate case. Numeric factors are updated to reflect the most recent available information as to percentages of customers, volumes, plant, and direct employees in each jurisdiction.

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Request No.: UG 344 OPUC DR 204

204. Please provide reports showing changes in Washington assets for the years 2011-2016. Please provide these reports in the same format, level of detail, and sort order as the reports "Account summary by functional class" and "Reserve balances and activity by functional class" provided for Oregon situs assets in docket RG 37.

Response:

The changes in the Cost of Washington Gross Plant for the years 2011 to 2016, in the format of the FERC Form 2, are in the attached Excel file, UG 344 OPUC DR 204 Attachment 1.

The changes in the Cost of Washington Accumulated Depreciation for the years 2011 to 2016, in the format of the FERC Form 2, are in the attached Excel file, UG 344 OPUC DR 204 Attachment 2.

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Request No.: UG 344 OPUC DR 205

205. Please provide a narrative explanation of all property transfers and adjustments reported on FERC form 2 (docket RG 37) for the years 2012 through 2016. For the $5.4 million in assets transferred from Oregon Non-Utility Property to Oregon Utility Property please provide a list of individual assets transferred and discuss why the assets were transferred, the internal process for approving the transfers, and why the assets were originally misclassified.

Response:

For the years 2012 through 2016,$5.0 million of assets were transferred from Non-Utility Natural Underground Storage at Mist to Utility Natural Underground Storage at Mist as part of the Company's Interstate Storage Recall Program. The associated Rate Base that was allocated to Oregon was included in the annual PGA Filings. $1.2 million of Gross Plant was transferred in 2011, and $3.8 million of Gross Plant was transferred in 2015.

The Gross Plant Transfers completed in 2011 were as follows. The support and approval for the Recall is included in the 2011 Recall Memo, attached as UG 344 OPUC DR 205 – Attachment 1. The Details that were included in the 2011-2012 PGA Filing are in the file attached as UG 344 OPUC DR 205 – Attachment 2.

From 2011 Recall Memo

FERC A/C	DESCRIPTION	AMOUNT
352.2	Reservoirs	476,149
354	Compressor Station Equip.	526,206
355	Measuring Reg. Equip.	152,838
	Subtotal	1,155,193
	Cushion Gas	64,025
	Total Gross Plant	1,219,218

The Gross Plant Transfers completed in 2015 were as follows. The support and approval for the Recall is included in the 2015 Recall Memo, attached as UG 344 OPUC DR 205 – Attachment 3. The Details that were included in the 2015-2016 PGA Filing are in the file attached as UG 344 OPUC DR 205 – Attachment 4.

From 2015 Recall Memo

FERC A/C	DESCRIPTION	AMOUNT
352.2	Reservoirs	1,427,935
354	Compressor Station Equip.	1,737,553
355	Measuring Reg. Equip.	458,515
	Subtotal	3,624,003
	Cushion Gas	192,074
	Total Gross Plant	3,816,077

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Request No.: UG 344 OPUC DR 206

206. Please refer to Oregon Utility FERC Account 303.1 Computer Software.
a. Please provide a list of all new software systems or enhancements to existing systems placed into service after 2011. Please provide a list of the asset numbers associated with each project.
b. Please provide a list of all software retired from 2012 through 2017 including the dollar amount, date retired, and identify replacement software placed into service.

Response:

The activity in FERC Plant Account 303.1 (Computer Software) from 12/31/2011 to 12/31/2017 is shown in the attached Excel file, UG 344 OPUC DR 206 – Attachment 1.

The detailed listings of the Asset Numbers for each year's Plant Additions and Plant Retirements are also included as separate worksheets in the attached Excel file, UG 344 OPUC DR 206 – Attachment 1.

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Request No.: UG 344 OPUC DR 207

207. Please refer to Oregon Utility FERC Account 303.2 CUSTOMER INFORMATION SYSTEM

a. Please provide a list of all new software systems or enhancements to existing systems placed into service after 2011. Please provide a list of the asset numbers associated with each project.

b. Please provide a narrative explanation of why there has been no further investment in this account since 2013.

c. Please provide a narrative explanation of what software is included in the 2016 yearend balance of $30.5 million and whether any portion of this amount is no longer in use.

Response:

The summary of Plant Additions, changes in Accumulated Depreciation and changes in Net Book Value from 2011 to 2017 to Oregon Utility FERC Account 303.2 CUSTOMER INFORMATION SYSTEM (CIS) is in the attached Excel file, UG 344 OPUC DR 207 – Attachment 1.

The detailed listings of CIS Asset Additions are included in a separate worksheet in the attached Excel file, UG 344 OPUC DR 207 – Attachment 1.

As shown in the above referenced Excel file, the Net Book Value of the CIS software at 12/31/2017 is zero, and was materially zero at 12/31/2013 ($3,210).

The Company is developing a plan for a replacement of the CIS software, and determined that it would not make significant additional investment in the existing CIS software after 2013.

The existing Customer Information System software is fully utilized.

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Request No.: UG 344 OPUC DR 208

208. Please refer to Oregon Utility FERC Account 303.4 CRMS

a. Please provide a list of all new software systems or enhancements to existing systems placed into service after 2011. Please provide a list of the asset numbers associated with each project.

b. Please provide a list of all software retired from 2012 through 2017 including the dollar amount, date retired, and identify replacement software purchased if any.

c. Please provide a narrative explanation of why the investment in this increased from $1.4 million to $2.0 million then declined to $683k at the end of 2016. Was the system partially retired from service? What software replaced it?

Response:

The summary of Plant Additions, Plant Retirements, changes in Accumulated Depreciation and changes in Net Book Value from 2011 to 2017 to FERC Account 303.4 Customer Relationship Management Software (CRMS) is in the attached Excel file, UG 344 OPUC DR 208 – Attachment 1.

The detailed listings of CRMS Asset Additions in 2012 and 2013 and the detailed listings of CRMS Asset Retirements on 2014 are included in separate worksheets in the attached Excel file, UG 344 OPUC DR 208 – Attachment 1.

The Gross Plant balance increased from $1.4 million at 12/31/2011 to $2.0 million at 12/31/13 as a result of CRMS Projects in 2012 and 2013, totaling $600,000. The Project numbers and related Assets are included in separate worksheets in the attached Excel file, UG 344 OPUC DR 208 – Attachment 1.

The Gross Plant balance decreased from $2.0 million at 12/31/2013 to $683,000 at 12/31/14 as a result of CRMS Retirements. The Asset numbers are included in a separate worksheet in the attached Excel file, UG 344 OPUC DR 208 – Attachment 1. These Assets were replaced by the CRMS Projects in 2012 and 2013 noted above.

The existing Customer Relationship Management Software is fully utilized.

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Request No.: UG 344 OPUC DR 209

209. Please refer to Oregon Utility FERC Account 352.1 STORAGE LEASEHOLD & RIGHTS

a. Please provide a narrative description of the $400,000 addition to this account. Please discuss the business purpose.

b. Please provide copies of any documents related to this transaction including but not limited to purchase agreements, easements, deeds, appraisal reports, consulting reports, etc.

Response:

The summary of Plant Additions from 2012 to 2016 to FERC Account 352.1 (Storage Leasehold and Rights) is in the attached Excel file, UG 344 OPUC DR 209 – Attachment 1.

The Gross Plant balance increased $400,000 in 2014. The Project number and related Asset are included in a separate worksheet in the attached Excel file, UG 344 OPUC DR 209 – Attachment 1. The 2014 Plant addition resulted from the purchase of Storage Rights from Enerfin Resources.

The following documents related to this transaction are attached:

UG 344 OPUC DR 209 – Attachment 2. Abandonment Letter from Enerfin Resources

UG 344 OPUC DR 209 – Attachment 3. Approved Office Voucher for $400,000.

UG 344 OPUC DR 209 – Attachment 4. Bruer Flora Extension Storage Assets Assignment.

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Request No.: UG 344 OPUC DR 210

210. Please refer to Oregon Utility FERC Account 354 COMPRESSOR STATION EQUIPMENT

a. Please provide a summary in excel format of additions, transfers, and adjustments at the same level of detail shown in work paper 200 wp7 - Gross Plant and Accum Deprec.

i. 354.1 RECIP TURBINE #1
ii. 354.2 RECIP TURBINE #2
iii. 354.3 GAS FIRE TURBINE #1
iv. 354.4 GAS FIRE TURBINE #2
v. 354.5 DEER ISL. COMPRESSOR
vi. 354.6 GF Turb #2 "15 Rebuild

Response:

FERC Plant Account 354.5 (Deer Island Compressor) is Non-Utility Asset.

The balances in the Oregon Utility FERC Accounts 354.1, 354.2, 354.3, 354.4 and 354.6 have remained the same from 12/31/16 to 12/31/17.

A summary of the FERC Account balances and the detailed Asset Listings supporting the balances in the Oregon Utility Plant Accounts are in the attached Excel file, UG 344 OPUC DR 210 – Attachment 1.

An extract of the balances in in the Response to DR 214 are in the attached Excel file, UG 344 OPUC DR 210 – Attachment 2.

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Request No.: UG 344 OPUC DR 211

211. Please refer to Oregon Utility FERC Account 360.2 LAND - OTHER
 a. Please provide a narrative description of the $22,303 retired from this account.
 b. Please provide copies of any documents related to this transaction including but not limited to purchase agreements, easements, deeds, appraisal reports, consulting reports, etc.

Response:

In October 2013, Northwest Natural sold a portion of the land and buildings associated with a property known as "Central" in Portland for a net gain of $1,055,434. The net book value of the land associated with this property transaction was $22,303.

Please see OPUC Docket UP 290. The Company's Initial Application Requesting Approval of the Sale of a Portion of the Central Property contains all of the documentation pertinent to this property transaction.

For a description of the policies and procedures for how gains and losses on the disposal of Oregon jurisdictional Fixed Assets are recognized and reported, please reference the Company's response to 2018 OPUC Plant Audit AIR 17.

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Request No.: UG 344 OPUC DR 212

212. Please refer to Oregon Utility FERC Account 380 SERVICES

a. Please provide an analysis showing the number of services added for new customers each year from 2012 through 2017 and cost by customer rate class for both Oregon and Washington.

b. Please provide an analysis showing the number of services replaced for existing customers for each year from 2012 through 2017 and cost by customer rate class for both Oregon and Washington.

Response:

Part A is provided in the two tables below:

Count of New Services

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	3,898	6,127	5,731	5,911	7,991	6,288
03C	Commercial	Commercial3and1 - OR	184	241	255	274	359	323
32CSF	Commercial	Commercial3and1 - OR	2	6	5	7	3	-
32ITF	Industrial	OR Industrial	2	-	-	-	-	1
31ISF	Industrial	OR Industrial	3	2	-	4	1	-
R02	Residential	Residential - WA	549	1,322	1,349	1,528	2,024	1,439
31CSF	Commercial	Commercial3and1 - OR	2	2	1	-	2	-
32ITI	Industrial	OR Industrial	1	-	-	-	-	-
03I	Industrial	OR Industrial	6	8	3	3	2	3
32ISF	Industrial	OR Industrial	2	1	-	-	-	1
C03	Commercial	Commercial3and1 - WA	21	32	35	47	51	50
I42TI	Industrial	WA Industrial	1	-	-	-	-	-
R01	Residential	Residential - WA	24	39	13	14	9	4
03R	Residential	Residential - OR	2	2	2	5	2	2
R27	Residential	Residential - WA	-	-	-	-	10	745
C41SF	Commercial	Commercial3and1 - WA	-	1	-	1	-	-
R03	Residential	Residential - WA	-	1	-	1	-	1
CUSE	Other	Other	2	1	1	-	-	-
32CSI	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
C01	Commercial	Commercial3and1 - WA	-	2	1	1	-	1
32ISI	Industrial	OR Industrial	-	2	-	1	1	-
32CTF	Commercial	Commercial3and1 - OR	-	1	1	-	-	-
03CV	Other	Other	-	-	-	-	-	-
CUSC	Industrial		-	-	-	-	-	-
27R	Residential	Residential - OR	-	-	-	-	23	1,676
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
C42SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
31CTF	Commercial	Commercial3and1 - OR	-	-	-	-	1	-
I41SF	Industrial	WA Industrial	-	-	-	-	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	-	1
Undetermined	Undetermined	Undetermined	17	33	53	54	78	605
Totals			**4,716**	**7,823**	**7,450**	**7,851**	**10,557**	**11,140**

Average Service Cost by Rate Class

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	$ 2,781	$ 2,849	$ 2,794	$ 2,820	$ 2,906	$ 3,295
03C	Commercial	Commercial3and1 - OR	$ 5,509	$ 6,009	$ 5,683	$ 6,836	$ 9,358	$ 8,056
32CSF	Commercial	Commercial3and1 - OR	$ 10,499	$ 18,325	$ 5,519	$ 9,146	$ 36,317	$ -
32ITF	Industrial	OR Industrial	$299,033	$ -	$ -	$ -	$ -	$133,630
31ISF	Industrial	OR Industrial	$ 71,452	$ 11,673	$ -	$ 17,190	$ 6,176	$ -
R02	Residential	Residential - WA	$ 1,903	$ 1,700	$ 1,942	$ 1,959	$ 1,913	$ 2,073
31CSF	Commercial	Commercial3and1 - OR	$ 11,483	$ 16,024	$ 3,169	$ -	$ 5,046	$ -
32ITI	Industrial	OR Industrial	$104,427	$ -	$ -	$ -	$ -	$ -
03I	Industrial	OR Industrial	$ 22,053	$ 9,257	$ 10,035	$ 15,828	$ 11,424	$ 8,391
32ISF	Industrial	OR Industrial	$ 37,570	$ 14,566	$ -	$ -	$ -	$ 45,504
C03	Commercial	Commercial3and1 - WA	$ 5,890	$ 7,029	$ 6,713	$ 10,211	$ 9,784	$ 5,582
I42TI	Industrial	WA Industrial	$ 21,695	$ -	$ -	$ -	$ -	$ -
R01	Residential	Residential - WA	$ 1,588	$ 2,466	$ 3,297	$ 3,416	$ 5,426	$ 4,262
03R	Residential	Residential - OR	$ 4,041	$ 3,305	$ 12,621	$ 12,646	$ 8,442	$ 17,696
R27	Residential	Residential - WA	$ -	$ -	$ -	$ -	$ 2,154	$ 1,611
C41SF	Commercial	Commercial3and1 - WA	$ -	$ 8,509	$ -	$ 7,278	$ -	$ -
R03	Residential	Residential - WA	$ -	$ 1,240	$ -	$ 1,339	$ -	$ 6,163
CUSE	Other	Other	$ 12,420	$ 14,519	$ 15,070	$ -	$ -	$ -
32CSI	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
C01	Commercial	Commercial3and1 - WA	$ -	$ 5,709	$ 3,721	$ 13,905	$ -	$ 2,841
32ISI	Industrial	OR Industrial	$ -	$ 13,440	$ -	$ 13,822	$ 2,686	$ -
32CTF	Commercial	Commercial3and1 - OR	$ -	$ 3,221	$ 62,175	$ -	$ -	$ -
03CV	Other	Other	$ -	$ -	$ -	$ -	$ -	$ -
CUSC	Industrial		$ -	$ -	$ -	$ -	$ -	$ -
27R	Residential	Residential - OR	$ -	$ -	$ -	$ -	$ 2,506	$ 2,094
C42TF	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
C42SF	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
31CTF	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ 3,640	$ -
I41SF	Industrial	WA Industrial	$ -	$ -	$ -	$ -	$ -	$ -
32C	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$140,577
Undetermined	Undetermined	Undetermined	$ 5,025	$ 3,222	$ 4,967	$ 4,847	$ 3,728	$ 3,924
Totals			**$ 3,047**	**$ 2,800**	**$ 2,791**	**$ 2,879**	**$ 2,988**	**$ 3,059**

Part B is provided in the two tables below:

Count of Replacement Services

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	-	-	1	-	-	-
03C	Commercial	Commercial3and1 - OR	-	-	-	-	-	1
32CSF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
32ITF	Industrial	OR Industrial	-	-	-	-	-	-
31ISF	Industrial	OR Industrial	-	-	-	-	-	-
R02	Residential	Residential - WA	-	-	-	-	-	-
31CSF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
32ITI	Industrial	OR Industrial	-	-	-	-	-	-
03I	Industrial	OR Industrial	-	-	-	-	-	-
32ISF	Industrial	OR Industrial	-	-	-	-	-	-
C03	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
I42TI	Industrial	WA Industrial	-	-	-	-	-	-
R01	Residential	Residential - WA	-	-	-	-	-	-
03R	Residential	Residential - OR	-	-	-	-	-	-
R27	Residential	Residential - WA	-	-	-	-	-	-
C41SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
R03	Residential	Residential - WA	-	-	-	-	-	-
CUSE	Other	Other	-	-	-	-	-	-
32CSI	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
C01	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
32ISI	Industrial	OR Industrial	-	-	-	-	-	-
32CTF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
03CV	Other	Other	-	-	-	-	-	-
CUSC	Industrial		-	-	-	-	-	-
27R	Residential	Residential - OR	-	-	-	-	-	-
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
C42SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
31CTF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
I41SF	Industrial	WA Industrial	-	-	-	-	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
Undetermined	Undetermined	Undetermined	262	551	374	523	1,050	539
Totals			**262**	**551**	**375**	**523**	**1,050**	**540**

Average Replacement Service Cost by Rate Class

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	$ -	$ -	$ 3,566	$ -	$ -	$ -
03C	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ 11,587
32CSF	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
32ITF	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
31ISF	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
R02	Residential	Residential - WA	$ -	$ -	$ -	$ -	$ -	$ -
31CSF	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
32ITI	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
03I	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
32ISF	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
C03	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
I42TI	Industrial	WA Industrial	$ -	$ -	$ -	$ -	$ -	$ -
R01	Residential	Residential - WA	$ -	$ -	$ -	$ -	$ -	$ -
03R	Residential	Residential - OR	$ -	$ -	$ -	$ -	$ -	$ -
R27	Residential	Residential - WA	$ -	$ -	$ -	$ -	$ -	$ -
C41SF	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
R03	Residential	Residential - WA	$ -	$ -	$ -	$ -	$ -	$ -
CUSE	Other	Other	$ -	$ -	$ -	$ -	$ -	$ -
32CSI	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
C01	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
32ISI	Industrial	OR Industrial	$ -	$ -	$ -	$ -	$ -	$ -
32CTF	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
03CV	Other	Other	$ -	$ -	$ -	$ -	$ -	$ -
CUSC	Industrial		$ -	$ -	$ -	$ -	$ -	$ -
27R	Residential	Residential - OR	$ -	$ -	$ -	$ -	$ -	$ -
C42TF	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
C42SF	Commercial	Commercial3and1 - WA	$ -	$ -	$ -	$ -	$ -	$ -
31CTF	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
I41SF	Industrial	WA Industrial	$ -	$ -	$ -	$ -	$ -	$ -
32C	Commercial	Commercial3and1 - OR	$ -	$ -	$ -	$ -	$ -	$ -
Undetermined	Undetermined	Undetermined	$ 6,031	$ 4,634	$ 7,089	$ 6,984	$ 5,980	$ 5,725
Totals			**$ 6,031**	**$ 4,634**	**$ 7,079**	**$ 6,984**	**$ 5,980**	**$ 5,736**

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 213

213. Please refer to Oregon Utility FERC Account 381 METERS, 381.1 METERS (ELECTRONIC), 381.2 ERT (ENCODER RECEIVER TRANS, 382 METER INSTALLATIONS, 382.1 METER INSTALLATIONS (ELECTR, and 382.2 ERT INSTALLATION (ENCODER

a. For each FERC account, please provide an analysis showing the number of meters added for new customers each year from 2012 through 2017 and cost by customer rate class for both Oregon and Washington.

b. For each FERC account, please provide an analysis showing the number of meters replaced for existing customers for each year from 2012 through 2017 by customer rate class for both Oregon and Washington.

c. Please provide a narrative explanation of why account 381.1 is only showing retirements in 2014 and none the other years.

d. Please provide a narrative explanation of why account 382.1 is only showing additions in 2012 and 2013, and why there are only retirements in 2014.

e. Please provide a narrative explanation why there are ERT additions for each year in account 382.1 but no installation costs recorded in account 382.2

Response:

Part A: See the tables below which detail the numbers of new meters and ERTs installed. The company does not have data on meter and ERT cost by rate class.

Count - New Meters

Rate Schedul	Description	Description 2	2012	2013	2014	2015	2016
02R	Residential	Residential - OR	6,536	7,886	7,956	8,150	8,913
03C	Commercial	Commercial3and1 - OR	715	686	731	850	771
32CSF	Commercial	Commercial3and1 - OR	4	1	9	5	3
32ITF	Industrial	OR Industrial	2	-	-	1	-
31ISF	Industrial	OR Industrial	2	-	1	7	1
R02	Residential	Residential - WA	977	1,720	1,505	1,859	2,123
31CSF	Commercial	Commercial3and1 - OR	4	4	1	1	1
32ITI	Industrial	OR Industrial	1	-	-	-	1
03I	Industrial	OR Industrial	7	14	12	7	4
32ISF	Industrial	OR Industrial	-	1	-	-	-
C03	Commercial	Commercial3and1 - WA	110	100	95	99	156
I42TI	Industrial	WA Industrial	-	-	-	-	-
R01	Residential	Residential - WA	141	59	12	17	11
03R	Residential	Residential - OR	4	2	3	5	4
R27	Residential	Residential - WA	-	-	-	-	7
C41SF	Commercial	Commercial3and1 - WA	-	2	1	1	-
R03	Residential	Residential - WA	4	4	-	1	-
CUSE	Other	Other	4	2	3	1	1
32CSI	Commercial	Commercial3and1 - OR	-	-	-	-	-
C01	Commercial	Commercial3and1 - WA	2	3	3	-	-
32ISI	Industrial	OR Industrial	-	2	1	-	2
32CTF	Commercial	Commercial3and1 - OR	-	-	-	-	-
03CV	Other	Other	-	1	-	-	-
CUSC	Industrial		-	-	-	-	1
27R	Residential	Residential - OR	-	-	-	-	31
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	-
C42SF	Commercial	Commercial3and1 - WA	-	-	-	-	-
31CTF	Commercial	Commercial3and1 - OR	-	-	-	-	1
I41SF	Industrial	WA Industrial	-	-	-	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	-
I42TF			-	-	-	-	-
I42			-	-	-	-	-
C41TF			-	-	-	-	-
CWUSE			-	1	-	-	-
32I			1	-	-	-	1
I61T			-	-	-	-	1
I03			1	1	1	-	-
Undetermined	Undetermined	Undetermined	140	190	148	130	100
Totals			**8,655**	**10,679**	**10,482**	**11,134**	**12,133**

Count - ERTs

Rate Schedul	Description	Description 2	2012	2013	2014	2015	2016
02R	Residential	Residential - OR	2,964	3,509	3,266	4,822	3,796
03C	Commercial	Commercial3and1 - OR	1,168	1,155	1,248	1,183	1,333
32CSF	Commercial	Commercial3and1 - OR	29	20	27	20	19
32ITF	Industrial	OR Industrial	5	2	3	1	1
31ISF	Industrial	OR Industrial	21	4	16	13	10
R02	Residential	Residential - WA	135	418	478	860	556
31CSF	Commercial	Commercial3and1 - OR	54	31	39	23	33
32ITI	Industrial	OR Industrial	-	-	-	1	-
03I	Industrial	OR Industrial	27	22	27	25	10
32ISF	Industrial	OR Industrial	5	4	3	6	3
C03	Commercial	Commercial3and1 - WA	81	139	241	153	149
I42TI	Industrial	WA Industrial	-	-	1	-	-
R01	Residential	Residential - WA	5	10	8	10	11
03R	Residential	Residential - OR	19	33	14	21	23
R27	Residential	Residential - WA	-	-	-	-	-
C41SF	Commercial	Commercial3and1 - WA	8	8	4	7	3
R03	Residential	Residential - WA	2	1	5	1	2
CUSE	Other	Other	5	3	4	4	3
32CSI	Commercial	Commercial3and1 - OR	-	1	1	-	2
C01	Commercial	Commercial3and1 - WA	-	-	1	-	-
32ISI	Industrial	OR Industrial	2	3	1	3	1
32CTF	Commercial	Commercial3and1 - OR	3	4	2	-	2
03CV	Other	Other	-	1	-	1	-
CUSC	Industrial		4	-	1	1	-
27R	Residential	Residential - OR	-	-	-	-	-
C42TF	Commercial	Commercial3and1 - WA	-	-	-	2	-
C42SF	Commercial	Commercial3and1 - WA	-	-	2	-	1
31CTF	Commercial	Commercial3and1 - OR	2	4	5	2	2
I41SF	Industrial	WA Industrial	-	-	1	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	1
I42TF			-	-	-	1	-
I42			-	-	-	-	-
C41TF			1	-	-	-	1
CWUSE			-	2	-	-	-
32I			1	1	-	-	-
I61T			-	-	-	-	-
I03			-	2	3	1	-
Undetermined	Undetermined	Undetermined	157	164	153	139	104
Totals			**4,698**	**5,541**	**5,554**	**7,300**	**6,066**

Part B. See the table below which details the number of replaced meters.

Count - Replaced Meters

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016
02R	Residential	Residential - OR	3,656	4,524	4,069	5,978	4,737
03C	Commercial	Commercial3and1 - OR	1,417	1,442	1,520	1,436	1,652
32CSF	Commercial	Commercial3and1 - OR	27	12	24	21	22
32ITF	Industrial	OR Industrial	2	9	4	6	5
31ISF	Industrial	OR Industrial	15	6	15	8	12
R02	Residential	Residential - WA	218	544	547	959	654
31CSF	Commercial	Commercial3and1 - OR	54	23	44	29	40
32ITI	Industrial	OR Industrial	3	1	2	2	6
03I	Industrial	OR Industrial	19	18	19	24	13
32ISF	Industrial	OR Industrial	6	3	3	5	5
C03	Commercial	Commercial3and1 - WA	109	182	251	166	164
I42TI	Industrial	WA Industrial	1	-	2	-	-
R01	Residential	Residential - WA	5	12	9	11	11
03R	Residential	Residential - OR	33	39	25	26	31
R27	Residential	Residential - WA	-	-	-	-	-
C41SF	Commercial	Commercial3and1 - WA	9	6	6	5	4
R03	Residential	Residential - WA	1	1	5	1	2
CUSE	Other	Other	2	1	4	4	3
32CSI	Commercial	Commercial3and1 - OR	1	2	-	1	4
C01	Commercial	Commercial3and1 - WA	-	-	1	-	-
32ISI	Industrial	OR Industrial	1	-	5	3	3
32CTF	Commercial	Commercial3and1 - OR	2	7	1	3	3
03CV	Other	Other	-	-	-	-	1
CUSC	Industrial		5	-	1	-	-
27R	Residential	Residential - OR	-	-	-	-	1
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	2
C42SF	Commercial	Commercial3and1 - WA	1	-	-	2	1
31CTF	Commercial	Commercial3and1 - OR	4	3	7	2	3
I41SF	Industrial	WA Industrial	-	-	-	1	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	2
I42TF			1	-	-	-	1
I42			-	-	-	1	-
C41TF			-	1	-	1	1
CWUSE			-	1	-	-	-
32I			3	-	1	2	-
I61T			-	-	-	-	-
I03			-	1	1	2	-
Undetermined	Undetermined	Undetermined	201	227	203	180	122
Totals			**5,796**	**7,065**	**6,769**	**8,879**	**7,505**

Part C: None of the customers with Electronic Meters discontinued gas service in the other years.

Part D: Installation Costs in the other years were charged to Electronic Meters (Account 381.1). The 2014 Retirements in Account 382.1 resulted from the 2014 Retirement of the Electronic Meters in Account 381.1.

Part E: As a result of the Company's Automatic Meter Reading (AMR) Project, ERT's (Account 381.2) were installed on existing Meters. The last year that contained significant ERT Installation additions was 2009 ($5.2 million). After that, we purchased new Meters with the ERT included.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 214

214. Please refer to Oregon Utility FERC Account 383 HOUSE REGULATORS
a. Please provide an analysis showing the number of house regulators added for new customers each year from 2012 through 2017 and cost by customer rate class for both Oregon and Washington.
b. Please provide an analysis showing the number of house regulators replaced for existing customers for each year from 2012 through 2017 and cost by customer rate class for both Oregon and Washington.
c. Please provide a narrative explanation of why there are no retirements in this account from 2012 – 2016.

Response:

Part A: The table below provides an analysis of house regulators added for new customers:

Count New House Regulators

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	3,898	6,127	5,731	5,911	7,991	6,288
03C	Commercial	Commercial3and1 - OR	184	241	255	274	359	323
32CSF	Commercial	Commercial3and1 - OR	2	6	5	7	3	-
32ITF	Industrial	OR Industrial	2	-	-	-	-	1
31ISF	Industrial	OR Industrial	3	2	-	4	1	-
R02	Residential	Residential - WA	549	1,322	1,349	1,528	2,024	1,439
31CSF	Commercial	Commercial3and1 - OR	2	2	1	-	2	-
32ITI	Industrial	OR Industrial	1	-	-	-	-	-
03I	Industrial	OR Industrial	6	8	3	3	2	3
32ISF	Industrial	OR Industrial	2	1	-	-	-	1
C03	Commercial	Commercial3and1 - WA	21	32	35	47	51	50
I42TI	Industrial	WA Industrial	1	-	-	-	-	-
R01	Residential	Residential - WA	24	39	13	14	9	4
03R	Residential	Residential - OR	2	2	2	5	2	2
R27	Residential	Residential - WA	-	-	-	-	10	745
C41SF	Commercial	Commercial3and1 - WA	-	1	-	1	-	-
R03	Residential	Residential - WA	-	1	-	1	-	1
CUSE	Other	Other	2	1	1	-	-	-
32CSI	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
C01	Commercial	Commercial3and1 - WA	-	2	1	1	-	1
32ISI	Industrial	OR Industrial	-	2	-	1	1	-
32CTF	Commercial	Commercial3and1 - OR	-	1	1	-	-	-
03CV	Other	Other	-	-	-	-	-	-
CUSC	Industrial		-	-	-	-	-	-
27R	Residential	Residential - OR	-	-	-	-	23	1,676
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
C42SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
31CTF	Commercial	Commercial3and1 - OR	-	-	-	-	1	-
I41SF	Industrial	WA Industrial	-	-	-	-	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	-	1
UNDETERMINED	UNDETERMINED	UNDETERMINED	17	33	53	54	78	605
Totals			**4,716**	**7,823**	**7,450**	**7,851**	**10,557**	**11,140**

The company does not have data to determine the cost of house regulators by customer rate class. The average cost per house regulator is provided below:

	2012	2013	2014	2015	2016
House Regulators	$ 155,177	$ 340,354	$ 163,858	$ 205,693	$ 193,633
House Regulator $ per Service	$ 31	$ 41	$ 21	$ 25	$ 17

Part B: The table below provides an analysis of house regulators replaced:

Count Replacement House Regulators

Rate Schedule	Description	Description 2	2012	2013	2014	2015	2016	2017
02R	Residential	Residential - OR	-	-	1	-	-	-
03C	Commercial	Commercial3and1 - OR	-	-	-	-	-	1
32CSF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
32ITF	Industrial	OR Industrial	-	-	-	-	-	-
31ISF	Industrial	OR Industrial	-	-	-	-	-	-
R02	Residential	Residential - WA	-	-	-	-	-	-
31CSF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
32ITI	Industrial	OR Industrial	-	-	-	-	-	-
03I	Industrial	OR Industrial	-	-	-	-	-	-
32ISF	Industrial	OR Industrial	-	-	-	-	-	-
C03	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
I42TI	Industrial	WA Industrial	-	-	-	-	-	-
R01	Residential	Residential - WA	-	-	-	-	-	-
03R	Residential	Residential - OR	-	-	-	-	-	-
R27	Residential	Residential - WA	-	-	-	-	-	-
C41SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
R03	Residential	Residential - WA	-	-	-	-	-	-
CUSE	Other	Other	-	-	-	-	-	-
32CSI	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
C01	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
32ISI	Industrial	OR Industrial	-	-	-	-	-	-
32CTF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
03CV	Other	Other	-	-	-	-	-	-
CUSC	Industrial		-	-	-	-	-	-
27R	Residential	Residential - OR	-	-	-	-	-	-
C42TF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
C42SF	Commercial	Commercial3and1 - WA	-	-	-	-	-	-
31CTF	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
I41SF	Industrial	WA Industrial	-	-	-	-	-	-
32C	Commercial	Commercial3and1 - OR	-	-	-	-	-	-
UNDETERMINED	UNDETERMINED	UNDETERMINED	262	551	374	523	1,050	539
Totals			**262**	**551**	**375**	**523**	**1,050**	**540**

As in Part A, the company does not have data to determine the cost of house regulators by customer rate class. The average cost per house regulator is provided below:

	2012	2013	2014	2015	2016
House Regulators	$ 155,177	$ 340,354	$ 163,858	$ 205,693	$ 193,633
House Regulator $ per Service	$ 31	$ 41	$ 21	$ 25	$ 17

Part C: When Meters are replaced at a premise, the House Regulator is left on premise. In those situations when a Meter is removed from a premise, the company does not have a mechanism to capture the removal of the House Regulator. The undepreciated book value of an individual House Regulator is immaterial in this circumstance.

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Request No.: UG 344 OPUC DR 215

215. Please refer to Oregon Utility FERC Account 391.2 COMPUTERS
a. Please provide a narrative explanation of why the company's investment in computers increased from $15.8 million in 2011 to $21.6 million at the end of 2016.

Response:

Below is a table showing the breakdown of computer investment changes between 2011 and 2016, which shows the drivers that explain this change over time. As shown below, the change results from the retirements and additions during that time, which include the items shown in the descriptions below:

Computers
FERC Account 391.2

12/31/2011	Additions	Retirements	Transfers/Adjust.	12/31/2016
15,825,634	17,775,599	(12,385,369)	403,919	21,619,783

	Beg Balance	Additions	Retirements	Transfers/Adjust.	End Balance
12/31/2011					15,825,634
12/31/2012	15,825,634	2,981,912	-	-	18,807,546
12/31/2013	18,807,546	2,658,917	(1,131,638)	38,650	20,373,475
12/31/2014	20,373,475	3,574,121	(971,541)	(78,666)	22,897,389
12/31/2015	22,897,389	2,862,978	(10,029,192)	443,935	16,175,110
12/31/2016	16,175,110	5,697,671	(252,998)	-	21,619,783
		17,775,599	(12,385,369)	403,919	

The **Retirements** shown include servers, computers and network hardware put out of service during this time frame.

The **Additions** shown represent technical refresh replacements of retired servers, computers, peripherals, and network hardware during this time frame. This column also includes capital projects requiring new or expanded hardware to support the new application or system.

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Request No.: UG 344 OPUC DR 216

216. Please refer to Oregon Utility FERC Account 392 TRANSPORTATION EQUIPMENT

a. Please provide a narrative explanation of why the company's investment in transportation equipment increased from $22.9 million in 2011 to $38.0 million at the end of 2016.

b. Please provide counts for each year from 2011 through 2017 by vehicle type (e.g. sedan, pickup, etc.)

Response:

DR 216a Response:

In calendar year 2011, NWN acquired 88 vehicles with a total cost of $4.1 million and $1.4 million in specialty equipment and trailers. During the same year, 92 vehicles were retired from service with a total value of $2.2 million.

- Five vehicles were added to support additions to staff. These five vehicles had a total cost of $550k.
- 54 vehicles were replaced due to end of life issues. These vehicles had a total cost of $2.2 million. Vehicle types that contributed to this total include the replacement of 25 ½ ton pick-up trucks ($865k), 10 1-ton service body trucks ($547k), and 12 ¾ ton vans ($363k).
- 29 vehicles were replaced to deal with gross vehicle weight (GVW) issues for a total cost of $1.4 million. When existing fleet vehicles were repurposed in 2011 to reduce service window and odor call response times, new on-board equipment was required. After this new equipment was installed on the existing vehicles, they exceeded GVW limitations and were replaced with more capable vehicles with increased GVW specifications.

In calendar year 2012, NWN acquired 107 vehicles with a total cost of $5.3 million and $1.3 million in specialty equipment and trailers. In the same year, 81 vehicles were retired from service with a total value of $1.8 million.

- 32 new vehicles were added to the fleet. Five vehicles were added to support additions to staff with a cost of $194k. Nine vehicles were acquired to support reductions in odor call response time with a cost of $468k. 18 vehicles were

acquired to support a reduction in service window time with a cost of $870k (17 of which were ¾ ton bi-fuel vans.).
- o 64 vehicles were replaced due to end of life issues at a cost of $3.2 million. Vehicle types that contributed to this total included 17 1-ton service body trucks ($1.1 million), 15 ¾ ton bi-fuel pick-up trucks ($887k), 11 ¾ ton pick-up trucks ($449k) and 11 ½ ton pick-up trucks ($368k).
- o 11 vehicles were replaced due to GVW issues for a total cost of $568k.

In calendar year 2013, NWN acquired 41 vehicles for a cost of $3.0 million and $1.2 million in specialty equipment and trailers. In the same year, 70 vehicles were retired from service with a total value of $1.7 million.
- o Three new vehicles were added to support additions to staff for a total cost of $110k.
- o 38 vehicles were replaced due to end of life issues with a total cost of $2.9 million. Vehicle types that contributed to this total include 13 ½ ton pick-up trucks ($451k), seven crew trucks ($1.3 million), five sprinter vans ($334k), six 1-ton vans ($317k) and three weld trucks ($243k).

In calendar year 2014, NWN acquired 17 vehicles with a total cost of $1.9 million and $1.1 million in specialty equipment and trailers. In the same year, 33 vehicles were retired from service with a total value of $1.2 million.
- o Two new Vacuum Trucks were added to the fleet with a cost of $560k.
- o 15 vehicles were replaced due to end of life issues with a total cost of $1.3 million. Vehicle types that contributed to this total were six 1-ton service body trucks ($372k), 5 sprinter vans ($382k), 1 vacuum truck ($300k), and two step vans ($227k).

In calendar year 2015, NWN acquired 67 vehicles with a total cost of $6.0 million and $1.4 million in specialty equipment and trailers. In the same year, 39 vehicles were retired from service with a total value of $1.3 million.
- o Three new trailers were added to the fleet to support increased mission requirements with a total cost of $110k.
- o 64 vehicles were replaced due to end of life issues with a total cost of $5.9 million. Vehicle types that contributed to this total were 11 crew trucks ($2.4 million), 14 dump trucks ($1.8 million), 13 ½ ton, bi-fuel pick-up trucks ($766k) and 9 ½ ton pick-up trucks ($406k).

In calendar year 2016, NWN acquired 65 vehicles with a total cost of $6.4 million and $1.4 million in specialty equipment and trailers. In the same year, 58 vehicles were retired from service with a total value of $2.1 million.

- Five new vehicles were added to support additions to staff with a cost of $210k. Contributors to this total were one ½ ton, bi-fuel pick-up truck ($65k) and three ½ ton pick-up trucks ($134k).
- 60 vehicles were replaced due to end of life issues with a total cost of $6.2 million. Vehicle types that contributed to this total were ten crew trucks ($2.1 million), eight dump trucks ($1.0 million), ten ½ ton, bi-fuel pick-up trucks ($656k), one vacuum truck ($325k), and four 1-ton service body trucks ($305k).

DR 216b Response
Response provided in the table below:

Row Labels	2011	2012	2013	2014	2015	2016
Vehicles	**568**	**602**	**584**	**574**	**587**	**598**
1/2T PU	116	116	123	119	117	120
1/2T PU CNG	8	7	1	2	15	27
1/2T Van	85	53	44	41	40	34
10YD Dump Truck	3	3	3	3	3	3
1T PU	23	27	24	22	20	16
1T Service Body	20	36	37	43	45	48
1T Van	5	6	11	10	9	11
3/4T PU	27	35	29	28	25	26
3/4T PU CNG	9	22	16	16	17	19
3/4T Van	30	31	31	31	31	34
3/4T Van CNG	51	86	85	85	85	87
Crane Truck	8	8	8	8	7	7
Crew Truck	56	52	56	48	57	53
Dump Truck	46	43	42	42	48	43
Express Van	16	11	7	4	2	2
Flatbed Truck	1	3	3	3	3	3
Passenger Vehicle	8	7	7	7	5	5
Plate Truck	1	1	1	1	1	1
Sprinter	6	7	12	17	17	18
Step Van	19	19	18	16	16	16
SUV	18	17	13	13	10	10
Tow Truck	2	2	2	2	2	2
Vac Truck				3	3	4
Volvo Tractor	1	1	1	1	1	1
Weld Truck	9	9	10	9	8	8
Equipment	**129**	**121**	**111**	**105**	**120**	**117**

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Request No.: UG 344 OPUC DR 217

217. Please refer to Oregon Utility FERC Account 394 TOOLS - SHOP & GARAGE EQUIPUI

a. Please provide a narrative explanation for the large amount retirements recorded in 2016 ($8.0 million).

Response:

In 2016, as part of a Tools Tracking Project, NW Natural determined that certain tools with vintage years prior to 2000 should be retired. Those assets were therefore retired in 2016 as an outcome of that project, which represents the amount referred to for 2016. The list of Asset Numbers that were retired, and their respective costs are in the attached Excel file, UG 344 OPUC DR 217 – Attachment 1.

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Request No.: UG 344 OPUC DR 251

251. Regarding the Company's response to DR 122:
   a. Regarding the Net Plant" tab of file 200wp7
      i. Please explain why the percentage land allocation for Oregon
         1. Increases from 81.7% to 83.4% in Feb 2018
         2. Increases from 83.4% to 84.8% in Dec 2018
      ii. Please explain the decision to use a blended rate Oregon allocation of 93.7% for structures for both gross plant and depreciation reserve when separate factors have been calculated in the supplemental work paper provided (UG 344 OPUC DR 122 Attachment 2 Structures Alloc - Dec 2016)
         1. Oregon gross plant 91.2%
         2. Oregon reserve 93.6%

Response:

251 a.i. – The land allocation is determined initially at 81.7% as of December 31, 2016 (see "Land Alloc – Dec 2016" file provided in response to DR 122). For Land, the initial allocation is established by a detailed review of the assets in the account, as shown in the file. Once the December 31, 2016 allocation was set, future projected additions to the account can be explicitly allocated to either state, or to both states, depending on the nature of the incremental plant asset added. Assets are shown to be added in both February 2018 and December 2018, and both are for Oregon-only operations. The overall state allocation for land therefore increases in each of those months of added assets.

251 a.ii. – The net plant allocation factor coming out of the analysis was adopted because the gross and reserve factors were different. The individual factors would be appropriate to use if the numbers being allocated were just the historical numbers. However, because the factor was to be used against future additions to both gross plant and the reserve, it would be unreasonable to assume that the factors would apply. For example, when all the individual plant assets eventually become fully depreciated, it would be expected that the allocation factor for the gross plant would be the same as the factor for the reserve. One could also expect that there could be a convergence in the factors slowly over time. The use of the net plant generated allocation factor was considered reasonable over the short term from year-end 2016 to October 2019, the ending month of the test year.

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Request No.: UG 344 OPUC DR 252

252. Regarding FERC Acct 374.2 Land Rights / Asset # 6062704 Easement/Right of Way FERC 374.2

a. Please provide a narrative explanation of the amounts added in this account for 2012-2014.

b. Please explain why there are no additional additions to this account after 2014.

Response:

Additions to FERC Account 373.2 (Distribution Plant Land Rights) were $19,389 in 2012, $13,382 in 2013, and $7,350 in 2014.

a. These costs were primarily incurred for expansion of the Company's distribution and transmission system in the mid-Willamette valley from 2012 to 2014.

b. Those expansion Projects were completed in 2014.

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Request No.: UG 344 OPUC DR 253

253. Regarding FERC Acct 375 Structures and Improvements / Assets #1028754 through 1028758 North Vancouver Gate Station

a. Please confirm these assets are not included in the UG 344 Utility Plant in Service.

Response:

The assets are not included in the UG 344 Utility Plant in Service. Distribution assets are designated by state for plant accounting purposes, and are directly attributed to each state for ratemaking purposes. These assets were properly designated as Washington assets.

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Request No.: UG 344 OPUC DR 254

254. Regarding FERC Acct 377 COMPRESSOR STATION EQUIPMENT / Asset 6091571 GASCO Line Heater Replacement

a. This asset appears to be related to the Portland LNG plant. Please provide a narrative explanation why it is recorded in distribution plant.

Response:

Asset 6091571 resulted from Project 200598 (Design - Gasco Line Heater) in 2013. The Project cost ($1,599.44) was incurred to design the Line Heater at the Portland LNG Plant. The cost should have been classified as Local Storage Plant. We will reclassify the cost in 2018 to the correct FERC Account.

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Request No.: UG 344 OPUC DR 255

255. Regarding FERC Acct 386 Other Property Located on Customer Premises / Asset #6154747 CNG Vehicle Refueling Facilities

a. Where is the facility located?
b. Who is the customer?
c. Please provide a narrative explanation of the circumstances underlying this investment.
d. How is the cost of the investment being recovered from the customer?

Response:

Asset #6154747 resulted from Project 201739 (City of Portland Schedule H, CNG).

a. The CNG Facility is located at the City of Portland's waste water treatment plant.

b. The customer is the City of Portland, under an Agreement dated May 2, 2017.

c. The investment consists of the installation of High Pressure Natural Gas Facilities to be used by the City of Portland to refuel their CNG vehicles.

d. The cost of the investment will be fully recovered from the City of Portland under Rate Schedule H. In addition, the City of Portland will reimburse NW Natural for scheduled and unscheduled maintenance of the CNG Facility.

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Request No.: UG 344 OPUC DR 256

256. For each item on the attached list of distribution assets (102 total), please provide the following information:

a. Please provide the project location - street address or city and state.

i. For projects located in Washington items b through g below may be skipped. For Oregon projects please provide all information requested.

b. Is the asset a standalone project or part of a larger project?

i. If part of a larger project please identify the project and provide a list of the other asset numbers included in the larger project.

c. Please indicate if the project has been discussed in an IRP filing.

i. If so, please identify the IRP year and page number.

d. Please indicate if the project has been specifically vetted with the commission as part of the System Improvement Program.

i. If so, please provide the docket number.

e. If additional project costs were incurred prior to 2012 or are expected after 2017 please provide the total cost of the project.

f. Please provide a narrative description of the business purpose of each project, alternatives considered, related highway or other public works projects, and how the project benefits ratepayers.

g. For each project, please provide the following information:

i. Dollar amount of construction overhead applied.

ii. Dollar amount AFUDC charged to the project.

iii. Dollar amount of contributions in aid of construction.

iv. A list of any outside contractors used and the amounts paid to each.

1. Narrative description of the bidding process and vendor selection criteria.

v. For pipe, the total length installed in feet.

vi. A narrative description of other equipment installed.

vii. Project budgets and final budget to actual variances.

Response:

Please see attached spreadsheet UG 344 NWN OPUC DR 256 Attachment 1 that contains the requested information for each asset.

DR 256(a) – Column C provides the city in Oregon that the project is located in. Assets listed as "WASHINGTON" are located in Washington state.

DR 256(b) – Column D states if the asset is a standalone project or part of a larger project. Assets marked as "Revision" are mini-projects. A revision is a way to group work orders together that are going to be completed at the same time – the work order that is the largest pipe size is the leading work order that will have all the information about the work to be done.

DR 256(b)i – Column E provides the project or work order number associated with the asset. Assets that are part of the same project will have the same project number.

DR 256(c) – Column F states if the asset was discussed in an IRP filing.

DR 256(c)i – Column G provides the IRP year and page numbers.

DR 256(d) – Column H states if the asset was part of the System Integrity Program (SIP)

DR 256(d)i – These projects were covered under docket UM 1406

DR 256(e) – Column I provides total project costs.

DR 256(f) – Column B provides a brief description of the project. For larger projects see UG OPUC DR 256 Attachment 2 for project documentation including project initiation memos and project charters. Column S also provides the type of work performed.

DR 256(g)i – Column J provides dollar amount of Construction Overhead associated with the work order or project.

DR 256(g)ii – Column K provides the dollar amount of AFUDC associated with the work order or project.

DR 256(g)iii – Column L provides the dollar amount of contributions in aid of construction associated with the work order or project.

DR 256(g)iv – Column M, Column N we regularly and typically have framework agreements with routine contractors. Our internal construction resources were primary used on all projects. Costs in column N represent total contractor costs for the entire project. NW Natural has a formal process through purchasing for bidding out work specific to a project – most of the time that would be for non-routine bores or contracting out an entire project to contractors – RFP's, quotes received and reviewed, contract awarded.

DR 256(g)v – Column O provides the total length of pipe installed including pipe size and material.

DR 256(g)vi – Column P provides a description of non-pipe assets installed.

DR 256(g)vii – Column Q, Column R provide project budgets and actuals for the work order associated with the asset and not the total project.

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Request No.: UG 344 OPUC DR 257

257. For each item on the attached list of transmission assets (50 total), please provide the following information:

a. Please provide the project location - street address or city and state.

i. For projects located in Washington items b through g below may be skipped. For Oregon projects please provide all information requested.

b. Is the asset a standalone project or part of a larger project?

i. If part of a larger project please identify the project and provide a list of the other asset numbers included in the larger project.

c. Please indicate if the project has been discussed in an IRP filing.

i. If so, please identify the IRP year and page number.

d. Please indicate if the project has been specifically vetted with the commission as part of the System Improvement Program.

i. If so, please provide the docket number.

e. If additional project costs were incurred prior to 2012 or are expected after 2017 please provide the total cost of the project.

f. Please provide a narrative description of the business purpose of each project, alternatives considered, related highway or other public works projects, and how the project benefits ratepayers.

g. For each project, please provide the following information:

i. Dollar amount of construction overhead applied.

ii. Dollar amount AFUDC charged to the project.

iii. Dollar amount of contributions in aid of construction.

iv. A list of any outside contractors used and the amounts paid to each.

1. Narrative description of the bidding process and vendor selection criteria.

v. For pipe, the total length installed in feet.

vi. A narrative description of other equipment installed.

vii. Project budgets and final budget to actual variances.

Response:

Please see attached spreadsheet UG 344 OPUC DR 257 Attachment 1 that contains the requested information for each asset.

DR 257(a) – Column C provides the city in Oregon that the project is located in.

DR 257(b) – Column D states if the asset is a standalone project or part of a larger project. Assets marked as "Revision" are mini-projects. A revision is a way to group work orders together that are going to be completed at the same time – the work order that is the largest pipe size is the leading work order that will have all the information about the work to be done.

DR 257(b)i – Column E provides the project or work order number associated with the asset. Assets that are part of the same project will have the same project number.

DR 257(c) – Column F states if the asset was discussed in an IRP filing.

DR 257(c)i – Column G provides the IRP year and page numbers.

DR 257(d) – Column H states if the asset was part of the System Integrity Program (SIP).

DR 257(d)i – These projects were covered under docket UM 1406.

DR 257(e) – Column I provides total project costs.

DR 257(f) – Column B provides a brief description of the project. For larger projects see attached UG 344 OPUC DR 257 Attachment 2 which includes project initiation memos and project charters. DR 257(g)i – Column J provides dollar amount of Construction Overhead associated with the work order or project.

DR 257(g)ii – Column K provides the dollar amount of AFUDC associated with the work order or project.

DR 257(g)iii – Column L provides the dollar amount of contributions in aid of construction associated with the work order or project.

DR 257(g)iv – Column M, Column N --- we regularly and typically us routine contractors that we have framework agreements with. Our internal construction resources were primary used on all projects. Costs in column N represent total contractor costs for the entire project. NW Natural has a formal process through purchasing for bidding out work specific to a project – most of the time that would be for non-routine bores or contracting out an entire project to contractors – RFP's, quotes received and reviewed, contract awarded.

DR 257(g)v – Column O provides the total length of pipe installed including pipe size and material.

DR 257(g)vi – Column P provides a description of non-pipe assets installed.

DR 257(g)vii – Column Q, Column R provide project budgets and actuals for the project.

Pages 59 through pages 61 are confidential and subject to Modified Protective Order No. 18-002.

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Request No.: UG 344 OPUC DR 264

264. Regarding UG 344 OPUC DR 203:

a. Please provide an excel worksheet reconciling the differences between UG 344 OPUC DR 203 Attachment 1 and the monthly increases embedded in 200 wp7 - Gross Plant and Accum Deprec. Staff calculated totals are in the attached file.

b. Regarding the response to UG 344 OPUC DR 203 b. "We do not have a single report that presents expenditure by projects by FERC. Our modeling system allocates expenditures to FERC once the project is placed in service and not while the project is in construction."

i. Please explain by FERC account how the additions by month in 200 wp7 - Gross Plant and Accum Deprec were determined.

1. For accounts with a balance assumed to increase by a percentage or other standard amount each month please explain the historical basis for the recurring additions and what periods of time are used to estimate the baseline increases.

ii. Please provide a list in excel of the major items is expected to be placed into service in the following months (please see the attached file). For items that discussed in the IRP process please identify the year and page number:

1. Oregon Intangible Software
   a. March 2018 $1,338,653
   b. June 2018 $6,957,826
   c. August 2018 $4,429,721
   d. December 2018 $1,182,150
   e. September 2019 $1,228,187
2. Oregon Transmission
   a. March 2018 $7,669,420
   b. August 2018 $5,811,338
   c. November 2018 $4,084,656
   d. December 2018 $2,381,332
3. Oregon General
   a. February 2018 $1,252,208
   b. June 2018 $1,149,395
   c. July 2018 $1,032,707
   d. August 2018 $1,232,898
   e. September 2018 $1,166,701
   f. December 2018 $5,736,804
   g. April 2019 $1,381,176

4. Oregon Storage and Storage Transmission
   a. May 2018 $2,702,999
   b. August 2018 $1,532,566
   c. September 2018 $3,361,424
   d. October 2018 $1,123,787
   e. November 2018 $1,580,107
   f. May 2019 $2,332,674
5. Oregon Land & Structures
   a. February 2018 $1,225,802
   b. April 2018 $848,215
   c. July 2018 $505,601
   d. August 2018 $3,385,038
   e. September 2018 $11,113,588
   f. December 2018 $3,209,770
   g. April 2019 $3,031,409
6. Oregon CNG/LNG
   a. December 2018 $1,000,000
   b. July 2019 $1,000,000
7. Washington Intangible Software
   a. March 2018 $148,739
   b. June 2018 $773,092
   c. December 2018 $140,201
   d. August 2018 $492,191
   e. December 2018 $131,350
8. Washington General
   a. December 2018 $651,312
9. Washington Storage and Storage Transmission
   a. June 2018 $990,821
   b. July 2018 $831,645
10. Washington Land & Structures
   a. August 2018 $226,467
   b. September 2018 $743,525
   c. April 2019 $202,808

c. Regarding the response to UG 344 OPUC DR 203 b. "The factor categories are the same as those used to allocate plant in the last rate case. Numeric factors are updated to reflect the most recent available information as to percentages of customers, volumes, plant, and direct employees in each jurisdiction. "

i. Please provide the detailed calculations showing how each "factor category" was determined for both UG 221 and UG 344

ii. Please identify how the "most recent available information" was determined for each of the following for each jurisdiction: Please provide the data and calculations used.

1. Percentages of customers
2. Volumes

3. Plant
4. Direct employees

Response:

264a. The monthly changes to total gross plant in each are identical. The attached file "UG 344 OPUC DR 264 Attachment 1 Summary Reconciliation" shows the information on changes from the other 2 files ("UG 344 OPUC DR 264 Attachment 2 – Gross Plant and Accum Deprec" and "UG 344 OPUC DR 264 Attachment 3 Ref DR 203 Att 1"). The calculations on the wp7 file are on rows 224 – 226, and on the DR 203 file on rows 712-713.

264bi. The capital expenditure projections are built from the ground up with large projects and run-rate expenditures identified. This is accomplished using historical and projected spend patterns in combination with known project work that is required to effectively serve customers, improve our system and operations, or serve additional customers in our area.

Large projects are captured under each "Applicant" (internal type of work/category) where the expenditure will occur, along with any run-rate component. Certain categories are built mostly from run-rate spend as the projects that happen throughout the year are smaller and/or often unidentified at the time of budget, yet continually come about each year.

The projections are initially developed using direct cost only, and COH is applied later using rates set by Accounting. Different methods are used depending on the category of work. Below is a description of major categories:

- New customer acquisition work is forecasted based on a forecast model that estimates new customer expenditures based on cost and volume assumptions. Important drivers of the forecast are historical trends, projected housing starts and non-residential growth in our service territory, and system expansion efforts to serve new customers. For unit costs, the estimate factors in work mix (company and contractor), historic and contracted costs, etc.
- The System Betterments and System Reinforcement categories are mostly project driven, and also have a small run-rate component for unidentified work that comes up throughout the year.
- Other expenditures are driven by jurisdictional requirements, compliance, damage reconstruction, and leakage, etc. and are forecasted using historical expenditures from the previous years in combination with known and required work. Annual spend in these categories includes Public Works (about $10 million per year) and Relocates ($6 million per year).
- Distribution and Transmission Integrity work uses a combination of run rate based on historic work and identified projects.
- Power operated equipment and transportation expenditures are based on the replacement schedule of vehicles and purchases of power operated equipment.

- Expenditures for Information technology are driven by projects, but also include a portion of software/hardware technology refreshes and smaller project run-rate spend (about $5-$6 million per year).
- Land and structure expenditures are mostly driven by projects, but also have a run-rate component for breakage/unexpected facilities costs (about $0.5-$1 million per year).

The forecast of Capital Expenditures is allocated to FERC accounts using the allocation factors provided in DR 203.

264bii. Please see attached file UG 344 DR 264 Attachment 4 Project List.

264ci. Please see attached files for UG 221 Allocation Factor derivations ("UG 344 DR 264 – UG 221 Attachment 5 Allocation Factors", "UG 344 DR 264 Attachment 6– UG 221 Allocation Factors – 2010 Earnings Test Report", and "UG 344 DR 264 Attachment 7 – UG 221 Allocation Factors – TME Sept 2011 OM".

Please see response to DR 218 for primary derivation of allocation factors ("200 wp10 – Allocation Factors – Linked"). Additionally, see attached file "UG 344 DR 264 Attachment 8 – Allocation Factors – TTM Sept 2017 OM" for derivation of 3 unlinked factors.

264cii.

Please see response to DR 218 for linked file with supporting calculations for allocations.

1. The percentages of customer allocation factors were determined using a simple beginning and ending average for the 12 months ended September 30, 2017.
2. The volumes allocation factors were determined using the actual volumes for the 12 months ended September 30, 2017.
3. Plant allocation factors were determined using the percentages resulting from the test period amounts for Oregon and System.
4. The employees directly assigned factor was developed using June and December data from the period December 2014 through June 2017.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 266

266. Regarding FERC Acct 368 Compressor Station Equipment:

a. The settlement agreement for UM 1808 lists this account as a depreciable asset (Original Cost $7,723,454.21).

b. The most recent FERC Form 2 filed [RG 37(5)] lists this account as non-utility.

c. The account does not appear included in UG 344 rate base (200 wp7 - Gross Plant and Accum Deprec).

d. Please verify if this account is utility property that should be included in rate base or, alternatively, should it have been excluded from the UM 1808 depreciation calculations?

Response:

The depreciation study included both utility and non-utility Mist assets. Non-utility Mist assets are subject to recall to utility purposes (IRP work establishes the schedule of recall), and as a result, the proper depreciation rate is of importance for state regulated accounting. In the long-term, all the non-utility Mist assets are expected to be transferred to utility service. The 368 account was correctly included in the UM 1808 depreciation study, and was appropriately excluded from the rate base for this rate case. There is a recall of non-utility assets and related accumulated depreciation in May 2019, however, and a portion of the non-utility account 368 is transferred to utility service. The transfer amount appears in account 354, which is storage related transmission. This transfer is determined in the Integrated Resource Planning process.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 366

366. Regarding asset numbers 6094517 South of Monmouth 12" $14,691,584 and 6106445 South of Monmouth 12" $9,846,581:

a. Please provide the following documents:
   i. Business case
   ii. Project charter
   iii. Change Orders
   iv. Project closing documents

b. Please confirm that the cost of both assets is part of the South of Monmouth Bare Replacement section shown on the map of the Mid-Willamette Valley Feeder shown in the direct testimony of Joe Karney 800/page 5.

Response:

a.

i. Both asset numbers 6094517 and 6106445 are part of the South of Monmouth Bare Steel replacement project (Project #200584). For the business case, please see section 7 of the attached Project Charters, UG 344 OPUC DR 366 Attachments 1-2 (200584 G-67 Financial Authorization.pdf and 200584 G-67 Financial Authorization 2014.pdf).

ii. The initial project charter, UG 344 OPUC DR 366 Attachment 1 (200584 G-67 Financial Authorization.pdf) is the project charter approved the project prior to the start of construction in 2013. The second project charter UG 344 OPUC DR 366 Attachments 2 (200584 G-67 Financial Authorization.pdf), was updated the charter upon completion of the 2013 construction and prior to the construction planned for 2014.

iii. There were no change orders for the project.

iv. Please see the attached final project close out document UG 344 OPUC DR 366 Attachment 3 (200584 Mid-Willamette Close Out Approved.pdf)

b. Both assets are part of the "MWVF South of Monmouth Bare Replacement (2013)" as shown in the direct testimony of Joe Karney 800/page 5.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 403

403. Regarding work paper 200 wp7 - Gross Plant and Accum Deprec:
a. Please provide a detailed explanation of the $33m adjustment embedded in the cell formulae in row 208.
b. Please provide the "file" referred to in cell B334.
c. Please provide a list of all Commission orders and or dockets related to the $33m adjustment.

Response:

a. The adjustment is made to specifically allocate $33 million of the total South Mist Pipeline Extension to Oregon, to reflect the amount of distribution system reinforcement estimated to have been avoided due to the construction of the pipeline. Transmission pipelines attributable to Mist Storage have been accepted as allocable to both states, consistent with the allocation of the storage facility itself. Because non-storage transmission pipelines are not allocated between states, the $33 million represented the portion of the project cost that was needed irrespective of the storage function. The allocation was documented in the Company's Direct Testimony in UG 152 (UG 152/NWN/400 Stinson at pages 20 – 22).

b. See attached file "UG 344 OPUC DR 403 Attachment 1."

c. UG 152 and NWN Advice No. OPUC 04-11A. As stated above, the general rate case included discussion of the issue. Because the project was delayed beyond the effective date of rates in the rate case, it was included in rates at the same time as the following year's Purchased Gas Cost Adjustment. While the allocation issue is not discussed in the advice filing, the amount of $13,988,123 included as an adjustment in the filing explicitly included the $33 million direct allocation. See attached file "UG 344 OPUC DR 403 Attachment 2."

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

REDACTED
April 20, 2018

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

A. My name is Rose Anderson. I am a Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I discuss my review of several categories of Northwest Natural Gas Company's (NW Natural or Company) test year expense, including expenses for advertising, promotional activities and concessions, NWN's Carbon Savings Goal, "atmospheric testing," and one category of revenue. I propose a downward adjustment to NW Natural's test year expense for advertising, and promotional accounts. I propose an upward adjustment to miscellaneous revenues accounts.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/402 – Budgeted and Actual Category "A" Advertising Expenditures

Exhibit Staff/403 – Examples of Environmental Advertising

Exhibit Staff/404 – NW Natural Responses to Staff Discovery Regarding Renewable Natural Gas

Exhibit Staff/405 – NW Natural Promotional Concessions Filings in Docket No. RG 31

Exhibit Staff/406 –NW Natural Response to Staff DR 244: Company Explanation of Miscellaneous Revenue Accounting Data

Exhibit Staff/407 –NW Natural Response to Staff DR 243: Company Explanation of Carbon Savings Goal.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ADVERTISING EXPENSES

Q. Does the Commission have a standard means of determining how advertising and promotional expenses are treated?

A. Yes, it does. OAR 860-026-0022 sets out how advertising expenses should be addressed in a rate case. This rule defines advertising expenses as "expenses for communications which inform, influence, and/or educate customers."[1] A key difference between an "advertising expense" and a "promotional activity" is that advertising expenses are specifically described as communicating a message to customers, while promotional activities are meant to promote the utility's product to a wider audience.

Utility advertising expenses are grouped into five categories:

- **Category "A"** contains energy efficiency advertising expenses not related to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.
  - **Utility service advertising expenses** are primarily for supplying customers with information about utility services such as office hours, repairs, and efficient, safe use of utility services.
  - **Utility information advertising expenses** are primarily for increasing customer understanding of utility systems and other contemporary items of customer interest, including environmental considerations.

[1] OAR 860-026-0022.

- **Category "B"** contains legally mandated advertising expenses.
- **Category "C"** contains institutional and promotional advertising expenses, as well as any other advertising expenses not fitting into Category "A," "B," or "D"'
  - o **Promotional advertising expenses** are primarily for communicating to customers with respect to a utility's promotional activities or concessions.
  - o **Institutional advertising expenses** are primarily for enhancing a company's reputation or image with customers, rather than conveying information.
- **Category "D"** contains political advertising expenses and nonutility advertising expenses.
- **Category "E"** contains energy efficiency or conservation advertising expenses that relate to a Commission-approved program.

OAR 860-026-0022(3) specifies that for ratemaking purposes:

- Category "A" expenses are presumed to be just and reasonable to the extent that expenses are twelve and one-half hundredths of 1 percent (0.125 percent) or less of the gross retail operating revenues determined in the rate proceeding.
- Category "B" expenses are presumed to be just and reasonable.
- Category "C" expenses can be included in rates, but the utility shall carry the burden of showing that any advertising expenses in this category are just and reasonable.

- Category "D" expenses are presumed to be not just and reasonable.
- Category "E" expenses may be capitalized and are subject to a prudence review.

Q. How do the Company's advertising expenses compare to historical trends when categorized under the OAR 860-026-0022 categories mentioned above?

A. In the base year,[2] NW Natural reports approximately $2,134,000 in total Category "A" advertising.[3] This represents a 65 percent increase from the average of Category "A" spending for the previous three years. Category "B" spending increased 32 percent from the previous three-year average to $701,214.[4] Category "C" advertising spending decreased approximately 19 percent from the previous three-year average to $558,979.[5] NW Natural includes Category "A" and Category "B" expenses but not Category "C" expenses in the test year. NW Natural reports that it had no Category "D" and "E" expenses in the base year.

Q. How did Staff perform its analysis of NW Natural's proposed advertising expenses?

A. Staff reviewed transactional accounting detail for the expenses included in Category "A" and Category "B" for which the Company is seeking recovery in rates. Staff also submitted follow-up data requests for more information

[2] NW Natural's "base year" is calendar year 2017.
[3] Staff/402, Company Response to Staff DR 313 Attachment 1.
[4] Staff/402, Company Response to Staff DR 313 Attachment 1.
[5] Staff/402, Company Response to Staff DR 313 Attachment 1.

regarding a sample of expenses and reviewed copies of NW Natural's advertisements.

Q. What is Staff's assessment of NW Natural's proposed advertising budget for the test year?

A. Staff concludes that about $1,152,000 of NWN's advertising expenses in Category "A" are related to an environmental media campaign by NW Natural. Staff finds that one portion of this expense should be reclassified as Category "C" advertising expense and another portion should be reclassified as promotional activity and concessions as defined in OAR 860-026-0010 and OAR 860-026-0015.

Q. Please explain how Staff arrived at this conclusion.

A. Staff's review of copies of advertising[6] indicate that NWN's environmental advertising is intended to:

- convey the notion that upgrading to natural gas appliances and vehicles has environmental benefits,
- inform the viewer of NW Natural's promotional offerings to upgrade to efficient natural gas appliances,
- enhance NW Natural's image as an environmentally friendly company,
- inform viewers about NW Natural's Smart Energy voluntary carbon offset program, and/or

[6] Staff/403, Anderson/1-13.

- describe environmentally friendly gas technologies like “power to gas” and renewable natural gas.

Most of these advertisements serve to promote a green image for NW Natural. They direct viewers, both current customers and prospective customers, to a website with environmental messaging and a connection to NW Natural’s promotional incentives for natural gas appliances.[7] This advertising is clearly directed at gaining customers or increasing the use of natural gas by current customers.

NW Natural spent approximately $1,152,000 in the base year on environmental advertising associated with the “Less We Can” project and other environmental messaging and research, including salary and payroll expense. Staff’s assessment indicates that about 60 percent of these costs do not belong in Category “A” for informational advertising to customers since they consist of a mix of “corporate” and “promotional” advertising, as well as “promotional activities.”

Of the 60 percent, or approximately $691,200, of environmental advertising expenses that should be removed from Category “A”:

- About half of this amount, or $345,600, is for advertising that is mainly directed at NW Natural customers and relates to the Company’s promotional programs and corporate image. This half is

[7] Staff/403, Anderson/11.

appropriately categorized in advertising Category “C” for promotional and institutional advertising.

- The other half cannot be classified as advertising expenses under the OAR definition because the media is directed at a wider audience than only NW Natural Customers.[8] This portion, approximately $345,600, is directed at increasing gas use by present and prospective customers and should be evaluated under the “promotional activity” category defined in OAR 860-026-0010.[9] Staff discusses NW Natural’s promotional activity in Issue 2 of this exhibit.

In summary, Staff recommends reclassifying sixty percent of the Company’s Category “A” environmental advertising expenses. Staff suggests 30 percent, or $345,600, should be counted as Category “C” advertising since it is likely to reach NW Natural customers and direct them to NW Natural’s promotional offers. Additionally, Staff suggests that 30 percent, or $345,600, should be counted as “promotional activity” since it will reach non-customers and promote the increased use of natural gas. Staff addresses promotional activities later in this testimony.

Q. Regarding the Category “C” advertising expenses, what is the standard for reviewing these expenses in a rate case?

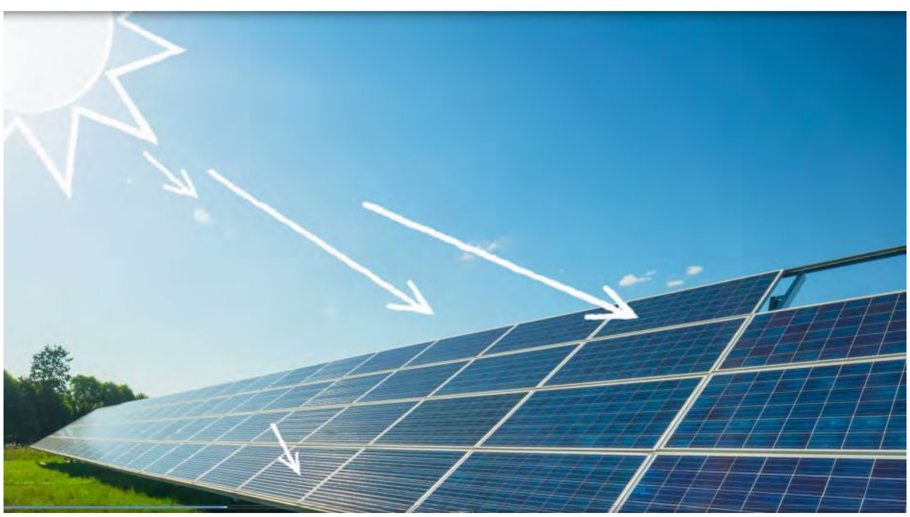
---

[8] Staff/403, Anderson/3.
[9] OAR 860-026-0010 defines “promotional activity” as “action by an energy or large telecommunications utility or its affiliate with the objective of increasing or preventing a decrease in the quantity of the energy or large telecommunications utility’s service used by present and prospective customers; inducing any person to use an energy utility’s service rather than a competing form of energy.”

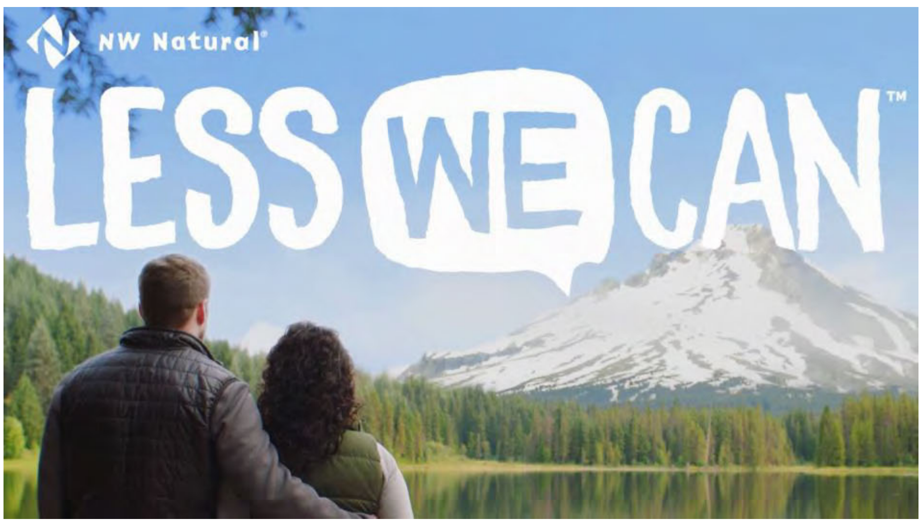
A. ORS 860-026-0022 states that Category "C" institutional and promotional advertising expenses may be recovered in rates if they are "just and reasonable for ratemaking purposes."

Q. Are the promotional and institutional advertising expenses related to the environment in the base year "just and reasonable?"

A. Partially. These expenses are partly for communicating to customers about NW Natural's corporate image and promotional offerings. However, some of the Company's advertisements imply environmental attributes for the Company that are not accurate. For example, one video on NW Natural's "Less We Can" website begins by describing the process of synthesizing renewable natural gas through electrolysis, and then depicts renewable natural gas flowing into residential homes, followed by NW Natural's logo. [10]



[10] http://lesswecan.com/what-were-doing/power-to-gas, accessed April 16, 2018.



A reasonable interpretation of this video is that NW Natural delivers renewable natural gas synthesized through electrolysis to customer's homes. In reality, the Company does not currently provide this product to customers. NW Natural's reply to Staff discovery indicates that the Company is only in the research and development stage of a small-scale electrolysis pilot project.[11]

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[11] Staff/404, Anderson/1 - 4, Company Responses to Staff DR Nos. 392 - 395.

The “Less We Can” electrolysis web video is located on a website dedicated to the benefits of Power to Gas technology. Only in the last sentence of the text does NW Natural divulge that that the Company is currently only “exploring ways this technology can be used here in the Northwest to create a new source of renewable natural gas.” Staff notes that the video is also sharable on social media and viewable on YouTube, where it is not accompanied by the text disclaimer found on the website.

Staff finds that the Company is attracting customers and improving its image through vague environmental statements based on plans for environmental action that have not yet been implemented. Until NW Natural has successfully integrated these environmentally friendly technologies into its system, advertisements implying that these technologies are currently utilized by NW Natural, cannot be called “just and reasonable.”

Q. What is your recommended adjustment for Category “C” advertising expenses?

A. Of the $345,600 in environmental advertising expenses Staff suggests moving from Category “A” to Category “C” only about 70 percent are “just and reasonable for ratemaking.” Staff recommends removing 30 percent of this expense from rates because this portion of the advertising strongly implies the Company’s product possesses environmental attributes that are not actually available to NW Natural customers at this time, such as gas generated through renewable and “power to gas” technologies. The result is a downward adjustment of $103,678. This brings Staff's total adjustment to advertising expenses to $449,275

Q. Does Staff have an adjustment for the advertising expense remaining in Category A?

A. No. As discussed above, Category "A" expense is presumed reasonable for purposes of ratemaking if the test year expense is less than 0.125 percent of the utility's forecasted gross retail revenues for the test year. For comparison, the $1,685,011 of Category "A" advertising expense remaining after Staff's re-classification of expenses is approximately 0.28 percent of the Company's 2016 revenues. So, only a portion of NW Natural's Category "A" expense is subject to the presumption of reasonableness.

Staff has reviewed these expenses and finds no further issues with the Category "A" advertising expenses. Staff's adjustment results in spending of $1,685,011, or $2.63 per customer. Although this is higher than the $759,012, or 0.125 percent, presumed reasonable under OAR 860-026-0022, NW Natural has pointed out in testimony that its gross retail operating revenues are driven in part by natural gas commodity costs, which are currently low. Further, as pointed out by NW Natural in testimony, on a per-customer basis, PGE's per-customer Category "A" spending is $2.48 and PacifiCorp's is $2.78 per customer.[12] Staff's adjustment brings NW Natural's Category "A" revenue in line with other Oregon utilities on a per-customer spending basis.

[12] NW Natural/1001, Heiting/1.

ISSUE 2. PROMOTIONAL ACTIVITY AND CONCESSIONS

Q. What are promotional activities?

A. A promotional activity is an action by a utility that seeks to promote the use of its product or service among present or prospective customers. ORS 860-026-0010 defines promotional activity as,

> action by an energy or large telecommunications utility or its affiliate with the objective of increasing or preventing a decrease in the quantity of the energy or large telecommunications utility's service used by present and prospective customers; inducing any person to use an energy utility's service rather than a competing form of energy[.]

Q. What are promotional concessions?

A. ORS 860-026-0010 defines a promotional concession as any consideration offered by a utility with the object of inducing a person to select the utility's service or an appliance that uses the utility's service. Examples could include rebates, provision of free goods or services, or providing financing for a natural gas appliance at a lower-than-market interest rate. Utilities are required to file a description of all promotional concession expenses with the Commission before making them.

Q. Has the Company filed its promotional concessions report with the Commission?

A. Yes. The Company filed a report in Docket No. RG 31 on December 6, 2017. In the filing, the Company reported a plan to spend up to $1,749,500 on promotional concessions in 2018. The Company reported that it would not charge these expenses to ratepayers.[13] The Company also filed a report of its 2017 promotional expenses, which also stated the expenses would not be charged to ratepayers.[14]

Q. Has the Company included any promotional concessions and activities in the base year?

A. Yes. NW Natural has included $4,743,217 in promotional activities and concessions expense in FERC accounts 911, 912, and 913 in the base year. **[Begin Confidential]** [redacted]. **[End Confidential].**

Q. Has Staff identified any additional promotional activities or concessions in the base year?

A. Yes. Staff identified $345,600 in advertising expenses that are more appropriately categorized as promotional activity expenses because they seek to attract business from potential customers rather than communicate a message to current customers. This brings the Company's total base year promotional expenses to $5,283,371.

Q. What are the standards for reviewing promotional activities and concessions?

---

[13] Staff/405, Anderson/9-10.
[14] Staff/405. Anderson/2-3.

A. Promotional Activities and Concessions should benefit both the utility and its ratepayers. ORS 860-026-0020 provides the following direction for promotional activities and concessions:

> All promotional activities and concessions shall be just and reasonable, prudent as a business practice, economically feasible and compensatory, and reasonably beneficial both to the energy or large telecommunications utility and its customers. The cost of promotional activities and concessions must not be so large as to impose an undue burden on the energy or large telecommunications utility's customers in general and must be recoverable through related sales stimulation within a reasonable time.[15]

Q. How did Staff perform its analysis regarding the Company's promotional activities and concessions expenses in the base year?

A. Staff reviewed the Company's RG 31 filing describing its promotional expenses for 2018, as well as transactional accounting data for FERC accounts 911, 912, and 913 for 2017. Staff also compared NW Natural's spending on promotional activity and concessions to its peers in the region.

Q. What are Staff's findings regarding promotional activities and concessions?

A. The RG 31 filing stated that the Company's promotional concessions campaigns would be charged "below-the-line," not to ratepayers. However, now that the Company is apparently changing course and requesting to include these expenses in customer rates, Staff has reviewed the expenses for compliance with the relevant OARs.

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[15] OAR 860-026-0020.

NW Natural described the promotional campaigns as follows in its RG 31 filing:

> For most campaigns, participating dealers or trade allies will offer customer incentives for installing the promoted, natural-gas fired appliances. The Company pays participating dealers or trade allies an incentive for the sale of promoted, natural-gas fired products. [16]

Staff is concerned that the appliance rebate programs initiated by the Company effectively create cross-subsidies where some ratepayers (who do not own a home or building) are paying for cash incentives that benefit other ratepayers (home/building owners).

Additionally, Staff finds that NW Natural's promotional activities and concessions spending levels of over five million dollars in 2017, almost eight dollars per customer, are exceptionally high among utilities. Staff's comparison of NW Natural's spending compared to the spending of other gas utilities in the region shows the degree that NW Natural is outspending its peers. For example, Cascade Natural Gas Company reported that promotional spending from 2014 through 2016 was under $20,000 per year, less than ten cents per customer.[17] Avista reported only $293 in promotional activity in 2016, and Puget Sound Energy, with over 790,000 customers, spent about $389,058 (about fifty cents per customer) in 2015 and $8,838 (about one cent per customer) in 2016.[18,19] NW Natural's

[16] Staff/405, Anderson/10.
[17] Form 2 filed with Federal Energy Regulatory Commission (FERC).
[18] FERC Form 2.
[19] https://pse.com/aboutpse/PseNewsroom/MediaKit/020_About_PSE_web.pdf

requested recovery of $4,825,577, or about $7.52 per customer in the base year, is an outlier among gas utilities in the region.

The Company has stated that an increase in load factor and a reduction in the cost of providing service were benefits of its promotional campaigns.[20] However, any potential benefits of the promotional campaigns have not been shown to be larger than the cost to customers, and do not address the cross-subsidization issue. Staff finds that NW Natural's promotional activity and promotional concessions campaigns should not be charged to ratepayers.

Q. What is Staff's recommended adjustment to the Company's promotional activities and concessions?

A. Staff recommends that no promotional activity and concessions expenses be included in rates. This amounts to a downward adjustment of $4,825,577 on a system basis, or $4,302,222 on an Oregon-allocated basis, for the test year.

[20] RG-31, 2016 Annual Report of Promotional Activities and Concessions. http://edocs.puc.state.or.us/efdocs/HAQ/rg31haq161510.pdf

ISSUE 3. MISCELLANEOUS OPERATING REVENUES

Q. Please describe NW Natural's miscellaneous operating revenues in the base year calendar 2017.

A. Miscellaneous revenues consist of revenues to the Company from customer fees (e.g. late payment fees) and property rentals. NW Natural reported $3.56 million in miscellaneous revenues in a "proxy" base year in its rate case filing. NW Natural reported miscellaneous revenues using the twelve months ending September 30, 2017, as a proxy base year because of data issues at the time of the rate case filing.[21]

Q. Has Staff compared NW Natural's proxy base year to the actual base year accounting data?

A. Yes. The actual Oregon allocated miscellaneous revenues for base year were $3.97 million. This is about $403,370 higher than the amount of miscellaneous revenues in the proxy base year initially used by the Company. Staff recommends the test year miscellaneous revenues be adjusted upward by $403,370 to reflect actual base year revenues.

Q. Does Staff have any other issues with the amounts included in the base year?

A. Yes. NW Natural diverged from the process described in testimony for estimating test year revenues in the "property rent" category of miscellaneous revenues.[22] NW Natural witness McVay testified that the

[21] Staff/406, Anderson/1.
[22] NW Natural/200, McVay/12.

Company estimates miscellaneous revenue using three years of history for each category of revenue. He explained that the Company will base the estimate for each category on the last year's revenue if the history shows an upward or downward trend and will base the estimate on a three-year average if there is no apparent trend.[23]

However, Staff's review of the test year reflects that, for one property in which a renter ceased renting from the Company, NW Natural predicted rental income for that property using only the last month of the proxy base year. This resulted in a $115,850 decrease to base year miscellaneous revenues. Given that the Company has provided no reason why this loss of rental revenue is not a part of the natural variability in rental income, Staff recommends forecasting income for this property using the method NW Natural described in testimony. Predicting rental income for this property using a three-year average results in an upward adjustment to miscellaneous revenues of $109,642.

Q. What is Staff's combined adjustment for miscellaneous revenues?

A. Staff's total adjustment is an upward adjustment of $513,013 reflecting the use of actual 2017 base year data and the consistent treatment of miscellaneous revenue.

[23] NW Natural/200, McVay/12, lines13 – 18.

ISSUE 4. CARBON SAVINGS GOAL

Q. Please describe NW Natural's Carbon Savings Goal.

A. In testimony, the Company explained that the Carbon Savings Goal (CSG) is a project by which the Company expects to reduce its carbon emissions 30 percent by 2035.

Q. What costs did the Company incur associated with its CSG in the base year?

A. In discovery, the Company explained that it has not incurred any expenses associated with the CSG in recent years. The Company counts voluntary ratepayer carbon offset purchases as well as public purpose funding for the Energy Trust of Oregon (ETO) toward the goal, and has not modified these programs in any way to meet the goal.[24]

Q. Does Staff have any concerns about the CSG?

A. Not at this time.

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[24] Staff/407, Anderson/1.

ISSUE 5. ATMOSPHERIC TESTING

Q. Please provide a summary of NW Natural's atmospheric testing.

A. Atmospheric testing consists of inspecting NW Natural meters for signs of atmospheric corrosion. This is regulated as a safety issue by the federal government under 49 CFR §192.481.

Q. What is NW Natural's atmospheric testing expense in the base year?

A. NW Natural's atmospheric testing expense in the base year was $80,700. Using the Portland-Salem Consumer Price Index to escalate costs from the base year, NW Natural forecasts a test year amount of $84,200.

Q. How did Staff perform its analysis of atmospheric testing expenses?

A. Staff has reviewed summary program data provided by the Company in response to Staff discovery. Staff also reviewed workpapers showing the escalation of base year costs to test year costs.

Q. Has Staff identified any issue with NW Natural's test year atmospheric testing expense projection?

A. Not at this time. However, Staff witness Gardner may recommend an escalation adjustment.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Rose Anderson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA Bachelor of Arts, International Political Economy University of Puget Sound, Tacoma, WA
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Utility Analyst in the Energy Resources and Planning Division. My current responsibilities include review of mergers and acquisitions, rate cases, and Integrated Resource Plans. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

April 20, 2018

UG 344
Data Request 249

Year	Cat. A Budget ($)	Cat. B Budget ($)	Cat. C Budget ($)	Cat. D Budget ($)	Cat. E Budget ($)	Cat. A Actual ($)	Cat. B Actual ($)	Cat. C Actual ($)	Cat. D Actual ($)	Cat. E Actual ($)
2014	$1,274,839	$495,000	$390,000	$0	$0	**$1,269,017**	$440,672	$316,413	$0	$0
2015	$1,456,593	$497,500	$774,836	$0	$0	**$1,278,609**	$434,324	$1,018,308	$0	$0
2016	$1,423,331	$627,500	$665,282	$0	$0	**$1,343,069**	$723,829	$727,208	$0	$0
2017	$2,004,845	$580,000	$420,141	$0	$0	**$2,134,287**	$701,214	$558,979	$0	$0

Oreogn Allocation Factor
CONSMR INFO-INTNT SR
Cost Center 11550 89.01%

Oregon Allocated Amounts

Year	Cat. A Budget ($)	Cat. B Budget ($)	Cat. C Budget ($)	Cat. D Budget ($)	Cat. E Budget	Cat. A Actual ($)	Cat. B Actual ($)	Cat. C Actual ($)	Cat. D Actual ($)	Cat. E Actual ($)
2014	$1,134,734	$440,600	$347,139	$0	$0	**$1,129,552**	$392,242	$281,639	$0	$0
2015	$1,296,513	$442,825	$689,682	$0	$0	**$1,138,090**	$386,592	$906,396	$0	$0
2016	$1,266,907	$558,538	$592,168	$0	$0	**$1,195,466**	$644,280	$647,288	$0	$0
2017	$1,784,513	$516,258	$373,968	$0	$0	**$1,899,729**	$624,151	$497,547	$0	$0

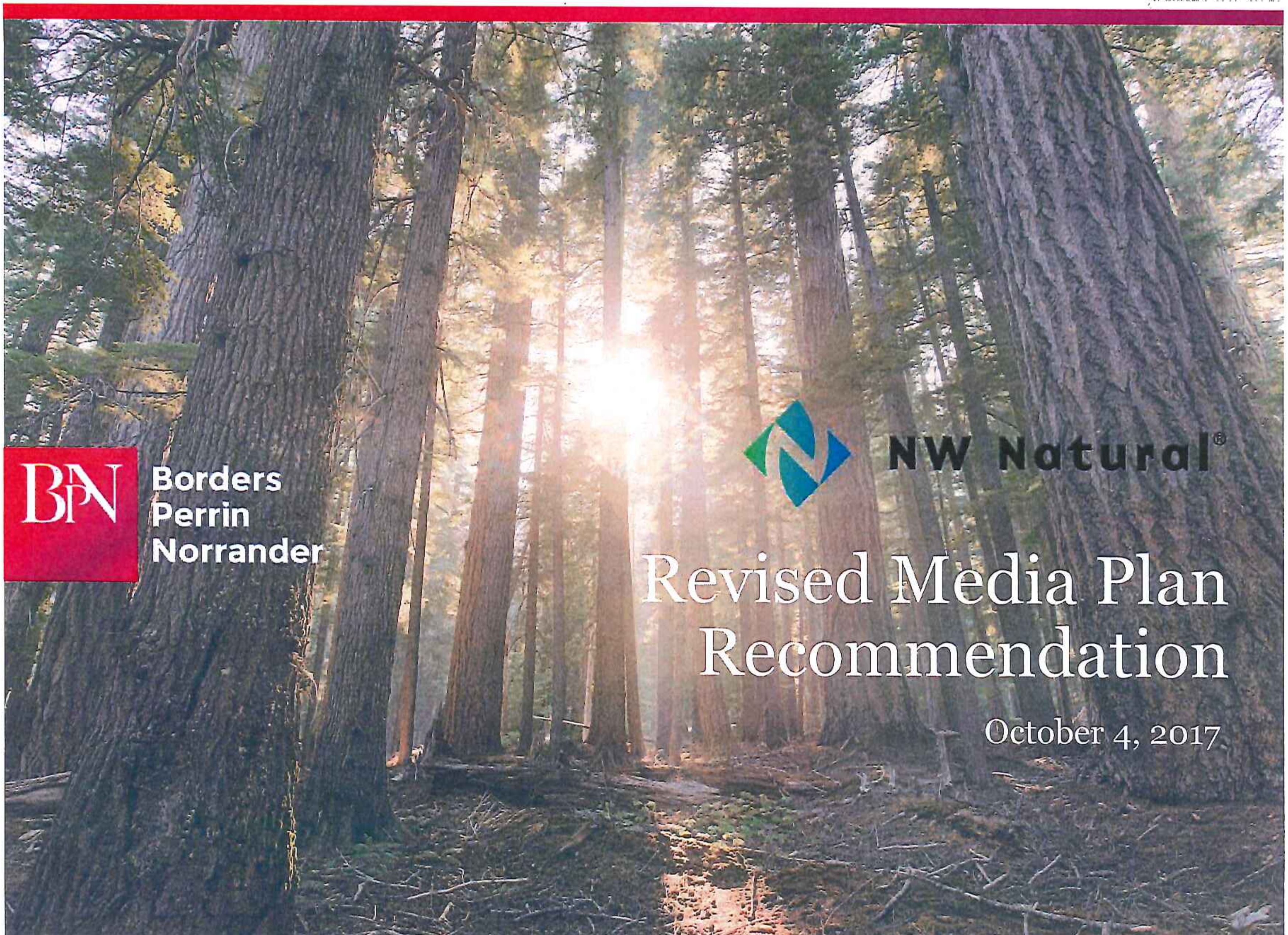
CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

April 20, 2018


Borders
Perrin
Norrander
NW Natural®
Revised Media Plan
Recommendation
October 4, 2017

CAMPAIGN OVERVIEW

Campaign Goals

Position NW Natural as a leader in environmental conservation.
Educate consumers of what NW Natural is doing to reduce carbon emissions and encourage consumer action.

Timing

October 18 – November 22

Geography:

NW Natural's Coverage Area

Budget:

$200,000

+$35,000 Agency Fee
Total: $235,000

TARGET

NW Natural Coverage Area

Portland/Eugene DMA
TV Buying Target: Adults 25-54
Secondary: The business community, key opinion leaders
Content Target: News, Environmental, Green, Etc.

Mediamark Research & Intelligence (MRI)

2016 Doublebase Survey

Green But Only If

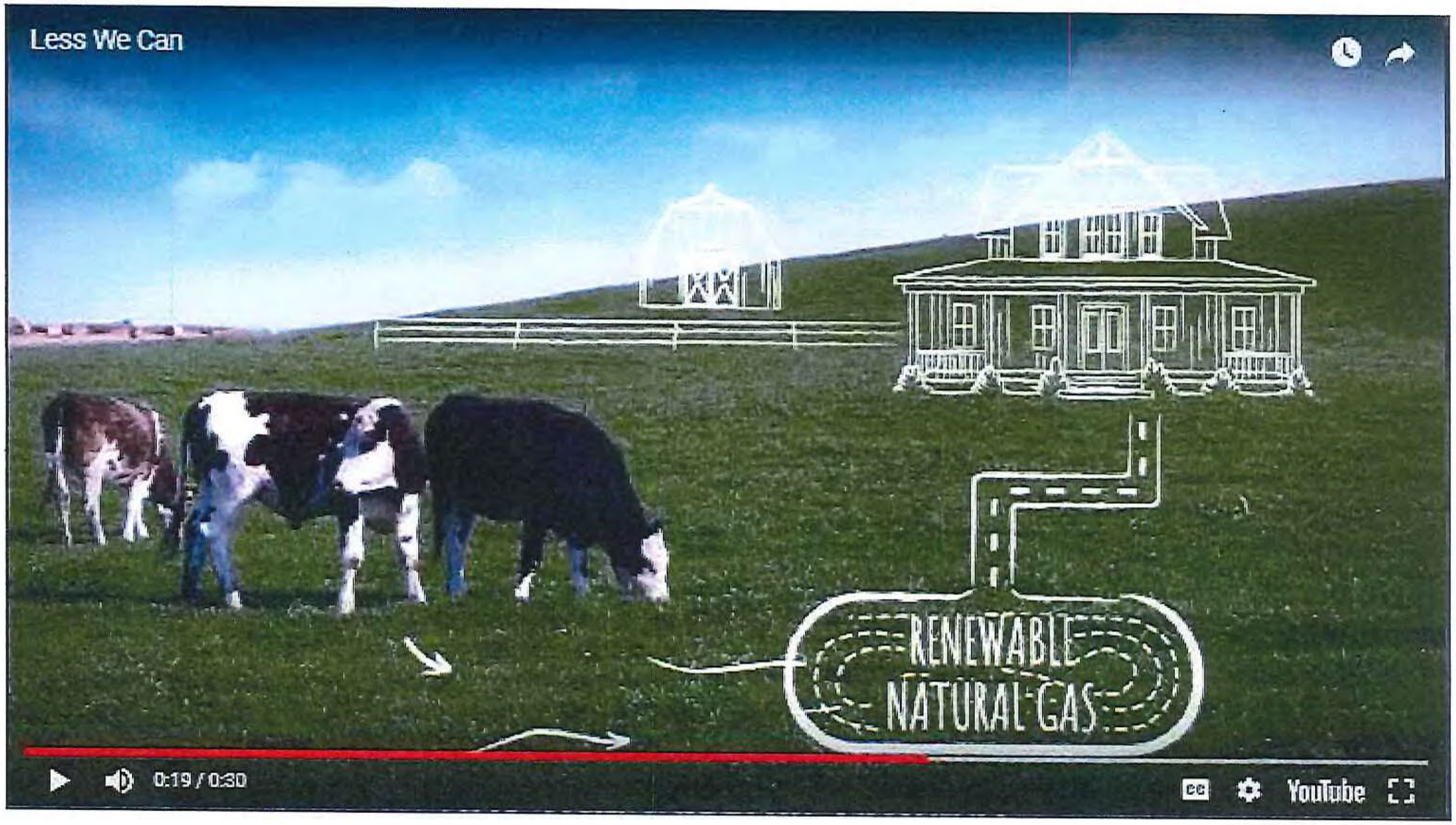
Members of this group may give responses indicating that they prioritize environmental issues. However, they are unwilling to pay more and/or give up convenience in return for environmentally safe products, although they do partake in environmentally motivated behavior.

Green at Their Best

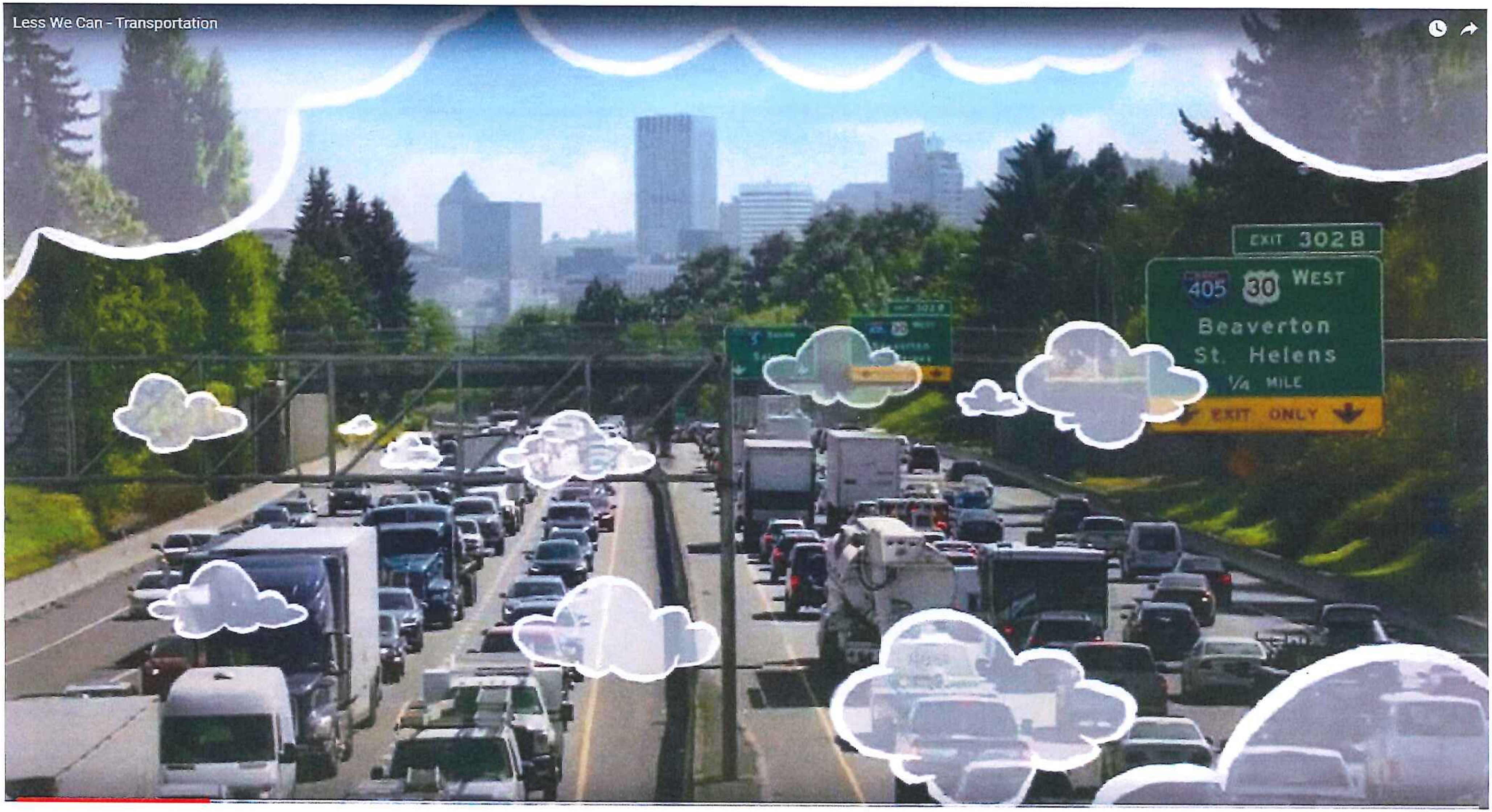
Members of this group give responses that indicate that environmental issues are a priority for them. They are willing to pay more money and/or give up convenience in return for environmentally safe products. Additionally, they partake in everyday environmentally motivated behavior.

Green Advocates

Members of this segment indicate that environmental issues are a priority for them. They are willing to pay more money, and/or give up convenience in return for environmentally safe products. Furthermore, they definitely partake in environmentally motivated behavior as well as participate in environmental causes/groups.


Less We Can
RENEWABLE
NATURAL GAS
0:19 / 0:30
YouTube

Staff/403
Anderson/5



Staff/403
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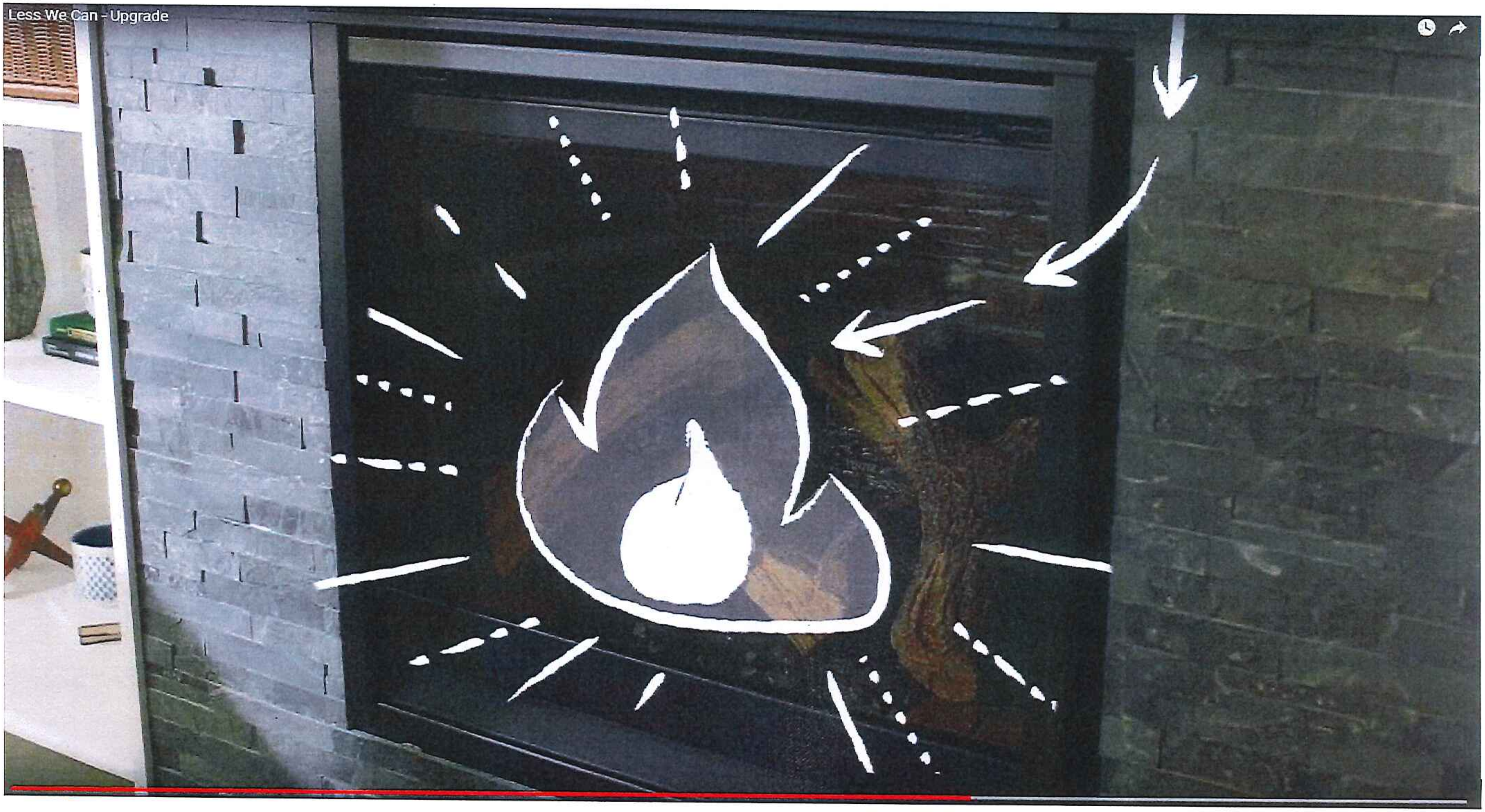
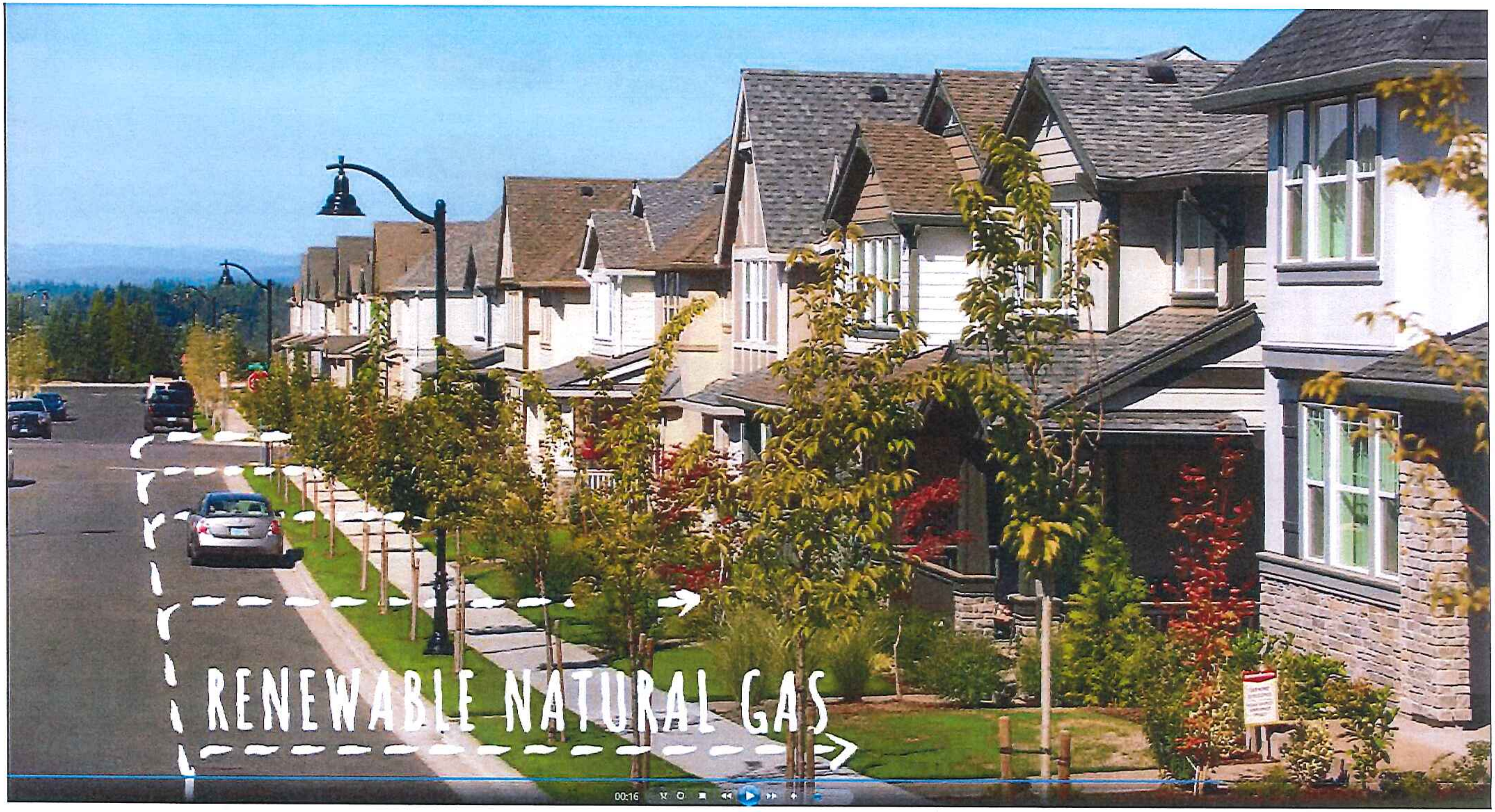

Less We Can - Upgrade

Staff/403
Anderson/9

Staff/403
Anderson/10



Services
Save Energy & Money
Benefits Of Gas
Special Offers
Safety
Smart Energy
Apartment

Special Offers

View the latest special offers available to help make upgrades and installations more affordable.

Furnace and Air Conditioning Special Offer

Now through May 31, 2018, get up to $1,550 back when you convert your electric or oil heating system to a new high-efficiency natural gas furnace and air conditioner, installed by a NW Natural Preferred Contractor.

View details »

Fireplace Special Offer

Get up to $950 back when a NW Natural Fireplace retailer installs a natural gas direct-vent fireplace, insert or freestanding stove. Now through May 31, 2018.

View details »

Instant Natural Gas Water Heater Discount Offer

Oregon customers, get a $100 instant discount on a high-efficiency natural gas water heater.

View details »

Spring 2018 Gas Equipment Tune-Ups ,

Get a tune-up. Get a discount. Get more efficiency from your heating and cooling. Expires May 31, 2018.

View details »

EnergyTrust of Oregon

Energy Trust of Oregon Incentives for Energy-Saving Upgrades

Energy Trust offers cash incentives and free resources to improve your home's energy efficiency.

Find a NW Natural Preferred Contractor
» Start Search

Energy Cost Comparison

Compare the cost of your current heating equipment to a new high-efficiency system.

Compare now »

Quick Links

- Guide to energy-efficient heating & cooling
- Federal Tax Credits for Efficient Equipment
- 2018 American Gas Association Playbook
- Selecting a heating system
- Smart thermostats
- Basking in the comfort of natural gas hearth products

Comfort Zone

NW Natural®

NATURAL GAS SAFETY AND CONSUMER INFORMATION • MAY 2017 • NWNATURAL.COM

Staff/403
Anderson/12

NW Natural adds Renewable Natural Gas

through partnership with City of Portland

Image courtesy of Coalition for Renewable Natural Gas.

In what the city refers to as Portland's largest climate action project, greenhouse gas emissions produced by wastewater will be converted into Renewable Natural Gas (RNG) at the City's wastewater treatment plant. That RNG will then be put on our pipeline and into vehicles.

Using RNG to replace diesel can reduce air pollution from trucks by 90 percent and greenhouse gasses by 80 percent – making it the lowest carbon fuel option for heavy-duty vehicles.

The RNG made from Portland's plant will replace 1.34 million gallons of diesel fuel with enough natural gas to run 154 garbage trucks for an entire year.

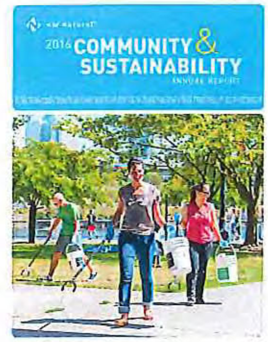
This project is a partnership with the City of Portland's Bureau of Environmental Services. NW Natural will build and maintain the fueling station and pipeline infrastructure needed to serve the facility.

"We're proud to partner with Portland to close the loop on waste," said David H. Anderson, NW Natural president and CEO." We look forward to this being the first of many other renewable natural gas projects that can help improve air quality and move us toward a low-carbon future."

WHAT IS RENEWABLE NATURAL GAS?

Renewable Natural Gas (RNG) is made from biogas released by organic materials as they decompose. Food waste, landfills, manure from dairy farms and sewage-treatment plants all produce biogas that can be captured and upgraded to create RNG to fuel vehicles or be placed in the pipeline. RNG is interchangeable with conventional pipeline natural gas and can also be stored for long periods of time.

Visit **nwnatural.com** to learn how this project will help the environment.



GIVING BACK

comes naturally to us

Together with you, we made big community and sustainability impacts in 2016, helping to make energy affordable for those in need, investing in local nonprofits and fostering a culture of community volunteerism.

HIGHLIGHTS BY THE NUMBERS:

CORPORATE GIVING
NEARLY $1 MILLION
in shareholder contributions

ENVIRONMENTAL STEWARDSHIP
540,125 METRIC TONS
of CO_2 equivalent offset by our Smart Energy customers since 2008

LIVING OUR VALUES
121% score on scale of City of Portland's Sustainability at Work Gold Certification

Visit **nwnatural.com/Community** to see all the results and read the story.

Staff/403
Anderson/13

In the Community: SPOTLIGHT ON SOLVE
NW Natural nonprofit Program of Focus 2017-2019

When Oregonians volunteer with SOLVE, they become hands-on stewards of the state. Cleaning litter from beaches, planting trees and removing invasive plants are just a few of the ways SOLVE volunteers roll up their sleeves to make a visible difference.

Photo by Darren Utt, SeeSaw.

SOLVE volunteers collected about 56,000 pounds of litter and debris along the Oregon coast on April 1.

Launched in 1969 by Tom McCall, Oregon's visionary governor, SOLVE reaches across the state to keep it clean, green and beautiful. Each year, 35,000 volunteers participate in nearly 750 cleanup projects that bring together families, friends, neighbors and businesses.

The fun and excitement that a SOLVE cleanup creates is infectious. SOLVE's annual Spring Oregon Beach Cleanup attracts thousands of volunteers up and down the Oregon coast, and there can easily be 400-500 people in one spot on a beach. It's not unusual for others – including tourists – to spontaneously join in because the energy is so good. "It feels like a movement," said Kris Carico, SOLVE's development director.

There are no age restrictions for volunteers: people of all ages and abilities can participate and contribute. Toddlers who show up with parents are given a small toy bucket and shovel, while senior citizens and those with disabilities are assigned tasks that suit their abilities.

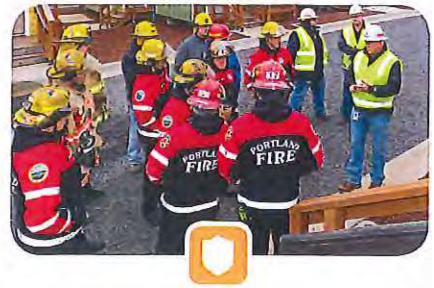
WOULD YOU LIKE TO HELP? Visit **solveoregon.org** to sign up for an event, become a leader or coordinator, or organize your own activity with SOLVE's support.

SOLVE is one of NW Natural's five nonprofit Programs of Focus for 2017-2019. The organization will receive $35,000 per year for three years from our Corporate Philanthropy Fund, plus in-kind resources and volunteer support from NW Natural employees.

WAYS TO SAVE:
Our seasonal offers can help you manage energy use

Every month, we offer incentives to help make high-efficiency natural gas equipment upgrades more affordable. With help from these limited-time special offers, you can improve comfort at home, while benefiting from lower upfront costs, reliable natural gas performance and ongoing energy savings.

Bookmark **nwnatural.com/Offers** to see a list of special offers.



PARTNER IN SAFETY
Always training for your safety

People rely on NW Natural to quickly respond to potential emergencies. To stay prepared, our field employees and first responders participate in ongoing, scenario-based trainings at **NW Natural's mock neighborhood Training Town,** supplemented by classroom instruction at our Training Center.

These trainings help NW Natural respond effectively to gas odor and pipeline damage calls. We answer 99 percent of emergency calls within 10 seconds.

To learn more about our safety efforts and what you can do, visit **nwnatural.com/Residential/Safety**.

THANK YOU FOR HELPING US BUILD A STRONGER COMMUNITY
one paperless bill at a time

PAPERLESS BILLS FOR DEVELOPING SKILLS

For every person who switched to paperless billing between March 1 and April 30, 2017, we donated $5 to local Boys & Girls Clubs. Together, we reached our goal of $15,000, which will help fund afterschool programs for grade and high school students. If you missed this opportunity to enroll in paperless billing, there's still time!

Visit **nwnatural.com/Paperless** to see how going paperless can simplify your billing.

FOLLOW US:

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 392

392. See NW Natural/1000, Heiting/9. Please provide the quantity of renewable natural gas delivered to residential customers each year in 2015, 2016, and 2017.

Response:

There was no renewable natural gas delivered to residential customers in 2015, 2016, 2017.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 393

393. Please provide the quantity of gas produced through electrolysis using renewable energy that was delivered to customers each year in 2015, 2016, and 2017.

Response:

No natural gas produced through electrolysis was delivered to customers in 2015, 2016, or 2017.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 394

394. Please provide a narrative description of any plans NW Natural has to deliver gas produced through electrolysis using renewable energy to customers within the next five years. Please include answers to the following questions:

a. Has NW Natural considered a tariff for customers who want to receive exclusively gas produced through renewable energy, similar to the renewable energy tariffs of electric companies?

b. Who are some of the suppliers of gas produced through electrolysis that NW Natural is currently purchasing from or plans to purchase gas from in the next five years?

Response:

Within the next five years, NW Natural intends to produce electrolysis-derived hydrogen and deliver it to customers as a proof-of-concept. In 2018, NW Natural is undertaking research and development to help guide and shape a pilot electrolysis project. The potential pilot project would likely include a small-scale electrolyzer that would utilize no- and low-cost excess renewable power to produce hydrogen from water. The hydrogen would then be delivered to customers in NW Natural's system, including both the distribution system and potentially its storage resources. The purpose of this potential pilot would be (1) to learn more about the technical issues of integrating hydrogen gas into the natural gas supply while ensuring that customers will continue to be provided safe and reliable service and (2) to gain experience in this burgeoning technology to be able to make better cost estimates about potential hydrogen projects for consideration in least cost resource planning. NW Natural is currently undertaking technical and economic analysis of pilot project options, and working with other utilities such as Fortis BC and SoCal Gas to understand how their electrolyzer pilots have been designed and are working. NW Natural is exploring a variety of potential funding options for this pilot. The cost-effectiveness of hydrogen projects is expected to become more and more attractive over the long-term (beyond the 5 years considered in this response). We want to be technically prepared to take advantage of this likely opportunity to cost-effectively provide customers with lower carbon footprint gas in the future (see NW Natural's response to OPUC UG 344 DR 374 Attachment 5 for more information on why hydrogen through electrolysis is likely to become more cost-effective through time).

a. NW Natural has considered a voluntary tariff for customers who may be interested in buying renewable natural gas (NW Natural defines traditional biogas-derived renewable natural gas as well as electrolysis-derived gas and potentially gas derived via thermal gasification as renewable natural gas) by paying a voluntary premium. We have reviewed similar tariffs offered by gas utilities such as Fortis BC and Vermont Gas and are assessing how these models could make sense for our customers. To better gauge interest and potential willingness to pay a premium for RNG we have surveyed our customers, and our customers appear to be generally supportive of renewable natural gas. NW Natural will continue to investigate whether such a tariff is in the best interest of our customers.

b. NW Natural is not currently purchasing gas produced through electrolysis, nor does it have specific plans to do so in the next five years. Largely, this is because there are no commercial electrolyzers currently operating that are selling their produced hydrogen into the gas market. In part this is why NW Natural is considering the above-mentioned pilot project, in order to develop a local source of electrolysis-derived gas and consider how such gas is integrated into our system and our customer rates.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 395

395. Please provide a narrative description of any plans NW Natural has to deliver renewable gas or "biogas" to customers within the next five years.

a. Has NW Natural considered a biogas tariff for customers who want to receive only biogas?

b. Who are some biogas suppliers NW Natural is currently purchasing from or plans to purchase biogas from in the next five years?

Response:

The Company's response to UG 344 OPUC DR 374 details how NW Natural has conducted (and continues to conduct) extensive research into existing biogas resources, technological issues associated with connecting and delivering RNG, the cost of different types of RNG projects, the market for the environmental attributes of renewable methane, the non-greenhouse gas emissions benefits of local RNG production, the barriers for using renewable natural gas in the direct use of natural gas sector, and the potential role of a direct use natural gas utility in renewable natural gas procurement and development. This ongoing work underpins NW Natural's work to bring renewable natural gas to customers going forward.

We are working with other gas utilities as well as the Gas Technology Institute (GTI) to understand best practices in system interconnection, and update our own interconnection standards and processes to encourage greater deployment of renewable natural gas on our system. With this as background, NW Natural expects to connect its first RNG project – the City of Portland's wastewater treatment plant in North Portland – for injection into its distribution system by the end of 2019 (expected late 2018 or early 2019). See the response to UG 344 OPUC DR 374 for more information about this project.

Other projects do not have the certainty of this project, though NW Natural expects that additional RNG projects will be connected to our system to deliver gas in the next 5 years and is currently negotiating options with suppliers of biogas and RNG sellers (see the answer to (b) below for more information).

In a more general sense, there are numerous options which NW Natural could pursue to procure or develop renewable natural gas for its customers, and the Company is evaluating a slate of these options through traditional resource planning in its 2018 IRP (see the response to UG 344 OPUC DR 374 Attachment 5 for more information). Per Commission Guidelines NW Natural considers expected greenhouse gas (GHG) emission compliance costs in its resource planning, with the expectation that the compliance cost to emit GHGs in Oregon will increase over time. When GHGs are priced or capped/restricted, low carbon resources like renewable natural gas become more cost-effective, which is important given that many RNG projects expect to produce gas far beyond 5 years and have decision points that may require action or commitments over the next 5 years. Resource planning analysis in the 2018 IRP and the regulatory process leading to IRP acknowledgement will determine when and if any RNG represents the best combination of low cost and low risk for customers under the typical cost-effectiveness framework.

a. NW Natural has considered a voluntary tariff for customers who may be interested in buying renewable natural gas (NW Natural defines traditional biogas-derived renewable natural gas as well as electrolysis-derived gas and potentially gas derived via thermal gasification as renewable natural gas) by paying a voluntary premium. We have reviewed similar tariffs offered by gas utilities such as Fortis BC and Vermont Gas and are assessing how these models could make sense for our customers. To better gauge interest and potential willingness to pay a premium for RNG we have surveyed our customers, and our customers appear to be generally supportive of renewable natural gas. NW Natural will continue to investigate whether such a tariff is in the best interest of our customers.

b. NW Natural is not currently purchasing biogas resources from any producers. There are several potential renewable natural gas producers that have contacted us to discuss the possibility of interconnecting with our system and/or selling us renewable natural gas. The extent of our conversations vary considerably with each party, but current potential producers the Company is working with are included as Confidential UG 344 OPUC DR 395 Attachment 1.

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

Exhibits in Support
Of Opening Testimony

April 20, 2018

e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: RG-31, Report of 2017 Promotional Concession Campaign

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒No ☐Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☐RE (Electric) ☒RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☒OAR 860-026-0030
☐Statute
☐Order
☐Other

Is this report associated with a specific docket/case? ☐No ☒Yes

If yes, enter docket number: RG-31

List applicable Key Words for this report to facilitate electronic search:
NW Natural, 2017, Promotional Concession, Promotional Campaigns

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

GAIL HAMMER
Tariffs and Regulatory Compliance
Tel: 503.226.4211 x2452
Fax: 503.721.2516
email: ork@nwnatural.com

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

December 9, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: Docket RG-31
NW Natural's Report of 2017 Promotional Concession Campaigns

In accordance with OAR 860-026-0030, NW Natural submits this letter as notice of the promotional concessions that NW Natural plans to offer during the 2017 calendar year.

Each campaign may include one or more offers as set forth in the Company's Tariff P.U.C. Or. 25, at Schedule 200 "Promotional Concessions," and more specifically within one or more of these promotional areas:

200-2 General Merchandise Sales Program
200-3 Equipment Sales Promotions
200-4 Cooperative Advertising Program
200-5 Showcase Developments
200-7 Equipment Financing Program
200-8 Promotions for Company-Offered Products and Services

The campaign category and associated budget is as follows:

- **Hearth Campaigns**
  - The program budget is up to $230,000
- **HVAC Campaigns**
  - The program budget is up to $ 480,000
- **Residential Builder Program and Campaigns**
  - This campaign includes residential new construction and multifamily programs.
  - The program budget is up to $130,000

- **Dealer Relations Campaigns**
  - The program budget is $200,000
- **Cooperative Advertising Program**
  - The program budget is up to $30,000
- **Retail Program Campaigns**
  - This campaign is a clearance sales event for customer returns, slow moving, damaged, and obsolete inventory.
  - The program budget is up to $33,000

For most campaigns, participating dealers or trade allies will offer customer incentives for installing the promoted, natural-gas fired appliances. The Company pays participating dealers or trade allies an incentive for the sale of promoted, natural-gas fired products.

All campaign costs will be accounted for below-the-line, in FERC accounts 912 or 913, in accordance with OAR 860-026-0010.

This notice contains a comprehensive list of the Company's 2017 planned promotional concessions. If additional campaigns are added during the year, the Company will separately notice the Commission in accordance with OAR 860-026-0030.

Please feel free to call should you have questions.

Sincerely,

/s/ Gail Hammer

Gail Hammer
Rates & Regulatory Affairs

cc: Mary Widman, Portland General Electric
R. Bryce Dalley, PacifiCorp

e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: RG-31, 2016 Annual Report of Promotional Activities and Concessions

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☒ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RO (Other)

Report is required by: ☒ OAR 860-026-0035
☐ Statute
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☐ No ☒ Yes

If yes, enter docket number: RG-31

List applicable Key Words for this report to facilitate electronic search:
NW Natural, 2016, Promotional Concessions, Promotional Activities, Marketing, Annual Report

DO NOT electronically file with the PUC Filing Center:

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- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

GAIL HAMMER
Rates & Regulation
Tel: 503.226.4211 ext. 5865
Fax: 503.721.2516
email: gail.hammer@nwnatural.com

NW Natural

220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

VIA ELECTRONIC FILING AND US MAIL

April 28, 2017

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: **RG-31 - 2016 Annual Report of Promotional Activities and Concessions**

Enclosed please find Northwest Natural Gas Company's, d.b.a. NW Natural ("NW Natural" or "Company"), 2016 Promotional Activities and Concessions Report, filed in compliance with OAR 860-026-0035.

The report is being filed as confidential pursuant to OAR 860-001-0070. NW Natural designates the report as confidential due to market sensitive information contained in the report. No portion of these materials may be copied, reproduced, or disclosed in any manner without the express permission of NW Natural.

If you have any questions or need further information, please let me know.

Sincerely,

/s/ Gail Hammer

Gail Hammer
Rates & Regulation

enclosure

NW Natural

Annual Report of Promotional Activities and Concessions
2016 Actual Expenditures

Program

1. General Merchandise Sales Program. Reference: Sheet 200-2

Expenditures: [redacted]

Benefits:
Activities under this program are specifically designed to increase the sale of gas appliances within the Company's service territory. The greater saturation of gas appliance usage per customer achieved through gas appliance sales benefits the system by increasing load factor and reducing the Company's cost of providing service.

2. Equipment Sales Promotions. Reference: Sheet 200-3

Expenditures: [redacted]

Benefits:
This program is designed to increase overall consumer interest in using natural gas equipment. Building and maintaining dealer interest in marketing gas equipment benefits the system because it serves to increase the saturation of gas appliance usage within the Company's service territory.

3. Cooperative Advertising Program. Reference: Sheet 200-4

Expenditures: [redacted]

Benefits:
Cooperative advertising serves to double the potential sales impact of every dollar spent to advertise in the space and water heating markets. Benefits of cooperative advertising to the system are the resulting minimization of potential customer losses to competing fuels, and the achievement of a healthy and diverse market of wholesale and retail gas appliance dealers, all of whom provide valuable sales and maintenance services to gas customers and the public generally.

The Company did not make any promotional offers in this category during 2016.

4. Showcase Developments. Reference: Sheet 200-5

Expenditures: [redacted]

Benefits:

The Company's participation in new home developments serves to educate the building trades and the general public concerning the use of high efficiency natural gas equipment in the new home construction market. The system benefits from such participation because potential customer losses to competing fuels are minimized and greater saturation of natural gas appliances is achieved, both of which result in a lower cost to the Company of providing service.

5. Natural Gas Vehicle Program. Reference: Sheet 200-6

Expenditures: [redacted]

Benefits:

This program is designed to encourage the purchase and use of natural gas in motor vehicles. Natural gas use in motor vehicles within the Company's service territory benefits the system by increasing natural gas usage, which reduces the company's cost of gas to all ratepayers.

The Company did not make any promotional offers in this category during 2016.

6. Equipment Financing Program. Reference: Sheet 200-7

Expenditures: [redacted]

Benefits:

Activities under this program are specifically designed to increase the sale of gas appliances within the Company's service territory. The greater saturation of gas appliance usage per customer achieved through gas appliance sales benefits the system by increasing load factor and reducing the Company's cost of providing service.

The Company did not make any promotional offers in this category during 2016.

7. Company offered Products and Services. Reference: Sheet 200-8

Expenditures: [redacted]

Benefits:

Activities under this program are specifically designed to increase enrollment in programs such as Smart Energy™, Paperless Billing, Equal Pay and Auto Pay.

e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: RG-31, Report of 2018 Promotional Concession Campaign

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒No ☐Yes

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If known, please select designation: ☐RE (Electric) ☒RG (Gas) ☐RW (Water) ☐RO (Other)

Report is required by: ☒OAR 860-026-0030
☐Statute
☐Order
☐Other

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If yes, enter docket number: RG-31

List applicable Key Words for this report to facilitate electronic search:
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PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

VIA ELECTRONIC FILING

December 6, 2017

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: Docket RG-31
NW Natural's Report of 2018 Promotional Concession Campaigns

In accordance with OAR 860-026-0030, NW Natural submits this letter as notice of the promotional concessions that NW Natural plans to offer during the 2018 calendar year.

Each campaign may include one or more offers as set forth in the Company's Tariff P.U.C. Or. 25, at Schedule 200 "Promotional Concessions," and more specifically within one or more of these promotional areas:

200-2 General Merchandise Sales Program
200-3 Equipment Sales Promotions
200-4 Cooperative Advertising Program
200-5 Showcase Developments
200-8 Promotions for Company-Offered Products and Services

The campaign category and associated budget is as follows:

- **Hearth Campaigns**
  - The program budget is up to $180,000
- **HVAC Campaigns**
  - The program budget is up to $ 800,000
- **Residential Builder Program and Campaigns**
  - This campaign includes residential new construction and multifamily programs.
  - The program budget is up to $460,000
- **Dealer Relations Campaigns**
  - The program budget is up to $240,000
- **Cooperative Advertising Program**

- The program budget is up to $30,000
- **Retail Program Campaigns**
    - This campaign is a clearance sales event for customer returns, slow moving, damaged, and obsolete inventory.
    - The program budget is up to $17,000
- **Paperless Campaign**
    - This campaign promotes paperless enrollment in exchange for financial donations to Boys & Girls Clubs.
    - The program budget is up to $22,500

For most campaigns, participating dealers or trade allies will offer customer incentives for installing the promoted, natural-gas fired appliances. The Company pays participating dealers or trade allies an incentive for the sale of promoted, natural-gas fired products.

All campaign costs will be accounted for below-the-line, in FERC accounts 912 or 913, in accordance with OAR 860-026-0010.

This notice contains a comprehensive list of the Company's 2018 planned promotional concessions. If additional campaigns are added during the year, the Company will separately notice the Commission in accordance with OAR 860-026-0030.

Please feel free to call should you have questions.

Sincerely,

/s/ Gail Hammer

Gail Hammer
Rates & Regulatory Affairs

cc: Mary Widman, Portland General Electric
Etta Lockey, PacifiCorp

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 406

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 244

244. Please provide detailed transaction-level data for FERC account 488000 and any other FERC accounts containing Miscellaneous Revenues for the Base Year (calendar 2017). Please include any available descriptions of each expense. Please provide the data in electronic, Excel format with all formulae and cell references intact.

Response:

Please see attached file "UG 344 OPUC DR 244 Attachment 1 for the data. The information for each tab includes amounts from the period October 1, 2016 through December 31, 2017, with all dates indicated. The filing included amounts from the period October 1, 2016 to September 30, 2017 as a proxy for the base period due to the timing of the rate case development. The totals in each tab are for the same 12 months ended September 30, 2017 time period, and were included as a cross reference to the filing.

All tabs include Oregon only information except for the Utility Prop Rent tab, which is on a system basis. The state allocation of the amount on that tab is presented on the "Exhibit 204 – Misc Revenues" tab of the "200 wp1 – Revenue Requirements Model" file.

CASE: UG 344
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 407

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 243

243. See NW Natural/100, Anderson/Page 6 which states, “we have established a voluntary goal for our Company to create carbon savings equivalent to 30 percent of the Company’s 2015 emissions by the year 2035.” Please provide:
a. Line-item transactional accounting detail for the voluntary carbon reduction program in the base year;
b. Total program budgeted and actual spending on the voluntary carbon goal in each calendar year from 2014 to 2017; and,
c. An explanation as to whether NW Natural recovers each expense from customers or shareholders.

Response:

a. There is no line-item transactional accounting detail from NW Natural’s Carbon Savings Goal in the base year to report. There are two existing programs that NW Natural has included in its Carbon Savings Goal – (1) Energy Efficiency (programs that are primarily administered by Energy Trust of Oregon and funded through the public purpose charge) and (2) the Company’s self-funded voluntary customer carbon offset offering *Smart Energy*. While these programs are included in NW Natural’s carbon goal, they have not changed as a result of the goal and there are no costs included from these programs in the base year. While NW Natural has not included any costs from its Carbon Savings Goal for recovery, the Company considers actions to reduce carbon emissions to comply with any rules or statutes or achieved at an expected incremental cost that is lower (in net present value terms) than the expected cost of carbon compliance it publishes in its IRP would be prudent costs to incur on behalf of customers. It is also NW Natural’s position that any costs to achieve greater carbon savings in excess of the expected cost of compliance or required by rule or statute would require regulatory approval or new legislation authorizing such action before included in rates.
b. As explained above, there is no program budgeted or spent from 2014 through 2017 specifically for the voluntary carbon goal alone.
c. Not Applicable.

CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

April 20, 2018

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

A. My name is Phil Boyle. I am the Consumer Services Manager with the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My educational background and work experience are set forth in my witness qualifications statement, which is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. To discuss Northwest Natural Gas Company's ("NWN" or "Company") fee free bankcard payment program and program operating costs. NWN did not provide written testimony regarding the fee free bankcard payment program, but program costs are embedded in NWN's rate request.

Q. Did you prepare any exhibits other than your qualification exhibit for this docket?

A. Yes. I have prepared the following exhibits:

Exhibit 501 – Witness Qualification Statement.

Exhibit 502 – Graph of NWN historic fee free bankcard transactions plus NWN's 2018 through end of test year projected transactions.

Exhibit 503 – Tables showing NWN projected transactions and Staff projected transactions using NWN average cost per transaction to arrive at total program costs January 2018 through the end of the test year.

Exhibit 504 - Graph of NWN historic fee free bankcard transactions plus Staff's 2018 through end of test year projected transactions following trend.

Exhibit 505 – Graph showing historical fee free bankcard payment adoption rates.

Exhibit 506 – Graph of NWN historic fee free bankcard transactions plus Staff's 2018 through end of test year projected transactions reflecting cap of 22 percent adoption rate in test year.

Exhibit 507 – NWN response to Staff DR 179.

Exhibit 508 – NWN response to Staff DR 376.

Q. How is your testimony organized?

A. My testimony first discusses the history of NWN's fee free bankcard program, followed by my analysis and final recommendations.

HISTORY

Q. Describe NWN's history with a fee free bankcard payment option for its customers?

A. Prior to 2012, NWN had historically accepted credit card payments from customers, but the customer was required to pay a third party payment processing fee of $3.95 per transaction. In NW Natural's last general rate case (UG 221), the Commission authorized the company to begin offering a fee free bankcard payment option where the Company would absorb the payment processing transaction charge and spread it to the rates of customers eligible for the payment option. Both residential and small commercial customers were allowed to make fee free bankcard payments.

Beginning in 2013, the Company was allowed $1,190,000 annually in rates to cover the transaction costs. Over the last five years (2013 through 2017) the Company has collected $5,950,000 against an expense of $5,373,776 for the fee free bankcard payment program, over collecting by $576,224. DR responses in UG 344 indicate the Company expects to spend $2,340,103 on the program in the test year.

STAFF'S REVIEW

Q. Did you review NWN's fee free bankcard payment option to residential and commercial customers?

A. Yes. I looked at historical transaction numbers from program inception through December 2017, projected transactions and costs from January 2018 through the test year, and potential related cost savings achieved due to the program.

TRANSACTIONS AND COSTS

I first graphed NWN historical transactions from November 2012 through December 2017 from data provided in response to Staff DR 172, then added NWN's projected transactions for 2018 through the end of the test year obtained in response to Staff DR 173, and added a trend line (Staff/602). It was clear that the historical trend line was not in alignment with the Company's projections for 2018 through the test year. I then replaced NWN's transaction projections (Staff/603, Table 1) with Staff's transaction projections (Staff/603,

Table 2), which more closely followed the historical trend line, resulting in what appears to be a more normal adoption growth rate (Staff/604).

For the test year, NWN projects a total of 2,001,276 transactions at an average cost of $1.169305 per transaction for a total cost of $2,340,103 (Staff 603, Table 1). Assuming consistent customer growth and ever increasing adoption of bankcard payments, Staff projects 1,738,750 transactions in the test year at the same cost per transaction the company has stated, leading to a total program cost of $2,033,129 (Staff/603, Table 2). The difference in the Company's projections versus Staff projections shows that Staff expects 262,526 fewer transactions in the test period if customer growth and bankcard payment adoption continues to grow in line with the historical trend.

ADOPTION RATE

At the end of 2017, slightly over 20 percent of combined residential and small commercial customers were making payments utilizing the fee free bankcard option (Staff/605). Due to general customer growth and resulting bankcard transaction growth, plus an increased bankcard adoption rate, Staff projects the combined adoption rate to increase to 22 percent by the end of October 2018, and to 25 percent by the end of the test year following the historic trend (Staff/606). While the bankcard adoption rate has increased steadily since the introduction of the fee free payment option, it seems improbable that the adoption rate will continue to increase indefinitely.

In DR 346 Staff asked the Company to provide any data or research that indicates a known or expected point of saturation for bankcard payments. The

Company said they had not conducted any analysis on the potential maximum bankcard adoption rate so were unable to provide any such data, but they did expect the adoption rate to continue to grow by about three percentage points each year consistent with historical growth.

In the absence of any data supporting an alternate level, Staff recommends basing the forecast of test year fee free bankcard transactions on the month-end October 2018 projected adoption rate of 22 percent. Staff's proposal will allow for transaction growth in the number of transactions commensurate with customer growth, but no further increase in the customer adoption rate (Staff/607). By using the fee free payment adoption rate of 22 percent, Staff calculates test year transactions to be 1,585,911 versus the company's projection of 2,001,276 (Staff/603, Table 3). Any future increases in adoption rate above this threshold should be reconciled in future rate proceedings.

RELATED COST SAVINGS

In DR 179, Staff asked the Company if they had considered any associated savings that may have occurred due to the introduction of the fee free bankcard payment option. The company's response (Staff/608Exhibit 8) states the introduction of the fee free bankcard payment option in 2012 is one factor that has contributed to an overall improvement in four metrics; collection agency fees, net write-offs, number of reminder notices, and field disconnects. Other factors NWN thought contributed to the improvement include: 1) economic cycle, 2) continued operational focus, and 3) technology advancements. The Company says they have "…not completed an analysis to determine the specific contribution of each of these drivers…" leading to the improved metrics, but their response acknowledges the introduction of the fee free bankcard payment option is a factor.

Staff asked the Company to identify annual cost savings for each of the four metrics from 2012 through 2017. NWN responded that for the six-year period, costs for the four metrics were reduced by $8.142 million, with $1.381 million savings in 2017 alone.[1] While there has been no analysis to determine how much of an impact the fee free bankcard payment option has had on the improvement in these metrics, the Company acknowledges at least some connection. The Company is experiencing cost savings in these four metrics, and possibly others like postage and mailing costs, improved cash flow, and others that have likely not been fully reflected in rates. As such, it seems appropriate and conservative to apply a 10 percent reduction to overall program cost to recognize a portion of these savings that may be attributable to the fee free bankcard program.

Q. What does Staff recommend?

A. Staff supports the continuation of the fee free bankcard payment option, but believes NWN's projected transactions and resulting costs are too high. Staff supports forecasting NWN's fee free bankcard payment expense using the adoption rate of 22 percent, the projected month-end October 2018 adoption rate, until such time as the Company demonstrates a higher adoption rate or

[1] Staff/609, Company Response to Staff DR 376.

produces data that indicates an expected maximum adoption rate. In addition, Staff believes there are related savings associated with improved Collection Agency Fees, Net Write-off, Number of Reminder Notices, Field Disconnects and possibly cash flow and lower postage and billing expenses, etc. As such, Staff proposes to reduce program costs an additional 10 percent.

Staff's adjustment is determined as follows:

1. Fewer transactions based on Staff's estimated growth and adoption rate of 22 percent (415,365 fewer transactions x $1.169305 per transaction = $485,689 adjustment).

2. Ten percent (10%) reduction for related savings ($1,854,414 X .10 = $185,441 Adjustment).

Staff's total adjustment is $671,130, leaving $1,668,973 ($2,340,103 – $671,130 = $1,668,973) for NWN's 2018 Test Year for PGE's fee free bankcard program.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Phil Boyle
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Program Manager Consumer Services Section
ADDRESS:	201 High Street SE., Suite 100 Salem, OR 97301
EDUCATION:	Bachelor of Science (Education) Portland State University, 1980
EXPERIENCE:	1980 to 2003 – PacifiCorp I worked at PacifiCorp (Pacific Power) in a variety of customer facing positions over the years, starting as an Energy Consultant, progressing through Sales and Commercial Account Manager position's, to local District Manager and Customer Service Manager. In my 23 years at PacifiCorp I learned about all aspects of customer service and distribution operations. 2004 to 2005 – Oregon Department of Revenue Worked in collections unit collecting delinquent taxes. 2005 to Present – Oregon Public Utility Commission I am currently Program Manager for the Consumer Services Section, beginning my work with the PUC as a Consumer Specialist, advancing to a Senior Compliance Specialist and finally to Program Manager. In these roles I have become very experienced working with utilities to help them comply with Division 21 Administrative Rules.

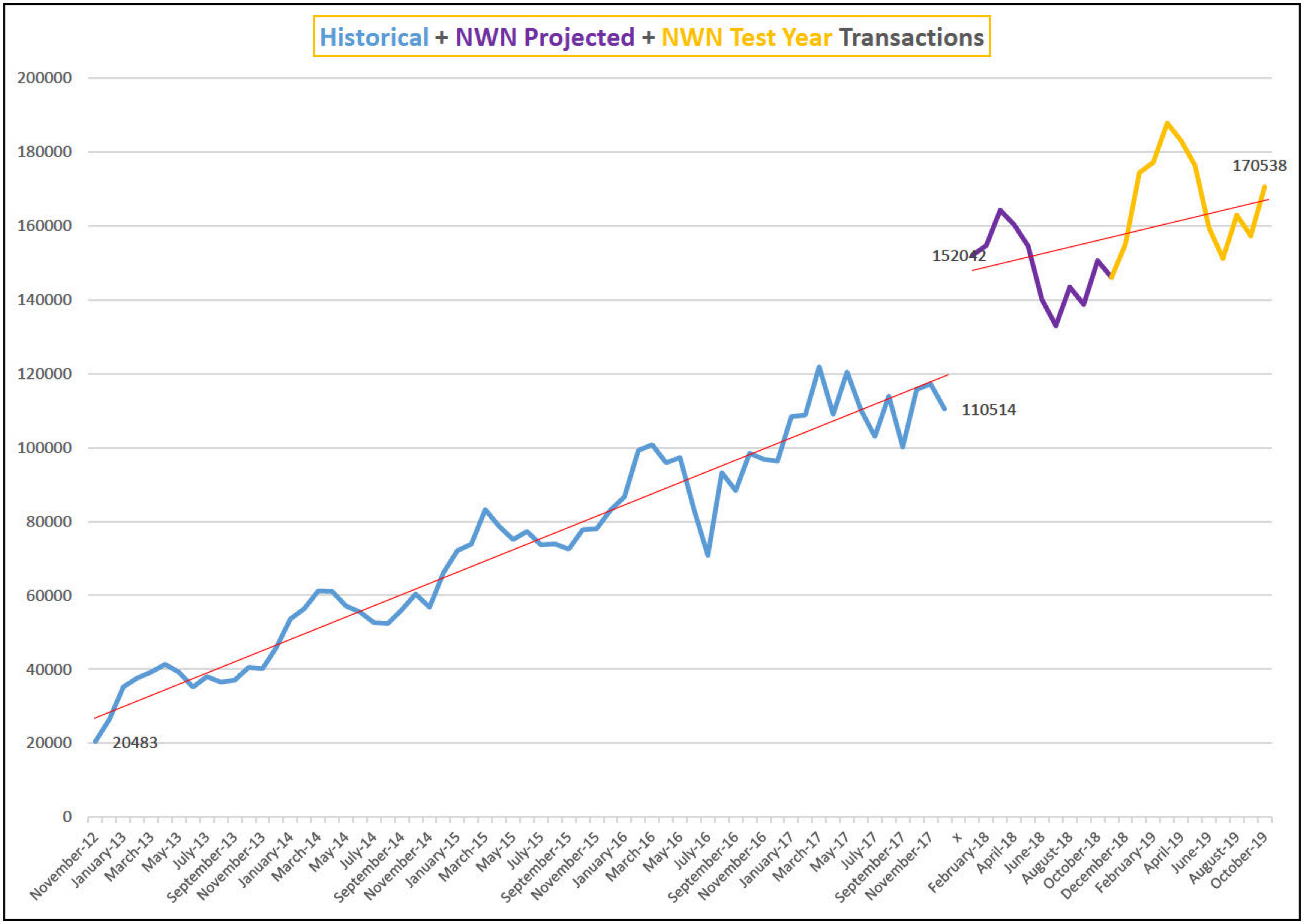
CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 502

Exhibits in Support Of Opening Testimony

April 20, 2018


Historical + NWN Projected + NWN Test Year Transactions
200000
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152042
170538
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August-18
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October-19

CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

April 20, 2018

Exhibit 503

Table 1

NWN Projections	Month	Transactions	Total Trans	Rate	Cost
NWN Projection	January-18	152042		1.470	$ 223,475
NWN Projection	February-18	154709		1.409	$ 217,960
NWN Projection	March-18	164216		1.326	$ 217,805
NWN Projection	April-18	160317		1.258	$ 201,735
NWN Projection	May-18	154627		1.147	$ 177,425
NWN Projection	June-18	140078		1.077	$ 150,890
NWN Projection	July-18	133033		1.040	$ 138,366
NWN Projection	August-18	143456		0.973	$ 139,559
NWN Projection	September-18	138774		1.005	$ 139,482
NWN Projection	October-18	150605	1,491,857	1.019	$ 153,424
NWN Test Year	November-18	146078		1.086	$ 158,696
NWN Test Year	December-18	155085		1.302	$ 201,911
NWN Test Year	January-19	174383		1.453	$ 253,348
NWN Test Year	February-19	177166		1.392	$ 246,642
NWN Test Year	March-19	187768		1.310	$ 246,002
NWN Test Year	April-19	183039		1.242	$ 227,380
NWN Test Year	May-19	176286		1.131	$ 199,446
NWN Test Year	June-19	159473		1.061	$ 169,176
NWN Test Year	July-19	151243		1.024	$ 154,823
NWN Test Year	August-19	162871		0.957	$ 155,869
NWN Test Year	September-19	157346		0.989	$ 155,674
NWN Test Year	October-19	170538	2,001,276	1.004	$ 171,136
					$ 2,340,103

Exhibit
503
Table 2

Staff no Freeze	Month	Transactions	Total Trans	Rate	Cost
Staff Projected	January-18	117500		1.18	$ 138,650
Staff Projected	February-18	120000		1.18	$ 141,600
Staff Projected	March-18	122500		1.18	$ 144,550
Staff Projected	April-18	125000		1.18	$ 147,500
Staff Projected	May-18	127500		1.18	$ 150,450
Staff Projected	June-18	128500		1.18	$ 151,630
Staff Projected	July-18	130000		1.18	$ 153,400
Staff Projected	August-18	132500		1.18	$ 156,350
Staff Projected	September-18	134500		1.18	$ 158,710
Staff Projected	October-18	135500	1,273,500	1.18	$ 159,890
Staff Test Year	November-18	135750		1.169305	158,733
Staff Test Year	December-18	137000		1.169305	160,195
Staff Test Year	January-19	138500		1.169305	161,949
Staff Test Year	February-19	140000		1.169305	163,703
Staff Test Year	March-19	142500		1.169305	166,626
Staff Test Year	April-19	145000		1.169305	169,549
Staff Test Year	May-19	146000		1.169305	170,719
Staff Test Year	June-19	147000		1.169305	171,888
Staff Test Year	July-19	149500		1.169305	174,811
Staff Test Year	August-19	150000		1.169305	175,396
Staff Test Year	September-19	152500		1.169305	178,319
Staff Test Year	October-19	155000	1,738,750	1.169305	181,242
					$ 2,033,129

Exhibit
503
Table 3

Test Yr Freeze at 22%	Month	Transactions	Total Trans	Rate	Cost
Staff Projected	January-18	117500		1.18	$ 138,650
Staff Projected	February-18	120000		1.18	$ 141,600
Staff Projected	March-18	122500		1.18	$ 144,550
Staff Projected	April-18	125000		1.18	$ 147,500
Staff Projected	May-18	127500		1.18	$ 150,450
Staff Projected	June-18	128500		1.18	$ 151,630
Staff Projected	July-18	130000		1.18	$ 153,400
Staff Projected	August-18	132500		1.18	$ 156,350
Staff Projected	September-18	134500		1.18	$ 158,710
Staff Projected	October-18	135500	1,273,500	1.18	$ 159,890
Staff Test Year	November-18	132246		1.169305	154,636
Staff Test Year	December-18	121142		1.169305	141,652
Staff Test Year	January-19	130326		1.169305	152,391
Staff Test Year	February-19	129634		1.169305	151,582
Staff Test Year	March-19	146709		1.169305	171,548
Staff Test Year	April-19	130242		1.169305	152,293
Staff Test Year	May-19	143398		1.169305	167,676
Staff Test Year	June-19	132648		1.169305	155,106
Staff Test Year	July-19	122980		1.169305	143,801
Staff Test Year	August-19	139665		1.169305	163,311
Staff Test Year	September-19	120326		1.169305	140,698
Staff Test Year	October-19	136595	1,585,911	1.169305	159,721
					$ 1,854,414

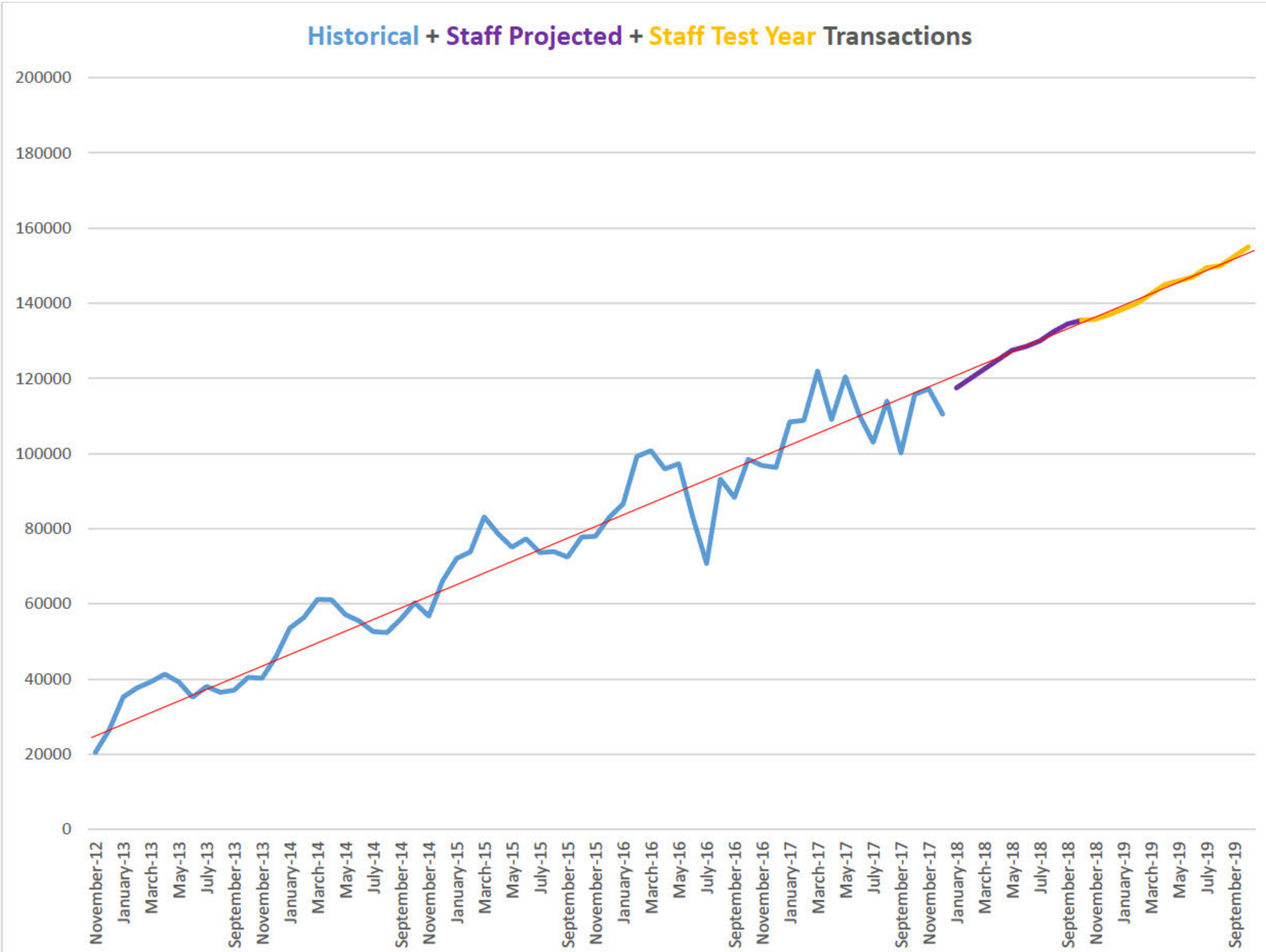
CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 504

Exhibits in Support
Of Opening Testimony

April 20, 2018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180000
160000
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120000
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January-13
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May-13
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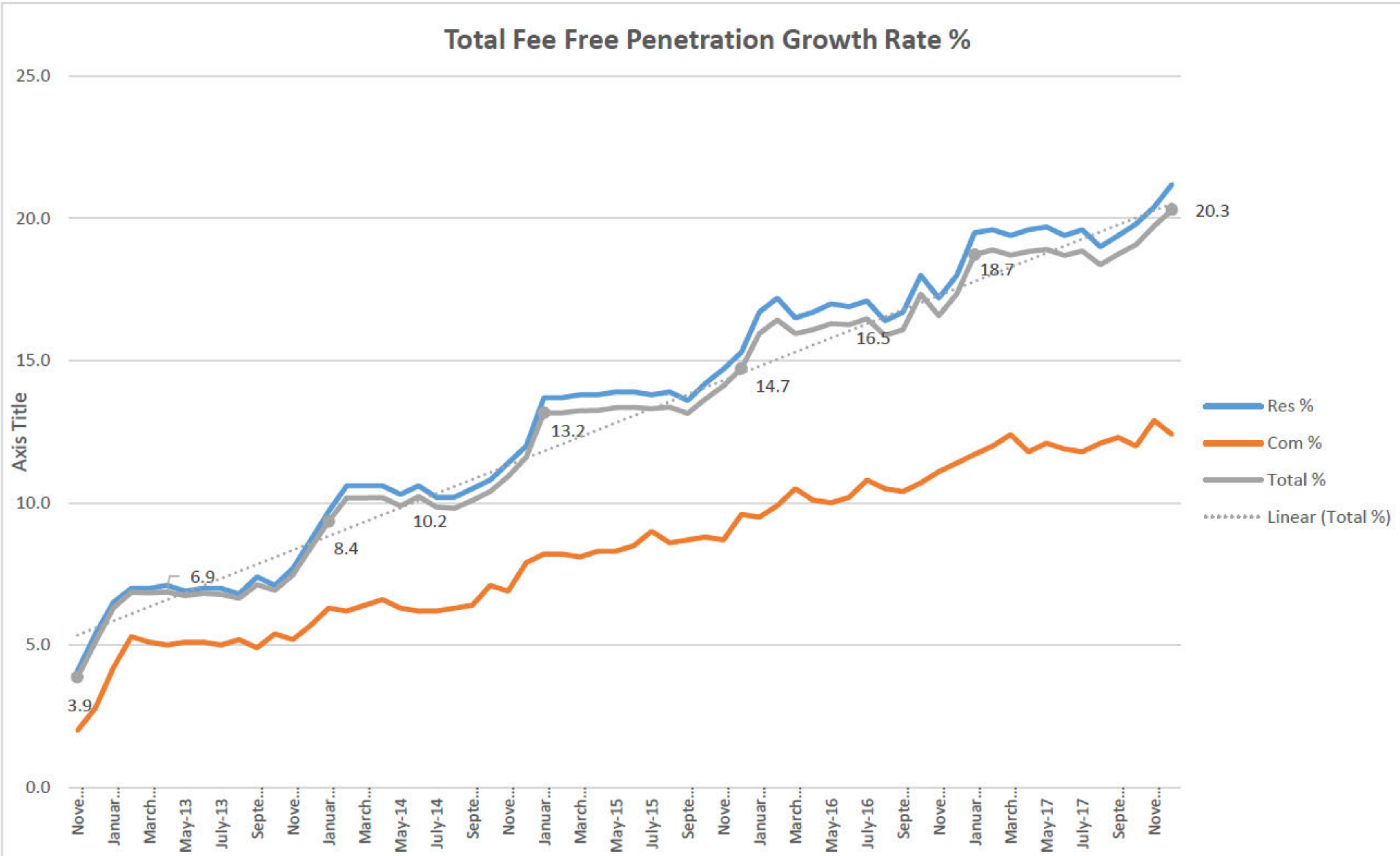
CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 505

Exhibits in Support
Of Opening Testimony

April 20, 2018


Total Fee Free Penetration Growth Rate %
Axis Title
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20.0
15.0
10.0
5.0
0.0
3.9
6.9
8.4
10.2
13.2
14.7
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Res %
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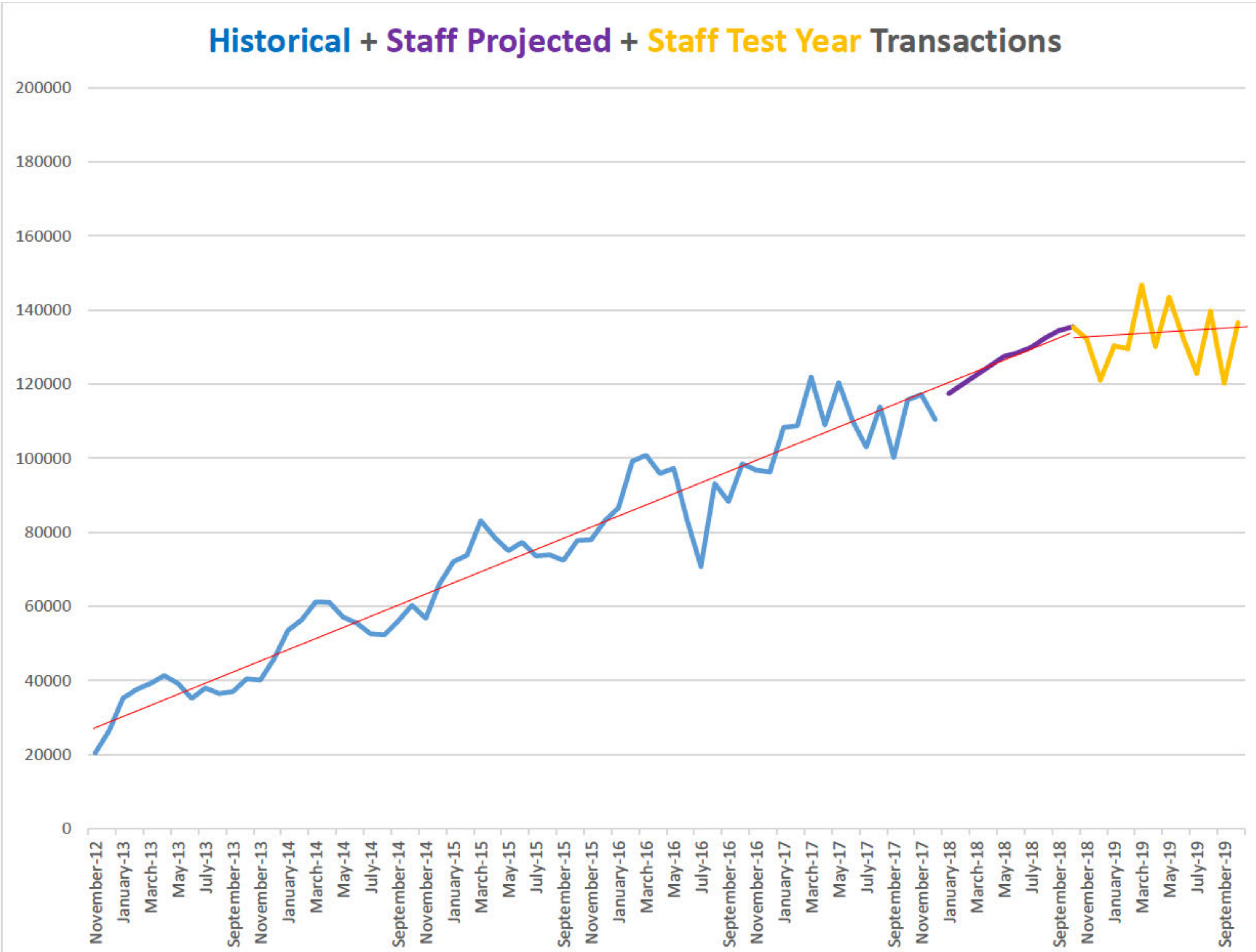
CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 506

Exhibits in Support
Of Opening Testimony

April 20, 2018


Historical + Staff Projected + Staff Test Year Transactions
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180000
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80000
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CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 507

Exhibits in Support
Of Opening Testimony

April 20, 2018

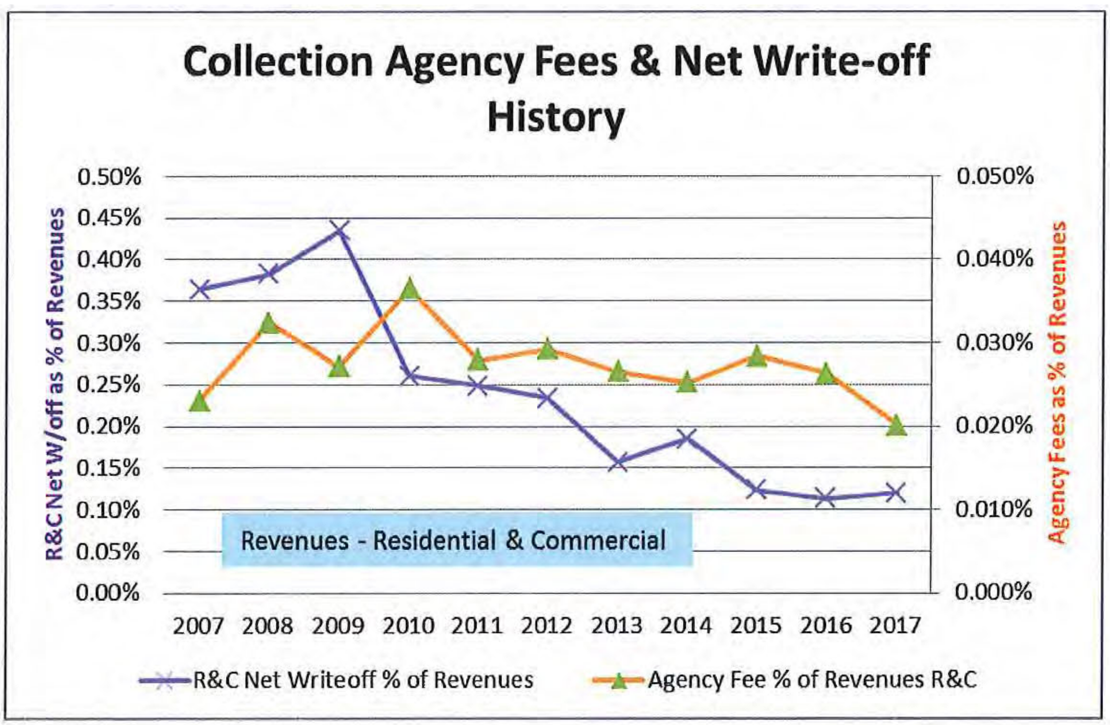
NW Natural®

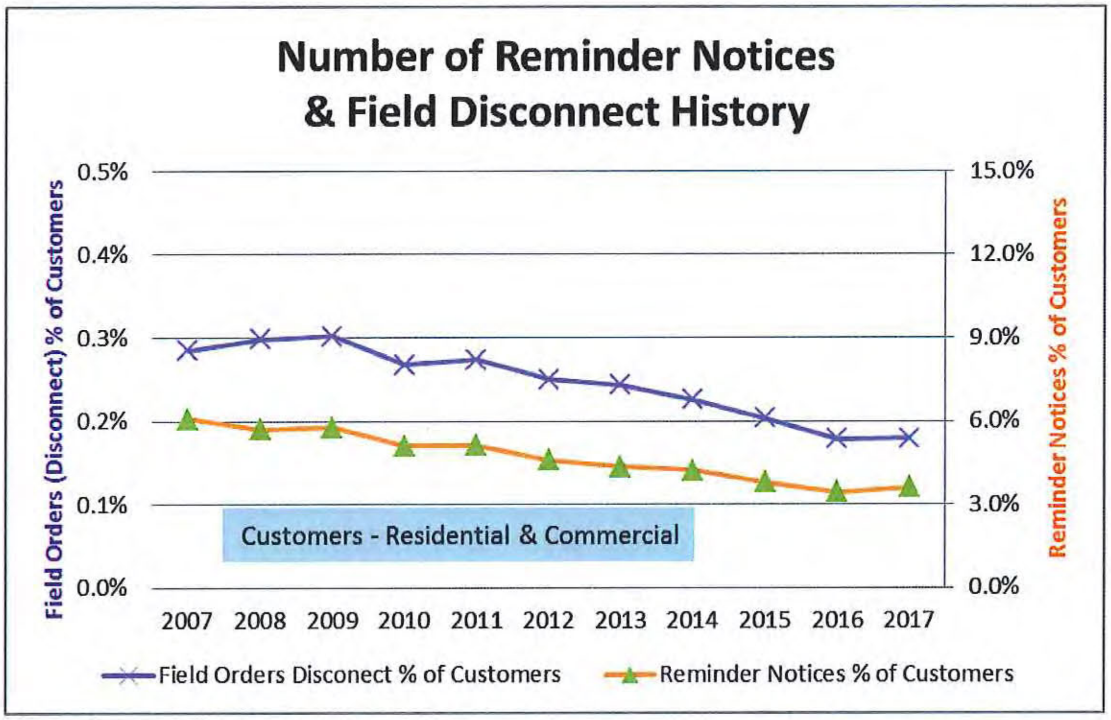
Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 179

179. Provide any data or analysis the company has which examines whether the fee free bankcard payment program results in savings to the company in other areas, such as improved cash flow, reduced write-offs, reduced collection expenses, reduced billing costs, etc.

Response: Response: The Company tracks several metrics which all show positive results from 2007 to current. We believe the implementation of bankcard payment program in 2012 is one of several key drivers which have contributed to the improvement in these metrics as shown below. Other factors, we believe have also contributed to the improvement include: 1) economic cycle, 2) continued operational focus, and 3) technology advancements. The Company has not completed an analysis to determine the specific contribution of each of these drivers and others due to the complexity.




Number of Reminder Notices
& Field Disconnect History
Field Orders (Disconnect) % of Customers
Reminder Notices % of Customers
0.5%
0.4%
0.3%
0.2%
0.1%
0.0%
15.0%
12.0%
9.0%
6.0%
3.0%
0.0%
Customers - Residential & Commercial
2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017
Field Orders Disconect % of Customers
Reminder Notices % of Customers

CASE: UG 344
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 508

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 376

376. In the company's response to DR 179, four metrics were identified which have shown improvement since 2007. Please identify annual cost savings to the company for each of these metrics from 2012 through 2017.

Response:

The estimated financial impacts from the improvements indicated in DR 179 and corresponding metrics are shown in the tables below. There are several factors that drive these results. As mentioned in DR 179, we believe the implementation of the bankcard program in 2012, as well as the economic recovery from the recession, are two of the factors that have contributed to the improvement in the metrics shown below. In addition, continued operational focus and technology advancements have improved the metrics. The Company has not completed an analysis to determine the specific contribution of each of these factors and potentially other factors, due to its complexity.

Collection Agency Fee as a % of Revenue				
	Historical Rate*	Actual Rate	Actual Revenues	Variance from Actual
2012	0.029%	0.029%	$ 650,833,978	$ 1,187
2013	0.029%	0.027%	$ 669,996,743	$ 19,033
2014	0.029%	0.025%	$ 666,677,932	$ 27,827
2015	0.029%	0.028%	$ 628,225,750	$ 6,500
2016	0.029%	0.026%	$ 598,627,285	$ 18,189
2017	0.029%	0.020%	$ 688,443,523	$ 64,140
			Savings	**$ 136,876**

Net Write off as a % of Revenue				
	Historical Rate*	Actual Rate	Actual Revenues	Variance from Actual
2012	0.338%	0.234%	$ 650,833,978	$ 677,971.91
2013	0.338%	0.156%	$ 669,996,743	$ 1,216,510.02
2014	0.338%	0.185%	$ 666,677,932	$ 1,022,846.35
2015	0.338%	0.124%	$ 628,225,750	$ 1,346,977.13
2016	0.338%	0.113%	$ 598,627,285	$ 1,348,016.37
2017	0.338%	0.119%	$ 688,443,523	$ 1,504,905.51
			Savings	**$ 7,117,227.28**

Reminder Notices as a % of Customers				
	Historical Rate*	Actual Rate	Total Customers	Variance from Actual x $0.41
2012	66.7%	55.0%	685,018	$ 32,900.03
2013	66.7%	52.1%	693,955	$ 41,723.61
2014	66.7%	50.6%	703,715	$ 46,579.76
2015	66.7%	45.6%	713,425	$ 61,862.87
2016	66.7%	41.1%	724,133	$ 76,094.37
2017	66.7%	43.4%	736,684	$ 70,411.40
			Savings	**$ 329,572.03**

Field Order Disconnections as a % of Customers				
	Historical Rate*	Actual Rate	Total Customers	Variance from Actual x $15.00
2012	3.4%	3.0%	685,018	$ 43,385.70
2013	3.4%	2.9%	693,955	$ 52,596.41
2014	3.4%	2.7%	703,715	$ 75,384.86
2015	3.4%	2.4%	713,425	$ 105,419.63
2016	3.4%	2.1%	724,133	$ 139,813.05
2017	3.4%	2.1%	736,684	$ 141,385.17
			Savings	**$ 557,984.82**

*Historical rate is the average of 2007-2011 rates

CASE: UG 344
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 600

Opening Testimony

April 20, 2018

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

A. My name is Scott Gibbens. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. I will discuss Staff's analysis and review of several issues in NWN's general rate case. The issues relate to directors & officers (D&O) insurance expense, purchased gas expense, medical benefits, rate spread and rate design,

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/602, workpapers supporting my adjustment to D&O insurance expense; Exhibit Staff/603, workpapers supporting my adjustment for medical benefits expense; and Exhibit Staff/604, a 2017 benchmarking study performed by Willis Towers Watson.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. D&O INSURANCE EXPENSE

Q. What is D&O insurance?

A. D&O insurance is liability insurance payable to the directors and officers of a company, or to the organization itself, as indemnification (reimbursement) for losses or advancement of defense costs in the event an insured suffers such a loss as a result of a legal action brought for alleged wrongful acts in their capacity as directors and officers. Such coverage can extend to defense costs arising out of criminal and regulatory investigations and trials as well. Intentional illegal acts, however, are typically not covered under D&O policies.

Q. Does the Company include D&O insurance expense in its test year expense?

A. Yes. The Company includes its total D&O insurance expense based on premiums for excess layers of liability coverage.

Q. Please explain your adjustment to D&O insurance expense.

A. Staff's standard practice is to recommend 50 percent sharing of the entire expense between ratepayers and shareholders. This adjustment is shown in Exhibit Staff/602, Gibbens/1. In its application the Company requested a total system test year amount of $560,300. As shown in Exhibit Staff/602, the Oregon allocated adjustment of $249,502, based on the allocation percentage as described in the Company's response to Staff DR 303.

Q. What is the basis for Staff's adjustment to D&O Insurance expense?

A. The majority of the time, this issue is settled by parties before the Commission rules on the matter, including in NWN's previous rate case UG 221. However, in Commission Order No. 09-020, the Commission stated, "[t]he cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense."

D&O insurance protects senior management in the event they are sued in conjunction with the performance of their duties, whether by customers, shareholders, or others. This sharing approach is reasonable for several reasons. First, a sharing approach aligns the interests of customers and shareholders. Second, customers typically have no say in electing or appointing utility directors or officers, and therefore should not be held financially responsible for providing the entirety of the insurance coverage for protection against business decisions or improprieties by management which could result in lawsuits. Moreover, in an article published in *The University of Chicago Law Review,* Professors Tom Baker and Sean J. Griffith of Columbia and Fordham law schools state "the dominant source of D&O risk, both in terms of claims brought and liability exposure, is shareholder litigation."[1] So much so that Professors Baker and Griffith "[t]reat the central purpose of D&O insurance as providing coverage against shareholder litigation."[2]

[1] Baker, Tom & Griffith, Sean. (2006), Predicting Corporate Governance Risk: Evidence from the Directors' and Officers' Liability Insurance Market. *University of Chicago Law Review*. 74.
[2] *Ibid.*

ISSUE 2. PURCHASED GAS & OTHER GAS EXPENSE

Q. What is "other gas expense?"

A. "Other gas expense" is expense recorded in FERC account 813, and includes the cost of labor, materials used and expenses incurred in connection with gas supply functions including research and development expenses, not provided for in any other FERC account for gas expense.[3]

Q. Please summarize NWN's proposal related to other gas expense.

A. According to the Company's response to Staff DR No. 277, NWN is not seeking any test year expense associated with FERC account 813. There have been no recent historical expenses that have been charged to this account.

Q. Please summarize NWN's proposal related to purchased gas.

A. In the Company's response to Staff DR No. 278, NWN states:

> Gas supply expenses are not included in the test year on an itemized basis. Commodity and pipeline demand charges are administered on an annual basis in the Purchased Gas Adjustment (PGA) filing. For rate cases, the company includes current revenue rates including the current commodity (weighted average cost of gas or WACOG) and demand rate increments that are built into billing rates. On the expense side, the cost calculated by the same volumes and rate increments are included as gas costs. As a result, the revenue recovered for gas costs and expense incurred for gas costs are equal, and the gas cost component does not produce any impact on incremental revenue requirement.

Q. Please describe Staff's proposed adjustment of purchased and other gas expense.

[3] See 18 C.F.R. § 205 (FERC account 813).

A. The actual cost of gas is reconciled with customers each year in the Purchased Gas Adjustment.[4] NWN is not seeking any recovery of other gas expense. Staff has confirmed the veracity of the Company's response with a review of their workpapers. Therefore, Staff has no proposed adjustment for purchased and other gas expense in this rate case at this time.

[4] Order No. 14-238 in Docket No. UM 1286. Docket No. UG 334/Advice No. 17-12A, reflects changes in the cost of purchased gas and the amortization rate for the Purchased Gas Adjustment balancing account that went into effect on November 1, 2017.

ISSUE 3. MEDICAL BENEFITS EXPENSE

Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.

A. The Company has requested approximately $19.61 million in test year expenses relating to medical benefits. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees. Benefit plan premiums are typically shared between the Company and the employees. The Company generally shares costs with employees at a ratio of 85/15 or 80/20 (*i.e.,* employees pay 15 percent of premium costs and the Company pays 85 percent), depending on whether an employee participates in a health assessment or not.

Q. Please describe the analysis performed by Staff.

A. Staff typically recommends employer/employee sharing of premium costs at the industry average, however NWN's premium contribution is already aligned with this average. A survey in the 2017 Kaiser Family Foundation publication indicates that the average employer/employee sharing ratio in the industry is 82/18 for single employees.

Because the cost of health insurance increases by 13.1 percent from the base year, Staff used trend analysis of 2011 through 2017 costs to forecast the test year costs. Staff found that the Company's proposed medical expense deviates significantly from the trend by roughly $3.2 million. Staff identified several potential factors skewing the results of the trend analysis. First, medical rates decreased in 2013 from 2012, this likely is not representative of the current rate environment. Second, NWN is requesting a relatively large increase in FTE in the test year, which could skew the results. In order to improve the trend forecast, Staff reduced the historical timeframe to 2014-2017. In these years, medical costs increased every year by at least four percent. Second, Staff weighted the forecast by total FTE for each year, which mitigates the effect of additional FTE in the test year. Staff found that the based on historic trends, the test year forecast is roughly $541,000 too high.

Staff reviewed other sources for information on why the test year forecast might reasonably be above trend. Staff found that accounting firm PwC projected medical rates to increase by 6.5 percent in 2018, which is below the increase forecast by NWN. Lastly, Staff reviewed the 2017 benchmarking study performed by Willis Towers Watson (WTW) for NWN on their medical insurance offerings.[5] In that report, WTW noted that NWN's program was five percent less efficient than the average database performer. This means that their program costs are five percent higher than would be expected for the offerings they have in their medical benefits.

Q. Does Staff propose any adjustments relating to medical benefits?

A. Yes. Staff's adjustment is based on the trend analysis, and results in a reduction of $541,085 to medical benefits in the test year. Details and calculations of Staff's adjustment can be found at Confidential Exhibit Staff/603.

[5] See Staff/604, Gibbens/1-30.

ISSUE 4. RATE SPREAD AND RATE DESIGN

Q. Please describe Staff's general approach to rate spread and rate design.

A. Staff's general approach is to strive for rates that adhere to Bonbright's principles of rate making. In his book, *Principles of Public Utility Rates*, Bonbright lists eight principles widely accepted as the central goal for all ratemaking. They are:

1. Simplicity, understandability, and public acceptability
2. Freedom from controversy
3. Revenue sufficiency
4. Revenue stability
5. Stability of rates
6. Fairness in apportionment of total costs
7. Avoidance of undue rate discrimination
8. Encouragement of efficiency

Some of these principles are at odds with one another and must therefore be balanced when setting rates.

For example Staff utilizes the information resulting from the long-range incremental cost (LRIC) study to inform what a truly cost based revenue spread would look like, which is represented in the sixth (fairness) and seventh (avoidance of undue rate discrimination) Bonbright principles. Staff then must consider the fifth (rate stability) and second principle (no controversy) in looking at the rate impact for each particular rate class if strict cost-based rates were implemented. The fourth (revenue stability) and eighth principles (efficiency) are at odds when considering fixed- versus variable- rate designs. The ideal rate spread and rate design considers a number of different and competing goals to come up with a fair and reasonable approach.

Q. Please describe the Company's proposed rate spread and rate design.

A. The LRIC study showed subsidization of the residential and certain commercial schedules by generally industrial and firm transportation schedules. However NWN opted to propose a proportionate increase for all rate schedules by using an equal percent of margin methodology. The Company states that their goal was to minimize rate impact and maintain equality in sharing the burden of the rate increase.

Q. Does Staff agree with the Company's proposed rate spread?

A. No. Staff agrees with the Company that sharing the burden of the rate increase across schedules will minimize a large impact to a single schedule. However, the LRIC shows large amounts of subsidization among classes. Just because it is impossible to achieve perfect unity between cost and revenue because of the large discrepancies does not mean that improvements can't be made. Staff views a movement away from subsidization as an improvement. Staff witness George Compton discusses proposed changes to LRIC. Based on his results, Staff worked on a rate spread that would both limit a large impact to any single schedule but also move all schedules closer to achieving cost based rates.

Q. Please explain the approach Staff recommends.

A. Based on Staff's revised LRIC results, ten out of fourteen schedules currently pay more than their fair share of costs. Of the other four schedules, Residential, Basic Commercial Firm, Commercial Dry-out Service, and Large

Volume Transportation, Residential is nearest cost unity in that the revenues recovered under the schedule largely cover the costs of service for that schedule. The remaining three schedules are being subsidized, meaning that the utility is not recovering sufficient revenue from the customers to offset the cost of serving these schedules.

Staff's recommendation is to maintain the Company-proposed increase for the residential class. This is the average overall increase and will maintain the approximate cost unity.

For the ten schedules that are subsidizing the others, Staff recommends they receive an increase equal to 2/3 the average margin increase. Based on the Company's initial request this would result in a 10 percent increase on a margin basis for these classes. By receiving a lower than average increase, they will move closer to cost unity, while at the same time reducing the rate impact on the other classes.

The other three schedules will split the remaining revenue requirement equally. This equates to a 17.28 percent increase as opposed to the Company's proposed 14.99 percent increase. This increase will not have a drastic difference on the average bill for the three schedules, but will move all schedules towards cost based rates. In summary:

1. Schedule 2: Residential Service will receive the average increase.
2. Schedules: 3 ISF, All of 31, 32 CSF, 32 ISF, 32 CSI, 32 ISI, and 32TI will receive an increase equal to 2/3 the average.

3. Schedules: 3 CSF, 27 CSF, and 32 TF will receive the remainder of the revenue requirement spread on an equal percentage of margin basis.

A final note is that the Commission-approved revenue requirement will likely be less than the Company's initial request, which will further reduce the rate shock for all schedules. While Staff's proposal should work regardless of the ultimate increase to rates, all parties may want to reexamine the rate spread to ensure further improvements can't be made.

Q. Does Staff have any recommendations regarding the Company's proposed rate design?

A. No. Staff views the proposed rate design as fair and reasonable. Implementing the rate increase as part of the volumetric rate for all classes allows customers to potentially mitigate increases in their bill by reducing consumption.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 601

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon
Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UG 344
WITNESS: SCOTT GIBBENS

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STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 602

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CASE: UG 344
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 603

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STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

April 20, 2018

Willis Towers Watson High Performance Insights in Health Care

2017 Health Care Financial Benchmarks

NW Natural

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Willis Towers Watson

Survey Overview — Major Areas Included

Cost Efficiency	Health plans are evaluated on how efficiently they perform by adjusting cost data for plan design, demographics and geographic cost differentials. This helps employers understand how well their plans are performing on an apples-to-apples basis.
Employee Cost-Sharing	How health plans are priced to employees is analyzed to determine the impact on net company costs. This is important because prior studies have shown that many employers create unintended incentives for employees — and increase company costs — by pricing options without a clear understanding of true costs.
Employee Incentives	An increasing number of employers are using arrangements such as HSAs, HRAs and wellness incentives to encourage responsible behavior among plan participants.
Dental	Dental plan costs are compared, as well as enrollment, administration and employee contributions.

- This year's database includes:
  - 1,978 companies in 18 industry groups
  - An annual medical premium-equivalent cost of $129.9B from more than 11.0M enrollees
  - An annual dental premium-equivalent cost of $8.3B from more than 10.2M enrollees

Survey Overview — Specific Questions Addressed

Medical Benchmarks

- How do your plan costs compare to others in your industry, as well as to best performers?
- How does enrollment by plan type compare to the database?
- What is the cost impact of key factors in your population, including: age/gender, family size, geography, plan value?
- After adjustments, how efficient is your total plan overall? What is the financial impact of moving to benchmark or best practice performance?
- After adjustments, how efficient are each of your individual plans relative to benchmarks?
- How does the employer's contributions as a percentage of plan cost compare to employee contributions?
- How does your account funding for HRAs and/or HSAs compare to other employers?
- How do your incentives/wellness credits compare with the database?
- Where do your administrative fees fall within the range of other employers' fees?

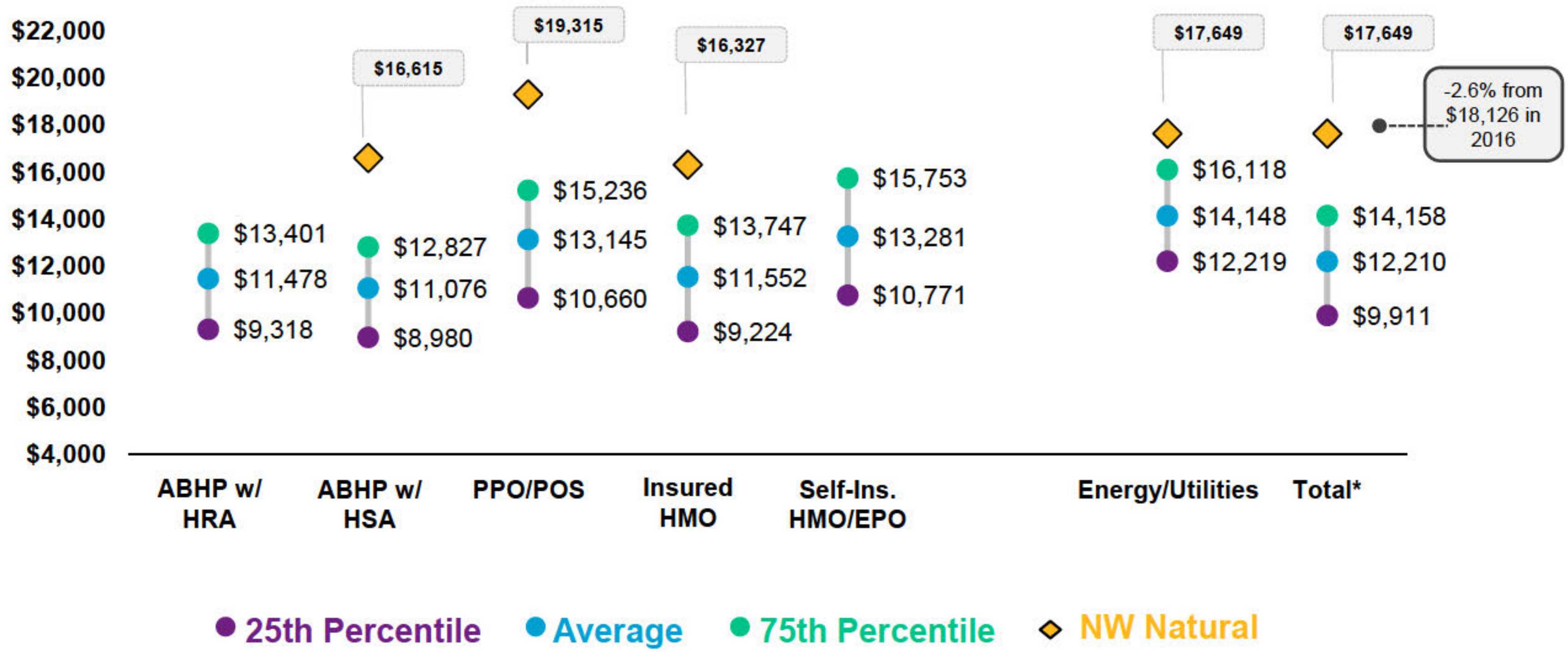
Dental Benchmarks

- How do your plan costs compare to others in your industry, as well as to best performers?
- How does enrollment by plan type compare to the database?
- How do employee contributions compare to the database?
- Where do your administrative fees fall within the range of other employers' fees?

Medical Cost Benchmarks

Medical Cost Benchmarks Total Cost per Covered Employee per Year (Unadjusted)

? How do your plan costs compare? How does enrollment across plan type impact the average cost? Even if total plan costs are favorable, are some plans more exposed to the excise tax?



✓ NW Natural's actual costs are 45% above the benchmark average, 25% above average for NW Natural's industry.

*Total costs represent an enrollment weighted average of all plan types.

Medical Cost Benchmarks — Enrollment by Plan Type and Age Breakdown

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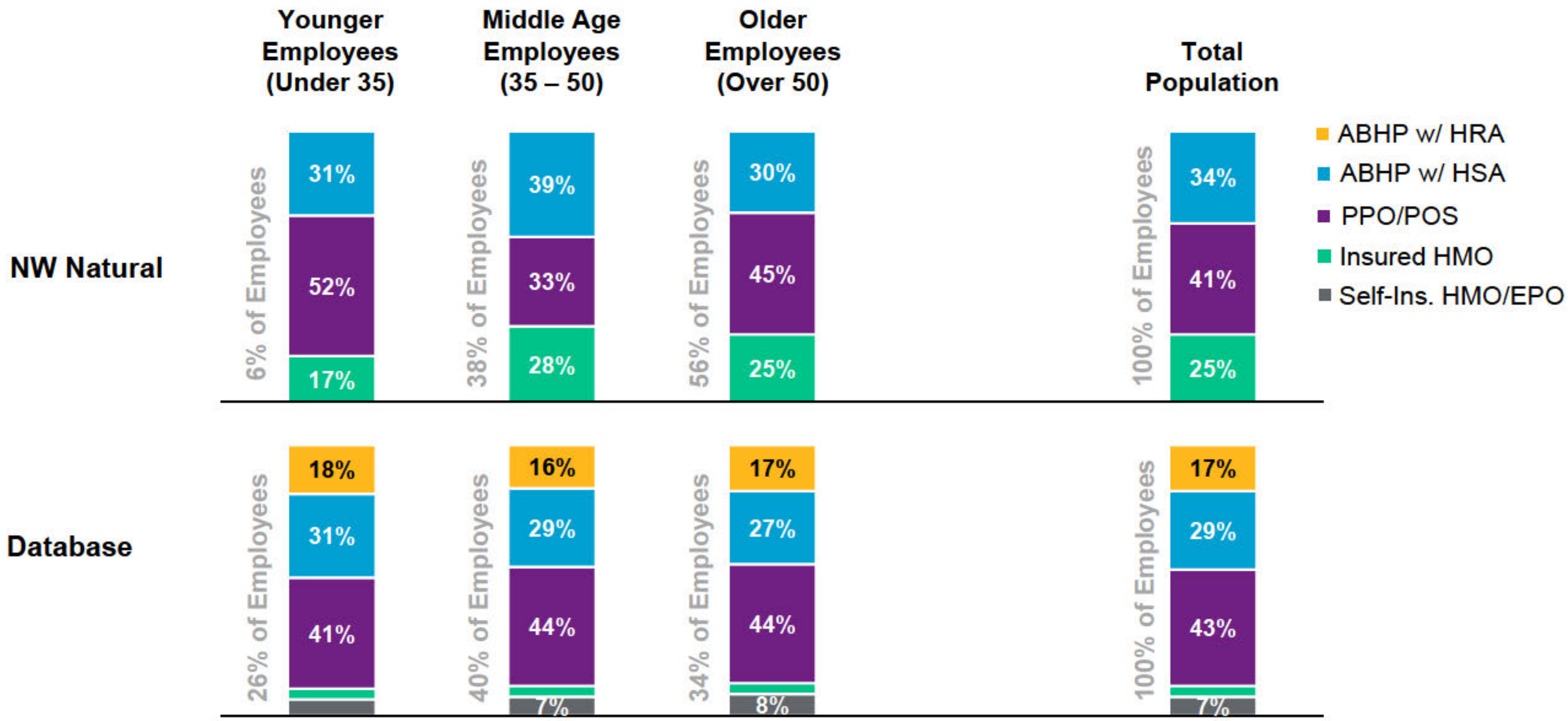
- How does enrollment by plan type compare to the database?
- Does the enrollment by age have implications for plan pricing?
- Is the plan enrollment by age influenced by employer funding of employees/dependents?



- Is employee enrollment aligned with the appropriate plans?
- What are the implications of enrollment on pricing and funding?

Medical Cost Benchmarks Developing a Population Adjusted Benchmark

The first step in understanding the cost benchmarks is to understand your population. The average cost for employers in the database is the benchmark.

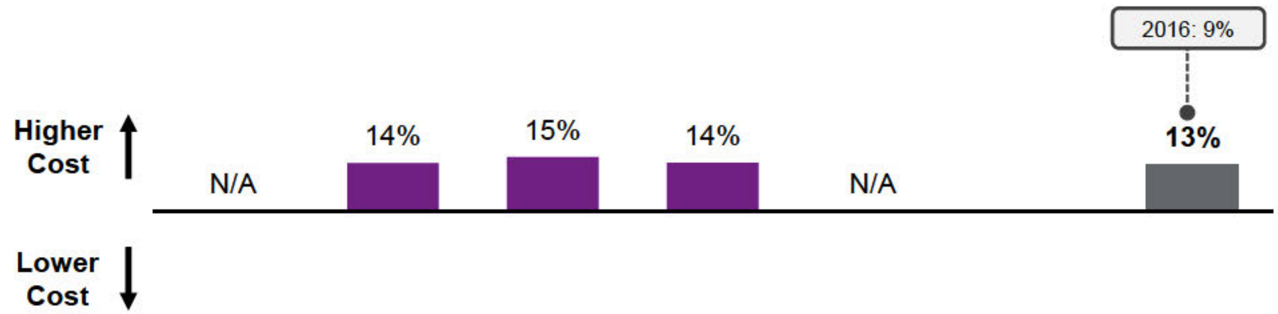
- The benchmark is adjusted to reflect differences between your organization and the database for each of four key criteria, noted below
- The result of these adjustments is a benchmark that is customized to your population (custom benchmark)
- The custom benchmark is the database cost if the database looked like your population with your plan designs

Age/Gender	The age/gender profile of the population — cost is directly correlated with age. The impact of gender on expected cost varies with age.
Family Size	The estimated number of members covered per employee, expressed in terms of adult cost equivalents — larger-than-average family size is expected to increase costs per employee.
Geography	The underlying cost for basic health care services in an area — provider competition and more prevalent managed care plans may reduce costs in some areas. More enrollment in higher-cost areas is expected to increase costs.
Plan Value	The level of benefits covered under NW Natural's medical plan — plans reimbursing a higher percentage of medical expenses than the database average are expected to increase costs.

Medical Cost Benchmarks Adjusting for Age/Gender

- What is the cost impact of age/gender in NW Natural's population?
- How different is the impact of demographics by plan?
- If it is significant, why do company averages have a different pattern across plans than the database?

Impact of Age/Gender on Benchmark

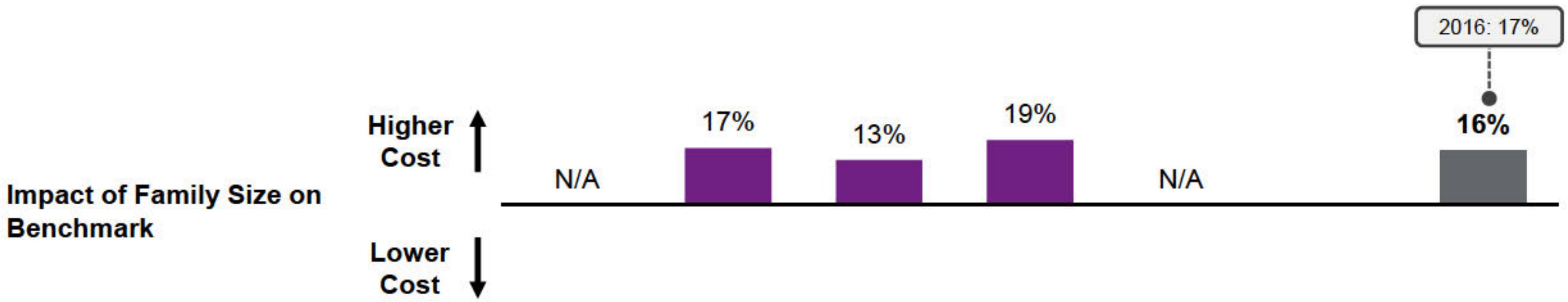


	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Average Age — Database	44.8	43.0	45.9	44.1	45.2	44.8
Average Age — NW Natural's Company	N/A	50.3	53.1	51.7	N/A	51.8 (2016: 49.9)
% Female — Database	44%	38%	42%	41%	46%	41%
% Female — NW Natural's Company	N/A	39%	38%	36%	N/A	38% (2016: 37%)

The custom benchmark will be increased by 13% due to age and gender demographics.

Medical Cost Benchmarks Adjusting for Family Size

- How different is the impact of family size by plan?
- If it is significant, why do company averages have a different pattern across plans than the database?
- How has this been impacted by contribution strategies of the company?



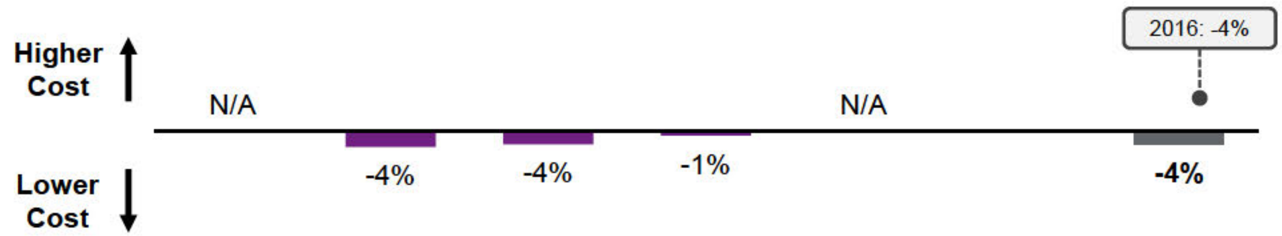
	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Dependents (%) — Database	51%	51%	53%	52%	55%	52%
Dependents (%) — NW Natural's Company	N/A	69%	70%	72%	N/A	71%

The custom benchmark will be increased by 16% due to family size.

Medical Cost Benchmarks Adjusting for Geography

- How does the geographic footprint of NW Natural's covered population impact NW Natural's costs?
- Does the geographic impact vary by plan?

Impact of Geography on Benchmark



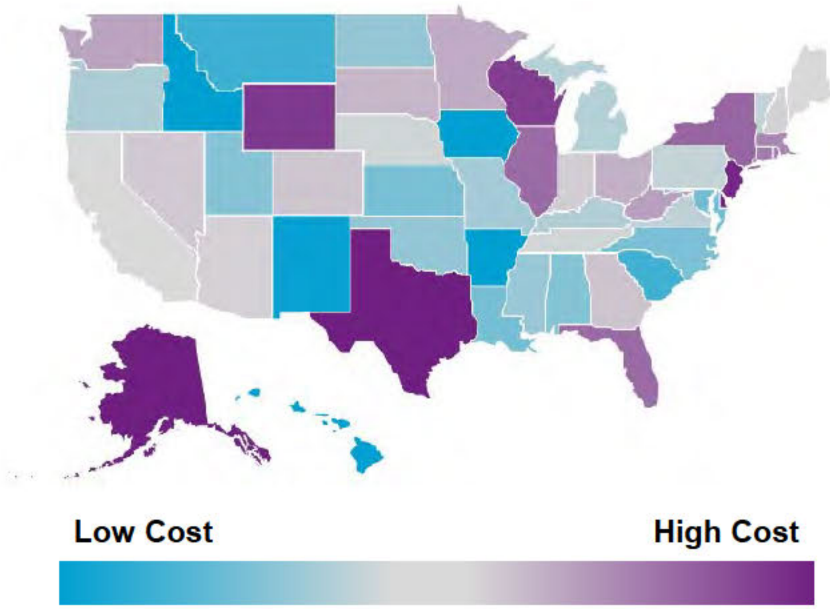
	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/ EPO	Total
Geographic Factors — Database	1.00	1.00	1.00	0.99	1.00	1.00
Geographic Factors — NW Natural's Company	N/A	0.96	0.96	0.98	N/A	0.96

The custom benchmark will be decreased by 4% due to NW Natural's population's geography.

Medical Cost Benchmarks Adjusting for Geography — Additional Details

How do overall health care costs vary by state?

Health Care Costs by State



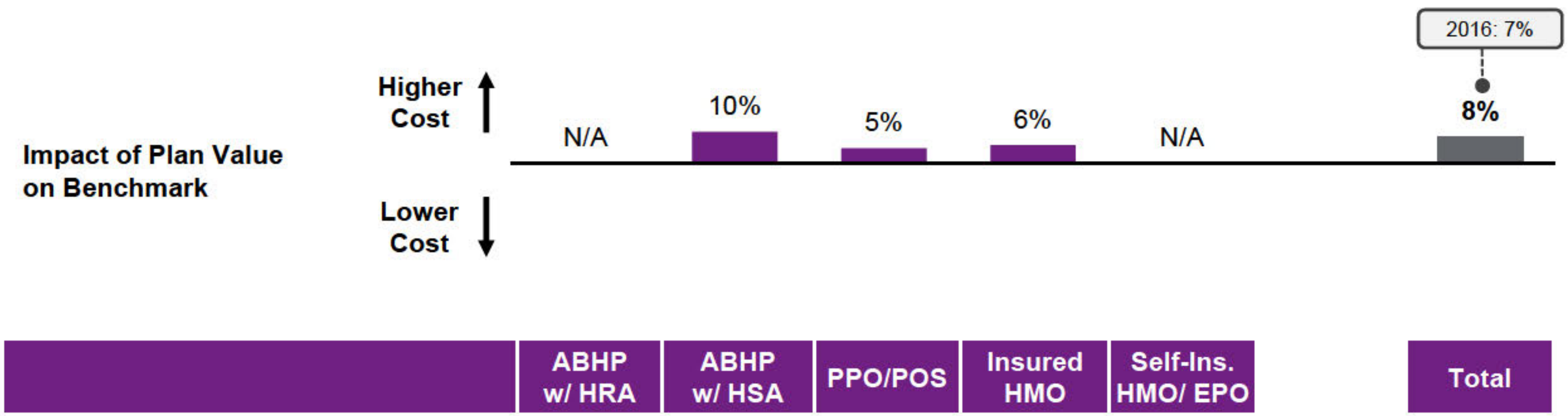
NW Natural's Top States for Enrollment

Rank	State	NW Natural's Enrollees	% of Total
1	OR	429	87%
2	WA	63	13%
3	AZ	1	0%
4	GA	1	0%
5	UT	1	0%
Total — Top 5 States		495	100%

Understanding the impact of the geographic footprint of NW Natural's employees is important to understand NW Natural's relative cost position.

Medical Cost Benchmarks Adjusting for Plan Value

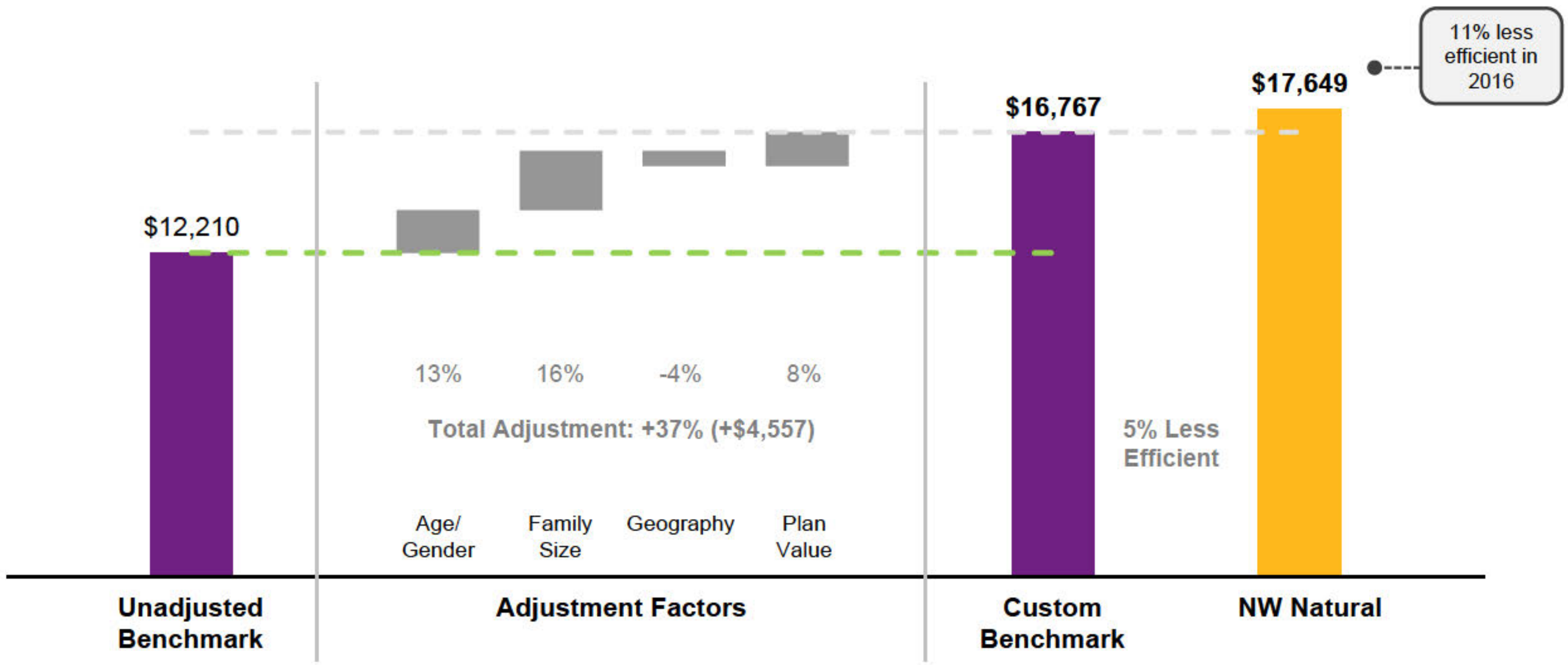
How do NW Natural's plan values compare to benchmark?



The custom benchmark will be increased by 8% due to plan value.

Medical Cost Benchmarks Overall Program Efficiency

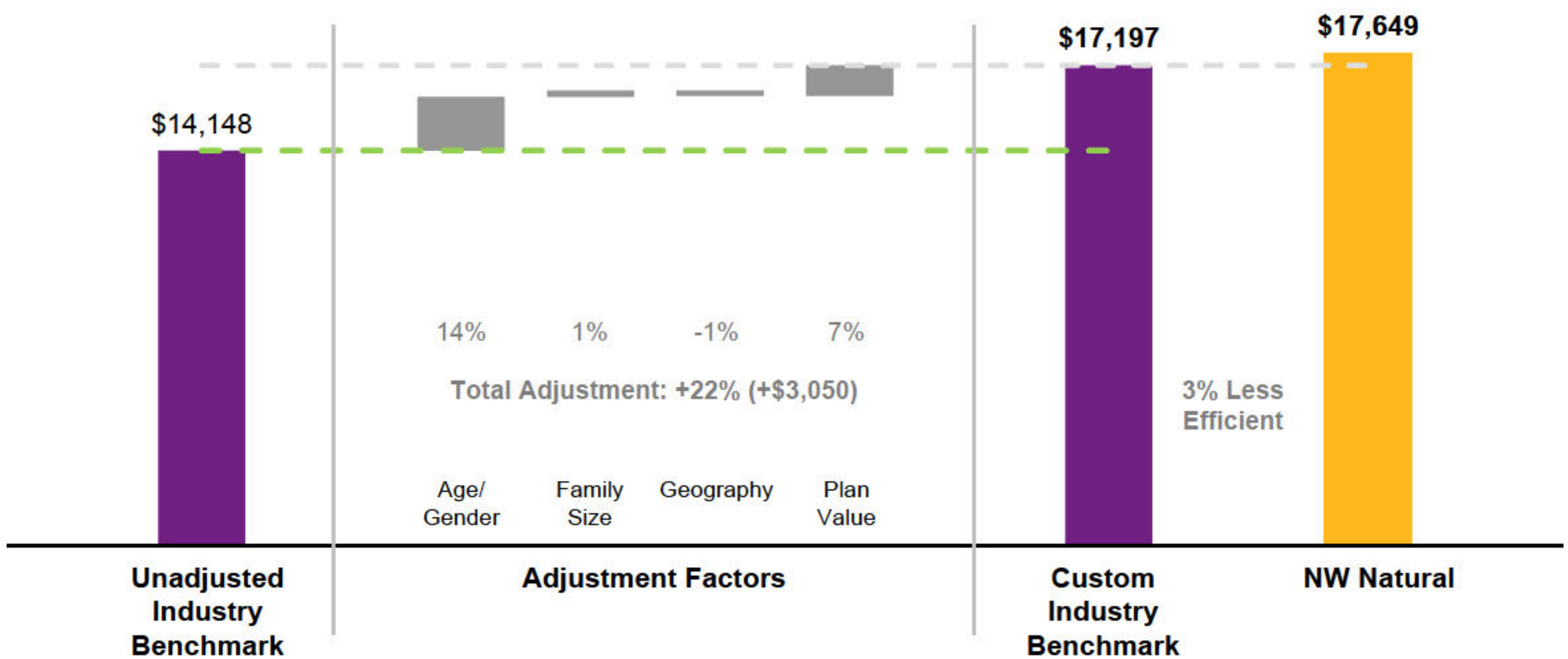
- After adjustments, how efficient is NW Natural's total plan overall?
- What is the financial impact of moving to benchmark performance?



NW Natural's total program is 5% less efficient than the average database performance. This translates into a potential cost avoidance of $0.4 million. Relative to top-quartile performers, NW Natural's total program is 17% less efficient, translating into a potential cost avoidance of $1.2 million.

Medical Cost Benchmarks Industry Efficiency

After adjustments, how efficient is NW Natural's total plan compared to the energy/utilities industry?

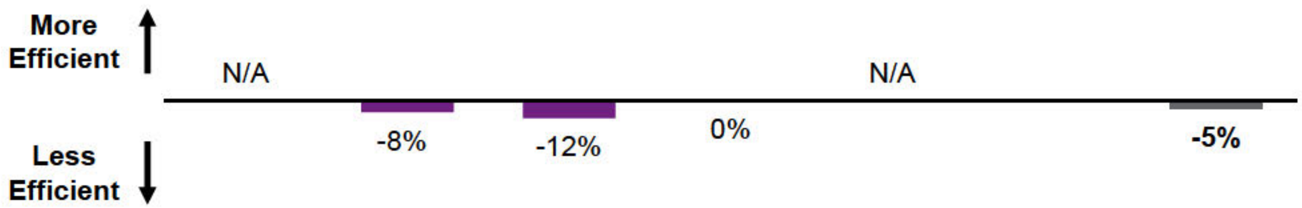


NW Natural's total program is 3% less efficient than NW Natural's industry. This translates into a potential cost avoidance of $0.2 million.

Medical Cost Benchmarks | Delivery System Cost Efficiency

How efficient are NW Natural's plans relative to the benchmark?

Delivery System Cost Efficiency



	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/EPO	Total
Enrollment	0%	34%	41%	25%	0%	100%
Actual cost per employee	N/A	$16,615	$19,315	$16,327	N/A	$17,649
Custom benchmark cost per EE	N/A	$15,417	$17,302	$16,323	N/A	$16,767
Efficiency	N/A	-8%	-12%	0%	N/A	-5%

Summary		Average Enrollment	High Enrollment	Average Enrollment		
		Low Efficiency	Low Efficiency	Average Efficiency		Low Efficiency

Plan efficiency is most important for plans with higher enrollment, as this drives overall efficiency.

Medical Cost Benchmarks Employee Cost-Sharing Overview

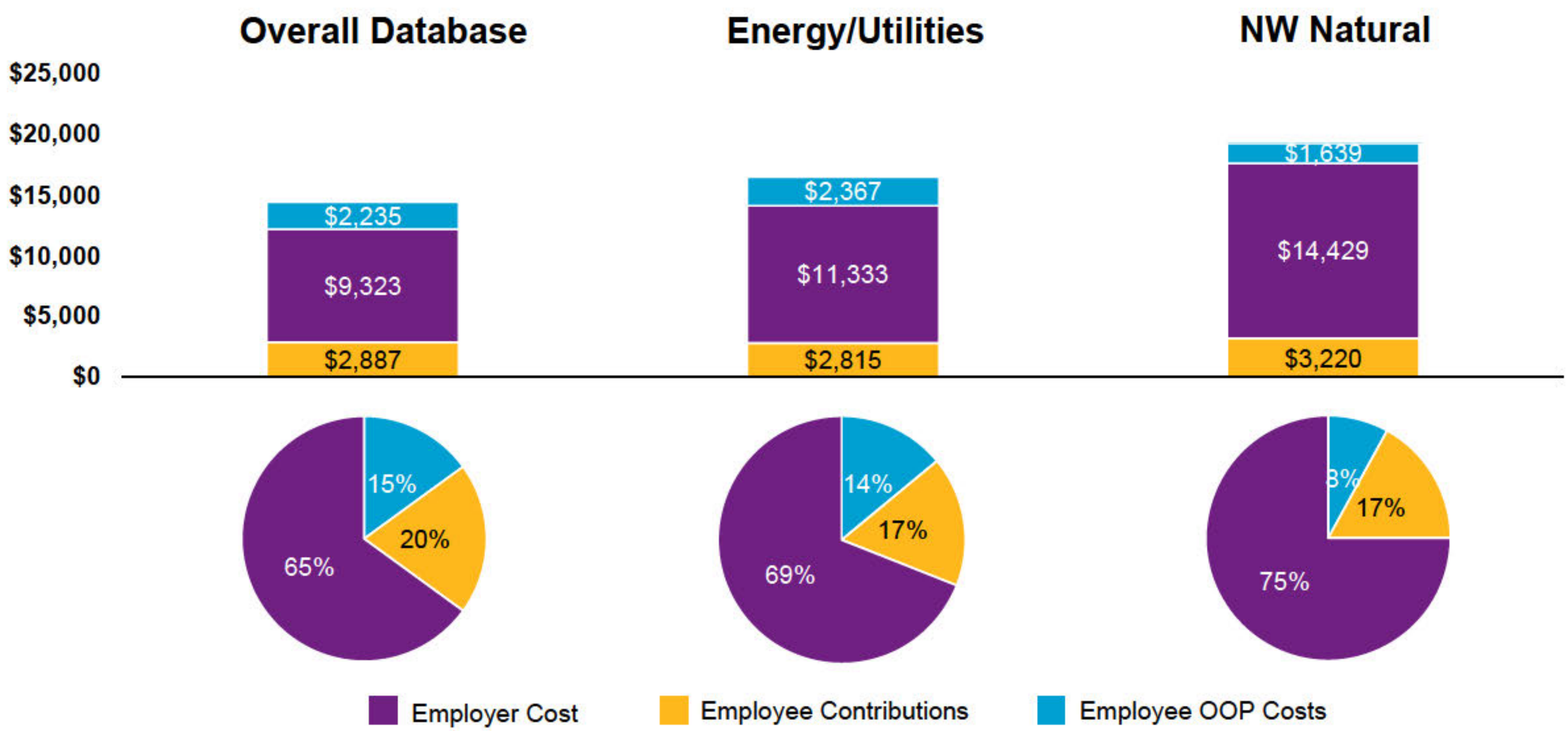
An important driver of overall cost results is how employers price different medical plan options to employees. This section shows how NW Natural's company's employee contributions compare with the database averages and how contributions are structured for different delivery systems.

Included are:

- Comparisons of employee vs. dependent subsidy levels
- Net cost analysis by plan type

Medical Cost Benchmarks Total Cost and Contributions

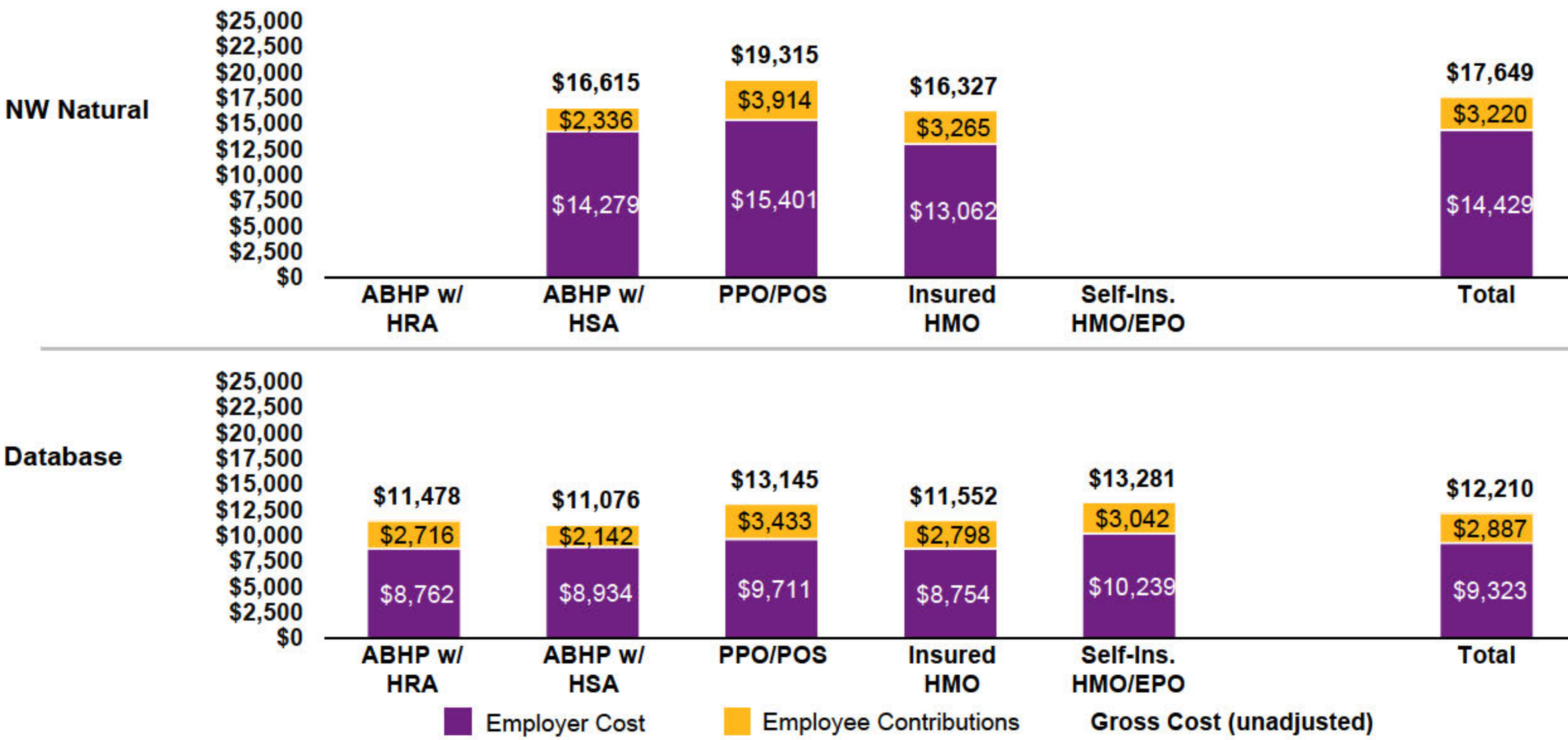
How does NW Natural's employees' share of total cost, including contributions and out-of-pocket expenses, compare to benchmarks?



- Compared to the overall database, NW Natural's employee share of total costs is lower
- Compared to others in NW Natural's industry, NW Natural's employee share of total costs is lower

Medical Cost Benchmarks Employee Cost-Sharing (Unadjusted)

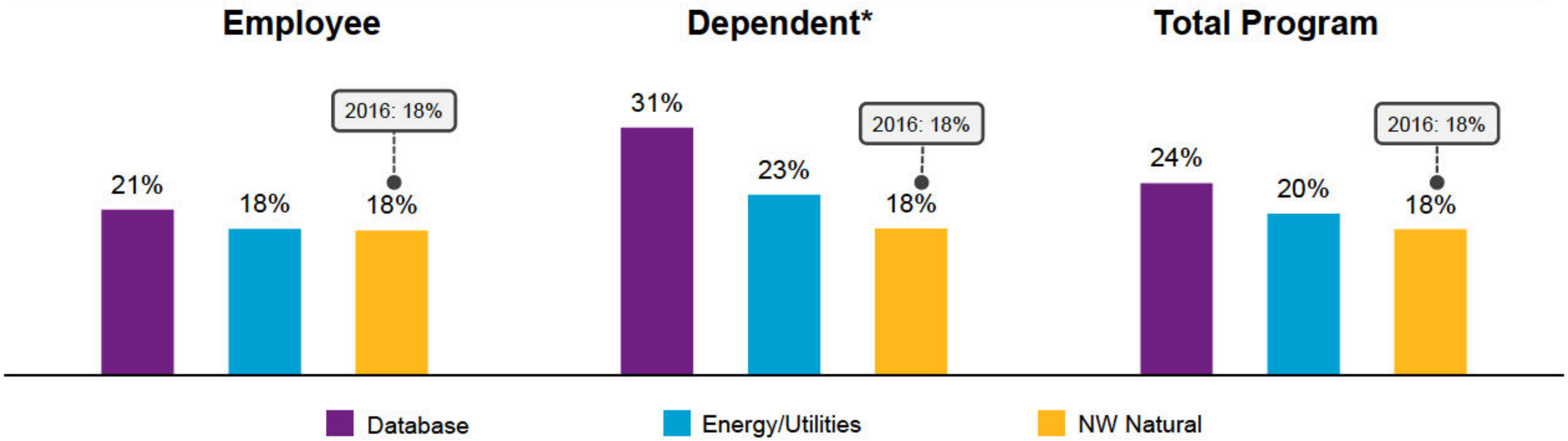
How do NW Natural's employee payroll contributions vary across plans?



On average, NW Natural's employees pay $333 more per year than the database.

Medical Cost Benchmarks Employee Contributions as a % of Plan Cost

How does NW Natural's cost sharing, for employees and dependents, compare to benchmarks?



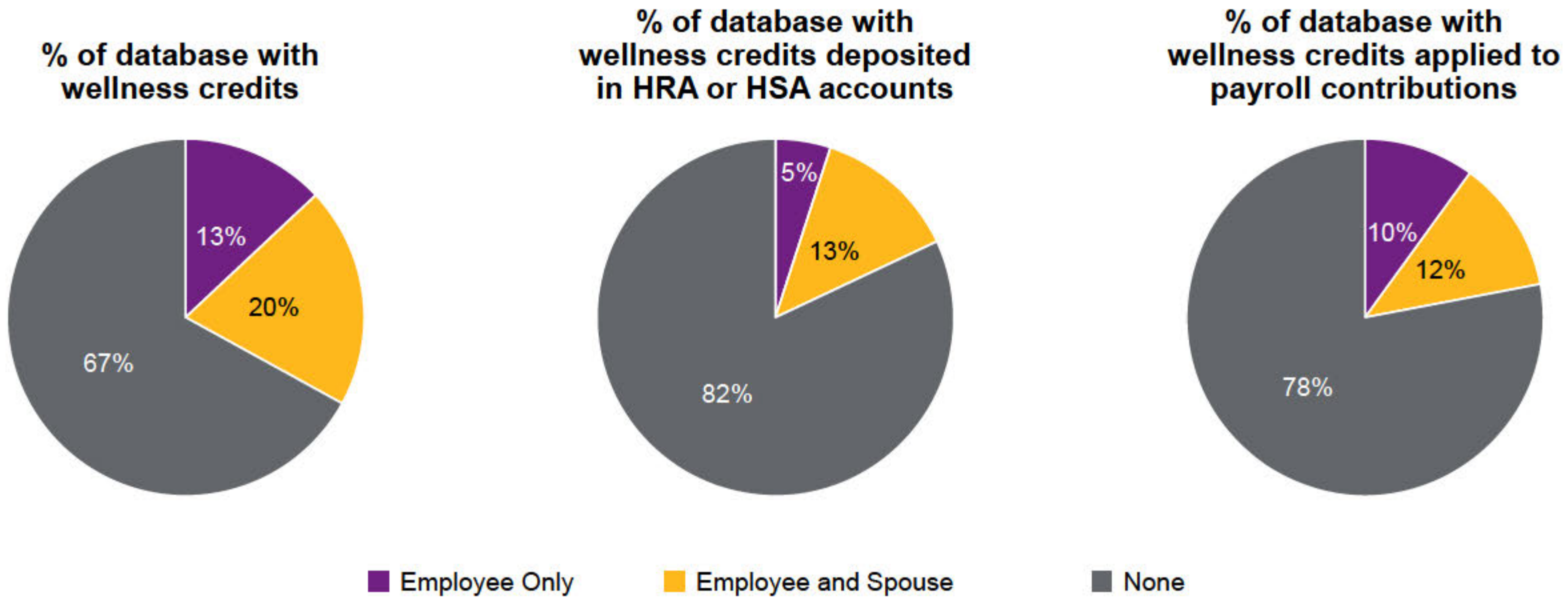
Employee Contributions as a % of Total Cost	ABHP w/ HRA	ABHP w/ HSA	PPO/POS	Insured HMO	Self-Ins. HMO/EPO
NW Natural	N/A	14%	20%	20%	N/A
Database	24%	20%	27%	25%	24%

- Employees contribute less than the database average but about the same as the industry average
- Dependents are below the database and industry averages

*Dependent includes spouse, children, family, etc.

Medical Cost Benchmarks Wellness Credits for Accounts and Contributions

How does the company's approach compare to the database?



NW Natural's provides wellness credits through payroll contributions.

http://natct.internal.towerswatson.com/clients/604927/NWNatural2017HB/Documents/2017%20Health%20Care%20Financial%20Benchmarks%20-%20NW%20Natural.pptx

Medical Cost Benchmarks Impact of Account Seeding on HRA Plan Design*

?

- How does NW Natural's funding of the HRA compare with the database?
- How does NW Natural's net deductible (deductible minus guaranteed and earned incentives) compare with the database?

HRAs	Client	Database		
		25th	Average	75th
Base Deductible	N/A	$1,303	$1,819	$2,000
– Guaranteed Contribution	N/A	$243	$590	$750
– Average Earned Incentive	N/A	$0	$738	$0
Net Deductible Paid by Employees	N/A	$750	$477	$1,473

✓ Not applicable.

*Employee coverage only

Medical Cost Benchmarks — Impact of Account Seeding on HSA Plan Design*

- How does NW Natural's funding of the HSA compare with the database?
- How does NW Natural's net deductible (deductible minus guaranteed and earned incentives) compare with the database?

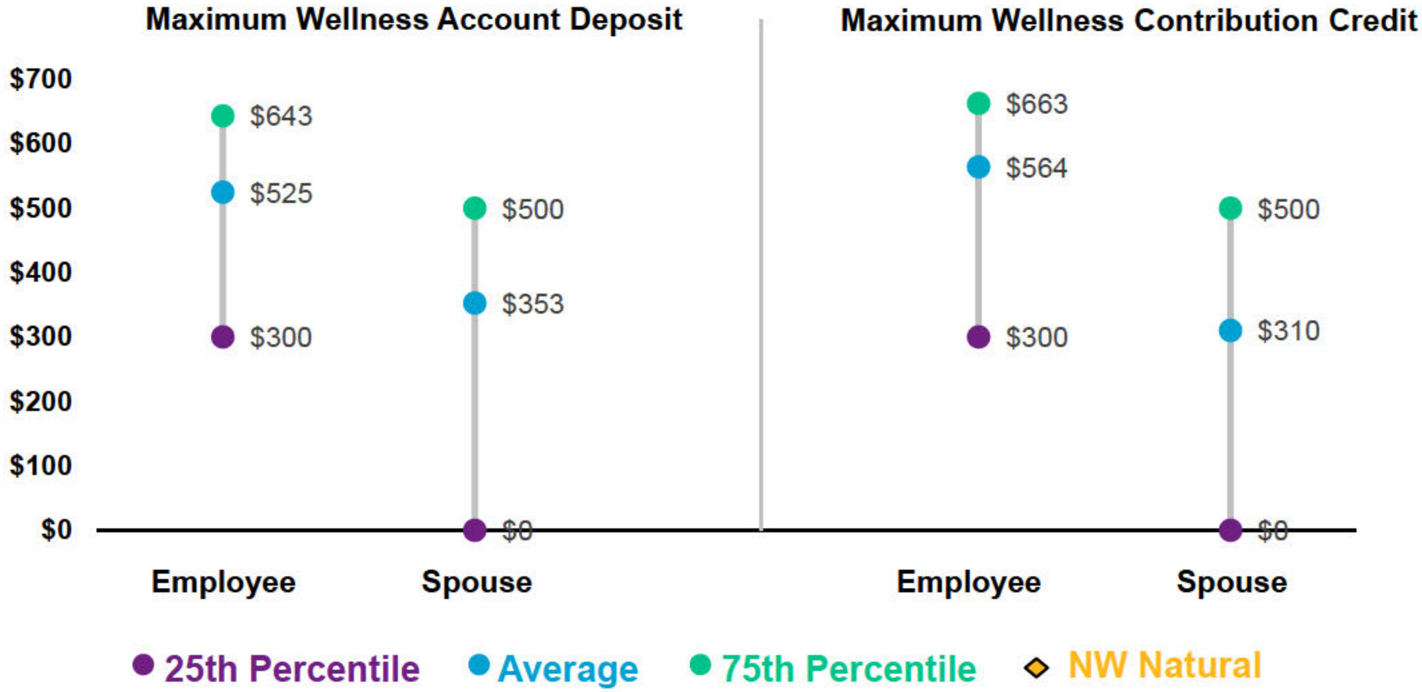
HSAs	Client	Database		
		25th	Average	75th
Base Deductible	$1,500	$1,500	$2,171	$2,600
– Guaranteed Contribution	$750	$0	$427	$600
– Average Earned Incentive	$0	$0	$44	$0
Net Deductible Paid by Employees	$750	$1,000	$1,699	$2,100

NW Natural's net deductible is $949 less than the database average.

*Employee coverage only

Medical Cost Benchmarks Wellness Incentives

- How does the company's maximum potential wellness credit compare with the database?
- How does the allocation between employee and spouse compare to the database?
- How does the approach for employees and spouses compare between contributions and wellness credits?

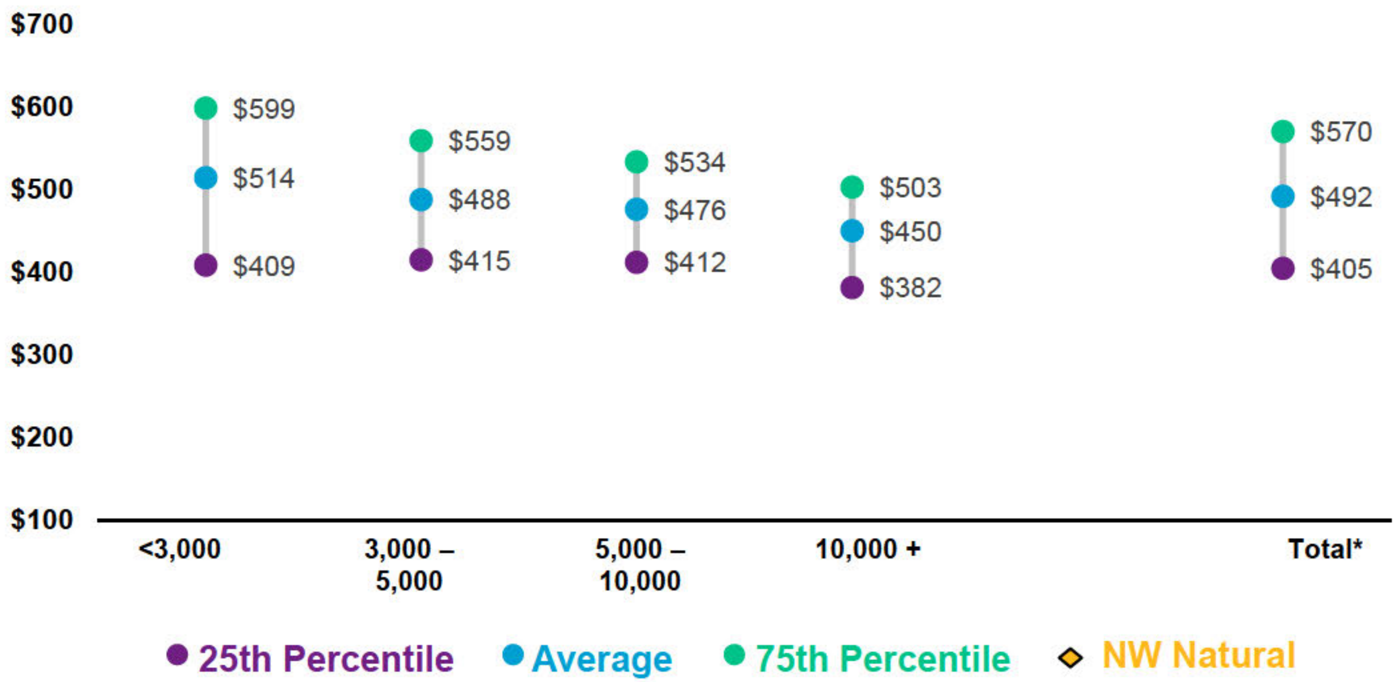


Maximum wellness account deposits and contribution credits average $525 and $564 for employees and $353 and $310 for spouses.

Medical Cost Benchmarks

Annual Self-Insured Administration Fees by Covered Employee by Employer Size*

? How do NW Natural's administration fees compare to the database? What is contributing to the company's variance from average? Number enrolled? Number of vendors?



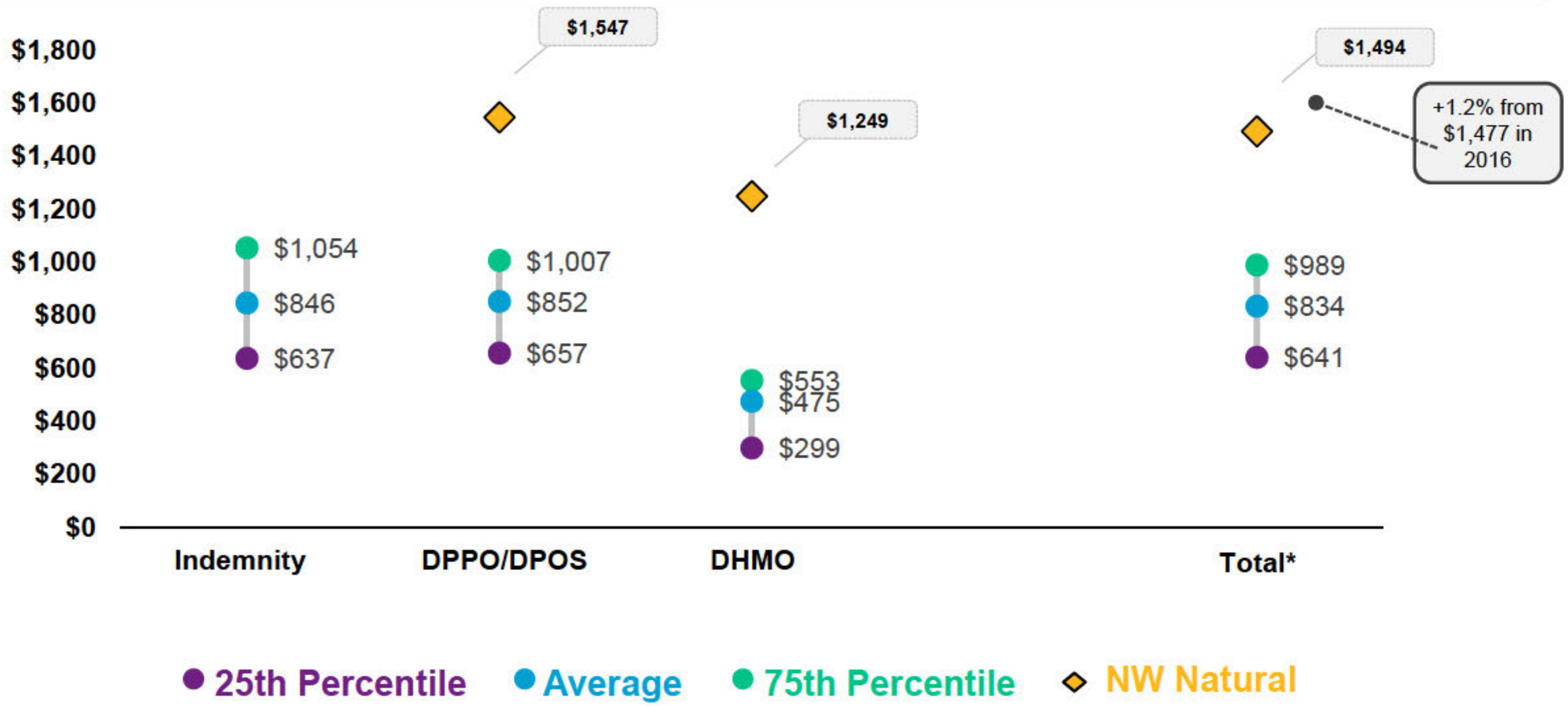
Not applicable.

*Results by employer size for companies with self-insured arrangements.

Dental Cost Benchmarks

Dental Cost Benchmarks Total Cost per Covered Employee per Year (Unadjusted)

- How do NW Natural's plan costs compare to the database?
- How do costs vary by plan type?

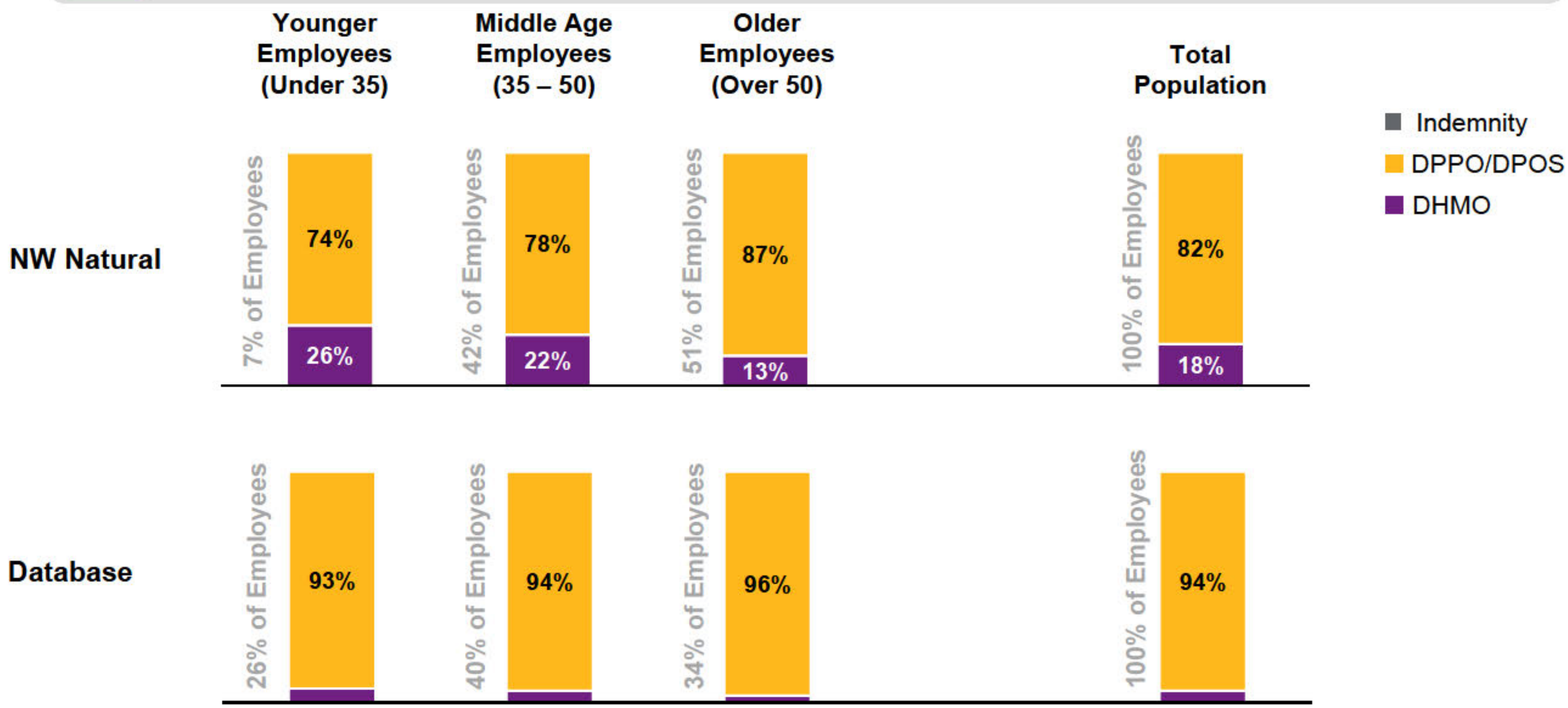


NW Natural's dental costs are 79% higher than database average. DHMOs are the lowest-cost delivery system.

*Total costs represent an enrollment weighted average of plan types.

Dental Cost Benchmarks Enrollment by Plan Type and Age Breakdown

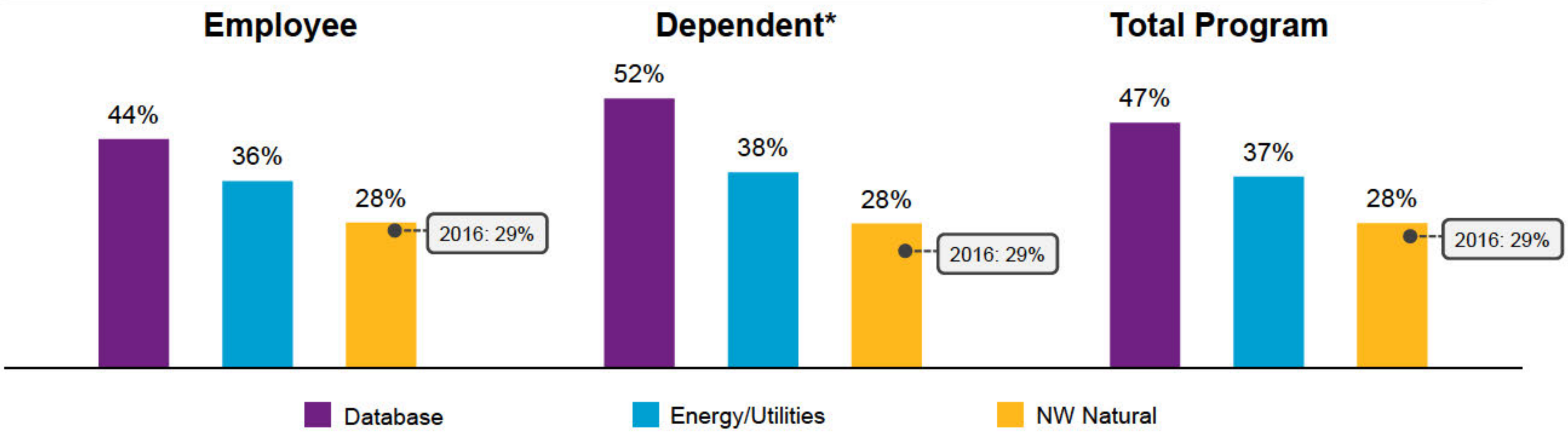
How is enrollment distributed by age and plan?



The majority of employees in the database are enrolled in DPPO/DPOS dental plans.

Dental Cost Benchmarks Employee Contributions as a % of Plan Cost

How do employee contributions as a percentage of plan cost compare to the database benchmarks?



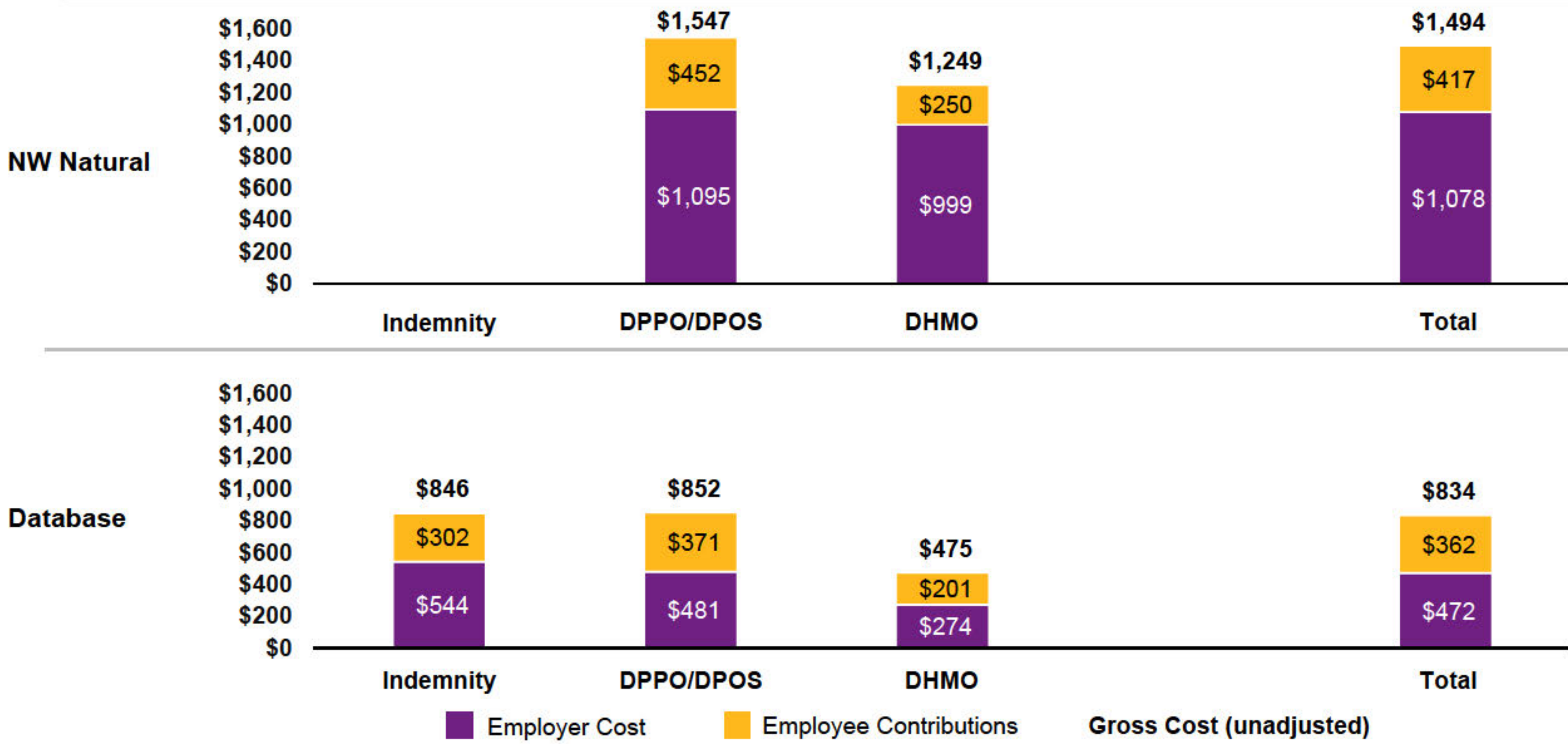
Employee Contributions as a % of Total Cost	Indemnity	DPPO	DHMO
NW Natural	N/A	29%	20%
Database	39%	48%	47%

Across NW Natural's total program, contributions as a percentage of total cost are less than the database and industry averages.

*Dependent includes spouse, children, family, etc.

Dental Cost Benchmarks Employee Cost-Sharing — Net Cost Analysis

? How do NW Natural's employees' payroll contributions vary across plans?



On average, NW Natural's employees pay $55 more per year than the database.

Dental Cost Benchmarks

Annual Self-Insured Administration Fees per Covered Employee by Employer Size*

How do administration costs compare to the database benchmarks?

Not applicable.

*Results by employer size for companies with self-insured arrangements.

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

April 20, 2018

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

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. My testimony addresses issues related to plant investments, affiliated interests, revenue, and decoupling.

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to this testimony, I prepared the following exhibits:

Staff/701.. Witness Qualification
Staff/702...Data Requests
Staff/703.................................Confidential Data Requests
Staff/704......................................MWVF Alternatives Cost
Staff/705.................................Capital Spending Summary
Staff/706...................................... Woodburn Public Works
Staff/707..............................Non-Bare Steel Replacement
Staff/708...................... Business Services Operating Ratio
Staff/709..Officer Non-Utility Time
Staff/710... Insurance Allocations
Staff/711..................................Pages from nwnatural.com
Staff/712.............................GeoEngineer Article on MWVF
Staff/713.....................Contemporary Project Management
Staff/714...Non-Utility O&M Costs
Staff/715.......................................Staff Revenue Forecast

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What do you propose in this testimony?

A. I propose the following rate related adjustments:

- Reduce rate base by $20.2 million for Mid-Willamette Valley Feeder
- Reduce rate base by $14.1 million for Corvallis Loop
- True up depreciation expense for rate base reductions
- Reduce expenses by $5.541 million for allocation adjustments
- Increase revenue by $2.329 million for revenue forecast

I also make the following recommendations:

- Staff should continue to review other distribution mains investments
- NW Natural should improve descriptions in project records for distribution mains investments
- The Commission should decline NW Natural's proposal to modify its decoupling mechanism by:
  - Changing the weather adjustment
  - Decoupling large commercial firm sales customers
  - Creating separate groups for each decoupled schedule
- The Commission should adopt NW Natural's decoupling proposals to:
  - Update use per customer
  - Update WARM parameters
- The Commission should adopt Staff's recommendation to:
  - Limit decoupling to the number of customers forecasted in the rate case

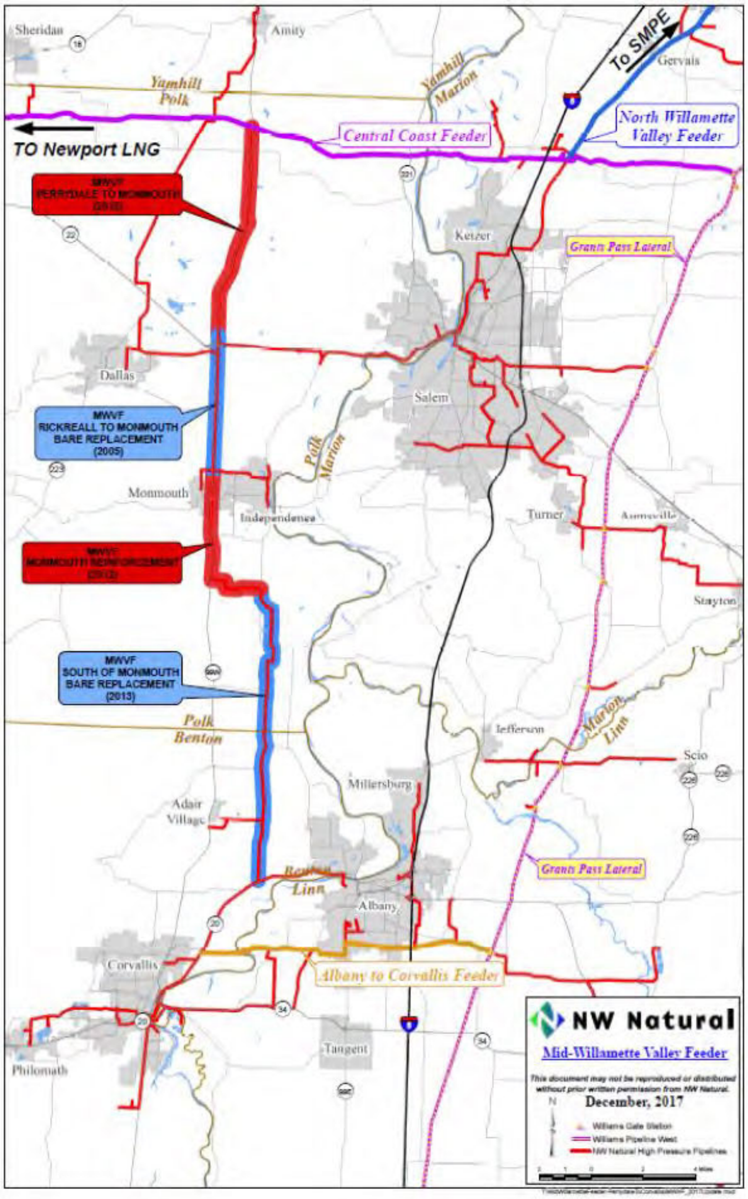
ISSUE 1. MID-WILLAMETTE VALLEY FEEDER

Q. Please summarize this issue.

A. The Mid-Willamette Valley Feeder (MWVF) was a four-phase project undertaken by NW Natural Gas Company (NWN or the Company) between 2005 and 2014 to construct a 12-inch pipe between the central coast feeder west of Salem and the Albany/Corvallis distribution system. The four phases of the MWVF were (1) Rickreall to Monmouth Bare Replacement (completed 2005), (2) Perrydale to Rickreall (completed 2012), (3) Monmouth Reinforcement (completed 2012), and (4) South of Monmouth Bare Steel Replacement (completed 2014).[1] The Commission previously authorized NWN to include the cost of Rickreall to Monmouth Bare Steel Replacement and South of Monmouth Bare Steel Replacement phases into rate base under NWN's now terminated Bare Steel Program and System Integrity Program (SIP).[2] NWN has not yet been authorized to recover the costs of the Perrydale to Rickreall or Monmouth Reinforcement phases in rates.

[1] There is an additional phase identified in UG 221 as "Willamette Crossing" that Staff is continuing to investigate. The status of this phase is discussed later in this section.
[2] Staff/702, Kaufman/96, NW Natural's Response to OPUC DR 292.

Figure 1. Mid-Willamette Valley Feeder NW Natural/800, Karney/5



In NW Natural Gas Company's last rate case Docket No. UG 221, NWN requested that investment in the Perrydale to Monmouth and Monmouth Reinforcement phases be incorporated into base rates. In support of this request, NWN claimed that the MWVF:

1. Addressed capacity limitations of the Corvallis-Albany feeder;

2. Replaced bare steel; and
3. Extended system storage delivery capability from Newport and Mist to Corvallis, thereby reducing the risk of a Northwest Pipeline[3] outage.[4]

The Commission concluded that NW Natural failed to demonstrate that the MWVF was needed for capacity or reliability and accordingly, that NWN's decision to construct the two phases at issue in the rate case was imprudent. The Commission declined to allow NWN to include costs for the Perrydale to Monmouth and Monmouth Reinforcement phases of the MWVF in rates.[5]

Staff has reviewed both the evidence from Docket No. UG 221 and the evidence and arguments in this case. NW Natural did not provide analysis of alternatives to the MWVF in Docket No. UG 221 nor in this case. Staff's analysis reveals options that would have been less expensive than the total cost of the MWVF that NW Natural is requesting to include in rates. Accordingly, Staff maintains its previous position regarding the prudence of the MWVF and recommends the Commission conclude that MWVF remains an imprudent investment.

Q. What standard did the Commission establish for reconsideration of the MWVF?

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[3] The Northwest Pipeline is the main interstate gas transmission line that supplies natural gas to NW Natural. This pipeline is discussed in more detail later in this testimony.
[4] UG 221 NWN/600, Yoshihara/5-6.
[5] *In the Matter of Northwest Natural Gas Company, dba, NW Natural, Request for a General Rate Revision,* UG 221, Order No. 12-437, p.16.

A. The Commission said the following:

> Our conclusion here – that the company has failed to demonstrate the prudence of the project – is based on the company's assertion that the project is currently needed for reliability purposes. If facts change, if, for example, the incremental loads in the area start growing faster, and the company makes an evidence-based showing of need, we would be willing to consider the depreciated costs of the project for inclusion in rates on an alternative basis.[6]

Q. Does the Company identify need or provide any alternatives analysis of the MWVF in this docket?

A. The Company testimony identifies a minor reliability need in the Monmouth-Independence area, but includes no alternatives analysis or cost benefit analysis.

Q. What is the normal approach to prudence evaluations?

A. Prudence generally has the following components:

1. Was the decision to invest prudent, given the information available at the time of the investment?
2. Was the project prudently managed?

The Commission has explained how these components are related:

> Prudence in planning and constructing a plant is relevant for determining the valuation of the facility once placed in rate base. If a plant shown to be used and useful was constructed at an unnecessarily high cost, only the cost deemed appropriate rather than actual historical cost would be placed in rate base. In this review, therefore, we must determine whether [the utility's] actions or decision based on what it knew or should have known at the time, were prudent in light of existing circumstances. This analysis includes a review of not only the company's

[6] Order No. 12-437, p. 18.

> decision to make an investment, but also to the amount of money it decided to invest. Expenditures found excessive, unaccounted for, or caused by lack of foresight should be deemed imprudent and disallowed.[7]

Q. What is Staff's proposed framework for evaluating the prudence of the MWVF?

A. This issue is unique because:

1. The Commission has already deemed the MWVF to be imprudent given the information available when the investment was made.
2. The data necessary to evaluate the prudence of the MWVF is not available. NW Natural has been unable to provide either the project documents or the forecasted or actual costs for the first phase of the MWVF, Rickreall to Monmouth.[8]

Item one above means that the prudence of the initial decision is no longer relevant. Item two above means we cannot evaluate the management or costs of the earliest portions of the investment. In place of the normal prudence questions, Staff proposes a counter-factual framework for evaluating this project. The counter-factual framework will test the forward-looking costs of the investment against the cost of the alternatives that could have meet the system need.

Q. What were the forecasted and actual costs of the MWVF?

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[7] *In the Matter of Application of Northwest Natural Gas Company for a General Rate Revision,* UG 132, Order No. 99-697.

[8] Staff/702, Kaufman/96 and 97, NW Natural's Response to Staff DRs 292 and 293.

A. The table below provides the forecasted and actual cost of the MWVF by section:

	Forecast	Actual[9]
Perrydale to Monmouth	$13,500,000	$14,161,979
Rickreall to Monmouth	Unknown	Unknown
Monmouth Reinforcement	$8,100,000	$10,056,777
South of Monmouth	$14,300,000	$29,170,312
Willamette Crossing	Unknown	Cancelled?
Total	$35,900,000	$53,389,068

As already noted, NW Natural was not able to locate forecasted or actual costs for the Rickreall to Monmouth section.[10] For the purpose of Staff's analysis, Staff assumes that it is equal to the average cost of $2 million per mile,[11] for five miles, or $10 million. Staff is continuing to investigate the status of the final leg of the MWVF, the "Willamette Crossing." This leg is discussed in more detail later in this testimony.

<u>Current System Needs and Alternative Solutions</u>

Q. How does the MWVF benefit the system?

A. Northwest Natural claims that:

[9] There is a small discrepancy between the costs in NW Natural/800, Karney/10 and NW Natural's response to Staff DR 293. See Staff/702, Kaufman/97, NW Natural's Response to Staff DR 293. NW Natural reconciles these differences in Staff/702, Kaufman/126, NW Natural's Response to Staff DR 353 Attachment 1.
[10] Staff/702, Kaufman/97, NW Natural's Response to Staff DR 293.
[11] Staff/702, Kaufman/14, NW Natural's Response to Staff DR 162.

1. The Company would not be able to serve Monmouth-Independence load requirements at peak times without the MWVF.[12]
2. The MWVF provides backup supply for the Albany-Corvallis Feeder.[13]
3. The MWVF allows gas to flow from Newport to Albany.[14]

In this testimony Staff shows that:

1. Monmouth-Independence load requirements could have been met with a 4-inch rather than 12-inch pipe.
2. The MWVF is incomplete, is an unreliable backup for the Albany-Corvallis Feeder, and more reliable, less expensive alternatives exist.
3. Gas does not flow from Newport to Albany in realistic models of Company operations.

<u>Serve Peak Loads in Monmouth Independence</u>

Q. What system needs does the MWVF serve related to peak load?

A. The only system need that NW Natural identifies is a reliability need in the Monmouth-Independence distribution area. NW Natural demonstrates a system need by analyzing at-the-meter pressures during an extreme cold event if the MWVF were absent from the distribution system.

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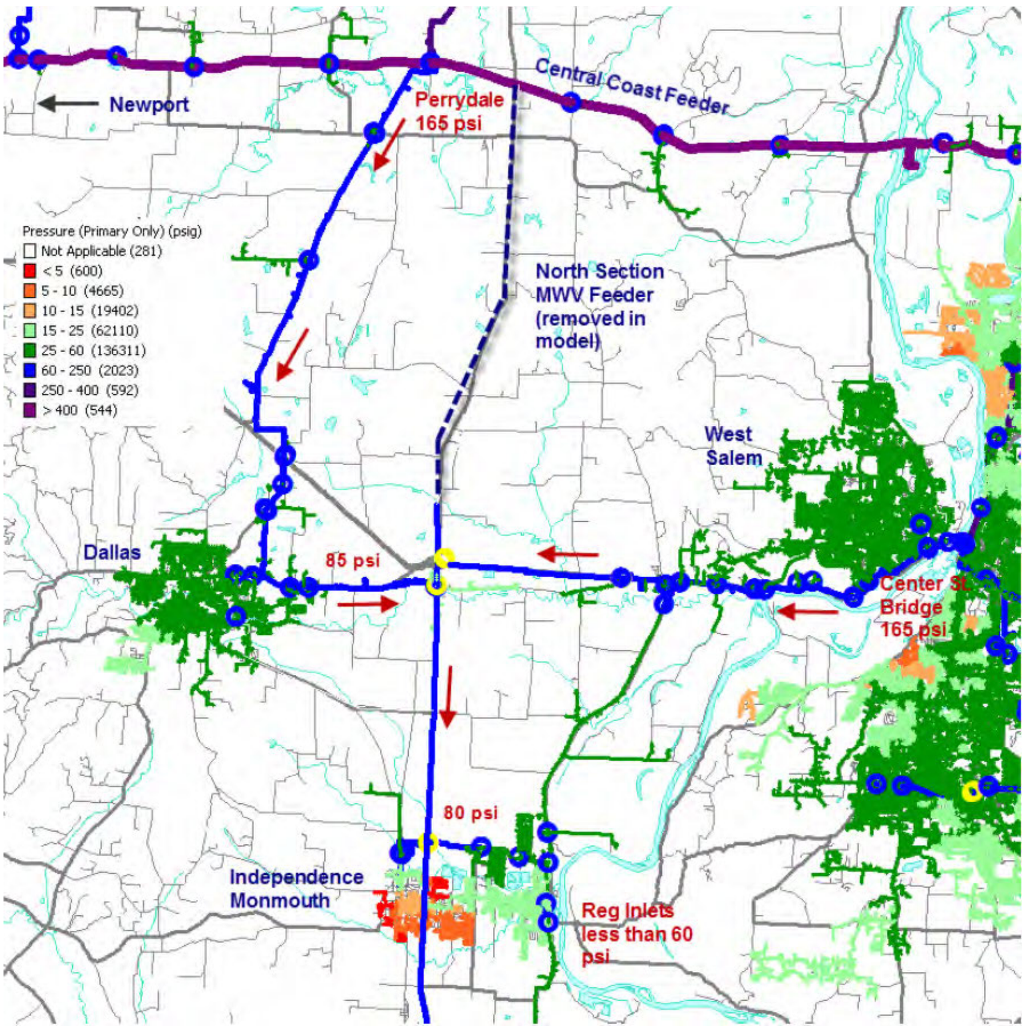
[12] NW Natural/800, Karney/10.
[13] NW Natural/800, Karney/11.
[14] NW Natural/800, Karney/11.

NW Natural found that a small area in Monmouth-Independence would have unreliable low pressure in this scenario. This finding is reflected in the red portions of the figure below,[15] which indicate that during peak weather and absent the MWVF Monmouth would experience unreliably low pressures in some locations.

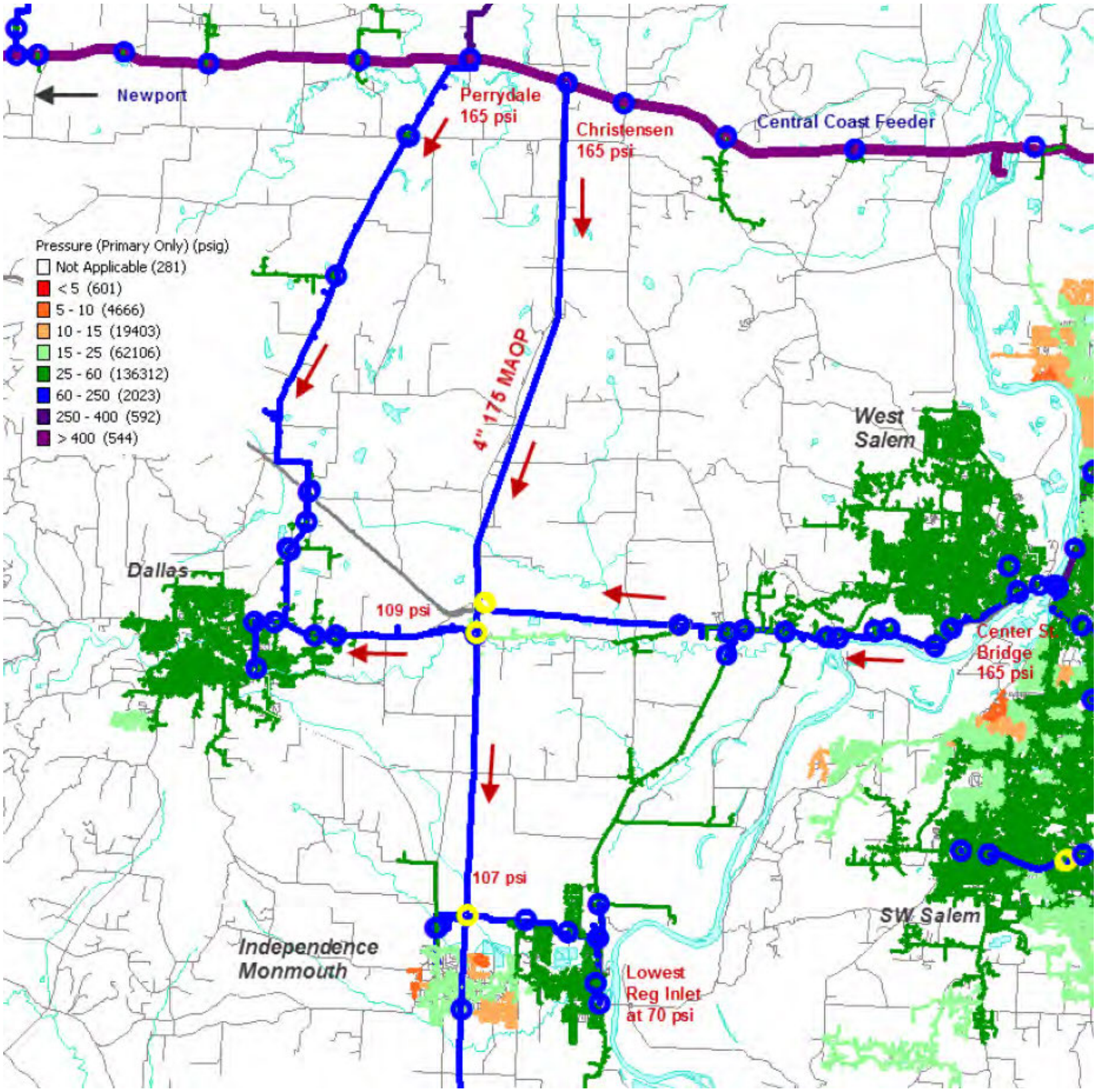


[15] NW Natural/800, Karney/14.

Q. Was a 32-mile 12-inch transmission pipe required to serve this need?

A. I am not aware of any other instance of meeting such a small need with such a large investment. NW Natural could have met this need with an eight-mile long 4-inch pipe. The figure below provides the peak day distribution pressure model results with a 4-inch line replacing the MWVF up to Monmouth.[16] Notice that this figure has no red sections, indicating sufficient pressure. This shows that the Monmouth-Independence reliability need identified in NW Natural's testimony as supporting the MWVF could have been met with a much smaller investment in a shorter 4-inch pipe.

[16] Staff/702, Kaufman/16, NW Natural Response to OPUC DR 163.



<u>Backup feeder for Corvallis-Albany</u>

Q. What system need is underlying the use of the MWVF as a backup feeder for Corvallis-Albany?

A. The Company claims that the MWVF provides backup service to the Albany-Corvallis area in the event that there is an outage at the Albany gate station or an outage upstream of the pipeline feeding the Albany gate station.[17] This is the same argument the Company made in Docket No. UG 221.[18]

Q. Please explain why an outage upstream of the Albany gate station is a concern for Albany gas reliability.

A. NW Natural's system is fed by the Northwest Pipeline ("NW Pipeline"). The figure below identifies the NW Pipeline.

[17] NW Natural/700, Karney/17.
[18] Docket No. UG 221, NWN/600, Yoshihara/6.

Source: Northwest Gas Association, 2015 Gas Outlook

The red spur extending south through the Willamette Valley is called the Grants Pass Lateral. Albany is served by a gate station on the Grants Pass Lateral. If there is a problem on the Grants Pass Lateral or on the NW Pipeline than NW Natural could experience difficulty moving gas to anywhere "down-stream" of the problem.

Q. How did the Commission respond to the single-feeder reliability need proposed by NW Natural?

A. The Commission has previously rejected this argument, stating:

> The company conducted no comprehensive cost-benefit analysis of whether and when the [MWVF] should be built. It failed to evaluate a range of alternative build dates and its impact on reliability and customer rates, and offered no credible evidence on the likelihood of disruptions based on the historical experience on the Grants Pass Lateral. The company offered no evidence on the range of possible reliability incidents. It offered no evidence about projected loads and customers in the area. Nor did it adequately consider alternatives, including the use of interruptibility or increased demand-side measures to improve reliability and system resiliency.[19]

Q. How has the Company remedied any of the concerns raised by the Commission in Order No. 12-437?

A. The Company has not addressed any of the concerns raised by the Commission regarding this argument.

Q. How likely is an outage upstream of Albany gate station?

A. NW Natural identifies two outages upstream of Albany gate station since 1930, one in 1938 caused by a road construction crew and once in 1952 caused by a log truck.[20] This suggests that the probability of an outage is something less than once every 44 years. NW Natural admits to having no knowledge of the probability of an outage.[21]

[19] Order No. 12-437, p. 16.
[20] Staff/702, Kaufman/24, NW Natural Response to OPUC DR 166.
[21] Staff/702, Kaufman/22, NW Natural Response to OPUC DR 164.

Q. Does Staff agree that there is a substantial reliability risk if Albany-Corvallis is a single feed system?

A. Staff does not see a substantial reliability risk in Albany. There is a small possibility of an extreme event that would cause outages in Albany-Corvallis, but the probability of such an event is so small that it is more than twice as extreme as the most extreme events considered in NW Natural's IRP (substantially less than one in 44 verses one in 20 for peak weather). While reliability is important, it is impossible to be 100 percent reliable and there is a tradeoff between reliability and cost. Furthermore, Eugene customers experience as many service losses as Albany in the event of a pipeline interruption.[22] However, the Company does not appear to have a similar concern with reliability in Eugene.

Q. What effect does the MWVF have on reliability in Albany-Corvallis in the event of an outage on upstream of the Albany Gate Station?

A. The Company's filing includes no evidence that the MWVF provides any additional reliability in the event of an outage on the Northwest Pipeline or the Grants Pass Lateral. I have requested modeling of the Albany-Corvallis area under an outage of the Grants Pass Lateral. NW Natural was not able to provide pressure modeling of this

[22] Staff/702, Kaufman/36, NW Natural First Supplemental Response to OPUC DR 167.

scenario. However, NW Natural did provide an approximation based on the number of residential customers served in the region.[23] During any weather colder than 40 degrees, Albany continues to experience significant service loss.[24] While the MWVF does connect Albany to the Newport liquefied natural gas (LNG) facility, this does not provide reliability to Albany in the event of a NW Pipeline outage. This is discussed further in the following section on Newport LNG.

Q. How does the MWVF affect reliability in the event that there is an Albany Gate Station outage but the Grants Pass Lateral remains in Service?

A. In response to a Staff DR, NW Natural provided pressure modeling showing that the MWVF eliminates service loss if there is an Albany Gate Station outage during temperatures above 40 degrees. However, during periods with temperatures below 40 degrees, the distribution system was so stressed that NW Natural was not able to model customer service loss. NW Natural estimates that even with the MWVF, about 25 percent of customers in Albany would lose service in the event of an Albany Gate Station loss during normal winter weather.[25]

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[23] Staff/702, Kaufman/36, NW Natural First Supplemental Response to Staff DR 167.
[24] Staff/702, Kaufman/36, NW Natural First Supplemental Response to Staff DR 167. This response indicates no outage during warm weather. Without actual modeling of the Company's system this can't be verified. Staff suspects that there continues to be widespread outages even during the summer.
[25] Staff/702, Kaufman/25, NW Natural's Response to OPUC 167 part a.

Q. Why does Albany continue to lose service when there is an Albany gate station outage even with the MWVF in service?

A. While the MWVF is a large 12-inch diameter pipe, which should be sufficient to serve normal winter loads in Albany, the MWVF ties into the Albany-Corvallis system through a 6-inch pipe. The 6-inch pipe acts as a constriction point that eliminates most of the capacity of the 12-inch MWVF.[26] This is similar to attaching a garden hose to the end of a fire hose. NW Natural originally planned to tie the 12-inch pipe to the 10-inch Albany-Corvallis feeder via a fifth leg, the Willamette Crossing.[27] Work on this section of the project began in 2012.[28] NW Natural does not discuss the Willamette Crossing component of the MWVF in opening testimony or in response to any MWVF data requests. The Willamette Crossing is not included in NW Natural's Synergy distribution models, suggesting that it was never completed.

Q. What alternatives are there to the MWVF to protect Albany in the event that the gate station fails?

A. One alternative is to improve maintenance at the gate station. Many of the causes of gate station outages identified by NW Natural could be prevented with additional maintenance.[29] Another alternative would

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[26] Staff/702, Kaufman/133, NW Natural Response to Staff DR 366, Attachment 1.
[27] Docket No. UG 221, NWN/600, Yoshihara/5. Staff/702, Kaufman/84, NW Natural Response to Staff DR 239 Attachment 5 shows the Willamette Crossing tying the MWVF to the Albany Corvallis Feeder and the Corvallis Loop.
[28] Staff/712, https://www.geoengineers.com/news/delivering-more-natural-gas-capacity-to-oregons-willamette-valley/
[29] Staff/702, Kaufman/22, NW Natural Response to Staff DR 164.

be to enhance the gate station with redundant systems, such as redundant compressors. A third alternative would be to build a second gate station in the Albany area and connect it to the Albany feeder rather than rely on a 30-mile pipeline. All three of Staff's alternatives would prevent the widespread outages that continue to be a risk with the MWVF.

Delivery Capability for Newport LNG

Q. In what situations does the MWVF provide delivery capability for Newport LNG?

A. The MWVF only provides delivery capability for the Newport LNG for times and situations that it is typically not needed. The Newport LNG facility was not sized to support all of Lincoln County, Salem, and Albany-Corvallis. The peak winter load in Salem alone far exceeds the Newport LNG vaporization capacity. Because of this there is no additional capacity value added to NW Natural's system by having delivery capability to Albany.[30]

In the event that NW Natural is capacity restrained on the Grants Pass Lateral and NW Natural needs to dispatch LNG, NW Natural can use all of the Newport LNG facility to service Salem and continue to meet Albany's load with the Grants Pass Lateral.

[30] This is achieved by dispatching Newport LNG to serve Salem and utilizing the freed up NW Pipeline capacity to deliver gas to Albany. This may require increasing the meter capacity of the Albany gate station.

If the Albany gate station is out of service and weather is mild, gas can flow from upstream Grants Pass Lateral gate stations to Albany and there is no need to dispatch Newport.[31] If weather is severe, Albany continues to experience 25 percent outages.

If the Grants Pass Lateral is out of service the Newport facility is unable to support Albany, Salem and Newport simultaneously. During any weather colder than 40 degrees Albany continues to experience significant service loss.[32] During warm weather the Newport LNG storage is not prepared for vaporization and requires hours advance notice to prepare for vaporization.[33] In the event there is a summer outage, during which time the Newport LNG facility is generally not vaporizing, all customers in the area would continue to lose pressure soon after the outage. Even if the LNG facility came on line, it would take several months before restoring gas service due to the need for NW Natural to visit every location that lost pressure prior to restarting service.[34]

<u>Costs of MWVF vs Alternatives</u>

Q. What was the total cost of the MWVF?

[31] If NW Natural had built a second gate station at Albany rather than the MWVF, there would be a similar result during mild weather, but without the large expense of the MWVF.
[32] Staff/702, Kaufman/36, NW Natural First Supplemental Response to Staff DR 167.
[33] Staff/702, Kaufman/36, NW Natural First Supplemental Response to Staff DR 167. This response appears to be a rough estimate. It is possible that the service loss in Albany would be much higher than indicated in the response.
[34] Staff/702, Kaufman/22, NW Natural Response to Staff DR 164 parts d and e.

A. NW Natural was not able to identify the cost of one leg of the MWVF. As noted above, Staff estimates the total cost to be $63.4 million. However, full utilization of the MWVF will require utilization of the Newport Refurbishment ($26 million), the completion of the Willamette Crossing (about $10-15 million), and the construction of the Christenson Compressor Station (about $30 million), for a total cost of $129 – 133 million dollars.[35]

Q. What alternatives could have served the need that NW Natural has identified and that the MWVF currently serves?

A. As shown in the testimony above, the only real reliability benefit that the MWVF provides is to Monmouth. This need could have been met with an 8-mile long 4-inch diameter pipe. To account for future Monmouth growth a 6-inch pipe may have also been a reasonable option. In addition, the South of Monmouth bare steel would still need to be upgraded to meet Oregon's bare steel replacement goals. The south of Monmouth pipe was predominantly 6-inch pipe. NW Natural has no documentation explaining why the south of Monmouth bare steel replacement was up-sized to 12-inch pipe. Therefore a reasonable alternative to the MWVF is a 6-inch pipe of same length as the MWVF, 31.6 miles.[36]

[35] NW Natural's 2016 Integrated Resource Plan 3.36.
[36] Staff is continuing to investigate which portions of the South of Monmouth project were bare steel. It is possible that only a portion of the South of Monmouth project was bare steel. If this is the case the alternative would be reduced by the amount of non-bare steel replaced in the South of Monmouth project.

This testimony has already shown that there is no substantial benefit of the MWVF to Albany in the event of a pipeline outage. Staff has also shown limited benefit in the event of an Albany gate station outage.

Q. If the Commission does want to consider an alternative to mitigating the single feed risk at Albany Corvallis, what additional alternative would you recommend considering?

A. A reasonable solution to the risk of an Albany gate station outage is to add a second gate station close to Albany.

Q. What is a reasonable costs estimate for the 6-inch MWVF?

A. The Interstate Natural Gas Association of America estimates distribution pipe costs of 6-inch gathering lines at $24,892 per inch mile. An inch-mile is the cost per inch of diameter per mile, so the per-mile cost of a 6-inch pipe would be $145,000. At 31 miles the total cost would be approximately $4.6 million.[37]

Gathering Line Costs

Diameter (Inches)	Gathering Line Costs (2012$/inch-mile)
1	$46,228
2	$34,671
4	$28,892
6	$24,164
8	$25,215
10	$39,398
12	$68,291
14	$110,316
16	$122,135

[37] Staff/704, Cost of Alternative to MWVF.

Q. What does NW Natural claim to be the cost of installing 12-inch pipe and 6-inch pipe?

A. NW Natural claims that the average installed cost of 12-inch pipe is $289 per foot while the average installed cost of 6-inch pipe is $242 per foot. However, this is not consistent with the either the installed cost data for actual projects or the built up cost of pipe plus directional drilling. The cost of 12-inch steel pipe is $47 per foot compared to $20 for 6-inch pipe. Boring costs for 12-inch pipe is $220 per foot compared to $90 for 6-inch.[38] In addition, 12-inch pipe requires more trenching, more backfill, more welding, and larger equipment.

Average Cost per Foot	
4"	$234
6"	$242
8"	$360
10"	$771
12"	$289

Figure 2. Response to OPUC DR 298

Q. Does NW Natural suggest why 12-inch pipe may have a similar cost as a 6-inch pipe?

A. NW Natural indicates that the percent of projects using directional drilling accounts for the apparent low cost of the 12-inch projects. It may be more appropriate to split this table into two parts, one for directional drilling and one for open trench. However, even using the

[38] Staff/702, Kaufman/127, NW Natural Response to Staff DRs 354 and 355.

average cost for a 6-inch pipe supports an ongoing finding that alternative is less expensive than the MWVF.

Q. What evidence is there that for similar construction methods and environments, 6-inch pipe is substantially less expensive to install than 12-inch pipe?

A. The directional drilling cost of 6-inch pipe is $90-$125 per foot. The cost of directional drilling 12-inch pipe is $220-$260, nearly two and a half times the cost of 6-inch pipe.[39] For a 31.6-mile directional-drilled pipeline this would represent a $21.7 million dollar cost savings.

Q. What is Staff's cost estimate if the MWVF had been built with 6-inch pipe?

A. Using NW Natural's 6-inch cost of $242 per foot would result in a total cost of $40.4 million.[40] Using INGAA's 6-inch cost would result in a total cost of $4.6 million.[41] These two values constitute the high and low range estimate of Staff's alternative pipeline cost. This estimate does not account for the miles south of Monmouth that were not bare steel and did not need replacement.

Q. What is the cost of a backup gate station for Albany?

A. A backup gate station would cost $1-2 million.[42] Staff does not agree that there is a need for a backup gate station at Albany. However,

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[39] Staff/702, Kaufman/128, NW Natural's Response to Staff DR 355.
[40] Staff/704, Cost of Alternative to MWVF.
[41] Staff/704, Cost of Alternative to MWVF.
[42] Staff/702, Kaufman/14, NW Natural's Response to Staff DR 162.

even including the cost of the backup in the alternatives analysis does not alter Staff's recommendation to exclude the incremental rate base of the MWVF.

Q. What is the net capital for the MWVF as it was built?

A. Staff has not found an exact number for the total accumulated depreciation for the MWVF, nor an exact cost for the Rickreall to Monmouth section. However, under reasonable assumptions the test year net book value will be $50.2 million. Of this amount $30 million is currently in NW Natural rate base due to bare steel programs.[43]

Q. The MWVF has already experienced substantial depreciation. How can the cost of an existing pipe be compared with a new pipe that would last longer in the ground?

A. One simple approach is to apply the same ratio of net book value to original cost as exists for the MWVF. This ratio is about 81 percent for the MWVF as built. Adjusting the cost of Staff's alternative, which includes a backup Albany gate station, by the same amount results in an alternative cost of $33.7 million.[44]

Q. What is your recommendation regarding the MWVF?

A. The total cost of the MWVF alternative discussed above is close to the amount already in rates (within $3.5 million), and Staff's alternative is

[43] This figure is a rough estimate based on the depreciated value of the portions of the MWVF that NW Natural is requesting to bring into rates. It is not based on NW Natural's actual plant records. Staff is continuing to investigate the depreciated cost of the MWVF that is currently in rates.
[44] Staff/704, Cost of Alternative to MWVF.

based on conservative assumptions, i.e., installing the full length of the MWVF with 6-inch pipe rather than installing a 4-inch pipe from Perrydale to Rickreall, and replacing only bare steel for the remainder of the project, which would result in fewer miles of pipe. Furthermore, Staff's alternative provides more reliability in the event of a gate station outage. Accordingly, Staff recommends not allowing any of the amounts previously found imprudent into rates, which means removing the proposed incremental costs of the MWVF from rate base in this case. This results in a reduction to NW Natural's filed rate base of $20.2 million.

ISSUE 2. CORVALLIS LOOP

Q. Please summarize this issue.

A. The Corvallis Loop is a ten-mile long, 12-inch diameter high-pressure distribution line tying the existing Corvallis feeder to the OSU Energy Center.[45] In Docket No. UG 221 NW Natural proposed adding the Corvallis Loop into rates at a forecasted cost of $12.8 million.[46] The actual cost of the Corvallis Loop was $28.4 million. In UG 211 Staff supported the inclusion of the Corvallis Loop into rates, however, the project was not completed in time to be used and useful before rates went into effect. The Corvallis Loop was ultimately not included in rates in UG 221.

NW Natural proposes to bring this project into rate base in this case. However, Staff has the following concerns:

1. NW does not demonstrate a current reliability need for this project;
2. Corvallis Loop was built to serve OSU;
3. NW Natural did not charge the OSU Energy Center for the amount of this project exceeding the OSU Energy Center line extension allowance;
4. NW Natural did not provide alternatives analysis for this project;

[45] Staff/702, Kaufman/161, NW Natural's Response to Staff DR 367 Attachment 1.
[46] UG 221 NWN/600, Yoshihara/4.

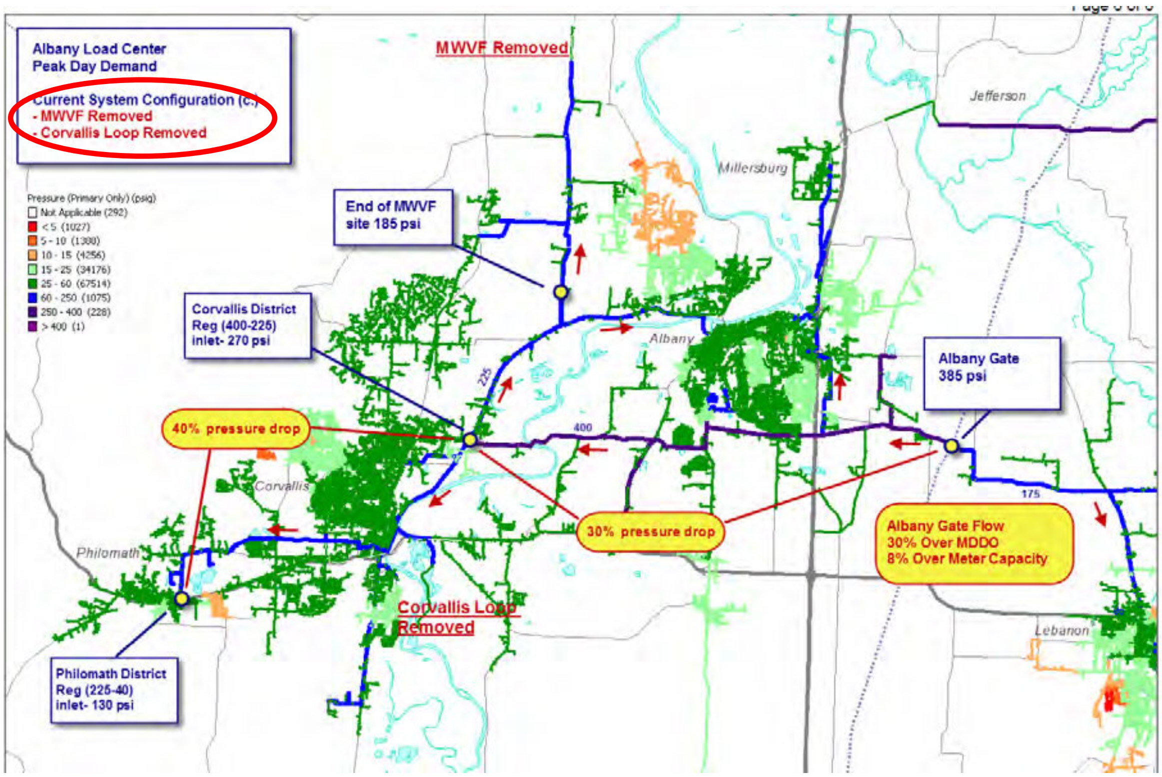
5. The final project cost was \$28.4 million, which is \$15.6 million higher than the forecasted cost that Staff supported in Docket No. UG 221.[47]

Based on these concerns, Staff recommends including only the amount previously recommended by Staff of \$12.8 million, net of a proportionate amount of depreciation.

<u>No Reliability Benefit</u>

Q. Please describe the reliability need that NW Natural claims this project supports.

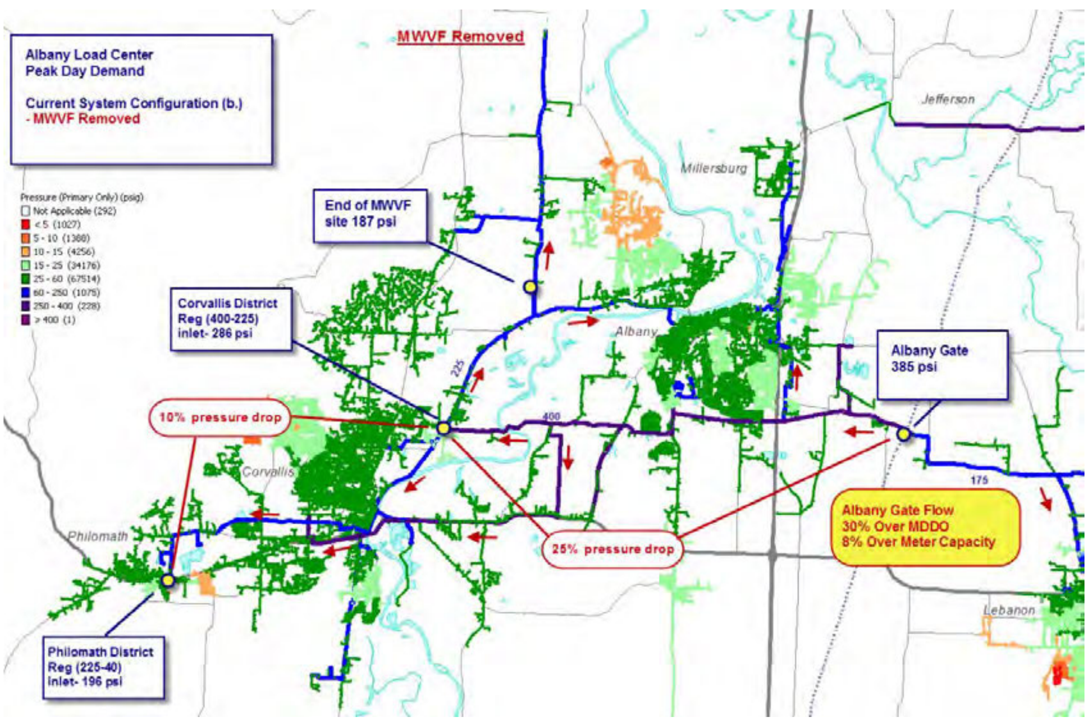
A. NW Natural shows that the Corvallis transmission mains have substantial pressure drops during cold weather. However, NW Natural provides no evidence that this translates into low pressures at the



[47] Staff/702, Kaufman/160 NW Natural's Response to Staff DR 367.

customer meters. At Staff's request NW Natural modeled actual system reliability at customer meters absent the Corvallis Loop, which is where low pressure actually can cause reliability problems. There are no red distribution areas in Corvallis with the Corvallis Loop removed. The results indicate that even without the Corvallis Loop, Corvallis is one of the most reliable parts of NW Natural's system. Nearly all of Corvallis is at normal pressure during peak weather, and none of Corvallis is below five psi.[48]

More importantly, the addition of the Corvallis loop has *no effect on reliability!* The figure below shows that Corvallis has the same distribution pressure with and without the Corvallis loop.



[48] Staff/702, Kaufman/99, NW Natural's Response to OPUC DR 295. This data response does indicate pressure drops at some high-pressure regulators, however NW Natural provides no evidence that these pressure drops negatively affect customer reliability.

Corvallis Loop was Built to Serve OSU

Q. If the Corvallis Loop provides no system reliability benefit, why was this pipeline built?

A. This pipeline was built to serve the Oregon State University (OSU) Energy Center. In UG 221 NW Natural stated that it needed the Corvallis Loop because it interrupted interruptible customers every winter. This may sound like the system was stressed, however the figures above show that the system was not stressed. The problem is that Corvallis had a very large interruptible customer, OSU. The system was only stressed when the interruptible customer was using gas. Interruptible customers do not pay capacity costs and therefore should not be a justification for distribution improvements.

- On April 1, 2010, NW Natural sent OSU an out of cycle transfer from interruptible to firm service.[49] The document was not signed by OSU.
- On May 8, 2010, NW Natural developed a project proposal to bring a 12-inch pipe directly to the OSU Energy Center.[50]
- On June 2010, the OSU Energy Center became fully operational.
- In June, 2011 NW Natural executives and directors signed a project charter with:

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[49] Staff/702, NW Natural Response to Staff DR 351 Attachment 3.
[50] Staff/702, NW Natural Response to Staff DR 351 Attachment 1 states that the Corvallis Loop project will "end in Corvallis by OSU on SW 35th."

- A project description to build a 12-inch pipe that ends at "the Campus Energy Center at Oregon State University located on SW 35th Ave in Corvallis, Oregon."[51]
- A project objective "To supply additional capacity and support the increasing demand of natural gas fuel consumption at the Oregon State University Energy Center."[52]
- A business case stating "This project will provide additional reinforcement to OSU…"[53]
- Project deliverables to install 12 inches of pipe directly to the Energy Center and to "Rebuild the gas supply meter set at the OSU Energy Center and tie the existing service over to the new 12-inch pipeline."[54]
- A project justification that the project "will supply additional capacity and support the increasing demand of natural gas fuel consumption at the Oregon State University Energy Center."[55]

- On April 4, 2013 NW Natural Vice President David R. Williams signed a letter to OSU stating "We understand OSU continues to

[51] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 1.
[52] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 1.
[53] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 1.
[54] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 1.
[55] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 1.

desire to obtain firm service from NW Natural, and that your intent is to remain a firm service customer for at least five years. In return we intend to complete the [Corvallis Loop] project this year."[56]

- On April 11, 2013, seven days after committing to complete the Corvallis Loop project in 2013 in exchange for firm service from OSU, NW Natural approved a $9 million dollar increase to the cost of the project. Project documents at this point in time now focus on reinforcing Corvallis and no longer on reinforcing OSU.[57]
- NW Natural admits that most correspondences with OSU regarding the Energy Center were not memorialized.[58] A formal line extension allowance was never calculated for extending the Corvallis Loop to OSU. The allowance would have been $290,000, leaving an OSU customer contribution of $28.1 million.

<u>No Customer Contribution from OSU</u>

Q. What is NW Natural's line extension policy?

A. NW Natural's line extension policy is contained in Schedule X Distribution Facilities Extensions for Applicant-Requested Services and Mains. This schedule lays out the terms for line extensions to new service as well as expansions at existing services. Schedule X outlines how the costs of extending mains are shared between

[56] Staff/702, Kaufman, NW Natural's Response to Staff DR 351 Attachment 4.
[57] Staff/702, Kaufman, NW Natural's Response to Staff DR 367 Attachment 2, p. 3 – other impacts section.
[58] Staff/702, Kaufman, NW Natural's Response to Staff DR 351 Attachment 4.

NW Natural and the customer requesting the extension. NW Natural's share of construction costs is called the customer allowance. The customer's share of construction costs is called the customer contribution.

Q. Please explain the customer allowance and customer contribution.

A. The customer allowance is the amount of investment that is economic for NW Natural to make in serving the customer, given the customer's expected sales. The customer allowance recognizes the fact that increased sales associated with new customers will contribute towards some of the fixed costs of the system. For NW Natural, the customer allowance for non-residential customers is calculated as five times the expected annual distribution margin. The customer contribution is the forecasted construction cost less the customer allowance. If this amount is negative the customer contribution is zero.

Q. Did NW Natural follow its line extension policy with the Corvallis Loop?

A. No, all of the documentation of the Corvallis Loop indicates that the project was built to deliver firm gas to the OSU Energy Center. Given that there is no system benefit to this pipe, NW Natural cannot reasonably claim that this project was a system reinforcement. NW Natural admits to not applying the line extension policy.[59]

[59] Staff/702, Kaufman/117, NW Natural's Response to OPUC DR 351.

No Alternatives Analysis Performed

Q. What is the Commission's policy regarding alternatives analysis of large capital projects?

A. In Order No. 12-437, the Commission states that NW Natural should evaluate alternatives prior to implementing large capital projects.

Q. What alternatives to the Corvallis Loop did NW Natural consider?

A. NW Natural does not appear to have considered any alternatives to the Corvallis Loop.

Q. What alternatives does Staff think NW Natural should have considered?

A. NW Natural should have considered the following alternatives:

1. Keeping OSU as an interruptible customer.
2. Connecting with the primary Albany feeder after it crossed the Willamette rather than before it crossed the Willamette.
3. Reducing customer incentives in stressed distribution areas.

Q. What are the costs and benefits of the first alternative?

A. The first alternative would have cost NW Natural the incremental margin associated with the project, or $290,000.[60] The benefit is that NW Natural would have avoided $28.4 million in capital expenditures.

Q. What are the costs and benefits of the second alternative?

[60] Staff/702, Kaufman/117, NW Natural's Response to Staff DR 351.

A. Crossing the Willamette River added $3-4 million to the cost of the Corvallis Loop.[61] This would also have shortened the project by about 6 miles, which at $2.5 million per mile would have saved an additional $15 million, for a total cost close to the initial UG 221 estimate of $12.8 million.

Q. What are the costs and benefits of the third alternative?

A. The cost is the opportunity cost of having fewer customers contributing to NW Natural's fixed costs. The benefit is that it would involve no investment.

Project Management

Q. What evidence is there that this project was not managed appropriately?

A. NW Natural has extensive experience with pipeline construction. Based on this, NW Natural has the experience and ability to do appropriate due diligence to ensure that budgets are accurate prior to committing funds to capital projects. It is standard project management practice to have the project costs accurately estimated to within 10 to 20 percent early in the construction process.[62] The fact that NW Natural went over budget by 50 percent indicates that NW Natural did not invest sufficient time or resources on the planning phase of the project.

[61] Staff/702, Kaufman/14, NW Natural's Response to Staff DR 162.
[62] Staff/713, Contemporary Project Management.

It appears that NW Natural also did not properly control the project. The project control process is intended to prevent problems from becoming outsized. NW Natural did not generate communications or manage processes in response to being over budget until most of the initial budget was spent and the project was only 44 percent complete.[63] The need for additional funding should have been identified earlier, the cause of the budget over-runs clearly identified, and the project should have been re-evaluated from a business case and planning perspective prior to proceeding with the more expensive project.

Further, the fact that NW Natural accelerated completion of the project in return for a five-year commitment from OSU suggests that accelerating the completion of this project may have added to the cost of the project.

Q. How could the cost over-runs been identified earlier and what would have been the benefit of early identification?

A. In addition to more accurate budgeting prior to executing the project, the project manager should have communicated cost over-runs earlier to the project sponsor. The Project Charter indicates that the project was to have bi-monthly updates provided to the Capital Projects meetings. At these updates the project manager should have identified the percent of work completed and the percent of budget

[63] Staff/702, Kaufman/173, NW Natural's Response to Staff DR 367 Attachment 2.

spent. This would have given the Capital Projects team an opportunity to cancel the project once it became apparent that it was not economic, but before the entire budget had been sunk into the project. Instead, there was no documentation of the cost over-run until all the funds had been expended and the project was only half complete.[64]

Q. What is your recommendation regarding the Corvallis Loop?

A. Staff recommends that the Corvallis Loop be allowed into rates at the originally approved amount of $12.8 million net of depreciation. The depreciated amount of $12.8 million is $10.8 million.[65] This results in a reduction to NW Natural's filed rate base of $14.1 million.

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[64] Staff/702, Kaufman/176, NW Natural's Response to Staff DR 367 Attachment 2.

[65] NW Natural notes that the Corvallis Loop is 84 percent depreciated. NW Natural/800, Karney/26.

ISSUE 3. OTHER DISTRIBUTION MAINS INVESTMENTS

Q. Please summarize this issue.

A. NW Natural has made $224 million in distribution mains investments since 2012.[66] This represents the 35 percent of the Company's plant additions. While investigating the MWVF and the Corvallis Loop, Staff became concerned that much of this small incremental investment should be reviewed for prudence. Staff has the following concerns related to other distribution mains:

1. Extensions to new customers may not have sufficient customer contributions.
2. Relocates[67] and other pipe replacement may include unwarranted up-sizing of pipe.
3. Relocates and other pipe replacement operations may include main extensions.
4. NW Natural may not be adhering to Rule 20 requirements that customers pay for distribution relocations.
5. Bare steel projects include the cost of abandoning and replacing non-bare steel pipe.
6. System reinforcements may be driven by the Company's policy of incentivizing customers to switch from electric to gas heating.

[66] Staff/705, Staff Summary of NW Natural's Response to Staff DR 197.
[67] Relocates are generally customer driven requests to relocate services or mains. They involve abandoning old pipe and installing new pipe. Staff/702, Kaufman/113, NW Natural's Response to Staff DR 339.

Line Extensions

Q. Why are you concerned that extensions to new customers may not have sufficient customer contributions?

A. While investigating the Corvallis Loop Staff found that NW Natural did not charge an appropriate customer contribution from OSU. This practice conflicts with NW Natural's line extension policy and could result in uneconomic expansion of NW Natural's system.

Q. What approach have you taken to investigate customer contributions?

A. Staff requested that NW Natural provide documentation supporting all main line extensions, including documentation sufficient to calculate the appropriate customer contribution. NW Natural found this data request too burdensome and provided Staff with a selection of ten extensions.[68]

Q. What conclusions did Staff draw from the non-random sample of ten extensions?

A. NW Natural only provided data on extensions that had been performed at least three years ago. This is because NW Natural performs main extensions to individual residential customers under the assumption that it will take three years for enough customers will connect to the main to make the investment economic. This policy could result in

[68] Staff/702, Kaufman/105, NW Natural's Response to Staff DR 335.

uneconomic extensions if NW Natural errors in forecasting how many customers will ultimately connect to the extension.

Q. What is your proposal related to this issue?

A. Staff recommends that any extensions made after January 1, 2012, which continue to be uneconomic today based on current net plant and customer distribution margin, be excluded from rate base. This would require a complete response to Staff DR 335.

Q. Are there any alternatives that would not require the Company respond to your complete data request?

A. If the Company agrees to apply the results of a Staff-designed random sample of extensions to all extensions performed since 2012, it may not be necessary to gather all relevant line extension documents. This alternative would use the following steps:

1. Staff designs and selects a random sample of extension projects.
2. NW Natural provides data on the Staff sample.
3. Staff analyzes the sample for economic viability, and proposes a disallowance to the Commission.
4. The Commission makes a decision regarding Staff's proposal.
5. The ratio of disallowed plant to total plant in Staff's sample is calculated.
6. The plant disallowance for the un-sampled extensions is calculated by multiplying the ratio from step 5 with the total plant in the un-sampled extensions.

Q. Why does the sampling approach require the Company's agreement?

A. The Commission has previously indicated that plant adjustments should be based on analysis of specific projects. The sampling approach analyzes specific projects, but applies the result generally to plant that was not specifically examined. While this approach deviates from the Commission's preference, it would result in a statistically accurate and precise estimate of the disallowance that would occur if Staff analyzed all main extensions.

Q. What is the size of your proposed adjustment?

A. It is not possible to calculate the full size of this adjustment until NW Natural provides a complete response to Staff DR 335.

<u>Pipe Upsizing as Part of Replacement Projects</u>

Q. Why were you concerned that NW Natural may be replacing smaller diameter pipe with larger diameter pipe unnecessarily?

A. This concern is due to NW Natural's decision to replace 6-inch pipe with 12-inch pipe for portions of the MWVF projects. NW Natural admits to not having documentation for the original analysis or the rationale for upsizing these pipes as part of the bare steel replacement program.

Q. What did you find regarding other potential pipe upsizing?

A. Staff requested documentation of the before and after pipe size for pipe replacement projects.[69] NW Natural found the request to be too burdensome and instead provided a list of projects, with project descriptions. Some of the project descriptions included the size of the abandoned pipe and the size of the replacement pipe. For projects with pipe diameters in the description, Staff did not identify any additional examples beyond the MWVF of pipes being upsized by more than two inches (i.e., 4 inches to 6 inches may be reasonable in locations with stressed distribution systems, but 4 inches to 8 inches may not be warranted without thorough documentation and analysis.)

Q. What is your recommendation regarding projects that did not include pipe diameter in the project descriptions?

A. The data available do not show unwarranted upsizing. However, Staff was not able to confirm that this is true for projects lacking description. Staff recommends that NW Natural update project descriptions to include the pipe size of both the abandoned pipe and the new pipe. Staff will review the remaining projects once NW natural has remedied the descriptors.

Main Extensions as Part of Replacement Projects

Q. What evidence is there that NW Natural is performing main extensions as part of replacement projects?

[69] Staff/702, Kaufman/107, NW Natural's Response to Staff DRs 336, 337, and 338.

A. Staff requested documentation of pipe replacement projects. While not initially concerned with the length of these projects, NW Natural provided a list of projects with project descriptions that included the length of abandoned pipe and the length of the replacement pipe. Staff observed many instances where the replacement pipe was substantially longer than the abandoned pipe.

Q. What is your concern with the practice of charging mains extensions as relocates or replacements?

A. Main extensions should be justified on an economic basis. Relocates and replacements may be justified for non-economic reasons, such as license agreements or safety issues. If main extensions are not explicitly identified they may not receive the appropriate level of financial analysis. If main extensions are included as bare steel projects the Company may be unfairly adding rate base outside of a general rate case.

Q. Is there evidence of similar issues with bare steel projects?

A. Yes, some bare steel projects also appear to include funding for main extensions. Staff is continuing to investigate this issue.

Q. What is your recommendation related to misidentified main extensions?

A. Staff recommends that project descriptions be enhanced to include the lengths of abandoned and installed pipe. Staff also recommends that any installed pipe in excess of abandoned pipe be tested for economic viability or satisfying legal and safety obligations.

<u>NW Natural may not be Charging Customers for Relocations</u>

Q. What is NW Natural's tariff schedule related to relocations?

A. Schedule 20 Distribution Facilities Standards identifies how customer requested relocates are treated. Schedule 20 states:

> Applicant or Customer will be required to pay the entire cost of any upgrade, relocation, rearrangement, removal, replacement or abandonment of existing Distribution Facilities, or the installation of new or additional Distribution Facilities, when requested by an Applicant or Customer for the convenience of the Applicant or Customer.

Q. What were the total costs for relocates between 2014 and 2017?

A. The total cost of relocations was $40.6 million.[70] Staff has not yet identified whether these relocations were paid by customers.

Q. What does Staff recommend related to Customer requested relocates.

A. Staff recommends that customer-requested relocates be reviewed for consistency with Schedule 20, and that any costs not consistent with Schedule 20 be excluded from rate base.

<u>Bare Steel Projects include non-Bare Steel Replacements</u>

[70] Staff/705, Staff Summary of NW Natural's Response to Staff DR 197. This amount includes service relocates.

Q. What evidence is there that NW Natural was including non-bare steel replacement costs in the Bare Steel programs?

A. NW Natural provided a list of bare steel projects. Of the projects with complete descriptions, 49 included abandonment of pipe that was not bare-steel. In some cases up to 1,000 feet of non-bare-steel pipe was abandoned as bare-steel. The total cost of these non-bare-steel abandonments was $282,000.[71] NW Natural assumes an abandonment cost equal to 23 percent of the replacement cost. This means that the install cost for replacement pipe was approximately $1.2 million, for a total cost of $1.48 million.

Q. Why is Staff concerned that the bare steel program includes replacement cost for non-bare-steel pipe?

A. The bare steel programs were safety programs that allowed the Company to add plant to rate base outside of general rate cases in order to enhance. This was a unique rate making mechanism that should not have included the cost of general pipe replacement.

Q. What is Staff's recommendation related to this concern?

A. Staff recommends that the Commission minimize programs that allow capital recovery outside of general rate cases. The type of analysis and review that is needed to approve plant into rates is more appropriately performed within a general rate case.

<u>System Reinforcement Issues Driven by Customer Cash Incentive</u>

[71] Staff/707, Staff Summary of NW Natural's Response to Staff DR 336.

Q. What evidence is there that system reinforcement issues are driven by cash incentives for new customers?

A. NW Natural claims that the primary driver of the SE Eugene Project is "Residential growth … stressing the distribution system to failure."[72] However NW Natural has been strongly incenting customer growth in South Eugene. NW Natural spent $104,000 in below the line cash incentives to acquire new customers in Eugene between 2012 and 2017. More than half of this spending, $58,133, was spent in Southeast Eugene.[73] NW Natural appears to have been targeting the stressed areas of its system for growth.

Q. What do you recommend regarding cash incentives?

A. Staff recommends that NW Natural's customer acquisition team coordinate with NW Natural's IRP team to ensure that NW Natural does not incent new customers in distribution areas that are stressed or are expected to be stressed.

[72] NW Natural/800, Karney/27.
[73] Staff/702, Kaufman/130, NW Natural's Response to OPUC DR 362 Attachment 1.

ISSUE 4. DEPRECIATION ASSOCIATED WITH DISALLOWED PLANT

Q. Please summarize this issue.

A. Staff proposes several plant adjustments. NW Natural's filed case includes depreciation expense tied directly to the plant that Staff proposes to exclude. Any plant adjustments made in this case should have associated depreciation adjustments made. This principle applies to plant adjustments and generic rate base adjustments made in settlement. Parties should be aware of the depreciation impact of plant adjustments.

As noted in the section on the MWVF, the Commission found the MWVF to be imprudent in Docket No. UG 221 and ordered that the costs be removed from rates. Order No. 12-437 specifically calls out depreciation as a cost that should not be recovered. However, NW Natural only removed the costs from rate base, NW Natural did not remove the cost from depreciation expense.[74] As a result NW Natural's testimony at NW Natural/800, Karney/9 is in error where it states "the unrecovered depreciation expense will total $4.6 million." In fact, NW Natural has recovered all depreciation expense associated with the imprudent portions of the MWVF.

Q. Why hasn't Staff calculated the depreciation impact of the proposed adjustments?

[74] Staff/702, Kaufman/123, NW Natural's Response to OPUC DR 352.

A. NW Natural's case does not tie projects to FERC accounts. NW Natural depreciates based on FERC accounts.

Q. What is a reasonable rule of thumb that the Commission can use to estimate depreciation expense?

A. Depreciation expense is approximately 10 to 20 percent of original cost per year for software and related IT plant, and two to five percent of original cost per year for all other plant.

Q. Using this rule of thumb what do you estimate as a depreciation adjustment related to MWVF and Corvallis Loop?

A. If the depreciation rate for these projects was four percent, Staff's plant adjustments would reduce MWVF depreciation expense by $808,000 and Corvallis Loop depreciation by $566,000. This reduction has not been included in Staff's proposed test year expense.

Q. What is Staff's recommendation regarding depreciation expense?

A. Staff recommends that depreciation expense be trued-up when final plant in rate base is determined by the Commission.

ISSUE 5. AFFILIATED INTERESTS AND COST ALLOCATIONS

Q. Please summarize this issue.

A. NW Natural provides and receives services from affiliated interests ("affiliates"). Transactions between NW Natural and affiliates are governed by a master services agreement (MSA) and by NW Natural's cost allocation manual (CAM). NW Natural files an affiliated interest report annually. This report identifies transactions between NW Natural and affiliates and contains NW Natural's cost allocation manual. Staff reviewed the transactions between NW Natural and affiliates as well as NW Natural's non-regulated operations. This review resulted in the following concerns:

1. NW Natural bills labor to affiliates at cost, rather than at the higher of cost or market.
2. The amounts that NW Natural includes in bills to affiliates and for unregulated activities do not include all the costs of providing affiliates with service.
3. NW Natural has not accounted for overtime costs associated with non-utility allocations.
4. NW Natural executives have not accurately accounted for time spent on non-utility projects.
5. NW Natural is not allocating sufficient insurance costs to affiliates.
6. NW Natural is not allocating sufficient web site costs to unregulated operations.

7. NW Natural is including North Mist, civic engagement, and investor relation expenses in the test year expense.

Labor Not Billed at Higher of Cost or Market

Q. What law governs how NW Natural should bill affiliates?

A. Transfer prices for services between NW Natural and affiliates are addressed by OAR 860-027-0048(4)(d) and (e):

> (d) When services or supplies are sold by an energy utility to an affiliate, sales shall be recorded in the energy utility's revenue accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the energy utility's cost or the market rate, whichever is higher. Approved rates shall be established as appropriate.

> (e) When services or supplies (except for generation) are sold to an energy utility by an affiliate, sales shall be recorded in the energy utility's accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies (except for generation) are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower.

Q. What evidence is there that NW Natural always bills labor at cost?

A. NW Natural's Master Services Agreement, which is the affiliated interest agreement on file with NW Natural for NW Natural affiliates, states that "All costs billed by NW Natural to Affiliates shall be at the higher of cost or market…"[75] NW Natural's CAM states "Affiliates or

[75] Docket UI 385 NW Natural's Application for Transactions Between Affiliated Interests Master Services Agreement, p. 17.

non-public utility activities are charged directly for materials, supplies and services (e.g., consulting services) purchased by NWN on behalf of the affiliate on the basis of the full cost of the items supplied." The manual also states:

> Management oversight and other labor performed by NWN employees for the benefit of affiliates or non-public utility activities are recorded on the books of the utility in accordance with the labor allocation methods described below… If an employee has any [non-utility time], the employee must report and record the exception time in the CATS system. The CATS system then calculates the cost of the reported hours for each employee, adds the appropriate overhead load and generates an accounting entry in which the costs of the reported hours including overhead load are transferred at the employee average pay rate, by pay grade, from the employee's cost center to the cost center for the reported activity.

The labor charge for non-utilities is a cost-based charge. NW Natural states that NW Natural's allocated cost is a market rate because NW Natural pays market prices.[76] However, NW Natural's theory is inconsistent with the concept of "lower of cost or market". Under NW Natural's theory, because all costs are incurred in a market, all services billed at cost are billed at a market rate. If this is the case, there is no meaningful differentiation between cost and market, and OAR 860-027-0048(4)(d) and (e) are unnecessary.

Q. What factor is missing from NW Natural's reasoning?

A. NW Natural is not considering the operating margin that business services firms build into their pricing structure. By acting as an

[76] Staff/702, Kaufman/4 NW Natural's Response to OPUC DR 123 Attachment 1.

intermediary firm acquiring, organizing, and managing resources on behalf of affiliates, NW Natural is functioning as a business services firm. If business services firms charged at cost, they would earn no profit. The operating margin represents the incremental amount above cost that business services firms charge to earn a profit.

Q. How can the total amount that a firm charges (i.e. cost plus profit) cost be calculated?

A. This is calculated with the following equation:

$$\frac{Cost}{1 - Operating\ Margin}$$ [77]

The incremental amount that business services firms charge is:

$$\frac{Cost}{1 - Operating\ Margin} - Cost$$

Q. How do you recommend that NW Natural bill for goods and services?

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[77] This formula is derived as follows:

$$Revenue = Revenue$$
$$\frac{Cost * Revenue}{Cost} = Revenue$$
$$Cost * \frac{Revenue}{Cost} = Revenue$$
$$Cost * \left(\frac{Cost}{Revenue}\right)^{-1} = Revenue$$
$$Cost * \left(\frac{Revenue - Profit}{Revenue}\right)^{-1} = Revenue$$
$$Cost * \left(1 - \frac{Profit}{Revenue}\right)^{-1} = Revenue$$
$$Cost * (1 - Operating\ Margin)^{-1} = Revenue$$
$$\frac{Cost}{1 - Operating\ Margin} = Revenue$$

A. Staff recommends that NW Natural obtain annual quotes for the same service or good from an independent vendor, such as a staffing agency, consultancy, or other business support firm. These quotes could provide a baseline market rate. NW Natural would then compare the loaded cost against the market rate and bill affiliates according to the higher of the two amounts.

Q. Do you propose an adjustment in this case?

A. Yes. NW Natural has not surveyed the market to establish a market rate. In place of an adjustment based on market quotes, Staff recommends the Commission adjust revenue requirement to account for the incremental charge that business services firms charge. Exhibit Staff/708 identifies the recent operating margin for three business services firms. The average operating margin for these firms is 9.2 percent. This means that for every dollar in costs business services firms receive $1.102 in revenue, with a margin of $0.102 per dollar of cost.[78] Staff recommends adjusting NW Natural's revenue requirement by applying this market based operating margin and NW Natural's cost of non-utility service to the formula above in order to approximate a market rate for the services provided by NW Natural. This adjustment applies to all non-utility expense and is presented as part of the adjustments below.

<u>NW Natural Has Not Sufficiently Accounted for Hold Co. Costs</u>

[78] This is calculated using the formulas derived in the testimony above.

Q. What adjustment does NW Natural make to account for future Holding Company cost allocations?

A. NW Natural excludes $153,034 from rates to account for future Holding Company allocations.[79]

Q. Why do you think this amount is not sufficient?

A. The Holding Company represents a major investment for the Company, and will require both oversight and management. In 2016 and 2017 NW Natural spent on average **[Begin Confidential]** [redacted] **[End Confidential]** on the Holding Company and other strategic initiatives. In 2016 and 2017 NW Natural executives billed an average of **[Begin Confidential]** [redacted] **[End Confidential]** to non-utility and affiliates, including the Holding Company.[80] However, NW Natural's case only allocates **[Begin Confidential]** [redacted] **[End Confidential]**[81] in utility executive payroll to non-utility in the test year.

Q. What adjustment do you recommend regarding the Holding Company?

A. Staff recommends allocating the average 2016 and 2017 executive non-utility payroll to non-utility in the test year. The difference between NW Natural's test year executive non-utility payroll and Staff's executive non-utility payroll should be considered to be Staff's test

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[79] Staff/702, Kaufman/9, NW Natural's Supplemental Response to Staff DR 125.
[80] Staff/709, Staff Summary of NW Natural's Response to Staff DR 126 Confidential Attachment 1.
[81] Staff/703, Kaufman1, NW Natural's Supplemental Response to Staff DR 125 Confidential Attachment 2. Sheet named "Non-Utility Payroll OH".

year Hold Co. allocation. This amount is **[Begin Confidential]** [redacted] **[End Confidential]**

<u>Executive Time is Not Correctly Identified as Non-Utility</u>

Q. How does executive time get billed to non-utility?

A. NW Natural employees, including executives, track their time in NW Natural's Cross Application Time System (CATS).[82] When executives spend time on non-utility they are supposed to book the time as non-utility in the CATS system. This time record is used to allocate executive payroll and payroll overhead. However, all time that is not specifically identified in CATS is assumed to be charged to the employee's home cost center, which for executives, counts as utility time. This results in a potentially biased estimate of the amount of time spent on non-utility activities because all errors in not recording time is booked to utility, rather than split proportionately between non-utility and utility.

Q. What evidence is there that executives are not tracking non-utility time correctly?

A. Staff reviewed a NW Natural board meeting agenda for February 23, 2017.[83] **[Begin Confidential]** [redacted]

[82] NW Natural's 2016 Affiliated Interest Report, p. 39.
[83] Staff/703, Kaufman/2 NW Natural's Response to Staff DR 131 Confidential Attachment 1.

[redacted]

[84] **[Begin Confidential]** [redacted]. **[End Confidential]**

[85] Calculated as **[Begin Confidential]** [redacted] **[End Confidential]**

[86] Calculated as **[Begin Confidential]** [redacted] **[End Confidential]**

[redacted] **[End Confidential]**

Overtime Costs Not Included in Non-Utility Labor Allocation

Q. What evidence is there that overtime costs are not included in labor allocations to non-utility?

A. NW Natural provided the foundational rate case operations and maintenance expense model in the Supplemental Response to OPUC DR 125, Confidential Attachment 2.[87] The non-utility labor allocation is calculated on sheet "Non-Utility Payroll OH". NW Natural has hard coded the overtime section of this sheet to equal zero.

Q. What do you recommend regarding overtime allocation?

A. Staff recommends applying NW Natural's non-utility labor allocators to both base pay and overtime pay. After accounting for additional benefits this results in a **[Begin Confidential]** [redacted] **[End Confidential]** increase to non-utility allocations.

Some Costs of Providing Services are not Included in Bills

Q. What costs of providing services are not included in bills?

A. NW Natural does not apply an administrative overhead rate to the majority of labor allocated to non-utility.[88] However, because these are NW Natural employees, the employees cause NW Natural to incur

[87] Staff/703, Kaufman/1.
[88] NW Natural's Affiliated Interest Report for Year End December 31, 2016, p. 40 n2.

payroll expenses, insurance, recruiting and human resource costs, management costs, overhead for management, and so on.

Q. What overhead costs do you recommend be charged to NW Natural affiliates?

A. Staff recommends that all labor billed to affiliates include NW Natural's administrative overhead rate of 27.5 percent.[89] Staff's total non-utility payroll is $6.5 million on a system basis. This results in administrative overhead of $1.79 million. NW Natural removes $225,000 from the test year to account for administrative overhead of non-utility payroll.[90] Staff's approach results in a system reduction of $1.56 million, which is a $1.4 million reduction to Oregon allocated revenue requirement.

Q. What is Staff's total non-utility labor adjustment after accounting for the operating margin?

A. Staff calculates non-utility labor related services cost NW Natural $8.298 million. The margin associated with these costs is $845,000. The total amount that NW Natural should have charged using a market rate is $9.143 million. NW Natural allocates $4.533 million to non-utility labor. Staff's adjustment is a reduction to expense of $4.611 million system wide basis, and $4.121 million on an Oregon allocated basis.

<u>NW Natural does not Allocate Insurance Correctly</u>

[89] NW Natural's Affiliated Interest Report for Year End December 31, 2016, p. 40.
[90] Staff/702, Kaufman/9, NW Natural's Supplemental Response to Staff DR 125.

Q. Please explain Staff's concerns with NW Natural's insurance allocations.

A. NW Natural uses four allocation factors: revenues, assets, payroll, and number of directors and officers. Staff updates three of these factors:

1. Assets: Staff updates Mist Storage to account for the cost of North Mist.
2. Payroll: Staff updates payroll to include the non-utility payroll
3. Number of Directors and Officers: Staff updates Directors and Officers to be consistent with NW Natural's most recent Affiliated Interest Filing.[91]

In addition to updating the allocation factors, Staff proposes changing which factors are used to allocate three policies. NW Natural carries numerous insurance policies that cover NW Natural's regulated and unregulated operations and affiliates. NW Natural allocates the premium of each policy using some combination of the four allocators described above. Staff found that three of these policies are not allocated with the most relevant drivers.

NW Natural's general liability and excess liability policies are general policies that cover all of NW Natural's and NW Natural's affiliate operations. NW Natural allocates this policy based only on one cost driver, revenue. This approach allocated *de minimis* cost to NNGFC, KB Pipeline, The Dock, NW Natural Gas Storage, Trail West

[91] Staff/710, CONFIDENTIAL Insurance Allocation Adjustment.

and BioGas because these companies do not have revenues. Staff found that an equal weighting of all four allocators recognizes more of the cost drivers for this policy and results in all of NW Natural's affiliates and unregulated operations contributing to the costs of these policies.

NW Natural allocates property insurance based on payroll. However, "Assets" is a more direct cost driver for property insurance than payroll.

Q. What is your recommendation to the Commission for insurance allocations?

A. Staff recommends that the Commission adopt the allocation changes described above. This results in a decrease to Oregon allocated insurance cost of $872,000.

Website Costs are not Allocated

Q. What is your concern related to website costs?

A. NW Natural maintains investor relations on nwnatural.com.[92] NW Natural also hosts promotional videos, such as the benefits of natural gas patios on nwnatural.com, and directs customers to the NW Natural Appliance Center.[93]

Q. What are the costs associated with nwnatural.com?

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[92] Staff/711, Screenshots of nwnatural.com.
[93] Staff/711, Kaufman/2 shows nwnatural.com includes a direct link to the NW Natural Appliance Center without identifying non-utility options.

A. NW Natural claims the cost to maintain and host the site is $9,500. NW Natural hosts the site on NW Natural owned servers, but claims no cost associated with this. Staff is continuing to investigate how NW Natural can own and operate servers at no cost to ratepayers.

Q. What is Staff's recommendation for the NW Natural website costs?

A. Staff recommends allocating 20 percent of the cost to host and maintain nwnatural.com to non-utility. This is calculated as one primary menu devoted to non-utility divided by five primary menus. This adjustment reduces NW Natural's Oregon Allocated costs by $1,700.

North Mist, Civic, and Investor Expenses in Test Year

Q. What North Mist cost is NW Natural including in the test year and why is it a concern?

A. NW Natural has included **[Begin Confidential]** [redacted] **[End Confidential]** (Oregon allocated) in legal expenses related to North Mist in the test year. NW Natural has stated that the North Mist project "will not affect the ratemaking for our other utility customers."[94] Staff recommends excluding **[Begin Confidential]** [redacted] **[End Confidential]** [95] from test year expense.

[94] NW Natural/200, McVay/25.
[95] Staff/714.

Q. What Civic expenses does NW Natural include in the revenue requirement and why is it a concern?

A. NW Natural includes **[Begin Confidential]** [redacted] **[End Confidential]** [96] Oregon Allocated in civic expenses in the test year. NW Natural's CAM identifies civic expenses as non-utility. Staff recommends excluding these costs from the test year expense.

Q. What Investor expenses are included in the test year and why is it a concern?

A. NW Natural includes **[Begin Confidential]** [redacted] **[End Confidential]** [97] (Oregon Allocated) in shareholder and investor relations expenses in the test year. While these expenses primarily benefit investors, Staff finds some benefit to customers in maintaining relationships with investors. Staff recommends sharing these expenses 50 percent with shareholders. This results in a test year expense reduction of **[Begin Confidential]** [redacted] **[End Confidential]** [98]

[96] Staff/714.
[97] Staff/714.
[98] Staff/714.

ISSUE 6. REVENUE FORECAST

Q. Please summarize this issue.

A. NW Natural forecasts gas transaction volumes for the test year that result in $361.9 million in margin revenue at current rates.[99] Staff forecasts gas transaction volumes for the test year that result in $364.2 million in total margin revenue. Under Staff's forecast, NW Natural has a smaller revenue shortfall, and consequently needs a smaller rate increase.

The difference in the revenue forecasts of Staff and NW Natural is due to several factors. Staff's forecast of residential and commercial customers is very similar to NW Natural's, however Staff forecasts NW Natural's eight load centers separately, while NW Natural forecasts load centers in aggregate. Staff uses a simple three-year average forecast for NW Natural's industrial sales and obtains a different forecast than NW Natural.

Q. Please explain why Staff's approach to forecasting residential and commercial load is an improvement over NW Natural's approach.

A. Gas sales for commercial and residential customers are highly sensitive to weather. NW Natural has a geographically diverse service area in Oregon, spreading from The Dalles in northern Oregon to the coastal Coos County far to the south. These regions each have

[99] NW Natural/203.

relatively independent weather systems. They also have a different mix of age and types of buildings. For example, new home constructions tend to be less sensitive to weather relative to older homes. For these reasons, it is important to allow the weather response coefficients to vary by region. Staff's model allows this, while NW Natural's model does not.

Q. Please explain why Staff's approach to forecasting industrial load is an improvement over NW Natural's.

A. Staff does not have access to NW Natural's industrial forecast methodology. However, the results of NW Natural's industrial forecast are not consistent with NW Natural's recent history. Staff's approach to forecasting industrial customers use is identical to NW Natural's method of forecasting other revenue. Specifically, because there is no trend in industrial revenue for the last three years Staff uses an average of the last three years.

Q. Please compare your test year sales forecast by schedule compared to NW Natural's test year sales forecast by schedule.

A. This is provided in Exhibit Staff/715. In general, Staff forecasts lower use by residential schedules, higher use by large commercial schedules, and higher use by industrial schedules.

ISSUE 7. DECOUPLING

Q. Please summarize this issue.

A. NW Natural proposes several changes to its decoupling mechanism and weather adjusted rate mechanism (WARM):[100]

1. A weather adjustment methodology change that makes weather decoupling applicable to all customers in WARM rate schedules, even customers who have opted out of WARM;
2. Inclusion of large commercial firm sales customers in the decoupling mechanism;
3. Creation of four separate groups, or customer classes, for the decoupling mechanism;
4. An update of the decoupling use-per-customer; and
5. An update of the WARM normal heating degree days and WARM and decoupling statistical coefficients.

Staff responds to each of these proposals, and proposes an additional change that was not addressed in NW Natural's opening testimony:

6. Apply decoupling adjustments only to customers forecasted in base rates.

<u>Don't Change Weather Adjustment</u>

Q. Please summarize the weather adjustment change.

A. The NW Natural WARM program decouples weather risk for both NW Natural and Customers. For customers enrolled in the WARM

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[100] NW Natural/900, Walker/2.

program, NW Natural's revenue is relatively independent of weather and customer distribution charges are relatively independent of weather. However, about 10 percent of customers have decided not to participate in WARM. That means that these customers do not want to be decoupled for weather risk. NW Natural is proposing to ignore these customer preferences and to decouple them anyway.

Q. Staff recently investigated the WARM program in Docket No. UM 1750. What was the result of that investigation?

A. Staff and parties raised a number of concerns regarding the WARM program. One of the concerns that NW Natural raised in Docket No. UM 1750 was that NW Natural was exposed to weather risk for customers who had opted out of WARM. The parties to Docket No. 1750 reached a stipulated agreement in that docket and the Commission adopted the parties' stipulation in Order No. 16-223. The stipulation did not include modifications to WARM to account for weather risk associated with opted out customers. The stipulation also did not reserve the right for NW Natural to argue in favor of extending weather decoupling to opt-out customers.

The stipulation results in changes that all parties agreed would improve the WARM program but did not include all of Staff's proposed changes. If the Commission allows NW Natural to extend weather decoupling to opt-out customers, the Commission should also allow parties to revisit the other issues raised in the WARM investigation but not addressed by the WARM stipulation.

Q. How does extending weather decoupling to cover opt-out customers affect customer risk exposure?

A. Extending weather decoupling to cover opt-out customers will have no tangible benefit to customers. This is contrary to the goal of the WARM program, which is to provide benefit to both the Company and customers.

Q. What is Staff's recommendation?

A. Staff recommends that the Commission maintain the WARM program as it is and not adopt the Company's proposal regarding weather normalization.

Don't Decouple Large Commercial Customers

Q. What is the company's proposal regarding large commercial customers?

A. The Company currently decouples Schedule 2 Residential Sales, Schedule 3 Basic Firm Sales Non-Residential, and Commercial Firm Sales customers in Schedule 31 Non-Residential Firm Sales and Firm Transportation Service. NW Natural proposes extending decoupling to Commercial Firm Sales customers in Schedule 32 Large Volume Non-Residential Sales and Transportation Service. Industrial, transmission, and interruptible customers would continue to not be decoupled.

Q. What is the rational for decoupling?

A. The purpose of decoupling is to remove the utility incentive to increase sales and their disincentive to decrease sales in between rate cases. Decoupling can help hold utilities indifferent to energy efficiency programs and policies. However, decoupling can also shift risk from utility shareholders to customers.

NW Natural seeks to extend decoupling to large customers because large commercial customers participate in energy efficiency programs.[101]

Q. What is Staff's position regarding decoupling?

A. Decoupling mechanisms for smaller customers have generally been supported by Staff. Staff has supported decoupling mechanisms because they help hold the utilities harmless for Oregon energy policy related to energy efficiency. Staff has generally not supported decoupling for large customers because large customers are more sensitive to economic conditions than small customers, and decoupling mechanisms shift economic risk traditionally born by utility shareholders to customers. Staff finds that the balance of incentive benefit and risk transfer favors decoupling for small customers, however, the negative aspect of risk transfer outweighs the benefits associated with energy efficiency.

[101] NW Natural/900, Walker/15. NW Natural also notes that large customers have smaller heat response than small customers.

Q. Why are the benefits of decoupling for large customers smaller than small customers?

A. Schedule 32 customers are large sophisticated customers. These customers make energy efficiency decisions based on financial gain, and are less likely to be subject to influence by NW Natural. Furthermore, because the Energy Trust of Oregon (Energy Trust) administers Demand Side Management (DSM) programs, NW Natural has little ability to interfere with energy efficiency efforts of large customers. This means that even without decoupling NW Natural has relatively little opportunity to influence large customer gas use and the incentive benefits of decoupling are relatively small.

Q. Why is the cost of decoupling greater for large customers?

A. Large customers are relatively more sensitive to economic factors than small customers. In periods of economic contraction, large customers may decrease use. If NW Natural's proposal is accepted, the decreased use would be matched by an increase in cost. This shifts the risks associated with economic slowdown from the Company's shareholders to the Company's customers. By decoupling large customers, NW Natural will be shifting substantial economic risk away from shareholders and towards customers.

Q. What is Staff's recommendation regarding large customers?

A. Staff recommends maintaining the decoupling program as it is, without extending it to large customers.

Q. If NW Natural is particularly concerned with lost margins associated with large customer energy efficiency what alternatives are there to decoupling?

A. NW Natural could have contemplated a mechanism that makes NW Natural whole for lost margins due to energy efficiency programs. One example is PGE's Lost Revenue Recover Adjustment Schedule 123, or Avista's Lost Margin Recover in Schedule 466. These programs allow the utilities to recover lost revenue directly related to energy conservation and demand side management.

<u>Create Separate Groups for Decoupled Customers</u>

Q. What is the value of creating separate groups for decoupled customers?

A. Under the current method, all commercial schedules are grouped together. This means that there is one average use per customer applied to both Schedule 3 and Schedule 31. The current method over-adjusts small commercial customers and under-adjusts large commercial customers. Unless the actual number of customers in each group matches the forecasted number in the rate case, this results in an over- or under- adjustment. Using separate groups of customers is more precise.

Q. What is your recommendation regarding this change?

A. Staff recommends having a separate group for each schedule that is included in the decoupling mechanism. This is similar to NW Natural's proposal, however, because Staff does not recommend extending decoupling to Schedule 32 only three groups would be created.

Update Baseline Use Per Customer and Weather Adjustment Parameters

Q. Why should the baseline use per customer be updated?

A. The decoupling mechanism is an adjustment that is relative to the base revenue requirement. This means that revenues are adjusted to match those that were targeted in the most recent rate case. Updating baseline use per customer is performed in each rate case for utilities that have decoupling mechanisms. Weather adjustment parameters are updated for similar reasons.

Q. What is your recommendation regarding these updates?

A. Staff recommends that the Commission adopt the update, with the caveat that the final numbers should reflect the final load forecast that is used to set rates.

Decouple Only the Number of Customers Forecasted in Base Rates.

Q. Why does Staff propose to decouple only the number of customers forecasted in base rates?

A. Decoupling mechanisms are designed to allow utilities to recover fixed costs of providing service. If a utility is fully decoupled, and the utility has the same number of customers as included in the previous rate case forecast, the utility distribution revenues will exactly equal the distribution revenue requirement from the rate case. However, if the number of actual customers exceeds the number of customers in the rate case forecast the utility will recover more than the distribution revenue requirement. NW Natural adds 8,000-10,000 customers per year. It is likely that sometime during the year after the test year in this rate case NW Natural will have more customers than included in this rate case forecast, because the forecast only considers customer additions up to the end of the test year.

New customers tend to have lower baseline use than existing customers due to stricter building code standards, which are independent of the Utility's energy efficiency policy. Extending decoupling to new customers beyond those forecasted in the rate case results in the following problems:

1. The decoupling adjustment will consistently be in NW Natural's favor due to the average use of new customers being small relative to the average use of existing customers.
2. The decoupling mechanism will compensate NW Natural for building code improvements and other forms of energy savings that are independent of both NW Natural and the Energy Trust.
3. The revenue associated with new customers will exceed the incremental cost of new customers because the average cost of serving all customers is higher than the incremental cost of serving an additional customer.

These problems arising from NW Natural's proposal generally harm customers, while allowing the utility to recover more than the approved revenue requirement.

Q. Has Staff raised this issue with other utilities?

A. Yes, Staff raised this issue in Portland General Electric Company's general rate case filed in 2013 (Docket No. UE 262). Avista proposed a new decoupling program in Docket No. UG 288. The Stipulation settling the decoupling issue in UG 288 also applies decoupling to only customers forecasted in the rate case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, and PGE UE 308. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff 702 Non-Confidential Data Responses

Data Request **Page**

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 123

123. Please provide NW Natural's responses to all information requests from Docket No. UI 385.

Response:

Please see attached UG 344 OPUC DR 123 Attachment 1 (UI 385 IRs 1-4) and CONFIDENTIAL UG 344 OPUC DR 123 Attachment 2 (UI 385 IR 2 Attachment 1).

NW Natural

Rates & Regulatory Affairs

Data Request Response

Request No. UI 385-OPUC-IR 1**:**
1. Please refer to page 10 of Northwest Natural's initial filing at lines 17 to 24.
a. Please explain how Northwest Natural determines the market price of transactions between the Utility and Affiliates.
b. Please explain how Northwest Natural determines the cost of transactions between the Utility and Affiliates.

Response:

The cost and market value of transactions are generally established at the open market purchase price of the good or service as follows:

Salaries & Administrative Overhead - Employee time is charged using the average wage of the employee's pay grade. Wages at NWN and its affiliates are competitive with the labor market and the cost of labor is also considered the market value as each employee's compensation is subject to an annual review against market rates. An overhead of 27.5% is applied to employee time charges from NWN to affiliates for associated expenses including (but not limited to) rent, utilities, and supplies costs. An overhead of 18% is applied to employee time charges from affiliates to NWN for similar costs (note that the lower rate is due to lower overhead costs at affiliates). The overhead rates are consistent with those filed in our Cost Allocation Manual filed with the Company's annual Affiliated Interest Reports for 2016. The Company last validated the appropriateness of these overhead rates utilized in 2016.

Insurance – Insurance policies are bought on the open market and as such the purchase price of policies is considered both the cost value and the market value. Insurance costs are paid by NWN and partially allocated to affiliates using a methodology consistent with the nature of the insurance (e.g. Property Insurance is allocated on the basis of total assets at each entity). See summary of allocation methodology within the 2016 Cost Allocation Manual filed with the OPUC.

Other Administrative Costs – Occasionally, goods or services are purchased by NWN and partially or fully billed to subsidiaries. The purchase price of such items are considered to be the cost value and the market value.

NW Natural

Rates & Regulatory Affairs

Data Request Response

Request No. UI 385-OPUC-IR 2**:**
2. Please refer to page 13 of Northwest Natural's initial filing at lines 4 to 6. Please provide transaction level details for the referenced $913,617. Please include a description of the transaction, the entity that the transaction was entered into with, and the account that the transaction was recorded to. Please also include any other data that is maintained in NW Natural's accounting records for these transactions.

Response:

See Confidential UI 385 IR 2 Attachment 1 for transaction-level detail of goods and services received by NW Natural of $913,617 in 2016.

NW Natural

Rates & Regulatory Affairs

Data Request Response

Request No. UI 385-OPUC-IR 3**:**
3. Please refer to page 17 of Northwest Natural's initial filing at section 3.1. Please explain when and why service costs and transactions governed by this MSA are not included in NW Natural's state operations revenue requirements.

Response:

Currently there are no transactions governed by the MSA that are not included in NW Natural's state operations revenue requirements.

Transactions between affiliates governed by this MSA would not be included within NW Natural's state operations revenue requirements if those transactions were determined to be non-utility.

NW Natural

Rates & Regulatory Affairs

Data Request Response

Request No. UI 385-OPUC-IR 4:
4. Please refer to page 19 of Northwest Natural's initial filing at section 4.2.
a. Please provide the results of NW Natural's most recent annual review.
b. Please explain how NW Natural makes the determination that billing is consistent with the agreement, including what data and factors are considered?

Response:

a. NW Natural completed our annual review of 2016 charges between NW Natural and its affiliates in preparation of the annual Affiliated Interest Report filed with the OPUC. No instances of noncompliant or inappropriate charges were noted.

b. On a monthly basis, intercompany payroll charges (representing the majority of charges between NW Natural and its affiliates) are examined for reasonableness to ensure the billing is consistent with the agreement. Variances from budgeted amounts are inspected for appropriateness.

On an annual basis, NW Natural prepares the Annual Affiliated Interest Report which is filed with the OPUC. In preparing the report, detailed supporting schedules of transactions between NW Natural and its affiliates are reviewed for appropriateness. Data points such as overhead rates, the nature of charges, charge volumes, and total charged amounts are analyzed.

NW Natural®

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UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 125

125. Please refer to NW Natural's affiliated interest report for the year 2016 accessible at http://edocs.puc.state.or.us/efdocs/HAQ/rg8haq16248.pdf. Please refer to pages 17 and 18 (19 and 20 of filing.)

a. Please explain how payments by the affiliates to NW Natural are accounted for in the current filing. Include reference to the filed workpapers.

b. Please explain why no Gill Ranch payments are allocated to Oregon.

Response:

125(a): When NW Natural incurs affiliate costs, those costs are not included in the Utility's expense. Rather, those costs are recorded at the affiliate company. The affiliate will then reimburse NW Natural for payments made on their behalf. Additionally, payments for the Shared Services overhead charges are included as credits to FERC 922 in the Utility's O&M, offsetting the respective O&M costs being covered by the overhead. The 2018 General Rate Case was submitted net of the costs charged to the affiliates and the subsequent payment reimbursements. Refer to SDR #57 for FERC 922 costs detail and NW Natural/600 Moncayo/11 Shared Services Overhead.

125(b): In the affiliated interest report for the year 2016, Gill Ranch operations are considered allocated to California in their entirety, consistent with the operating location of the affiliate. However, as noted in a) above, the Shared Services Overheads are included as O&M credits allocated to Oregon in our Oregon Rate Case.

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Supplemental Data Request Response

Request No.: UG 344 OPUC DR 125

125. Please refer to NW Natural's affiliated interest report for the year 2016 accessible at http://edocs.puc.state.or.us/efdocs/HAQ/rg8haq16248.pdf. Please refer to pages 17 and 18 (19 and 20 of filing.)

a. Please explain how payments by the affiliates to NW Natural are accounted for in the current filing. Include reference to the filed workpapers.

b. Please explain why no Gill Ranch payments are allocated to Oregon.

Supplemental Response:

How can the utility allocated insurance amount be confirmed in the O&M model?

The calculation of the insurance amount that was allocated to utility in the test year can be found in the attached file '**UG 344 OPUC DR 125 Supp Attach 1 - Test Year Utility Insurance Allocation**'. The utility allocation in the test year is $3,914,550. To confirm that same Utility allocated insurance amount in the O&M model see file '**UG 344 OPUC DR 125 Supp Attach 2– O&M Model**' and go to the Non-Payroll Forecast tab. Filter for "INSURANCE" in column I (Cost Center). If you scroll right to the months of the test year you can see that the total system test year amount is $3,914,550. This total gets picked up in the O&M TY FERC Allocation Summary tab in cell G127, which represents the sum of all non-payroll in FERC 924. To determine the OR state allocated amount, column AA in the same tab will show the OR allocation % to be used for FERC 924, which for the test year is 89.87%.

How can it be confirmed that the test year O&M was reduced for HoldCo. payroll expenses?

HoldCo payroll that was excluded from the test year ($153,034 prior to state allocation) can be found in the O&M model '**UG 344 OPUC DR 125 Supp Attach 2 – O&M Model**', HoldCo Payroll tab. This amount reflects the amount of total payroll charged to Holdco for the 12 month period 10/2016 – 09/2017. The $153k credit gets picked up in the O&M TY FERC Allocation Summary tab in cell Q124. This credit is in FERC 921. To determine the OR state allocated amount in the test year, column AA in the same tab will show the OR allocation % to be used for FERC 921, which for the test year is 89.25%.

Can you explain how the 25.2 FTEs allocated to non-utility was developed, and how many of those FTEs were allocated for affiliate and NW Natural non-utility

project activity? How would those FTEs compare to the FTEs included in DR 126 & DR 127?

The 25.2 FTEs was developed by using the projected test year FTEs and allocating them to O&M/Capital/Non-Utility based on the percentage of allocation derived using the budget submissions from each departmental manager based on the activity expected in the test year. In the O&M model '**UG 344 OPUC DR 125 Supp Attach 2 – O&M Model**', the outcome from this can be found in the Total FTE Allocation tab, in excel lines 58-77. In lines, 71-74 you can see the amount that was allocated to Non-Utility activity (25.2 FTEs) and removed from the test year.

These allocations and FTE counts did not include additional time that was removed from the Test Year for time spent on HoldCo. The amount removed from the test year reflected the amounts that were charged to HoldCo during the time frame 10/2016-09/2017. This amount would reflect roughly 0.5 FTEs. This would make the total FTEs allocated to non-utility 25.7 FTEs.

The breakdown of the 25.2 FTE's can be found at NW Natural/600/Moncayo/5. In this table, 7.0 of the 25.2 are allocated for affiliate activity. To compare the FTEs removed from the O&M model to DR 126 & 127 refer to '**UG 344 OPUC DR 125 Supp Attach 3 – Affiliate and Non-Utility Hours Reconciled**', you would also need to include with the 7.0 FTEs, the 0.5 FTE mentioned above for HoldCo activity, as well as FTEs for Strategic Initiatives and Projects, which are Business Development FTEs. This equivalent was 1.4 FTEs. Therefore, the total FTEs removed from the test year in the O&M model for affiliate and NW Natural non-utility projects in comparison to the FTEs shown in DR 126 & 127 '**UG 344 OPUC DR 125 Supp Attach 3 –Affiliate and Non-Utility Hours Reconciled** for 2016 and 2017 actuals, would be 8.9 FTEs. These 8.9 FTEs would be in comparison to the number of hours worked in DR 126 & 127 which for 2016 was 15,128 hours or 7.3 FTEs (15,128/2,080), and in 2017 was 15,674 hours or 7.5 FTEs (15,674/2,080).

How was the Shared Services overhead credit calculated for the test year and where can I find the credit in the O&M model?

The shared services credit for the base year was forecasted to be $214,439, and 2017 actuals came in at $241,230 – refer to '**UG 344 OPUC DR 125 Supp Attach 4 – Shared Services OH Credit'** for a reconciliation of the actuals in O&M and SDR 129 – 2017 Affiliate Transactions. To get to the test year forecasted amount, similar to other non-payroll expenses, the base year forecast was grossed up by CPI rates to get to the projected test year amount. You can find this in the O&M model '**UG 344 OPUC DR 125 Supp Attach 2 – O&M Model**' by going to the Shared Services OH Credit tab. The total system shared services credit in the test year is $225,287. The total gets picked up in the O&M TY FERC Allocation Summary tab in cell L124. To determine the OR state allocated amount, column AA in the same tab will show the OR allocation % to be used for FERC 921, which for the test year is 89.25%.

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Request No.: UG 344 OPUC DR 126

126. Please provide the following information separately by month for each NW Natural Officer in 2016 and 2017:
a. Hours billed to each affiliate and NW Natural non-utility project; and
b. Payroll and overhead dollars allocated to each affiliate and NW Natural non-utility project;

Response:

126. See attachment 'CONFIDENTIAL UG 344 OPUC DR 126 Attachment 1' for the hours billed to each affiliate and hours charged to NW Natural non-utility projects along with the associated payroll and overhead dollars allocated. The results are totaled separately for all of NW Natural's Officers by month for the years 2016 and 2017 respectively.

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Request No.: UG 344 OPUC DR 127

127. Please provide the following information by month totaled separately for Exempt, Non-Exempt, and Union employees, excluding Officers:
a. Hours billed to each affiliate and NW Natural non-utility project; and
b. Payroll and overhead dollars allocated to each affiliate and NW Natural non-utility project;

Response:

127. See attachment 'CONFIDENTIAL UG 344 OPUC DR 127 Attachment 1' for the hours billed to each affiliate and hours charged to NW Natural non-utility projects along with the associated payroll and overhead dollars allocated. The results are totaled separately between the Bargaining Unit (BU) employees and the non-Bargaining Unit (NBU) employees for the years 2016 and 2017 respectively.

NW Natural

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Request No.: UG 344 OPUC DR 130

130. Please provide the date and location for each NW Natural and NW Natural affiliate board of director and board of director committee meetings in 2016 and 2017.

Response:

Please see Confidential UG 344 OPUC DR 130 attachments 1 and 2.

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Request No.: UG 344 OPUC DR 162

162. Please refer to NW Natural/800 Karney/17.
a. Please provide all cost benefit analysis of the MWVF, the Central Coast Feeder and the Grants Pass Lateral alternatives.
b. Are the Central Coast Feeder and the Grants Pass Lateral pipelines the only alternatives to the Monmouth/Independence reliability needs that were evaluated by NW Natural? If no, please provide all cost benefit analysis of any other alternative evaluated.

Response:

The statement in the testimony that the "current alignment from the Central Coast Feeder to Monmouth/Independence provides the most direct connection of the additional distribution capacity to the area of low pressure" is a reference to the Mid-Willamette Valley Feeder (MWVF). In other words, the MWVF itself is that connection, and provides the "most direct connection" to the area of low pressure. Thus, to the extent the question is asking for NW Natural's analysis of the "Central Coast Feeder" as an alternative to meeting load, that alternative is represented by the MWVF itself.

With respect to a connection with the Grants Pass Lateral, the testimony notes that such a connection to the lateral would require a river crossing. NW Natural's experience with river crossings is that they add significant costs to the siting of a pipeline, and such costs would be expected to apply to this river crossing as well. This route would be an assumed 12 miles long. Historic construction costs of 12" gas main, based on the MWVF, Corvallis Loop and other high-pressure steel pipeline jobs, range from of $2 to $2.5 million per mile, so the baseline estimated cost would be in the range of $24 to $30 million. Additional costs for construction of a significant HDD bore of crossing the Willamette River is estimated to be an additional $3 to $4 million based on the crossing of the Willamette River on the Corvallis Loop project. A new gate station may also need to be constructed on William's Grants Pass lateral adding an additional $1 to 2 million. Therefore, $28 to $36 million would be a reasonable estimated cost range for a project of this scope.

The Grants Pass Lateral connection route crosses primarily privately held agricultural land and would include a crossing of the Willamette River. Environmental permitting is the significant risk associated with this alignment. The Joint Permit Application process is generally a 2 year process for the design studies and permit application process. Another risk for this route would be the extensive time and uncertain availability to secure multiple private easements. Approval of Land Use

Compatibility Statements (LUCS) by the County and Oregon DEQ would also be required for each private property, which is another extensive process and has risks due to uncertainty of outcome. This route overall is considered to have greater risks to impacting environmentally sensitive areas, such as wetlands and waterways, than a route that could be constructed primarily in developed public road rights-of-way.

Other alternatives, such as satellite LNG and Demand Side Management (DSM) to serve the load were not evaluated at the time to serve Monmouth/Independence area. For reference, similar satellite LNG being evaluated as an alternative for another project in Eugene, estimates the cost of installation to be $25 to 30 million with approximately $450 thousand in annual O&M costs. There are additional risks with finding a suitable site and obtaining necessary environmental permits for satellite LNG. Demand Side Management with customer-specific, geographically focused defined interruptibility agreements within the area of influence to delay system reinforcement is not an option, as there are no customers of appropriate size with firm service in the area.

Taken on the whole, NW Natural estimates that the connection to the Grants Pass Lateral would cost somewhere between $28 and $36 million. It would also present risks associated with permitting, obtaining easements, and crossing the Willamette River. A satellite LNG would cost between $25 and 30 million and have high operating costs for the life of the asset. DSM would not be able to reduce demand adequately to allow the existing infrastructure to meet firm customer loads during peak loads. For these reasons, NW Natural’s assessment is that these alternatives are inferior to the addition to rates of the MWVF.

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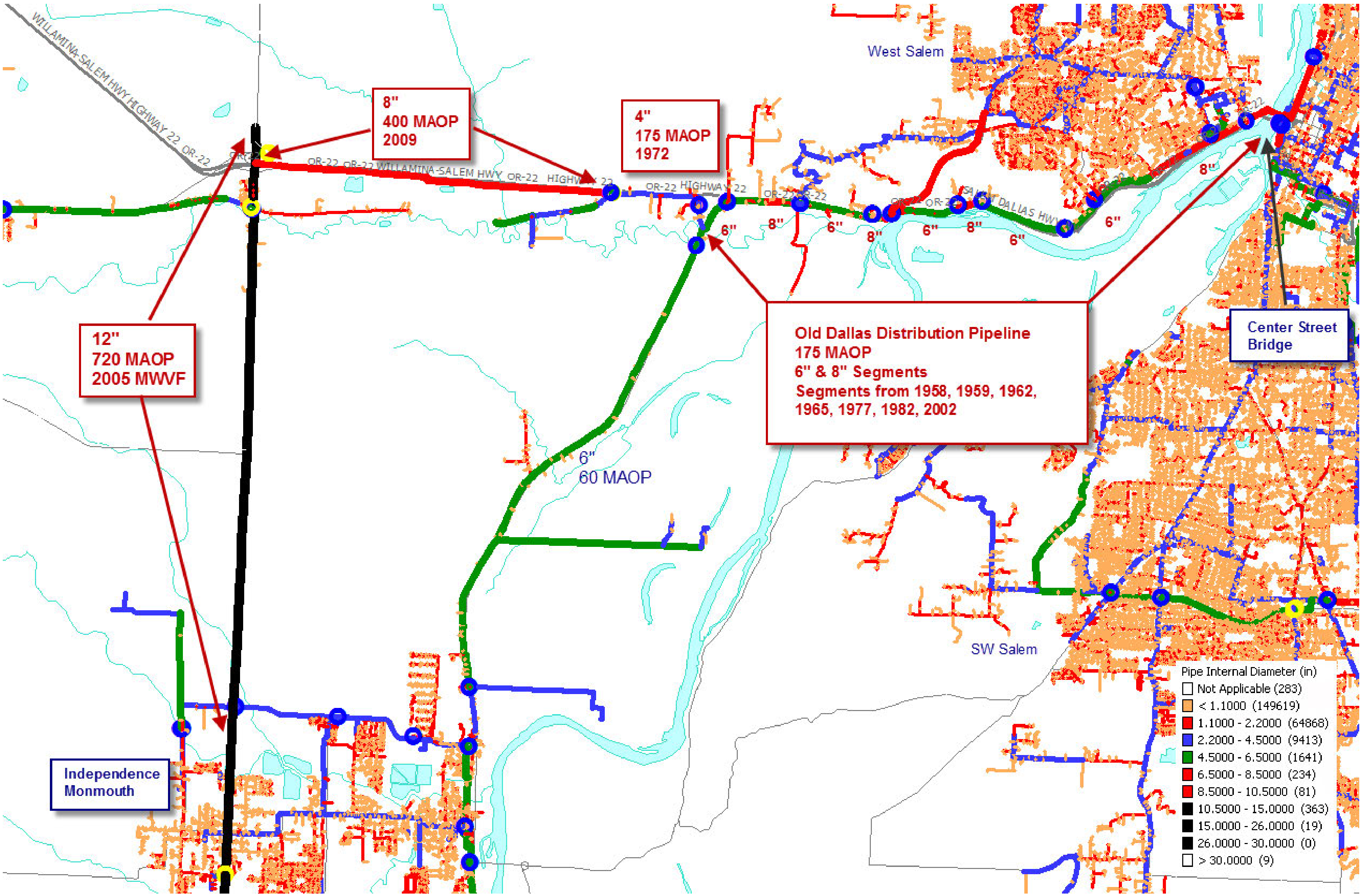
Request No.: UG 344 OPUC DR 163

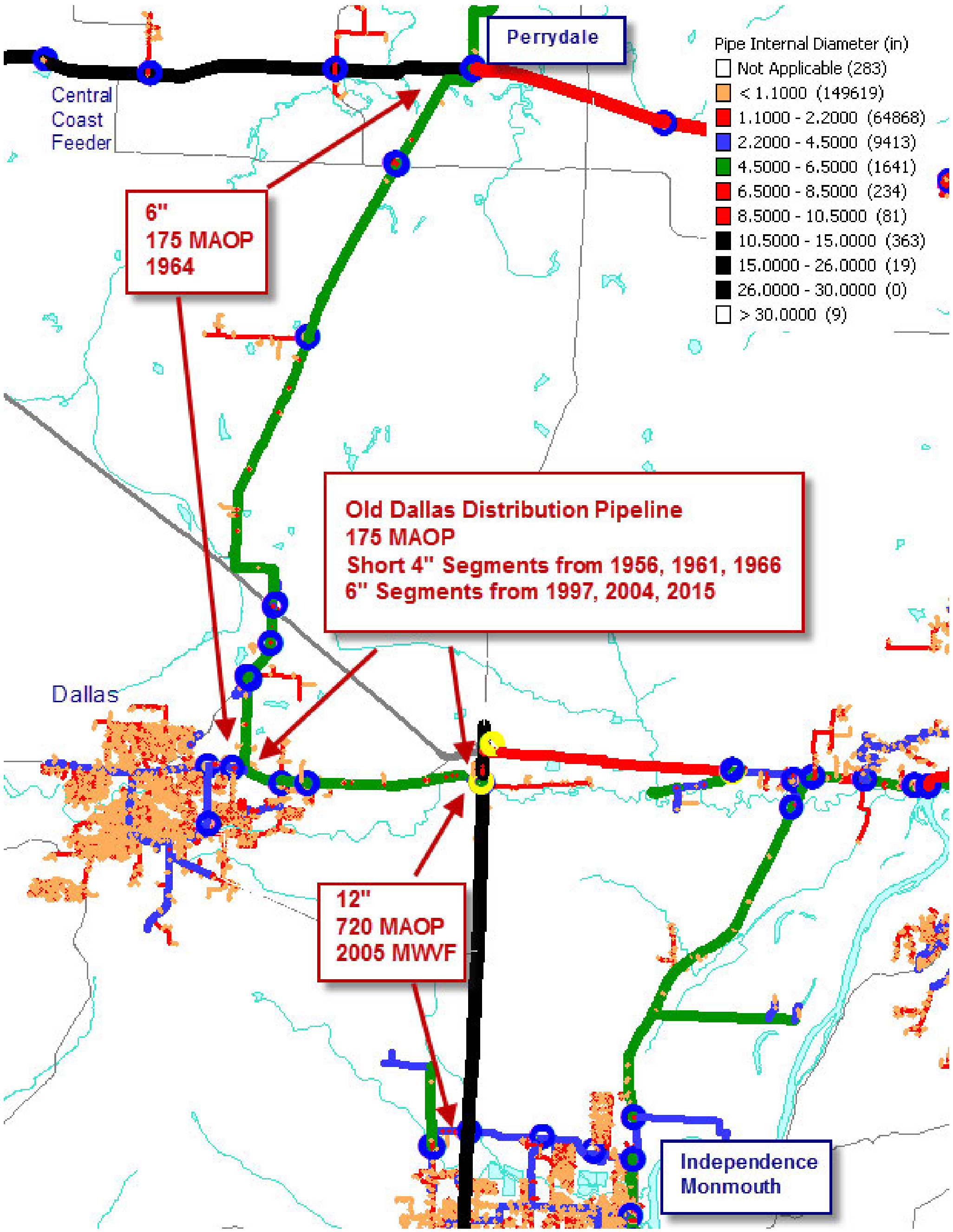
163. Please refer to NW Natural/800 Karney/14.
   a. Please provide the diameter each segment of the Center Street Bridge pipe route to Independence Monmouth.
   b. Please provide the diameter each segment of the Perrydale pipe route to Independence Monmouth.
   c. Please provide the significance of blue circles and yellow circles on this diagram.
   d. Please provide the sendout results from the model in this diagram modified to include a 4 inch 175 psig pipe following the dashed line which traces the north section of the MWVF.

Response:

a. The following Synergi Model display identifies the pipe diameter and MAOP of segments of the pipeline route from the Salem Center Street Bridge to Independence/Monmouth:

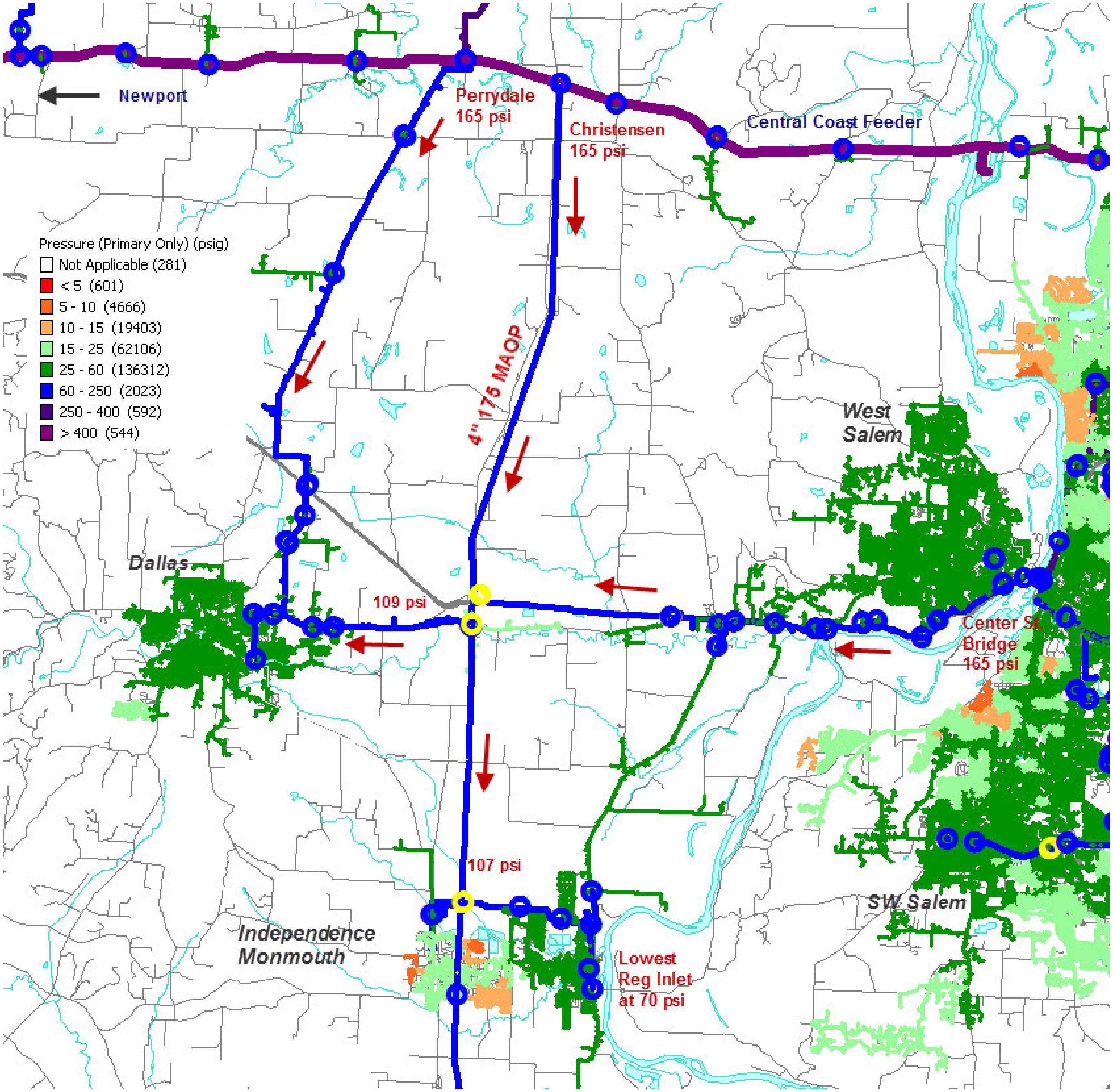

8"
400 MAOP
2009
4"
175 MAOP
1972
12"
720 MAOP
2005 MWVF
Old Dallas Distribution Pipeline
175 MAOP
6" & 8" Segments
Segments from 1958, 1959, 1962, 1965, 1977, 1982, 2002
Center Street Bridge
West Salem
SW Salem
Independence Monmouth
6"
60 MAOP
WILLAMINA-SALEM HWY HIGHWAY 22
Pipe Internal Diameter (in)
Not Applicable (283)
< 1.1000 (149619)
1.1000 - 2.2000 (64868)
2.2000 - 4.5000 (9413)
4.5000 - 6.5000 (1641)
6.5000 - 8.5000 (234)
8.5000 - 10.5000 (81)
10.5000 - 15.0000 (363)
15.0000 - 26.0000 (19)
26.0000 - 30.0000 (0)
> 30.0000 (9)

b. The following Synergi Model display identifies the pipe diameter and MAOP of segments of the pipeline route from Perrydale to Independence / Monmouth:


Perrydale
Central
Coast
Feeder
Pipe Internal Diameter (in)
Not Applicable (283)
< 1.1000 (149619)
1.1000 - 2.2000 (64868)
2.2000 - 4.5000 (9413)
4.5000 - 6.5000 (1641)
6.5000 - 8.5000 (234)
8.5000 - 10.5000 (81)
10.5000 - 15.0000 (363)
15.0000 - 26.0000 (19)
26.0000 - 30.0000 (0)
> 30.0000 (9)
6"
175 MAOP
1964
Old Dallas Distribution Pipeline
175 MAOP
Short 4" Segments from 1956, 1961, 1966
6" Segments from 1997, 2004, 2015
Dallas
12"
720 MAOP
2005 MWVF
Independence
Monmouth

c. The previous two Synergi Model displays show pipelines color coded by pipe diameter. The blue circles indicate active regulators which control pipe pressures in the model. The yellow circles indicate inactive regulators in the model which have been disabled (but not removed). The action of disabling a regulator is necessary in modeling to perform alternate operating pressure scenarios, for example operating a pipeline at 175 MAOP instead of 400 MAOP which is the result of removing the MWVF supply from the model.

d. The following map is a Synergi Model display by pipeline pressure on a peak day that includes a theoretical 4” 175 MAOP pipeline substituted for the northern most section of the 12” MWVF. The previously indicated customer outages in the Independence / Monmouth area are improved with this addition. It should be noted that this hypothetical pipeline is a short term improvement only. The 4” 175 MAOP pipeline would be near full capacity today, as seen by the 70 psig inlet pressures in Independence. An additional pipeline would be necessary in the near future to meet any growth in the Independence/Monmouth area. Additionally, the 175 MAOP operating pressure and the relatively small size (4”) of this pipeline does not allow gas to flow into the Albany/Corvallis load center in useful quantities.


Newport
Perrydale
165 psi
Christensen
165 psi
Central Coast Feeder
Pressure (Primary Only) (psig)
Not Applicable (281)
< 5 (601)
5 - 10 (4666)
10 - 15 (19403)
15 - 25 (62106)
25 - 60 (136312)
60 - 250 (2023)
250 - 400 (592)
> 400 (544)
4" 175 MAOP
West
Salem
Dallas
109 psi
Center St.
Bridge
165 psi
107 psi
SW Salem
Independence
Monmouth
Lowest
Reg Inlet
at 70 psi

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Data Request Response

Request No.: UG 344 OPUC DR 164

164. Please refer to NW Natural/800 Karney/18 at lines 1 and 2.
a. Please provide the date that the Albany/Corvallis area first began receiving gas service.
b. Did a single feeder gas service to Albany/Corvallis constitute an unreasonable risk when gas service began in the area?
c. If the response to part b is no, please identify the date that single feed gas service to the Albany/Corvallis area became an unreasonable risk.
d. Please describe the specific types of outages that could occur at the Albany/Corvallis gate station and provide the probability and expected duration of each type of outage.
e. Please describe the specific types of outages that could occur on the pipeline upstream of the Albany/Corvallis gate station and provide the probability and expected duration of each type of outage.

Response:

a. The Albany system initially received gas service in 1930 from a pipeline connected to the manufactured gas plant in Portland. That pipeline was converted to natural gas in 1956 after the connection with the interstate pipeline was installed at Sauvie Island. The Albany Gate Station and its associated pipeline was built in 1960, which provided a high pressure pipeline connection to the Albany/Corvallis load center, and eventually became the only feed due to the fact that the pre-existing 1930 pipeline was too small, of too low pressure to feed the system, and a bare steel pipeline eventually deteriorated to the point it was taken out of service.

b. No. When the original pipeline was installed in 1930 the Albany/Corvallis load center was small and did not present the same level of risk as supplying customers at the load center with a single feed.

c. The Company is unable to identify the exact date that the single feed became an unreasonable risk to supply the Albany/Corvallis load center. The transition from manufactured gas to natural gas in 1956 spurred significant customer growth system-wide, including in the Albany/Corvallis load center.

d. & e. All pipeline systems and facilities (such as gate stations) are subject to failures and outages due to the following causes:

- Corrosion Failure
- Natural Force Damage
- Excavation Damage
- Other Outside Force Damage
- Pipe or Weld Joint Failure
- Equipment Failure
- Incorrect Operations
- Other Causes

The probability of any given cause resulting in an outage is unpredictable, and the Company is unable to provide exact probabilities for each failure mechanism on its system or the interstate pipeline system. The Company provides examples of gate station and pipeline failures in DR 165 and 166. The consequences of an outage are very high in a single feed system. Depending on the cause of failure, the outage could be as short as a few hours or extend several weeks if a section of pipeline or gate station needs to be rebuilt. Any loss of gas service to a single feed system will require the isolation of each customer's meter, the purging of all mains and services, and the individual relight of all customers to safely restore service. For a load center the size of Albany/Corvallis, it is anticipated that a full restoration would take several months.

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Request No.: UG 344 OPUC DR 166

166. Has NW Natural ever experienced an unexpected outage or disruption to the pipeline upstream of the Albany/Corvallis gate station? If yes, please provide the dates and a brief description of the events.

Response:

Yes. On November 25, 1952, a log truck accident caused the bridge over the Tualatin River to collapse. The accident severed the pipeline installed on the bridge serving all NW Natural customers south of the Tualatin River. Additionally, on January 6, 1938 a road construction crew on Boones Ferry Rd, damaged the same pipeline. In both cases, all NW Natural customers in Salem, Albany, and Eugene lost gas service from the damage.

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Request No.: UG 344 OPUC DR 167

167. Please refer to NW Natural/800 Karney/18 figure 4.

a. Please also refer to lines 6 to 9. Please provide the distribution pressure results of the sendout model underlying this figure separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.

b. Please provide the results of the sendout model underlying this figure modified to exclude the MWVF and include the distribution pipe removed as part of the MWVF project. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.

c. Please provide the results of the sendout model underlying this figure modified to include a pipeline outage upstream of the McMinnville-Amity Gate Station. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.

d. Please provide the results of the sendout model underlying this figure modified to exclude the Newport LNG facility. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.

Response:

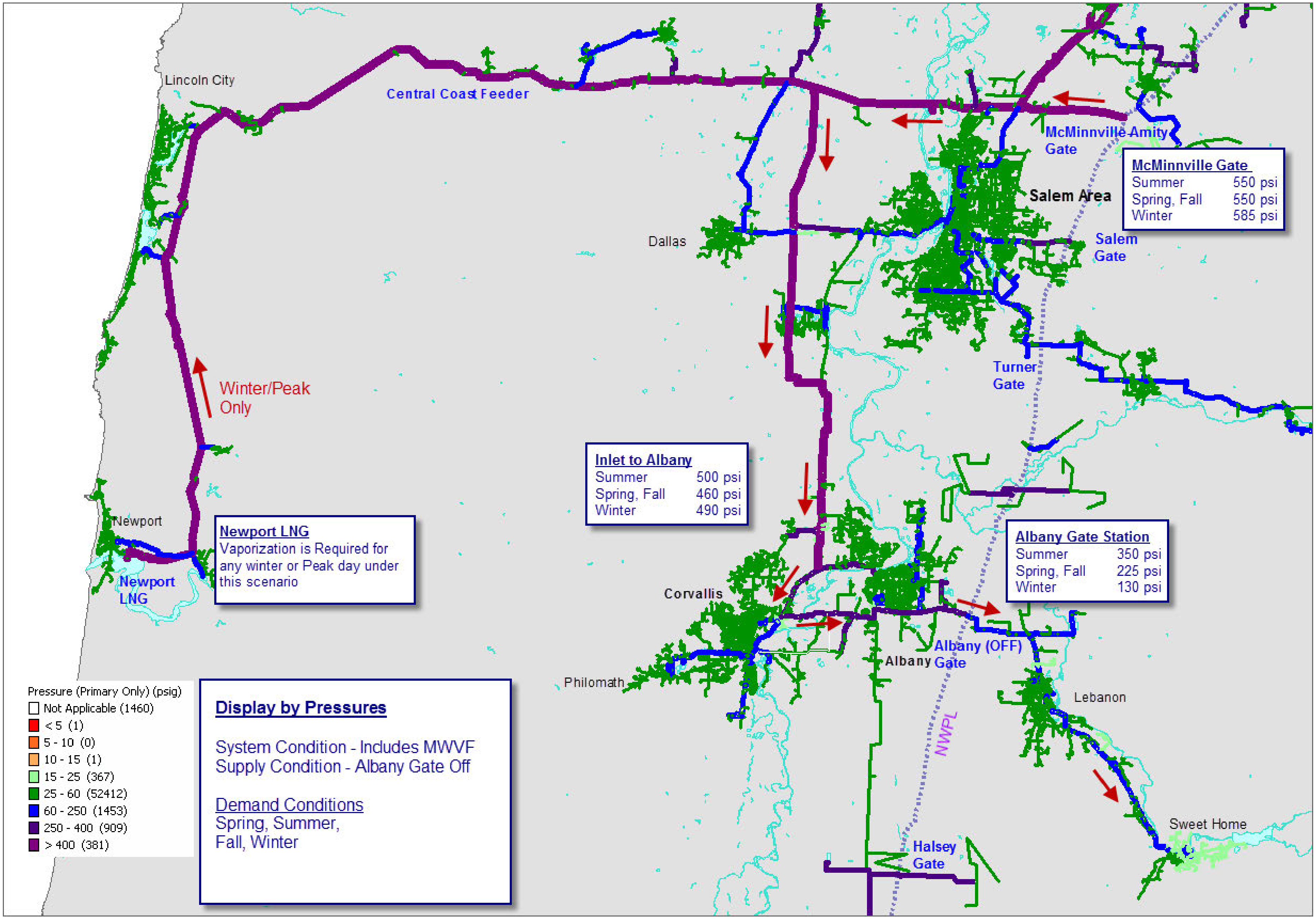
The Synergi model underlying the referenced figure 4 in testimony is a scenario which demonstrates the importance of the MWVF from a service reliability perspective. This scenario/model shows the MWVF as a complete pipeline connecting the central coast feeder pipeline to the Albany load center and indicates that Albany customers can continue to be served from the MWVF under the majority of weather situations with the loss of Albany Gate Station. This data request refers to figure 4 and asks for additional scenarios under varying weather based on the figure 4 model which has Albany gate out of service. The following responses and scenarios all begin with the initial condition of Albany Gate out of service or off.

This data request asks for modeled system pressures under customer demands from differing weather conditions ranging from typical summer to a peak day. Peak day demand is typically about nine times the demand on a warm summer day. NW Natural designs systems to reliably serve our customers on a peak day.

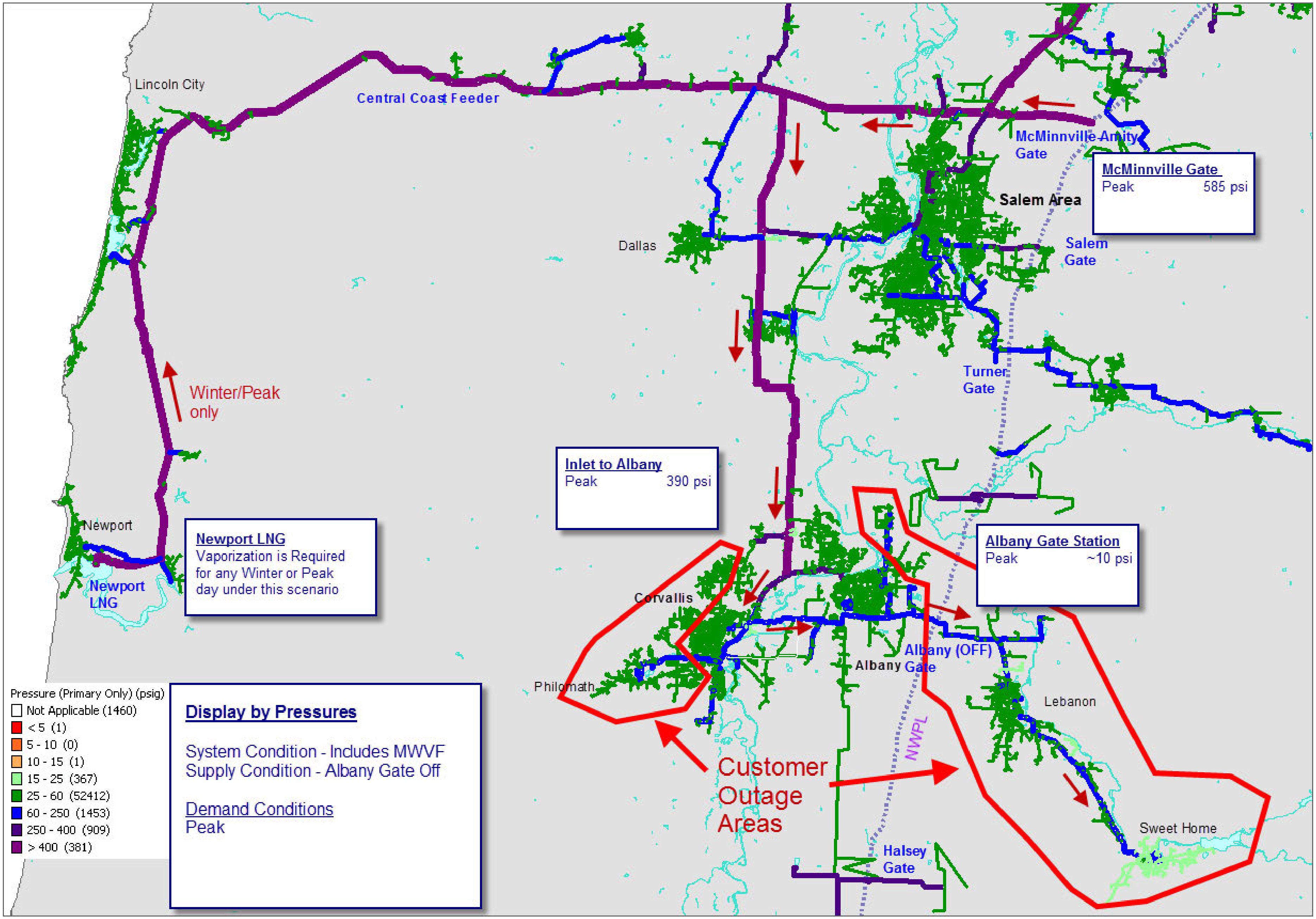
The customer demand conditions in all following scenarios are defined as:

Typical Summer = 0 HDD, Ave Temp 74 DegF
Typical Spring & Fall = 10 HDD, Ave Temp 55 DegF
Typical Winter = 25 HDD, Ave Temp 40 DegF
Peak Day = IRP Forecasted Peak Demand for 2017

a. The following Synergi display shows system pipeline pressures under the following conditions: **Includes MWVF, Albany Gate Off** for each of the following load conditions: **Spring, Summer, Fall, Winter**. Pressures are color coded by the included legend and numeric pressures are included at some locations for differing weather conditions. No customers are lost under these scenarios but it should be noted that the defined typical winter condition is the absolute maximum demand. The system is stressed to the point where outages are imminent if the demand increases. This indicates that the MWVF pipeline connection allows for the backfill of the loss of Albany Gate Supply for every day of the year except for the 20-25 coldest days of the year.


Lincoln City
Central Coast Feeder
McMinnville-Amity Gate
McMinnville Gate
Summer 550 psi
Spring, Fall 550 psi
Winter 585 psi
Salem Area
Salem Gate
Dallas
Turner Gate
Winter/Peak Only
Inlet to Albany
Summer 500 psi
Spring, Fall 460 psi
Winter 490 psi
Newport
Newport LNG
Vaporization is Required for any winter or Peak day under this scenario
Newport LNG
Corvallis
Albany Gate Station
Summer 350 psi
Spring, Fall 225 psi
Winter 130 psi
Albany
Albany (OFF) Gate
Philomath
Lebanon
NWPL
Sweet Home
Halsey Gate
Pressure (Primary Only) (psig)
Not Applicable (1460)
< 5 (1)
5 - 10 (0)
10 - 15 (1)
15 - 25 (367)
25 - 60 (52412)
60 - 250 (1453)
250 - 400 (909)
> 400 (381)
Display by Pressures
System Condition - Includes MWVF
Supply Condition - Albany Gate Off
Demand Conditions
Spring, Summer,
Fall, Winter

a. (continued) The final requested condition for scenario a. was for Peak Day demand combined with the Outage of Albany Gate with the MWVF in service. This scenario is too extreme for the Synergi modeling software to solve properly. Engineering pressure drop calculations and operational experience was used to determine the customer areas most impacted by this scenario. The following display uses the Synergi model as a background and uses red polygons to indicate areas where significant outages are expected to occur. About 25% of the customers in the Albany Load Center would lose service, approximately 10,000 customers.


Lincoln City
Central Coast Feeder
McMinnville-Amity Gate
McMinnville Gate
Peak 585 psi
Salem Area
Salem Gate
Dallas
Turner Gate
Winter/Peak only
Inlet to Albany
Peak 390 psi
Newport
Newport LNG
Vaporization is Required for any Winter or Peak day under this scenario
Newport LNG
Albany Gate Station
Peak ~10 psi
Corvallis
Albany (OFF)
Albany Gate
Albany
Philomath
Lebanon
Customer Outage Areas
NWPL
Sweet Home
Halsey Gate
Pressure (Primary Only) (psig)
Not Applicable (1460)
< 5 (1)
5 - 10 (0)
10 - 15 (1)
15 - 25 (367)
25 - 60 (52412)
60 - 250 (1453)
250 - 400 (909)
> 400 (381)
Display by Pressures
System Condition - Includes MWVF
Supply Condition - Albany Gate Off
Demand Conditions
Peak

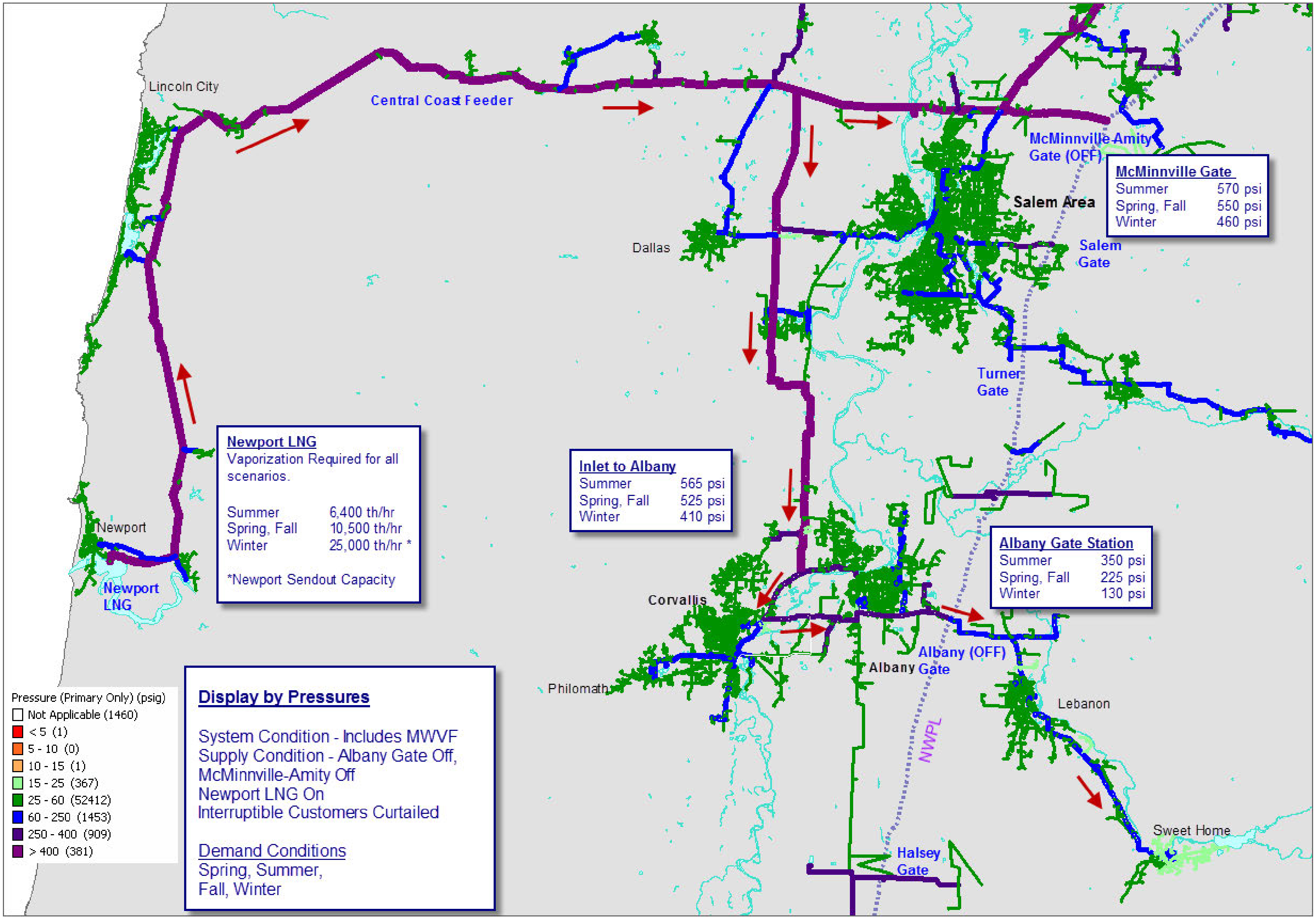
b. This section of the data request asks for pipeline pressures under the following conditions: **Pre-MWVF pipeline system, Albany Gate Off** for each of the following load conditions: **Spring, Summer, Fall, Winter, Peak**.

The Pre-MWVF pipeline system had no pipeline connection between the Albany Load Center and the Central Coast Feeder in the years immediately before the construction of the MWVF. There was a historical tie as manufactured gas was originally moved its source in the Portland area to serve Albany customers. This original pipeline was the driver for bare steel replacement along some portions of the MWVF. As there was no physical tie between Albany and other sources of gas, any failure of Albany Gate Station would result in the outage of all customers in the Albany Load Center if the MWVF were not in place.

c. This section of the data request asks for pipeline pressures under the following conditions: **Includes MWVF, Albany Gate Off and McMinnville-Amity Gate Off** for each of the following load conditions: **Spring, Summer, Fall, Winter, Peak**. This scenario requires Newport LNG to vaporize in all cases so it really becomes an exercise to see what weather conditions Newport LNG can support.

The following Synergi display shows system pipeline pressures under the following conditions: **Includes MWVF, Albany Gate Off, and McMinnville-Amity Gate Off** for each of the following load conditions: **Spring, Summer, Fall, Winter**. Pressures are color coded by the included legend and numeric pressures are included at some locations for differing weather conditions. No customers are lost under these scenarios but it should be noted that the defined typical winter condition is the absolute maximum demand. The volume of gas produced from Newport LNG under the typical winter scenario is approximately equal to the design volume of the vaporizers at Newport LNG. The plant can’t put out any more gas. Outages would increase as weather conditions get colder than typical winter.

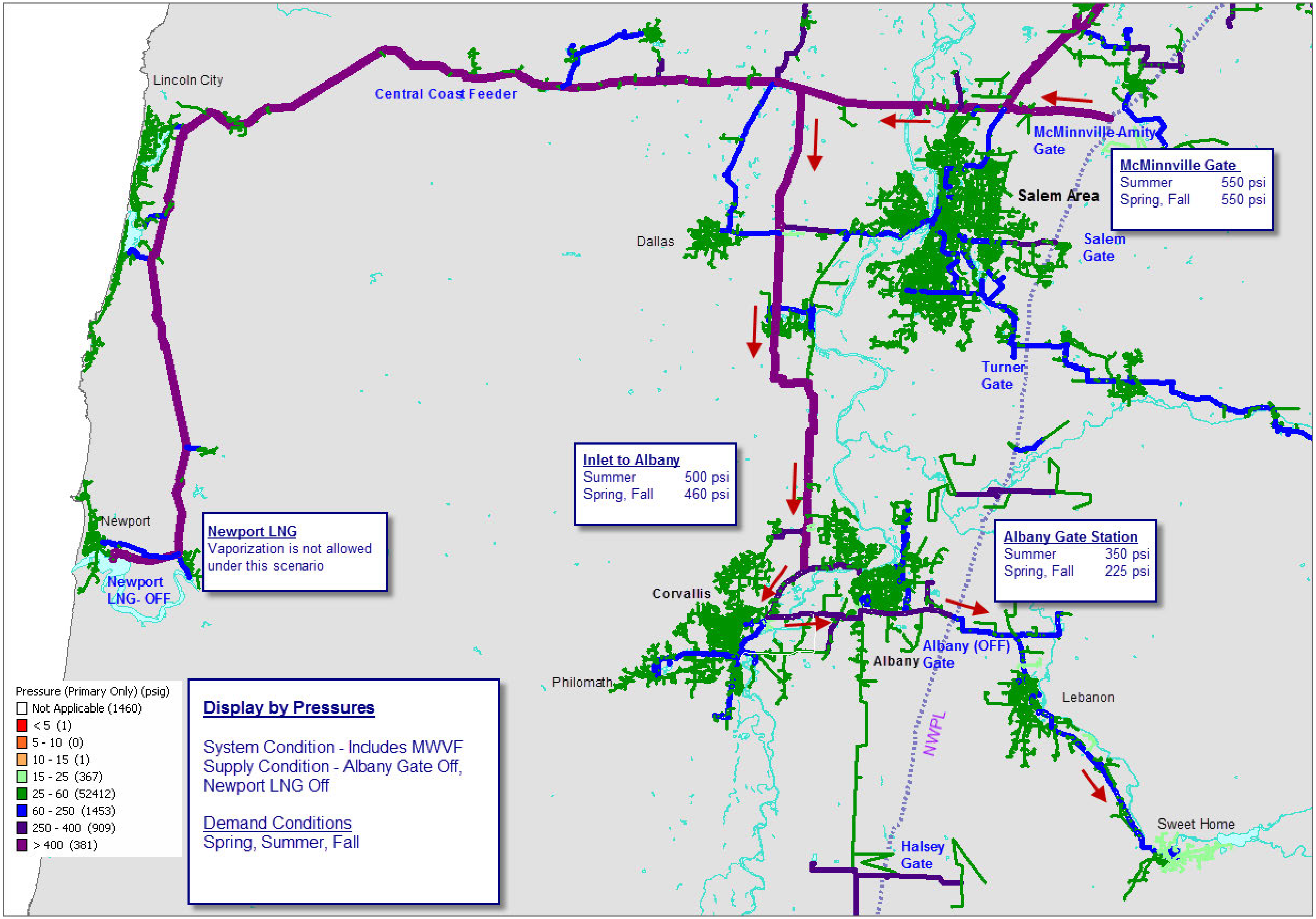
Newport LNG only has the LNG storage volume to vaporize for a couple of weeks so a prolonged outage event could seriously impact the cold weather readiness of Newport LNG.


Lincoln City
Central Coast Feeder
McMinnville-Amity
Gate (OFF)
McMinnville Gate
Summer 570 psi
Spring, Fall 550 psi
Winter 460 psi
Salem Area
Salem
Gate
Dallas
Turner
Gate
Newport LNG
Vaporization Required for all scenarios.
Summer 6,400 th/hr
Spring, Fall 10,500 th/hr
Winter 25,000 th/hr *
*Newport Sendout Capacity
Inlet to Albany
Summer 565 psi
Spring, Fall 525 psi
Winter 410 psi
Albany Gate Station
Summer 350 psi
Spring, Fall 225 psi
Winter 130 psi
Newport
Newport
LNG
Corvallis
Albany (OFF)
Albany Gate
Philomath
Lebanon
NWPL
Sweet Home
Halsey
Gate
Pressure (Primary Only) (psig)
Not Applicable (1460)
< 5 (1)
5 - 10 (0)
10 - 15 (1)
15 - 25 (367)
25 - 60 (52412)
60 - 250 (1453)
250 - 400 (909)
> 400 (381)
Display by Pressures
System Condition - Includes MWVF
Supply Condition - Albany Gate Off,
McMinnville-Amity Off
Newport LNG On
Interruptible Customers Curtailed
Demand Conditions
Spring, Summer,
Fall, Winter

c. (continued)

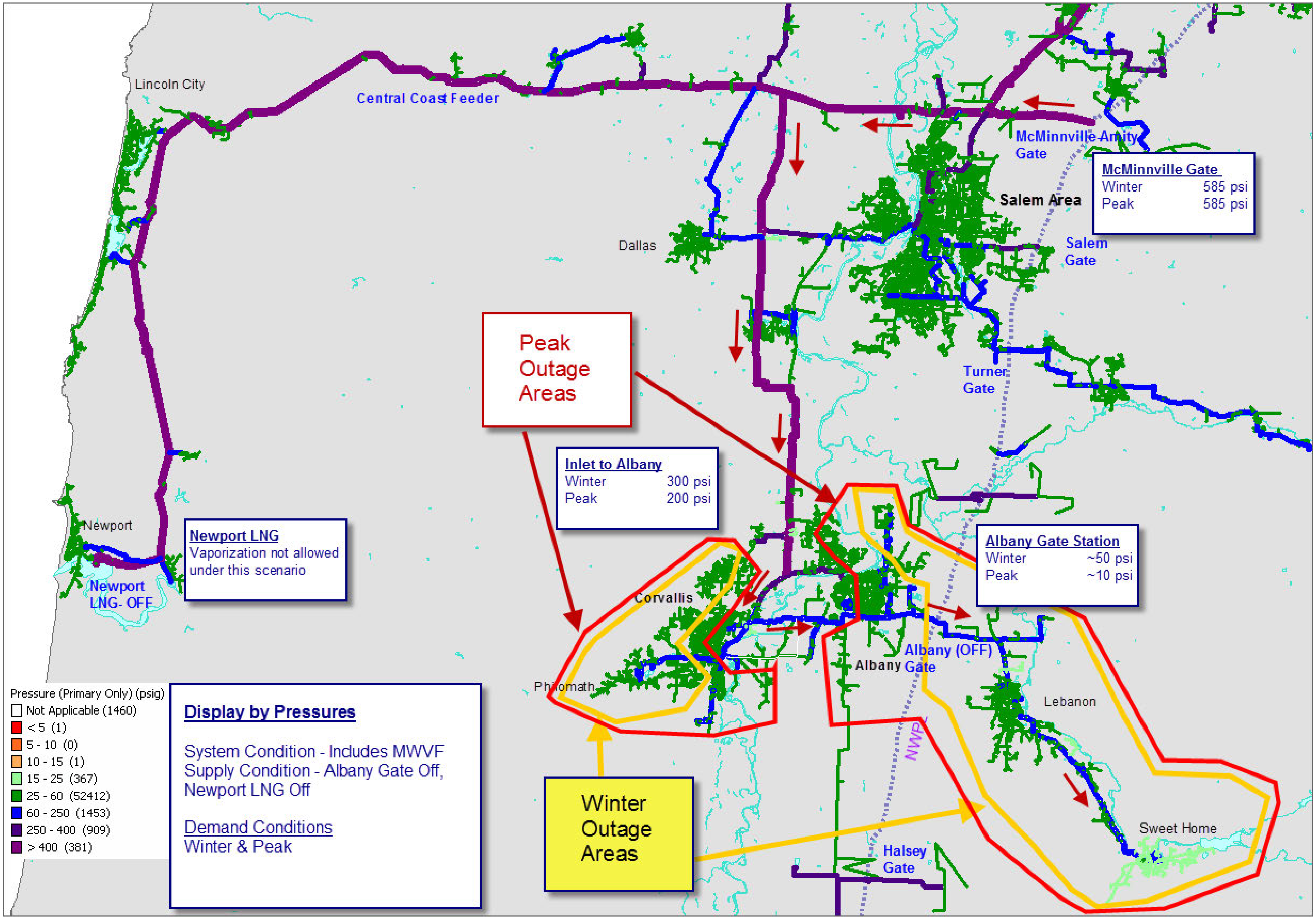
For the Peak condition of this scenario the outage area would be essentially the entire Albany Load Center. The volume shortfall between Newport sendout and system demand on Peak is approximately equal to the demand from Albany on Peak. The Albany Load Center is the end of the line and experiences the majority of outages in this scenario.

d. The following Synergi display shows system pipeline pressures under the following conditions: **Includes MWVF, Albany Gate Off, and Newport LNG Off** for each of the following load conditions: **Spring, Summer, and Fall**. Pressures are color coded by the included legend and numeric pressures are included at some locations for differing weather conditions. No customers are lost under these scenarios. It should be noted that Newport LNG is a peak shaving facility and is typically only utilized on Peak or very cold days or supply emergencies. The loss of Albany Gate supply would certainly qualify as a supply emergency. Newport LNG only has the LNG storage volume to vaporize for a couple of weeks so a prolonged outage event could seriously impact the cold weather readiness of Newport LNG.


Lincoln City
Central Coast Feeder
McMinnville-Amity Gate
McMinnville Gate
Summer 550 psi
Spring, Fall 550 psi
Salem Area
Salem Gate
Dallas
Turner Gate
Inlet to Albany
Summer 500 psi
Spring, Fall 460 psi
Newport
Newport LNG
Vaporization is not allowed under this scenario
Newport LNG- OFF
Corvallis
Albany Gate Station
Summer 350 psi
Spring, Fall 225 psi
Albany (OFF) Gate
Albany
Philomath
Lebanon
NWPL
Halsey Gate
Sweet Home
Pressure (Primary Only) (psig)
Not Applicable (1460)
< 5 (1)
5 - 10 (0)
10 - 15 (1)
15 - 25 (367)
25 - 60 (52412)
60 - 250 (1453)
250 - 400 (909)
> 400 (381)
Display by Pressures
System Condition - Includes MWVF
Supply Condition - Albany Gate Off, Newport LNG Off
Demand Conditions
Spring, Summer, Fall

d. (continued)
The colder weather scenarios (Typical Winter and Peak) both fail under the configuration of the Outage of Albany Gate and Newport LNG Off with the MWVF in service. This scenario is too extreme for the Synergi modeling software to solve properly. Engineering pressure drop calculations and operational experience have been used to determine the customer areas most impacted by this scenario. The following display uses the Synergi model as a background and uses yellow polygons to indicate expected outage areas for a typical winter day. Red polygons are used to outline the areas where significant outages are expected to occur on a Peak Day. Outage counts in the Albany Load Center for a typical winter day would be approximately 25%, about 10,000 customers. Peak day outage counts would be significantly higher about 50% or 20,000 customers.

Removing Newport LNG and Albany Gate as supply sources more than doubles the demand on McMinnville-Amity Gate which greatly exceeds its capacity. Outages would occur under this scenario for approximately the coldest 40 days of the year.


Lincoln City
Central Coast Feeder
McMinnville-Amity Gate
McMinnville Gate
Winter 585 psi
Peak 585 psi
Salem Area
Salem Gate
Dallas
Peak Outage Areas
Turner Gate
Inlet to Albany
Winter 300 psi
Peak 200 psi
Albany Gate Station
Winter ~50 psi
Peak ~10 psi
Newport
Newport LNG
Vaporization not allowed under this scenario
Newport LNG- OFF
Corvallis
Albany (OFF)
Albany Gate
Albany
Philomath
Lebanon
NWP
Pressure (Primary Only) (psig)
Not Applicable (1460)
< 5 (1)
5 - 10 (0)
10 - 15 (1)
15 - 25 (367)
25 - 60 (52412)
60 - 250 (1453)
250 - 400 (909)
> 400 (381)
Display by Pressures
System Condition - Includes MWVF
Supply Condition - Albany Gate Off, Newport LNG Off
Demand Conditions
Winter & Peak
Winter Outage Areas
Sweet Home
Halsey Gate

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Supplemental Data Request Response

Request No.: UG 344 OPUC DR 167

167. Please refer to NW Natural/800 Karney/18 figure 4.
a. Please also refer to lines 6 to 9. Please provide the distribution pressure results of the sendout model underlying this figure separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.
b. Please provide the results of the sendout model underlying this figure modified to exclude the MWVF and include the distribution pipe removed as part of the MWVF project. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.
c. Please provide the results of the sendout model underlying this figure modified to include a pipeline outage upstream of the McMinnville-Amity Gate Station. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.
d. Please provide the results of the sendout model underlying this figure modified to exclude the Newport LNG facility. Please include results showing both the source of gas and the distribution gas pressures separately for a peak day, typical spring weather, typical summer weather, typical fall weather, and typical winter weather.

Supplemental Response to C:

NW Natural is providing this supplemental response to part c as requested by Staff.

The Williams NWPL Grants Pass Lateral is an interstate transmission pipeline that begins with an interconnect to the NWPL Mainline near Washougal, WA and terminates at a dead end near Grants Pass, OR. This pipeline delivers natural gas to NW Natural customers in East Portland, Salem, Albany, and Eugene as well as many smaller cities. This NWPL facility also serves a number of non-NW Natural customers including Avista Energy in the Roseburg, Grants Pass area. Any loss of service along the length of this pipeline would directly affect customers to the south of the damage.

An outage upstream of the NWPL McMinnvile-Amity Gate Station would have similar impacts to the NW Natural system in the Salem and Albany areas as the DR 167 Part C previous response which assumed an outage of McMinnville-Amity gate. However, during colder weather there would be additional significant outages in the Salem area as both Salem and Turner gates would be disabled. This would make it even more difficult for Newport LNG gas to reach every portion of the Salem system. Newport LNG can support approximately 40,000 residential customers based on peak demand. The inability of the NWPL Grants Pass Lateral pipeline to flow southward past McMinnville-Amity Gate Station would result in the following:

Outages at all NWPL-NW Natural Gate stations from McMinnville-Amity Gate south are estimated to have this impact:

DR 167 Part C Outage Impact Estimate of NWPL Failure from McMinnville-Amity South

Gate Station Name	NW Natural District Customer Count	*	Expected Customer Outages by Weather Scenario: Summer	Spring & Fall	Winter	Peak
McMinnville-Amity Salem Turner	106,000	**	-	-	2,500	64,000
Albany	42,000		-	-	5,000	42,000
Brownsville-Halsey Coburg North Eugene South Eugene Creswell Cottage Grove	42,000		42,000	42,000	42,000	42,000
Coos County Pipeline	1,800		1,800	1,800	1,800	1,800
Customer Totals	**191,800**		**43,800**	**43,800**	**51,300**	**149,800**

* Customer Count is Based on Jan 2018 District Revenue Report from CIS

** Includes Lincoln City District Customers

Note-
Outage counts for Salem and Albany Districts may be much higher if Newport LNG is unable to vaporize immediately.
Several hours are typically required to prepare Newport LNG for vaporization.

This table does not include impact estimates for Avista Customers

Outages to NWPL Customers (non-NW Natural) from McMinnville-Amity south are estimated to have this impact:

Outages of the OreMet Pipeline in Albany, this impacts a number of Albany industrial customers
Outages of any customer directly fed from NWPL
Outages of the Avista service territory serving Roseburg, Grants Pass, and surrounding area.

All customers behind these impacted gate stations would experience outages if the duration of the outage event exceeded approximately 30 minutes. Gas pipelines can operate on residual pressure (linepack) for a varying amount of time depending upon customer demand at the time of the event. Many thousands of natural gas customers would experience an outage under this scenario and require relights or assistance from Customer Service technicians.

NW Natural®

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Data Request Response

Request No.: UG 344 OPUC DR 171

171. Please provide NW Natural's response to the following Staff Data Requests in Docket No. UG 221:

a. 156 through 158;
b. 165;
c. 170 through 177;
d. 267;
e. 340 through 342;
f. 359;
g. 376; and
h. 427 through 429;

Response:

Please see docket UG 221 for the above requested DRs. NW Natural has agreed that the Company's responses to UG 221 can be made part of this docket. As requested from Staff, NWN is uploading the Confidential portions of these DR responses to Huddle. Please see: Confidential UG 344 Attachment 1 (pdf version of all confidential UG 221 DRs requested above. Excel documents: Confidential UG 344 Attachment 2 (Confidential UG 221 attachment 18), and Confidential UG 344 Attachment 3 (Confidential UG 221 170 Attachment 1). Confidential UG 344 Attachment 4 (Confidential UG 221 428 Attachment 1).

NW Natural

Rates & Regulatory Affairs

Oregon General Rate Case – December 2011

Data Request Response

Request No. GR1-OPUC-DR 340:
In reference to the Company's response to Staff DRs 171-177 and the proposed Capital Projects in NWN/600:

i. Did the Company conduct an analysis to determine whether the MWVF project and Corvallis Loop project provide benefits to the ratepayers from a cost effectiveness perspective when compared to purchasing additional capacity on the Grants Pass Lateral or to other alternatives? Please provide the analysis or studies performed to support this conclusion. If none was performed, explain how the Company concluded that these projects were found cost effective from a ratepayer perspective?

ii. With regard to reducing the impact of an outage on the Grants Pass Lateral: Did the Company conduct a cost-benefit analysis from a risk mitigation perspective to its ratepayers of the proposed projects vs. purchasing additional capacity on the Grants Pass Lateral or vs. other alternatives?

iii. Provide a map showing the NWPL's Grants Pass Lateral in the Company's territory and identify the facilities with specifications where the two systems interconnect.

iv. What are the average demand (annually) and the peak demand in the last five years by customer class in the Albany region?

v. What is the Company's projected growth in the number of customers and the associated load during the test year in the Albany area?

Response: 2/23/2012

i) There is no additional capacity available on the Grants Pass Lateral and the Company is not aware of any plans by Northwest Pipeline (NWP) to expand or reinforce the Grants Pass Lateral. And, for other reasons, some of which are described in part ii below, the Company believes that the MWVF project offers advantages that would not be available through an expansion of the Grants Pass lateral. The Company's IRP contains additional analysis and discussion about the Grants Pass lateral and MWVF. See the Company's IRP at Docket LC-51 Chapter 1, page 1.9 and Chapter 3, pages 3.12 through 3.19. See also the Company's response to OPUC DR 177.

With respect to the Corvallis Loop Project, regardless of the fact that there is no expected expansion of the Grants Pass Lateral, a purchase of additional firm capacity on the Grants Pass Lateral is not a viable alternative because it does not address the pipeline restrictions downstream of the Grants Pass Lateral between the Albany Gate Station and the Albany and Corvallis service territories.

ii) With regard to the MWVF Project, please refer to the Company's IRP and the Company's response to OPUC DR 177. Purchasing additional capacity on the Grants Pass Lateral does not reduce the impact of an outage on the Grants Pass Lateral. See OPUC DR 340 Attachment-1, which is a copy of a system reliability study that was produced in 2008. The study priority ranks single feed systems within NW Natural's territory based on potential customer outages due to a system failure. Upon completion of the MWVF, Albany, the highest ranked system would no longer be a single feed system.

iii) See OPUC DR 340 Attachment-2, which is the requested map which shows the NWN interconnects with the Grants Pass Lateral in zones 12, 9 and 8 of the NW Pipeline System. See OPUC DR 340 Attachment-3, which provides the Maximum Daily Delivery Obligation (MDDO) and NW Pipeline's published Meter Capacity for each of the delivery points within these zones.

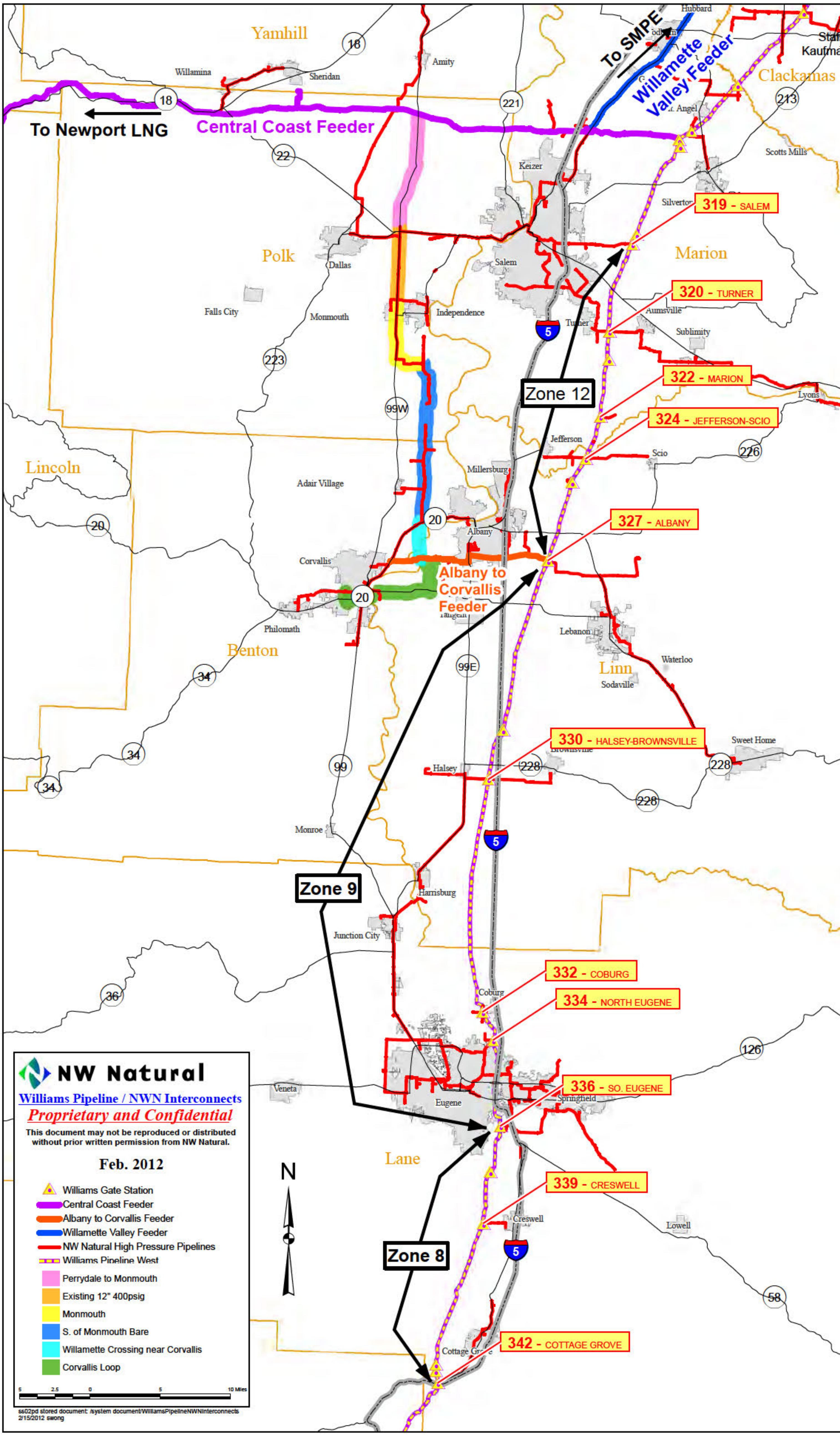
iv) The average annual demand for the Company's Albany District by customer class for 2007 through 2011 is provided at OPUC DR 340 Attachment-4.

Peak demand in therms per-hour as measured at the three gate stations in the Albany district is provided in OPUC DR 340 Attachment-5. Gas send-out at the gate stations represents all customers, including interruptible transportation customers, and cannot be reported by customer class.

v) Due to adjustments made to account for customer losses related to rate design and heat pumps, the projected change in Albany residential customer counts is a net loss of 951 customers.

The net decrease in load associated with those residential customers is 1,871 therms during the test year. Projected growth in commercial customer counts is 28, with an associated load of 76,384 therms during the test year.

Projected growth in industrial customer counts is 1, with expected additional therm usage of 2,507,333 based on the new customer add and usage changes of existing customers in the test year.


NW Natural
Williams Pipeline / NWN Interconnects
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Feb. 2012
Williams Gate Station
Central Coast Feeder
Albany to Corvallis Feeder
Willamette Valley Feeder
NW Natural High Pressure Pipelines
Williams Pipeline West
Perrydale to Monmouth
Existing 12" 400psig
Monmouth
S. of Monmouth Bare
Willamette Crossing near Corvallis
Corvallis Loop
10 Miles
To Newport LNG
Central Coast Feeder
To SMPE
Willamette Valley Feeder
Albany to Corvallis Feeder
Zone 12
Zone 9
Zone 8
319 - SALEM
320 - TURNER
322 - MARION
324 - JEFFERSON-SCIO
327 - ALBANY
330 - HALSEY-BROWNSVILLE
332 - COBURG
334 - NORTH EUGENE
336 - SO. EUGENE
339 - CRESWELL
342 - COTTAGE GROVE
Yamhill
Polk
Marion
Clackamas
Lincoln
Benton
Linn
Lane
Willamina
Sheridan
Amity
Hubbard
Keizer
Silverton
Scotts Mills
Salem
Dallas
Falls City
Monmouth
Independence
Turner
Aumsville
Sublimity
Lyons
Jefferson
Scio
Millersburg
Adair Village
Albany
Corvallis
Philomath
Lebanon
Waterloo
Sodaville
Sweet Home
Halsey
Monroe
Harrisburg
Junction City
Coburg
Veneta
Eugene
Springfield
Creswell
Lowell
N
ss02pd stored document: /system document/WilliamsPipelineNWNInterconnects
2/15/2012 swong

NW Pipeline Interconnect Capacities - Zones 12, 9 and 8

ZONE	DELIVERY POINT NUMBER	GATE STATION	MDDO TOTAL BY GATE (Dth/Day)	NORTHWEST PIPELINE METER CAPACITY (Dth/Day)*
12	319	SALEM	17,921	25,483
12	320	TURNER	8,462	9,595
12	322	MARION	125	558
12	324	JEFFERSON/SCIO	960	1,391
12	327	ALBANY	50,203	60,500
9	330	BROWNSVILLE/HALSEY	11,900	17,433
9	332	COBURG	600	2,178
9	334	N. EUGENE	25,994	33,443
9	336	S. EUGENE	17,935	35,070
8	339	CRESWELL	1,024	1,550
8	342	COTTAGE GROVE	2,940	4,700

* SOURCE: NW Passage EBB

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 197

197. Please refer to Capital Asset Policy 83.
a. Please provide copies of the annual approved capital budgets and all interim updates to capital budgets for calendar years 2012 through 2019.
b. Please provide the project level budget variance reports for the years 2012 through 2017.

Response:

a. Please see UG 344 OPUC DR 197 Attachments 1-6 and Confidential UG 344 OPUC DR 197 Attachments 7-8.

b. UG 344 OPUC DR 197 Attachments 9-14 includes annual actual to budget variances for the different categories of capital expenditures. In addition to that, we have created a document with actual to budget variances for projects with actual cost over 1 million dollars. UG 344 OPUC DR 197 Attachment 15 includes the list of large projects.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 239

239. Please provide the following documents for the Mid-Willamette Valley Feeder Projects:
   a. Business case;
   b. Project charter;
   c. Change orders; and
   d. Project closing documents.

Response:

Please see the following attached documents for the following Mid-Willamette Valley Feeder Projects

- Project 200163 – Mid Willamette Valley Feeder (Initial Engineering design)
  - UG 344 OPUC DR 239 Attachment 1 - 200163 Mid Willamette charter
  - UG 344 OPUC DR 239 Attachment 2 - Project change Request
  - There was no formal closing document for this project.
- Project 200580 – Monmouth Project
  - UG 344 OPUC DR 239 Attachment 3 - 200580 Project G-67 Charter Monmouth (includes Business case in item #7)
  - UG 344 OPUC DR 239 Attachment 4 - 200580 Project Closeout
  - There were no change orders associated with this project.
- Project 200581 – Perrydale to Monmouth
  - UG 344 OPUC DR 239 Attachment 5 - 200581 G-67 Project Plan Perry to Monmouth (includes Business case in item #7)
  - UG 344 OPUC DR 239 Attachment 6 - 200581 – Perrydale to Monmouth Project Closeout
  - There were no change orders associated with this project.
- Project 200582 – HWY 99 new Bethal Rd Tie in
  - UG 344 OPUC DR 239 Attachment 7 - 200582 Project Charter (Business case is included in “Purpose of Project section”)
  - There were no change orders associated with this project.
  - There was no formal closing document for this project.

PROJECT CHARTER

Project Title:	Mid Willamette Feeder Design Services	**Project Number:**	200163
Project Manager (PM):	Mark Schaefer	**Cost Center Manager:**	Kerry Shampine

PROJECT DESCRIPTION

Location:	Salem to Corvallis
Plats:	North Plat starting at 2-094-026, South Plat ending at 2-158-021
Scope of Project:	Engineering Design Services for approximately 28 miles of new 12" Class E Pipeline
Purpose of Project:	Project is part of the Integrated Resource Plan
Expected Impacts:	None expected for this phase
Major Constraints:	None expected for this phase
Items Specifically Excluded:	Construction
Start Date:	May 1, 2009
Construction Duration:	Complete all Design Services by December 2009
Critical Dates:	Complete all Design Services by December 2009
Funding:	30% System Reinforcement 70% Bare Steel - Mains
Estimated Cost:	$500,000
Contigency ($ and %):	$50,000 (10%)
Total Cost:	$550,000

RELATED PROJECTS

Preceding Project:	Hwy 99W – Rickreal 12"	**Completion Date:**	Sept 2005	**PM:**	Brian VanSmoorenburg
Succeeding Project:	N/A	**Start Date:**		**PM:**	
Parallel Project:	N/A	**Completion Date:**		**PM:**	

STAKEHOLDERS

NW Natural Stakeholders		**Comments**
x	**Contract Services**	Engineering firm to be contracted for design services
x	**Corrosion**	Input for preliminary design
	Distribution Crew	
x	**Elect/Communications**	Contact Communications Department for input of public outreach and communication plan
x	**Environmental/Haz Mat**	Delineation of environmentally sensitive lands
	Resource Management	
x	**Gas Supply**	Input for preliminary design
	Gasco/Mist/LNG Plants	
x	**Major Acct. Services**	Contact for potential customer acquisition
x	**Integrity Management**	Contact for input for tie-in design
x	**Purchasing / Stores**	Engineering firm to be contracted for design services
x	**Resource Center Engineer**	Greg Bronson, John Radosevich
x	**Risk and Land**	Contact for property owner coordination & ROW issues
	Safety	

x	**Specialty Const Crew (ROW)**	Input for preliminary design
x	**Station Design**	Input for preliminary design
x	**Surveying**	Engineering firm to be contracted for design services
x	**Transmission Const Crew**	Input for preliminary design
x	**Transmission Maint Crew**	Input for preliminary design
x	**Welders**	Input for preliminary design
External Stakeholders		**Comments**
x	**City**	Independence
x	**County**	Linn, Benton, Polk
x	**State**	ODOT
x	**Engineering Firm**	TBD
x	**Property Owners**	TBD
	Other	

CHARTER APPROVAL

		Date
Project Engineer:	Mark Schaefer	March 18, 2009
Project Sponsor: (Project Budget $100K to $250K)	K J. Shampine	3.18.2009
Executive Sponsor: (Project Budget $250K to $1 Mil)	Grant McGill	3/20/09
	for [illegible]	3/20/09

CAPITAL PROJECT CHANGE REQUEST

(Project schedule change of 2 months or 25% over budget)

Project Title:	Mid Willamette Feeder Design Services	**Project Number:**	200163
Project Manager (PM):	Mark Schaefer	**Cost Center Manager:**	Kerry Shampine

PROJECT CHANGE REQUEST

Details of Change Request:	Increase project budget by $235,000.
Reason for Requested Change:	Project was initially budgeted for $550,000 as a placeholder. Project was bid to four engineering firms. Project was awarded to WH Pacific for $667,755. Total cost is $785,000 which includes $66,775 for 10% contingency and ~$50,000 as a placeholder for internal design costs.
Reference Documents	Reference PR 10002920 for the Bid Award Recommendation
Immediate Action Requested:	Increase project budget to $785,000
Documents Affected:	Charter
Resource Impacts:	None
Schedule Impacts:	None
Revised Start Date:	May 15, 2009
Critical Dates:	Completion by December 31, 2009
Impact on Budget:	
Originally Budgeted Costs:	$550,000
Variance ($ and %):	$235,000 (43% increase)
Adjusted Budget:	**$785,000**

PROJECT CHANGE REQUEST APPROVAL

		Date
Project Engineer:	Mark Schaefer	May 4, 2009
Project Sponsor: (Project Budget $100K to $250K)		
Executive Sponsor: (Project Budget $250K to $1 Mil)		

NW Natural

Monmouth Project
Project #200580
G-67 Financial Authorization
August 2011

Jon Huddleston Sponsor	8/15/11 Date
Grant Yoshihara Executive Sponsor	8/16/11 Date
John Soh Finance	8/16/2011 Date
Alex Miller Director, Rates/Regulatory Compliance	8/19/11 Date
Steve Feltz Treasurer/Controller	8/23/2011 Date
David Anderson Senior VP, Finance and CFO	9/16/11 Date
Gregg Kantor President and CEO	9/19/11 Date

MONMOUTH – PROJECT 200580

Date Submitted: 8/12/11	Facility: P30	Business Unit: Engineering
Project Sponsor: Steve Nelson		Executive Sponsor: Grant Yoshihara
Project Manager: Greg Bronson	Desired Implement Date: November, 2011	Prepared By: Greg Bronson/Katie Gough
Engineer: Greg Bronson	Short Title: Monmouth	

1. **Project Title:** Monmouth

2. **Project Description:**
This project is for installation of approximately 27,400 feet (5 miles) of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig.

   This project is part of the Perrydale to Corvallis/Albany (Mid-Willamette Valley Feeder – P30 pipeline). This project starts North of Monmouth at Hoffman Rd heading South on Hwy 99, continues through Monmouth, heads East on Stapleton, South on Corvallis Rd and ends 2790' to the South of Stapleton.

   Phase 1 will be a bore through Monmouth in public ROW. Phase 2 will be bore/open cut South of Monmouth ending South of Stapleton.

3. **Project Manager Assignment:** Greg Bronson

4. **Project Objectives:**
This project is one phase of a larger project – Perrydale to Corvallis/Albany. The project will connect the Central Coast Transmission pipeline to the Albany/Corvallis Transmission pipeline. This project has been identified in the IRP long range forecast.

5. **Schedule**
This project will start in November 2011 and be completed in May 2012. Phase 2 is dependant on easement acquisition.

6. Cost Constraints

- Project is estimated at $8,087,373 and includes 10% contingency.
- Project funding is on the System Reinforcement 115 account.
- Project preliminary design costs are on Project number 200163.

Other cost constraints include:

- Easement and workspace acquisitions.
- Work restriction due to environmental permitting including wetland delineation and erosion control and sedimentation plans.
- Haul off and disposal of spoils and bore fluid from directional drill activity.
- ODOT limitation of work hours and permit requirements for traffic control and restoration on State Hwy 99.

7. Business Case

The Perrydale to Corvallis/Albany project is necessary for the following reasons:

- Increases Public Safety by accelerating the bare steel replacement.
- Increases reliability by providing an additional supply source for Willamette Valley customers.
- Complements IRP long term forecast.
- Availability of materials may be more difficult in 2015/16.
- Cost of Capital is expected to increase if project is constructed in 2015/16.
- Impact of new Integrity regulations may consume internal/external resources.

The Monmouth section can be completed during the winter. Due to the permitting delays with the Corvallis project, crew and pipe are available.

8. Project Deliverables

- Install approximately 27,400 feet of 12-inch steel Class E main.
- Install approximately 3,000 feet of 4-inch poly Class B main.
- Build 3 new Class E regulator stations.
- Install telemetry to the new regulator stations.
- Install a new bridle.

9. Communication Plan

The Communication Plan for this project is to specifically discuss the project at the Capital Projects Meetings scheduled on a bi-monthly basis. These meetings serve the function of communicating any project related management issues and addressing them in a small team environment. Key stakeholders regularly attending the meeting include Construction Supervisors, Resource Management Coordinator, Integrity Management Supervisor, Capital Project Manager, Project Engineer and Field Engineering. Outside stakeholders will be communicated with as necessary.

Approvals.	
Greg Bronson Date: 8-12-11	Date:
Date: 8/15/11	Date:
Date: 8/15/11	Date:
Date:	

PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

Working Hours	10
Working Days	100
Calendar Weeks	20
Calendar Months	5

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$50,000.00	1	LS	$50,000.00	
2	Design - HDD	$30,000.00	1	LS	$30,000.00	GeoEngineers
2	Survey	$25,000.00	1	LS	$25,000.00	
2	Permits	$3,000.00	1	LS	$3,000.00	1200 c = $1500. Polk County EFU & floodplain = $1500
3	Pothole crew	$1,000.00	5	day	$5,000.00	Sure flow = $125/hr
4	Flaggers	$600.00	75	day	$90,000.00	2 flaggers per day = $600/day
5	Work Staging area/Easements	$6,000.00	13	each	$78,000.00	$6000/easement - 13 properties
6	Traffic Control Standard	$0.00	0	0	$0.00	5 flaggers for 2400 hrs
7	Traffic Control Equipment	$20,000.00	1	LS	$20,000.00	Misc - Barriers signs etc
8	Erosion Control / Dewatering	$30,000.00	1	LS	$30,000.00	Rain for Rent tanks,silt fence, Inlet protection, sandbags, etc.
9	Porta Johns	$240.00	5	each	$6,000.00	5 months - 2 each. $120 per month each
10	Shrink Sleeves	$20.00	20	each	$400.00	Majority will be powercrete
10	Powercrete	$50.00	670	kit	$33,500.00	$50 per 4 lb kits - 1 kit per joint
11	Skids	$5,000.00	1	LS	$5,000.00	
12	Plywood	$5,000.00	1	LS	$5,000.00	
13	Light plants	$1,600.00	2	months	$3,200.00	$800 per month per light
14	Steel plates	$125.00	40	each	$25,000.00	$125 per plate per month
15	Pipeline drying equipment	$4,000.00	1	LS	$4,000.00	One time rental
16	Sideboom	$26,000.00	3.75	month	$97,500.00	$13,000 per month per boom - use 3.75 months
17	Equipment Rental - Trackhoes	$6,500.00	2	each	$65,000.00	$6500 per month per trackhoe - use 5 months
17	Equipment Rental - Backhoes	$3,500.00	2	each	$35,000.00	$3500 per month per backhoe - use 5 months
18	Equipment Rental - Dozer	$8,000.00	1	each	$8,000.00	$8,000 per month per dozer - use 1 month
19	Water Truck	$4,000.00	1	month	$4,000.00	2 water trucks $2000 per month per truck
19	Misc hardware & rent - pigs, pumps etc	$10,000.00	1	LS	$10,000.00	pumps $1500/month
20	Shoring Rental	$10,000.00	4	month	$40,000.00	$2100/month per box DP Nicoli - $10,000 per month - use 4 months
21	Drill Pipe - 12"	$47.18	27553	ft	$1,299,950.54	Guess price on pipe - assumed all drill pipe
22	Other Pipe - 12"	$32.75	0	ft	$0.00	
23	Dump Trucks	$1,360.00	40	day	$54,400.00	2 Dump Trucks for 40 days $85/day per truck
24	Haul / Dump fee (spoils)	$5.00	940	cy	$4,700.00	47 yd per hole (7x30x6) - $5.00 per yd - use 20 holes thus 20*47 = 940 cy
24	Pee Gravel	$3.00	0	cy	$0.00	
25	Rock	$14.25	940	cy	$13,395.00	
26	Asphalt Paving	$11.71	1000	sf	$11,710.00	10 holes to pave 5 x20 each = 100sf ea - 1000sf total
27	Concrete Paving	$15.25	500	sf	$7,625.00	5 holes to cast - 5x20 each 100sf ea - 500 sf total

PRELIMINARY CONSTRUCTION ESTIMATE
Corvallis Reinforcement 200363

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
28	Sawcut	$1.00	5000	lf	$5,000.00	
29	Sand	$15.00	940	cy	$14,100.00	
30	Elbows, Tees, Stopples, etc.	$60,000.00	1	LS	$60,000.00	see material list - Pipe Bender?
31	Other Misc stores	$10,000.00	1	LS	$10,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
32	Valves	$40,000.00	1	LS	$40,000.00	see material list
33	Electrostop	$6,000.00	1	each	$6,000.00	1-12" Electrostop
34	Gas Supply Meter set	$5,000.00	0	each	$0.00	Re-build meter set at OSU (materials only)
34	District Regulator/Relief	$20,000.00	3	each	$60,000.00	3 dist regs
	Equipment/Material Total				**$2,259,480.54**	

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
35	Tual Crew Labor - 'A'	$3,810.00	100	days	$381,000.00	10 hours per day 6 man crews 100 days
36	Tual Crew Labor - 'B'	$0.00	0	hours	$0.00	10 hours per day 1 - 6 man crews 200 days
37	Welder - Standard	$1,300.00	80	days	$104,000.00	2 welders for 100 days at 10 hr days
38	Specialty Crew	$1,200.00	70	days	$84,000.00	2 man crew for 70 days
39	X-Ray	$1,300.00	50	days	$65,000.00	
40	Trans Crew	$2,520.00	20	days	$50,400.00	4 man crew - $63*10*4 = 2520 per day - R/W crew - hydro test - 20 days
41	Gas Supply	$960.00	10	days	$9,600.00	2 man crew - $60*8*2 = 960 per day
42	Flatbed Truck & Operator	$80.00	80	hours	$6,400.00	Pipe Delivery
43	Per Diem	$324.00	80	day	$25,920.00	$54/day
44	Lodging	$480.00	100	day	$48,000.00	$100/day
	Labor Total				**$774,320.00**	

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
45	Caliper Pig - Post Construction	$0.00	1	ea	$0.00	Quote from Integrity Dept
46	Contract HDD Bore - Steel	$100.00	27553	ft	$2,755,300.00	
	Contract Total				**$2,755,300.00**	

Equipment/Material Total	$2,259,480.54	
Labor Total	$774,320.00	
Contract Total	$2,755,300.00	
Total	**$5,789,100.54**	
Construction Overhead (27% for System Reinforcement)	$1,563,057.15	
Total Cost	**$7,352,157.69**	
Contingency (10%)	$735,215.77	✓
Total Project Cost w/ OH	**$8,087,373.45**	✓

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

Project:	Monmouth
PS #:	200580
PM:	Greg Bronson

A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
PROJECT TEAM			●	●	●	●	●		●	●	●	●	●	●								●	●		●		●
INITIATION TASKS	8/1/11	8/12/11																									
Create Project in SAP			A																								
Create Initiation Memo			A																								
Outline Proposed Construction Dates			A	P																							
Preliminary Design Meeting			A	P		P	P																				
PLANNING TASKS	8/1/11	10/15/11																									
Identify Project Team			A																								
Create Work Orders					A																						
Assemble As Builts & Historical Documentation					A																						
Request Design Locates									A																		
Request Survey			A																								
Request Easements			A							P																	
Draft Preliminary Design			A	P	P	P																					
Draft Preliminary Cost Estimate			A	P		P	P																				
Contract for Outside Services			A								P																
Create Design Documentation			A		P	P																					
Finalize Design			A			I	I																				
Finalize Construction Dates			A	P			P		P													I					
Create Charter or G-67 Project Plan			A																								
Charter or G-67 Project Plan Approved			A																								
Complete Engineering Sketch			P	P	A																						
Complete Traffic Control Plan				A																							
Request Permit					A																						
EXECUTING TASKS	10/15/11	11/1/11																									
Request Construction Locates									A																		
Install Construction Field Stakes				A																							
Schedule Field Resources							I		A																		
Hold Pre-Construction/Safety Meeting			A	P		P	P		I			P	P									P	P				P
Notify Stakeholders of Firm Start Dates			A				I		I													I					

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8/15/2011

Staff/702
Kaufman/56

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

Project:	Monmouth
PS #:	200580
PM:	Greg Bronson

A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
MONITORING TASKS	11/1/11	4/1/12																									
Monitor Worksite Activities			P	P		P	A		P													A					
Complete and Submit Project Change Request Form as Necessary			A				I																				
Monitor Schedule			A				P		P													P					
Monitor Budget			A				P																				
Receive & Approve all Invoices			A				A																				
Coordinate Construction Activities with Stakeholders			A				A															A					
Finalize Tie-in Procedure			A			I	P							I								P	P		P		P
Tie-in Procedure Signed Off			A		I	I	I							I													
Schedule Tie-in and Coordinate with Support Crews			I			I	I		A					I								I					
Establish Final Punch List Items & Timeline for Completion			A				A															A					
CLOSEOUT TASKS	4/1/11	6/1/11																									
Complete As Built Packet							I															A					
Audit work orders and asbuilt					A																						
Complete project document review					A	I																					
Plat asbuilt					A	I																					
Conduct Project Learning Meeting			A	P		P	P																				
Complete Final Report for Project			A																								

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8/15/2011

Staff/702
Kaufman/57

Risk Analysis

Project:	Monmouth
PS Number:	200580
Project Manager:	Greg Bronson
Date:	8/12/2011

Risk	Probability	Impact	Score (Probability x Impact)	COMMENTS (Eliminate / Mitigate)
Acquisition of Materials	*3 Numerous Non-Stock or Specialty Items*	*2 - May Impact Project*	6	Mitigate: Order parts early, determine supply for equipment that is moving and may need repairs and determine who is responsible for repairs and how long they may take.
Land Acquisition	*5 Multiple Easements*	*2 - May Impact Project*	10	Mitigate: Start work on the section that doesn't require easements.
Standard Permits	*2 Permits with Minor Conditions*	*2 - May Impact Project*	4	ODOT and Monmouth permit requirements.
Special Permits	*1 No Special Permits*	*1 - Minimal or No Impact*	1	Mitigate: Avoid open cut in sensitive areas.
Environmental Impact	*1 No Impacts*	*1 - Minimal or No Impact*	1	
Ground Conditions	*1 No Concerns*	*1 - Minimal or No Impact*	1	
Utility Conflicts	*2 Minor Utility Conflicts*	*1 - Minimal or No Impact*	2	
Weather	*3 Winter*	*2 - May Impact Project*	6	Mitigate: Add time to cost estimate to cover winter work.
Construction Method	*1 Open Trench*	*1 - Minimal or No Impact*	1	
Bore Method	*1 Horizontal Directional Drill*	*1 - Minimal or No Impact*	1	
Resources	*1 Resources Available*	*1 - Minimal or No Impact*	1	
Working Hours	*1 No Restrictions*	*2 - May Impact Project*	2	Mitigate: Work with ODOT for highway restrictions. Make sure Traffic Control Plan keep the flow of traffic moving.
Contract Availability	*1 Resources Available*	*1 - Minimal or No Impact*	1	
System Impact	*1 No Impacts - Adequate Feed*	*1 - Minimal or No Impact*	1	
		Avg Score	**2.71**	**10**
				% Contingency

Staff/702
Kaufman/58

PROJECT TIMELINE

Project:	Monmouth
PS #:	200580
Project Manager:	Greg Bronson
Date:	8/12/2011

Construction Duration	24	Weeks
Construction Expected Start Date	11/1/2011	
Construction Expected Completion Date	4/1/2012	
Construction Timeline	Flexible	

Initiation Tasks

	8/1/2011 Required Task	8/12/2011 Resp
Complete Initiation Memo	Yes	PM
Complete Charter	Yes	PM
Complete Design Review	Yes	PM

Planning Tasks

	8/1/2011 Required Task	10/15/2011 Resp
Request Easements	No	N/A
Address Environmental Issues	Yes	Envir
Request Corrosion Input	Yes	Tual Eng
RFP for Outside Services	Yes	Purch
Complete Design	Yes	Tual Eng
Station Packet	Yes	N/A
Pressure Test Documentation	Yes	Tual Eng
Order Non-Stock Parts/Reserve Stock Parts	Yes	Stores
Complete Tie-in Details	Yes	Tual Eng
Finalize Design/Engineering Sketches	Yes	Tual Eng
Complete Traffic Control Plan	Yes	FET
Request Permits	Yes	EC
Notify Stakeholders Affected by Project	Yes	PM
Complete Bore Plan	Yes	Tual Eng
Draft Preliminary Procedure	Yes	Tual Eng

Executing Tasks

	10/15/2011 Required Task	10/31/2011 Resp
Pre-Construction/Safety Meeting with Crew	Yes	Tual Eng
Install Construction Field Stakes	Yes	FET
Notifiy Stakeholders of Firm Start Dates	Yes	PM
Review Preliminary Procedure with Crew	Yes	Tual Eng

Monitoring Construction Tasks

	11/1/2011 Required Task	4/1/2012 Resp
Monitor Schedule	Yes	PM
Monitor Budget	Yes	PM
Procedure Sign Off	Yes	Tual Eng

Closeout Tasks

	5/1/2012 Required Task	5/16/2012 Resp
Conduct Project Learning Meeting	Yes	PM
Complete Final Report for Project	Yes	PM

FINANCIAL ANALYSIS

Project Title:	Monmouth	**Project Number:**	200580
Project Manager:	Greg Bronson	**Cost Center Manager:**	Steve Nelson

Funding:	**System Reinforcement**
Act Type:	115 – System Reinforcement Category 3 (COH 22% 2011)
Total Cost:	2011 $2,500,000 2012 $5,587,373 **TOTAL** **$8,087,373**
Contingency ($ and %)	Contingency used is 10% based on the size of the project. Total contingency for this project is $735,215.
Project Justification:	• This project will be funded by the System Reinforcement account. • The project falls within the established Annual Capital Budget for 2011. Current Capital Budget for System Reinforcement is $19,212,598. Current projected forecast is approximately $15,500,000. • Project is one phase of a larger replacement of existing ageing and under-sized infrastructure to support future growth that is also connected to a larger, multi-year bare steel replacement program. • Project improves deliverability and reliability as supported by the Integrated Resource Plan. • Project increases capability to utilize storage gas to support peak day needs and provide non-interstate dependent delivery to areas that are currently dependent on a single interstate delivery point. • Project is expected to be completed and placed into service in 2012. • Project costs are expected to be included in Rate Base and recovered in customer rates beginning ~~Apr. 2012~~.

9/8/2011

Monmouth Reinforcement
Preliminary Financial Analysis

PROJECT BUDGETS

DIVISION	Monmouth CAP	Monmouth O&M
System Reinforcement	7,352,158	-
Subtotals	**7,352,158**	**-**
Contingency	735,216	
Construction Overhead		-
AFUDC		-
Totals	**8,087,374**	**-**
Project Totals		**8,087,374**

FINANCIAL METRICS

Without Rate Recovery	Monmouth
NPV	(7,212,677)
IRR	-3.4%
Discount Rate	7.2%
PV of Revenue Requirement	12,666,234

With Rate Recovery	Monmouth
NPV	2,225,379
IRR	9.5%
Discount Rate	7.2%

ANALYSIS ASSUMPTIONS

- 60 year project life, 60 year book, 39 year MACRS
- 2012 Oregon test year
- no change in annual operating expenses
- Capital structure approved in the last rate case of 49.82% debt, 0.68% preferred, and 49.5% common equity with a 7.07% debt rate, a 7.16% preferred rate, and a 10.2% equity rate. The
- A 39.29% tax rate and 1.48% property tax rate was used.

Project Closeout

Project Closeout

Project Name: Mid Willamette Valley Feeder – Monmouth Section
Project Number: 200580

Date: 12/15/2012

____
Grant Yoshihara, Executive Sponsor Date

____
Jon Huddleston, Project Sponsor Date

____
Steve Nelson, Project Sponsor Date

Brian Konrad and Greg Bronson 11/13/12
____
Project Manager Date

SUMMARY

This project is phase II of the Mid- Willamette Valley Feeder project, which entailed installation of 6.4 miles of 12" steel 720 MAOP pipeline.

The original project scope was based on a route of 5.2 miles in length. However, the original route had conflicts with overhead power poles requiring NWN to select another route. The new route added 1.2 miles of pipeline. The new route started at Hoffman rd and was installed through the City of Monmouth, south along HWY 99 to Parker/Haley Roads and then terminated at Corvallis Road. The original financial analysis stated an estimate of $8,087,373.00. The scope change created a $1.8 million variance to the original estimate.
The pipeline has been installed and is providing added supply reliability to the Monmouth and Independence areas.

PROJECT SCOPE DELIVERABLES

- Project # 200580 installed 6.4 miles of 12'' high pressure pipeline.
- Installed two pressure reduction regulators at Hoffman Road, and Haley Road, with all work performed by NWN Crews.
- The installation of the pipeline was divided into 7 HDD bores totaling 4.1 miles. The directional boring was subcontracted to Brotherton Pipeline with NWN construction crews welding and handling the pipe.
- Installed 2.3 miles of open trench. Trench and backfill services provided by Civil Works Northwest.
- The pipeline has been internally inspected by Enduro Pipeline Services. The Caliper Pig process assured that all field bends and installation practices met industry standards.
- Constructed by NW Natural Construction Crews. Dave Holliman was the Crew Leader.

PROJECT SCHEDULE

Project Start: February 2012
Project Completion: October 2012
Project Delay: SHPO concurrence delay July 5th – September 15th.

PROJECT BUDGET

As of February 15, 2013

	Budget	Actual	Forecast	Variance	Notes	COH
Aug 2011	4,000	4,556		556	pre-design	27%
Sep 2011	5,000	5,230		230	pre-design	27%
Oct 2011	8,000	8,143		143	pre-design	27%
Nov 2011	120,000	120,160		160	pre-design	27%
Dec 2011	111,000	111,064		64	design	27%
Jan 2012	158,000	158,488		488	design	27%
Feb 2012	650,000	638,437		-11,563	pipe	27%
Mar 2012	1,500,000	2,011,189		511,189	construction, pipe	27%
Apr 2012	1,500,000	1,137,721		-362,279	construction	27%
May 2012	1,500,000	2,441,695		941,695	construction	27%
Jun 2012	500,000	509,530		9,530	construction	27%
Jul 2012	100,000	166,182		66,182	arch hold	27%
Aug 2012	1,091,373	71,834		-28,166	arch hold	27%
Sep 2012	700,000	744,092		700,000	hydro, caliper pig, bridle	22%
		318,158		318,158	Design from 200163	0%
Oct 2012	20,000	912,393		892,393	bore, tie and reg	22%
Nov 2012	20,000	114,483		94,483	clean up	22%
Dec 2012		117,809		117,809	close out	22%
Jan 2013		7,823		7,823	close out	22%
Feb 2013		775,946		769,585	*pipe transfer	22%
Total	**8,087,373**	**10,056,777**	**0**	1,969,404		

Significant budget impact issues:

1. SHPO concurrence permitting process.
2. Demobilization and remobilization of HDD contractor.
3. Third party monitor for SHPO compliance.
4. Purchase of wooden construction mats.
5. Added labor costs due to project delay.

Budget Table

Mileage	Price Per Foot	Budget	10% Contingency	Total Budget
5.2 Miles	$ 266.84	$ 7,352,158	$ 735,216	$ 8,087,373
1.2 Miles (DIFF)	$ 266.84	$ 1,664,796	$ 166,480	$ 1,831,275
TOTALS		$ 9,016,953	$ 901,695	$ 9,918,649

Budget Table - The table uses price per foot, based upon the original estimate for calculating the additional budget needed for the additional 1.2 miles. From there, 10% contingency was added to the total cost creating a new budget of $9,918,849 for the 6.4 mile project.

Cost Variance Table

Cost Variance		
Estimate	$	9,918,648.57
Actual Cost	$	10,056,777.00
Difference	$	138,128.43

Contingency Utilization

Reasons For Spending Contingency		
Brotherton Re-Mobilization	$	80,000.00
Purchase Of Mats	$	157,000.00
Archeological Survey	$	150,000.00
Additional Regulator	$	60,000.00
Transfers from 200163	$	318,158.00
Transfers from 200363*	$	775,248
TOTAL	$	1,540,406

Contingency Table explains the reasons for spending the 10% contingency.

1. Mobilization change order by Brotherton Pipeline. NWN did not have the permits needed for the contractor to complete the requested services.
2. Crane mats where purchase because the workspaces where located in Agricultural zones. The rental fees would have exceeded the purchase price.
3. Archeological Survey and contract services from URS. This line item was not estimated in the original scope.
4. NWN added an additional regulator at Haley rd for system reinforcement.
5. The transfer of dollars from project # 200163 was applied to cover the cost of preliminary design.
6. * Transfer of charges for pipe from project # 200363 Corvallis Loop = $775,247.93. This transfer makes the total cost of the project ~ 1% over estimated cost.

OUTSTANDING TASKS

NWN needs to establish that using equipment on crane mats in archeological sites is an acceptable practice. NWN Environmental team is awaiting the results from URS.

PROJECT CHALLENGES

- Land Acquisition for temporary work space for the HDD bore sites and project team.

- Obtaining the State Historic Preservation Office concurrence to finish the project in a previously disturbed area at Hoffman Road.

- Short time lines to meet permitting processes.

- Transparency of Contract Environmental resources at Hoffman Road and Stapleton Road.

- Implementation of the contract for the trenching and backfilling service was challenging. NWN crews normally self perform this function or have used hourly contractors. The contracted trenching process required moving in added pipe handling equipment (Sideboom). This method required added inspection support and contract management.

LESSONS LEARNED

- NWN should gain all necessary permits prior to making commitments to contractors
- NWN needs to develop contract standards for HDD as-building. This is to include cross streets, bore entry, elevations and exit points.
- The Environmental team needs a year in advance to apply, permit and gain concurrences on large scale projects.
- HDD contractors need to sign off on acceptance of HDD designs.
- The project team needs more time to address land use application processes.
- Complete wetland delineation prior to selecting the alignment and construction process.
- Communication with the stakeholders and sponsors is crucial to meeting the deliverables.
- Having a communication plan is crucial for delivering a consistent message to all external/internal interest.
- NWN needs to plan, budget and permit before we commit to completion dates.

COMMENTS

The Monmouth 12 inch pipeline extension was a successful phase of the Mid Willamette Feeder project. The project accomplished installation of 6.4 miles of 720 MAOP 12'' steel pipeline.

NWN construction crews constructed a quality assured pipeline. NWN had Enduro Pipeline Services conduct a post construction multichannel pigging run on the pipeline. This process did not identify any defects or excessive dents and will act as a baseline when NWN uses the ILI tooling.

The Monmouth phase of the MWF had plenty of public inquiry and the team addressed these issues professionally and timely. The team was questioned by multiple agencies such as cities and counties and publications such as newspapers. The common questions were why, how and how much. The biggest interest was mostly about the large drilling equipment that was used to bore the 4.1 miles of pipeline in 7 separate sections. Preconstruction contacts with agencies such as ODOT and mayoral offices were quite helpful.

The excavation services for the 2.3 miles of direct burial on Parker Road and Haley Road was contracted to Civil Works Northwest. Civil Works Northwest provided trenching and backfilling services for the installation at approximately $20.00 per ft. NWN provided all the backfill materials. This practice allowed NWN crews to flex between the HDD phases and the trenching phases of work. Future projects that choose to outsource this service will need to address changing conditions of trench profiles and add to the estimated cost due to the large variability of depths and widths.

The number one priority of the project was to have a safe project. The exposure of the workers to high volume traffic along HWY 99 was of high concern. The traffic control plan was executed correctly and collisions still occurred in the work zone. These events were all rear end collisions and it was concluded that the drivers where not paying attention to the cautionary signage. We feel fortunate that nobody was seriously injured in any of the collisions and that all the workers avoided injury from this activity.

This project was successful because our consultants and employees where dedicated to meeting the project milestones. It could not have been completed on time without the hard work and dedication of NW Natural construction crews, the NW Natural environmental team and our contractors/consultants.

NW Natural

Perrydale to Monmouth Project
Project #200581
G-67 Financial Authorization
March 2012

Jon Huddleston Sponsor	4/13/12 Date
Grant Yoshihara Executive Sponsor	4/14/12 Date
John Sohl Finance	4/27/2012 Date
Alex Miller ~~Director, Rates/Regulatory Compliance~~ VP Finance & Regulation	4/30/12 Date
Steve Feltz Treasurer/Controller	5/10/2012 Date
David Anderson Senior VP, Finance and CFO	5/18/12 Date
Gregg Kantor President and CEO	5.18.12 Date

FINANCIAL ANALYSIS

Project Title:	Perrydale to Monmouth	Project Number:	200581
Project Manager:	Mark Schaefer/Brian Konrad	Cost Center Manager:	Steve Nelson

Funding:	**System Reinforcement**
Act Type:	115 – System Reinforcement Category 3 (COH 27% 2012)
Total Cost:	**2012 $13,451,105**
Contingency ($ and %)	Contingency used is 10% based on the size of the project. Total contingency for this project is $1,222,828.
Project Justification:	• This project will be funded by the System Reinforcement account. • The project falls within the established Annual Capital Budget for 2012. Current Capital Budget for System Reinforcement is $41,613,000. Current projected forecast is approximately $38,801,762. • Project is one phase of a larger replacement of existing ageing and under-sized infrastructure to support future growth that is also connected to a larger, multi-year bare steel replacement program. • Project improves deliverability and reliability as supported by the Integrated Resource Plan. • Project increases capability to utilize storage gas to support peak day needs and provide non-interstate dependent delivery to areas that are currently dependent on a single interstate delivery point. • Project is expected to be completed and placed into service in 2012.

Perrydale to Monmouth Reinforcement
Preliminary Financial Analysis

PROJECT BUDGETS

DIVISION	Perrydale to Monmouth CAP	Perrydale to Monmouth O&M
System Reinforcement	9,628,565	-
Subtotals	**9,628,565**	-
Contingency	1,222,828	
Construction Overhead	2,599,713	-
AFUDC		-
Totals	**13,451,106**	-
Project Totals		**13,451,106**

⑤

FINANCIAL METRICS

Without Rate Recovery	Perrydale to Monmouth
NPV	(11,994,370)
IRR	-3.4%
Discount Rate	7.2%
PV of Revenue Requirement	21,062,100

With Rate Recovery	Perrydale to Monmouth
NPV	3,679,339
IRR	9.5%
Discount Rate	7.2%

ANALYSIS ASSUMPTIONS

- 60 year project life, 60 year book, 39 year MACRS
- 2012 Oregon test year
- no change in annual operating expenses
- Capital structure approved in the last rate case of 49.82% debt, 0.68% preferred, and 49.5% common equity with a 7.07% debt rate, a 7.16% preferred rate, and a 10.2% equity rate. The WACC is estimated at ~~7.22%~~. 8.62% ①
- A 39.29% tax rate and 1.48% property tax rate was used.

PERRYDALE TO MONMOUTH
12"MID WILLAMETTE SYSTEM REINFORCEMENT 200581

Date Submitted:3-8-2012	Facility: S 36	Business Unit: Engineering
Project Sponsor: Steve Nelson		Executive Sponsor: Grant Yoshihara
Project Manager: Brian Konrad/ Mark Schaefer	Desired Implement Date: June 1 – October 1 2012	Prepared By: Brian Konrad
Engineer: Mark Schaefer	Short Title: Perrydale to Monmouth Project #: 200581	

1. **Project Title: Perrydale to Monmouth**

2. **Project Description:**
This project consists of installing approximately 8.3 miles of 12" (W) Class F pipeline. This site is located South of Amity, Oregon North of Bethel road on HWY 99W and continues south to the HWY 22 and 99 W junctions just north of Rickreal.
   - The connection of the P-30 Central Coast Feeder Pipeline to the Mid Willamette Feeder Line will allow storage gas from Mist and Newport LNG to the Mid Willamette Valley. This project is one of five phases to reinforce the supply system in the Mid Willamette Valley. The installation processes will consist of 5 miles of HDD (Horizontal Directional Drill) and 3.3 miles of direct burial. The installation will be performed by qualified contractors through an RFP bid process.

3. **Project Manager Assignment:** Brian Konrad and Mark Schaefer

4. **Project Objectives:**
   - Connect the P-30 to the S-36.
   - Design and construct for Integrity assessments, ILI.
   - Turn Key Contract except Hot Work.
   - Execute processes that reflect NWN Safety and Environmental Stewardship.
   - Have a positive outcome with property acquisitions and temporary work space agreements.
   - Contract management and change order request and approval.
   - Communicate to the local community prior to start of the project.

- Implement the use of Mutli- Channel Caliper Pig for quality control of bends and dents during the construction to establish a base line for this segment of pipeline.
- Make sure that all documentation of the project is accurate and complete for compliance.

5. Schedule (SEE DETAILED CHART)

- Route and alignment finalized. Geo- Bores and preliminary design for HDD executed and drafted. 2011
- Survey of ROW
- Environmental impact assessment and wetland delineation survey.
- Alignment Drafted- January 2012
- Alignment and scope presentation to ODOT January 2012 Permitting and land acquisition winter- spring of 2012.
- P&W railroad permits
- ODOT right of way permits
- Land use Compatibility Statement
- Erosion Control and 1200 C applications
- Pipe order February with the expected delivery date in May
- RFP March 5th with the expected start of construction in May
- Cultural Resource Survey
- Land Acquisition finalized- Permanent and Temporary Agreements.
- Public notice sent out to the community
- Pre- construction meetings with Damage Prevention and Safety
- Mobilization of construction crews
- Pipe delivery
- Start of construction June 1 through October 1
- Caliper Pig run and Hydrostatic test, dry and line put in service by October 31, 2012.

6. Cost Constraints

- Project is estimated at $13,451,105.31 this includes COH @ 27% and 10% contingency.
- Project funding is on the System Reinforcement account.
- The Construction Overhead rate for this project is 27%.
- The estimate was created from NW Natural current history of capital projects and will be constructed by contractors.

7. Business Case

- This project will allow storage gas to flow to the Mid Willamette Valley after the Aurora to Brooks S02 Project is complete.
- This project will improve the reliability of the system to the Mid Willamette area.

8. Project Deliverables

- Install 8.3 miles of 12", Class F main
- Install valve station at intertie and create ILI pigging stations.
- Install valve bridle at mid point.
- Quality Integrity inspection with Multi Channel Caliper Pig
- Hydrostatic test for 720 MAOP
- Inclusion by QA, Safety, Transmission and Environmental.
- Provide integrated inspection reporting.
- Project cost management and oversight.
- Completion by 10-31-2012.

Approvals.	
Brian Konrad Date: 2-7-2012	Date: 4/27/12
Date: 4/13/12	Date: 4/30/12
Date: 4/13/12	Date: 5/10/2012
Date: 4/19/12	5/18/12

COST ESTIMATE
Perrydale to Monmouth
200581

Working Hours	1,250
Working Days	125
Calendar Weeks	25
Calendar Months	5

Estimate completed based on company crew work. 2
The project is going to be turn key bid to a contractor.

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$65.00	900	hours	$58,500.00	
2	Design	$350,000.00	1	LS	$350,000.00	WH Pacific, GeoEngineers, Epic Land Solutions
3	Pothole crew	$20,000.00	1	LS	$20,000.00	Armadello
4	Traffic control (pothole crew)	$36.00	120	hours	$8,640.00	2 flaggers for 240 hrs
5	Work Staging area/Easements	$110,000.00	1	LS	$110,000.00	Estimate from Risk and Land
6	Traffic Control Standard	$36.00	5	flaggers	$172,800.00	5 flaggers for 960 hrs
7	Traffic Control Equipment	$20,000.00	1	LS	$20,000.00	Barrier rental - 500 LF at $10/LF for 4 months & Mob
8	Erosion Control / Dewatering	$90,000.00	1	LS	$90,000.00	Rain for Rent tanks,silt fence, Inlet protection, sandbags, etc.
9	Porta Johns	$125.00	6	each	$3,750.00	5 months - 4 each
10	Shrink Sleeves	$14.00	420	each	$5,880.00	
11	Skids	$25,000.00	1	LS	$25,000.00	
12	Plywood	$10,000.00	1	LS	$10,000.00	
13	Light plants	$240.00	4	each	$19,200.00	4 each for 20 weeks
14	Steel plates	$125.00	12	each	$7,500.00	12 each for 5 months
15	PowerCrete	$45.50	650	each	$29,575.00	150 each for a 4 lb kit
16	Sideboom	$19,000.00	4	each	$380,000.00	4 sidebooms for 5 working months
17	Equipment Rental - Trackhoes	$4,200.00	6	each	$126,000.00	6 Trackhoes for 5 working months
17	Equipment Rental - Backhoes	$46.58	2	each	$116,450.00	2 Backhoes for 5 working months
18	Equipment Rental - Dozer	$8,000.00	1	each	$40,000.00	1 Bulldozer for 5 months
19	Water Truck, Pigs, Pump & Hardware	$100,000.00	1	LS	$100,000.00	3 water trucks, dryer, compresser, etc.
20	Shoring Rental	$50,000.00	1	LS	$50,000.00	DP Nicoli
21	Drill Pipe - 12"	$59.30	26150	ft	$1,550,695.00	
22	Other Pipe - 12"	$35.00	17525	ft	$613,375.00	
23	Dump Trucks	$368,000.00	1	LS	$368,000.00	4 Dump Trucks for 5 working months
24	Haul / Dump fee (spoils)	$5.00	12000	yds	$60,000.00	
24	Pee Gravel	$3.00	0	cy	$0.00	
25	Rock	$14.25	16000	cy	$228,000.00	
26	Asphalt Paving	$6.00	4000	sf	$24,000.00	
27	Concrete Paving	$15.25	0	sf	$0.00	

28	Sawcut	$1.00	2600	lf	$2,600.00	
29	Sand	$15.00	4000	cy	$60,000.00	
30	Elbows, Tees, Stopples, etc.	$55,000.00	1	LS	$55,000.00	see material list
31	Other Misc stores	$20,000.00	1	LS	$20,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
32	Valves	$54,000.00	1	LS	$54,000.00	see material list
33	Electrostops	$12,000.00	1	LS	$12,000.00	see material list
	Equipment/Material Total				**$4,790,965.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
34	Tual Crew Labor	$63.50	14400	hours	$914,400.00	10 hours per day 2 - 6 man crews 120 days
35	Welder - Standard	$65.00	7200	hours	$468,000.00	6 welders for 120 days
36	Specialty Crew	$60.00	3200	hours	$192,000.00	4 man crew for 80 days
37	X-Ray	$1,300.00	108	days	$140,400.00	
38	Trans Crew	$63.00	600	hours	$37,800.00	4 man crew for 15 days
39	Gas Supply	$60.00	40	hours	$2,400.00	2 man crew 5 days
40	Flatbed Truck & Operator	$80.00	1200	hours	$96,000.00	Pipe Delivery
41	Per Diem	$54.00	2400	each	$129,600.00	
42	Lodging	$80.00	2400	each	$192,000.00	
	Labor Total				**$2,172,600.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
43	Caliper Pig - Post Construction	$50,000.00	1	ea	$50,000.00	Quote from Integrity Dept
44	Contract HDD Bore - Steel	$100.00	26150	ft	$2,615,000.00	
	Contract Total				**$2,665,000.00**	
	Equipment/Material Total				$4,790,965.00	
	Labor Total				$2,172,600.00	
	Contract Total				$2,665,000.00	
	Total				**$9,628,565.00**	
	Construction Overhead (27% for System Reinforcement)				$2,599,712.55	
	Total Cost				**$12,228,277.55**	
	Contingency (10%)				$1,222,827.76	
	Total Project Cost w/ OH				**$13,451,105.31**	

Risk Analysis

Project:	Perrydale to Monmouth
PS Number:	200581
Project Manager:	Mark Schaefer/Brian Konrad
Date:	3/8/2012

Risk	Probability	Impact	Score (Probability x Impact)	COMMENTS (Eliminate / Mitigate)
Acquisition of Materials	*3 Numerous Non-Stock or Specialty Items*	*2 - May Impact Project*	6	Mitigate: Order parts early, determine supply for equipment that is moving and may need repairs and determine who is responsible for repairs and how long they may take.
Land Acquisition	*5 Multiple Easements*	*2 - May Impact Project*	10	Mitigate: Start work on the section that doesn't require easements.
Standard Permits	*2 Permits with Minor Conditions*	*2 - May Impact Project*	4	ODOTand Polk County permits required
Special Permits	*2 Permits with Minor Conditions*	*2 - May Impact Project*	4	UP Railroad permit required
Environmental Impact	*3 Permits with Minor Conditions*	*2 - May Impact Project*	6	Wetlands and floodplain
Ground Conditions	*1 No Concerns*	*1 - Minimal or No Impact*	1	
Utility Conflicts	*2 Minor Utility Conflicts*	*1 - Minimal or No Impact*	2	
Weather	*1 Summer*	*1 - Minimal or No Impact*	1	
Construction Method	*1 Open Trench*	*1 - Minimal or No Impact*	1	
Bore Method	*1 Horizontal Directional Drill*	*1 - Minimal or No Impact*	1	
Resources	*2 Minor Resource Conflicts*	*1 - Minimal or No Impact*	2	
Working Hours	*2 Hours Restricted*	*2 - May Impact Project*	4	Mitigate: Work with ODOT for highway restrictions. Make sure Traffic Control Plan keep the flow of traffic moving.
Contract Availability	*2 Minor Resource Conflicts*	*1 - Minimal or No Impact*	2	Potentially
System Impact	*1 No Impacts - Adequate Feed*	*1 - Minimal or No Impact*	1	
		Avg Score	**3.21**	**20**
				% Contingency

Risk Analysis recommends 20% contingency, due to the estimated cost of this project a 10% contingency will be used instead.

Staff/702
Kaufman/76

200580 Perrydale to Monmouth

October 2012

ASSUMPTIONS AND CONSTRAINTS

Assumptions:
The following will all be obtained prior to project start:
Land Acquisition
Environmental Impacts
Safety
Pipeline Integrity
Permitting
Inspection process will be defined

Constraints:
Wetlands impacts
Narrow public right of way
Supply chain
Cultural resources
Contractor availability
Short scheduling timeline
Resource availability

200581 Perrydale to Monmouth

October 2012

PROJECT SCOPE STATEMENT

This project will provide system reinforcement and reliablity to the Mid Willamette Valley. The connection of the P-30 Central Coast Feeder Pipeline to the Mid Willamette Feeder Line will allow storage gas from Mist and Newport LNG to the Mid Willamette Valley. This project is one of five phases to reinforce the supply system in the Mid Willamette Valley.

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

Project:	Perrydale to Monmouth
PS #:	200581
PM:	Mark Schaefer/Brian Konrad

A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
PROJECT TEAM			●	●	●	●	●		●	●	●	●	●	●								●	●		●		●
INITIATION TASKS	8/31/11	12/1/11																									
Create Project in SAP			A																								
Create Initiation Memo			A																								
Outline Proposed Construction Dates			A	P																							
Preliminary Design Meeting			A	P		P	P																				
PLANNING TASKS	8/31/11	6/1/12																									
Identify Project Team			A																								
Create Work Orders					A																						
Assemble As Builts & Historical Documentation					A																						
Request Design Locates									A																		
Request Survey			A																								
Request Easements			A							P																	
Draft Preliminary Design			A	P	P	P																					
Draft Preliminary Cost Estimate			A	P		P	P																				
Contract for Outside Services			A								P																
Create Design Documentation			A		P	P																					
Finalize Design			A			I	I															I					
Finalize Construction Dates			A	P			P		P																		
Create Charter or G-67 Project Plan			A																								
Charter or G-67 Project Plan Approved			A																								
Complete Engineering Sketch			P	P	A																						
Complete Traffic Control Plan				A																							
Request Permit					A																						
EXECUTING TASKS	6/1/12	10/1/12																									
Request Construction Locates									A																		
Install Construction Field Stakes				A																							
Schedule Field Resources							I		A																		
Hold Pre-Construction/Safety Meeting			A	P		P	P		I			P	P									P	P				P
Notify Stakeholders of Firm Start Dates			A				I		I													I					

R:\Engineering\Engineering Project Management\!Charters and Init Memos\200581 Perrydale to Monmouth\200581 Responsibilty Matrix.xls

3/8/2012

Staff/702
Kaufman/79

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

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MONITORING TASKS	6/1/12	11/1/12																									
Monitor Worksite Activities			P	P		P	A		P													A					
Complete and Submit Project Change Request Form as Necessary			A				I																				
Monitor Schedule			A				P		P													P					
Monitor Budget			A				P																				
Receive & Approve all Invoices			A				A																				
Coordinate Construction Activities with Stakeholders			A				A															A					
Finalize Tie-in Procedure			A			I	P							I								P	P		P		P
Tie-in Procedure Signed Off			A		I	I	I							I													
Schedule Tie-in and Coordinate with Support Crews			I			I	I		A					I								I					
Establish Final Punch List Items & Timeline for Completion			A				A															A					
CLOSEOUT TASKS	11/1/12	12/31/12																									
Complete As Built Packet							I															A					
Audit work orders and asbuilt					A																						
Complete project document review					A	I																					
Plat asbuilt					A	I																					
Conduct Project Learning Meeting			A	P		P	P																				
Complete Final Report for Project			A																								

NW NATURAL

200581 Perrydale to Monmouth

October 2012

PUBLIC RELATIONS & COMMUNICATIONS PLAN

Public Relations Plan

Audiences

- Affected landowners
- Polk County Public Works
- ODOT
- General public in Polk County
- Local news media
- • State regulators (PUC)

NW Natural employees and retirees

Strategies

1. Increase Mid Willamette valley system reliability
2. Communicate our positive messages more assertively
3. Use new outlets and forums to gain positive exposure
4. Increase public awareness of the value of NW Natural to the local economy

Key messages

1. NW Natural is a valuable member of the community – we're here to stay
2. Taking advantage of NW Naturals storage capacities and delivering to Mid Willamette valley.
3. A portion of NW Natural's gains go back to the community via local taxing districts, to help fund services such as schools, police and fire protection
4. Storage gas helps keep local natural gas prices down, which encourages industry to grow (and provides more local jobs)

Tactics and actions

Action Responsiblity

- Scheduled meeting with Mayor of Monmouth
- Scheduled meeting with Polk County
- Scheduled meeting with ODOT
- Local business leaders
- News media briefings **(TBA – schedule as needed) Public Affairs**
- Employee Communications **(Ongoing, as needed) Communication**
- *Blue Flame* for photos and features
- Public Officials & Regulatory Agencies **Govt. Relations**
- Personal contacts Regulatory Affairs
- Monthly meeting for internal stakeholders to update on project process

Communications Plan

Communications and information exchange occur in written and verbal forms. The exchange can be formal or informal and there are processes to accommodate each type. Communication can be further broken down into internal and external to NW Natural.

Internal Communication

The most common means of internal communication for the project is through team and committee meetings. Team members are encouraged to attend bi-monthly team meetings and to meet as small groups as required. The Team meetings are intended to exchange the latest information, raise and address issues, and get team members current on the project status.

The other type of communication is in the form of presentations. There are opportunities to discuss the project with large company groups. As the project construction kicks off or when it comes to a close, there may be an opportunity to make a presentation.

Written communications are found in several different forms. Informal written communications can be provided through interoffice memos and e-mails. Formal written communications are often in the form of a drawing, report, study, or an approval document. The drawings are typically engineering design and are reviewed by several team members and approved by the Project Engineer. Reports and studies are often technical and submitted to the Engineer by consultants. The project approval documents are for gaining consent to move forward conceptually with a project.

Large audience written information exchange can also be accomplished through company communications in the FYI or Blue Flame.

External Communication

Most external communication is informal and either verbal through phone conversations or written in e-mail form. These communications are often casual and discretion needs to be used. Each team member can determine what informal correspondence warrants being saved. All team members are required to abide by Corporate Guidelines found in the **Information Management Policy** and are summarized below:

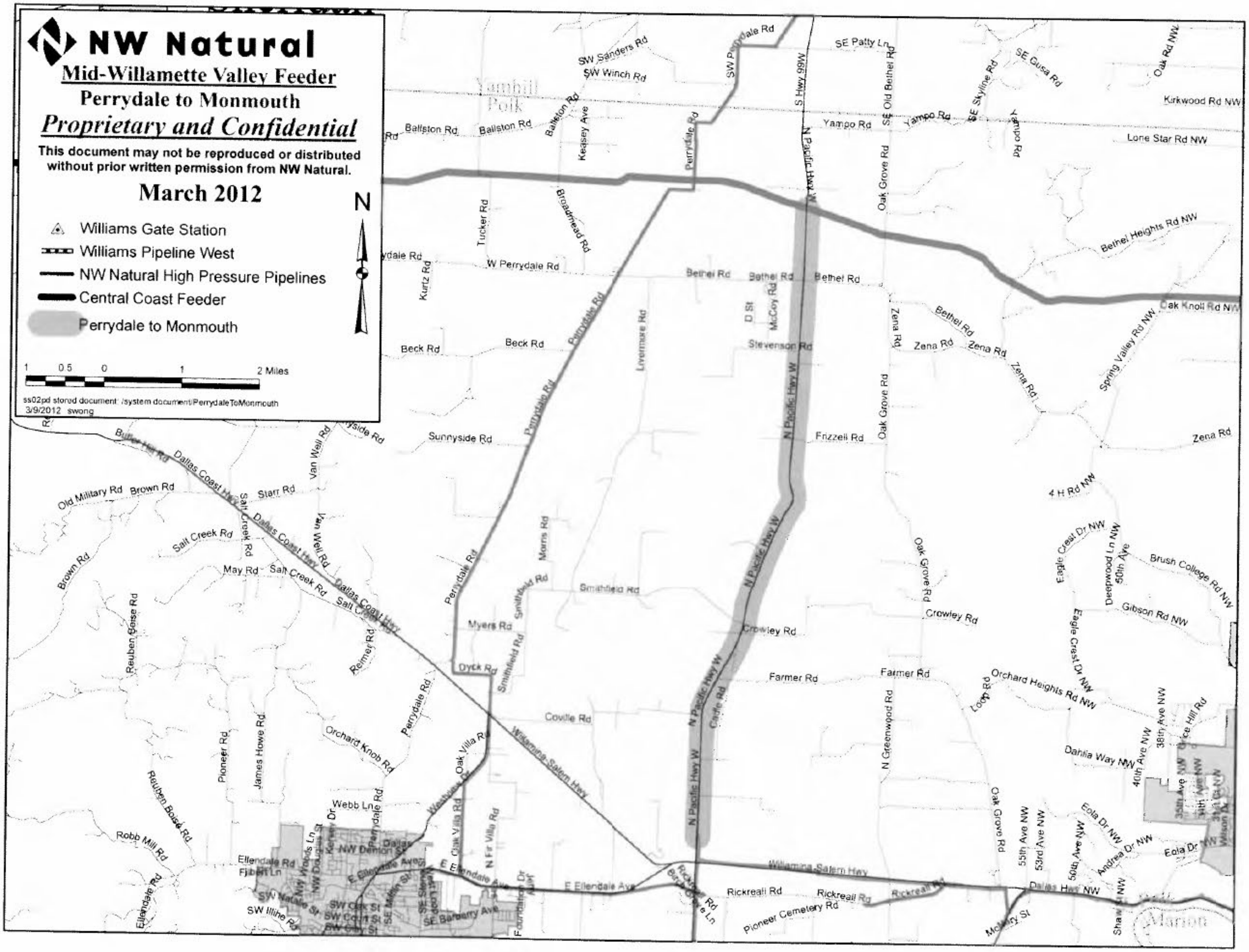
- Corporate information shall be managed to assure its accuracy, timeliness, availability, security and confidentiality, as required.
- All corporate information that is not specifically designated as public information shall be regarded as proprietary and be made available for use by employees on a business need-to-know basis only.
- Corporate information shall be managed in a manner that will satisfy the legal, regulatory, business, audit, and ethical requirements of the Company.
- It is the responsibility of all employees to assure the proper use and protection of corporate information.

<u>Although unlikely, if the media inquires about the project, all contacts need to be directed to the Corporate Communications Department.</u>

MEDIA SPOKESPERSONS:

24-hour pager: 503-818-9845

Melissa Moore: 503-226-4211 x2436 (office) or 503-223-2254 (cell)
Valerie White: 503-226-4211 x3515 (office) or 503-807-4236 (cell)



NW Natural
Mid-Willamette Valley Feeder
Perrydale to Monmouth
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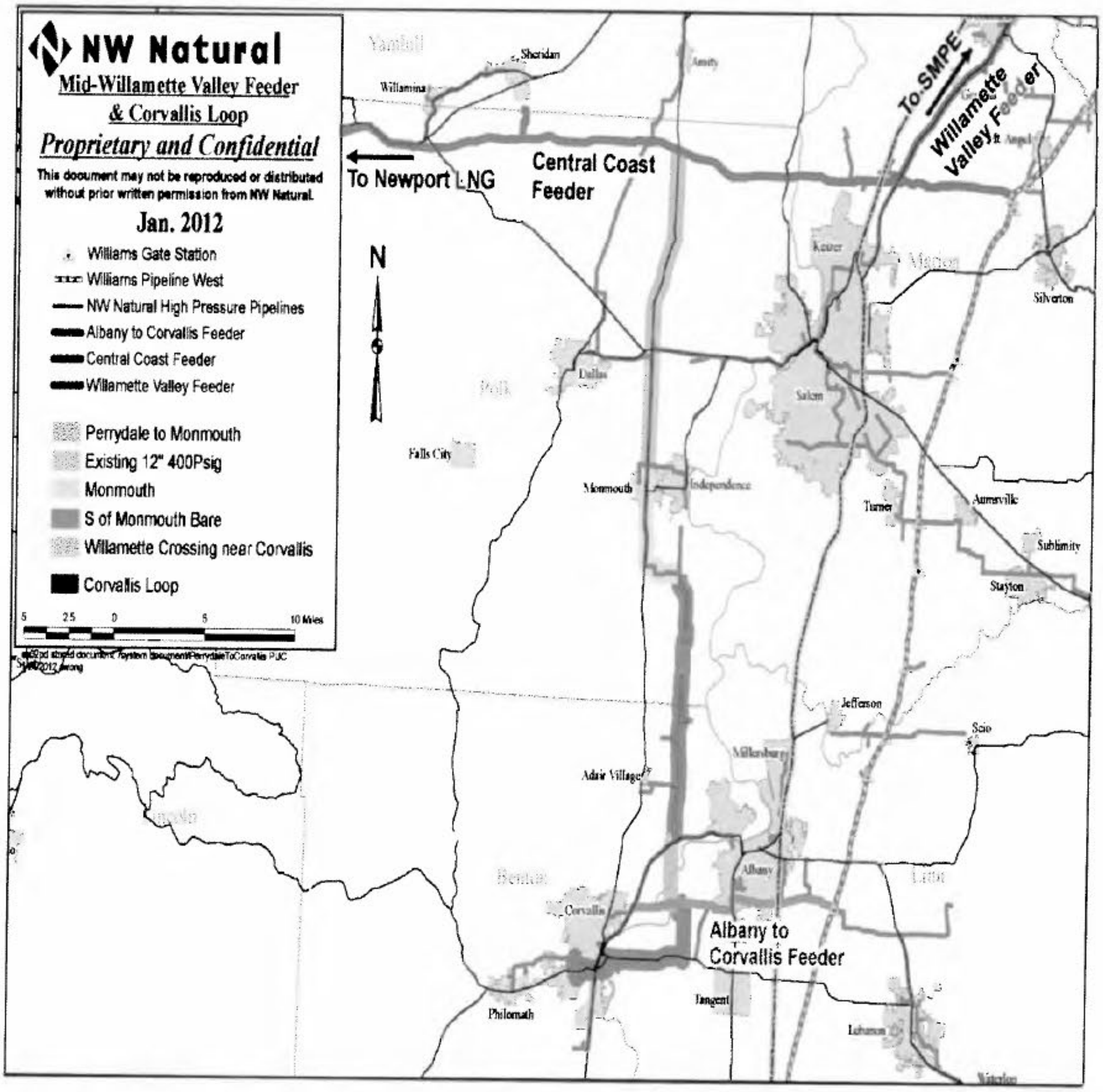
March 2012
N
Williams Gate Station
Williams Pipeline West
NW Natural High Pressure Pipelines
Central Coast Feeder
Perrydale to Monmouth
1 0.5 0 1 2 Miles
ss02pd stored document: /system document/PerrydaleToMonmouth
3/9/2012 swong
Yamhill
Polk
Marion
Ballston Rd
W Perrydale Rd
Beck Rd
Sunnyside Rd
Bethel Rd
Stevenson Rd
Frizzell Rd
Crowley Rd
Farmer Rd
Smithfield Rd
Myers Rd
Dyck Rd
Coville Rd
Orchard Knob Rd
Webb Ln
Rickreall Rd
Pioneer Cemetery Rd
Williamina-Salem Hwy
Dallas Coast Hwy
Salt Creek Rd
Brown Rd
Old Military Rd
Starr Rd
May Rd
Van Well Rd
Reuben Boise Rd
Robb Mill Rd
Pioneer Rd
James Howe Rd
Perrydale Rd
Tucker Rd
Kurtz Rd
Livermore Rd
N Pacific Hwy W
S Hwy 99W
Oak Grove Rd
Zena Rd
Bethel Heights Rd NW
Oak Knoll Rd NW
Spring Valley Rd NW
Lone Star Rd NW
Kirkwood Rd NW
Yampo Rd
SE Patty Ln
Orchard Heights Rd NW
Brush College Rd NW
Gibson Rd NW
Eola Dr NW
Dallas Hwy NW
Ellendale Rd
E Ellendale Ave


NW Natural
Mid-Willamette Valley Feeder
& Corvallis Loop
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Jan. 2012
Williams Gate Station
Williams Pipeline West
NW Natural High Pressure Pipelines
Albany to Corvallis Feeder
Central Coast Feeder
Willamette Valley Feeder
Perrydale to Monmouth
Existing 12" 400Psig
Monmouth
S of Monmouth Bare
Willamette Crossing near Corvallis
Corvallis Loop
10 Miles
N
To Newport LNG
Central Coast Feeder
To SMPE
Willamette Valley Feeder
Sheridan
Willamina
Amity
Keizer
Silverton
Dallas
Salem
Falls City
Monmouth
Independence
Turner
Aumsville
Sublimity
Stayton
Jefferson
Scio
Millersburg
Adair Village
Albany
Corvallis
Albany to Corvallis Feeder
Philomath
Tangent
Lebanon
Waterloo

NW Natural®
project management office

Project Closeout

Background

Project closeout is the last task of project management. Closeout of a project does not mean all project activity will cease. All of the continuing processes created by the project will remain as routine operations. Project closeout is simply the process of reviewing the project scope and verifying the deliverables were completed and the goals were achieved. Additionally, project closeout is an opportunity to review the performance of the project and document what was learned.

The following is the document control for the revisions to this template.

Version number	Brief Description of Change	Author(s)	Date
1.0	Creation of template, cover page, & instructions	Doug Ramsey	

Project Closeout

Project Name: Perrydale to Monmouth – Mid Willamette Feeder Phase 2

Date: 11/7/2012

____

(Name), Executive Sponsor Date

____

(Name), Project Sponsor Date

11/13/12

____

(Name), Project Manager Date

____

SUMMARY

This project consists of installing approximately 8.3 miles of 12" (W) Class F pipeline as part of the Mid-Willamette Feeder Improvements. The site is located south of Amity, Oregon and north of Bethel road on Highway 99W and continues south to the Highway 22 and Highway 99 W junction just north of Rickreal, Oregon.

PROJECT SCOPE

The connection of the P-30 Central Coast Feeder Pipeline to the Mid-Willamette Feeder Line will allow storage gas from Mist and Newport LNG to the Mid-Willamette Valley. This project is one of four phases to reinforce the supply system in the Mid-Willamette Valley. The installation processes will consist of 5 miles of HDD (Horizontal Directional Drill) and 3.3 miles of direct burial. The installation will be performed by qualified contractors through an RFP bid process.

PROJECT SCHEDULE

Project Start: November 2011
Project Completion: October 2012

PROJECT BUDGET

As of November 1, 2012

	Budget	Actual	Forecast	Variance	Notes	COH
Oct 2011	8,000	150		-7,850	pre-design	27%
Nov 2011	120,000	8,468		-111,532	pre-design	27%
Dec 2011	111,000	12,247		-98,753	design	27%
Jan 2012	108,808	108,808		0	design	27%
Feb 2012	158,768	158,768		0	design	27%
Mar 2012	160,700	160,700		0	design	27%
Apr 2012	150,231	150,231		0	design	27%
May 2012	250,698	250,698		0	design	27%
Jun 2012	2,500,000	3,036,068		536,068	pipe, construction	27%
Jul 2012	2,500,000	4,235,794		1,735,794	construction	27%
Aug 2012	2,500,000	2,989,470		489,470	construction	27%
Sep 2012	2,300,000	2,850,791		2,300,000	construction	22%
			404,520	-404,520	Design from 200163	0%
Oct 2012	2,000,000	199,786		2,000,000	clean up	22%
Nov 2012	50,000		50,000	0	clean up	22%
Dec 2012				0		22%
Total	**12,918,205**	**14,161,979**	**14,616,499**	6,438,678		

Significant budget impact issues:

- *Contracting of construction activity.*
- *Additional haul off of trench spoils due to jurisdictional requirements.*
- *Directional drill field modifications due to weather and to meet construction project timelines.*
- *Relocation of existing utilities to accommodate contractor drilling activity.*

BENFITS REALIZATION

This project will allow storage gas to flow into the Mid-Willamette Valley and improve the reliability of the system.

OUTSTANDING ISSUES

None

PROJECT CHALLENGES

- *The project timeline required creativity of route selection and design to avoid delays due to permitting and land acquisition.*
- *Approval from SHIPO (State Historical and Preservation Office) was delayed and threatened the planned construction start date of the project.*
- *Delivery of pipe was delayed and threatened the planned construction start date of the project.*
- *Coordination with local utility companies and land owners was required during construction to expedite existing utility relocations and avoid project delays.*
- *Transparency with NW Natural Project Management Team and Environmental Contractors to develop project schedules and communicate expectations.*

LESSONS LEARNED

- *Preliminary design, topographical survey and land owner coordination completed in 2009 was beneficial in identifying potential issues and strategies to expedite the final design and permitting of the project.*
- *NW Natural should gain all necessary permits prior to making commitments to contractors.*
- *NW Natural needs to develop standards for HDD as-building.*
- *NW Natural needs transparency from Environmental Contractors to accurately develop project schedules and communicate expectations.*

COMMENTS

The Perrydale to Monmouth project was a successful pipeline extension project that will allow storage gas into the Mid-Willamette Valley.

A multichannel caliper pig was implemented on the pipeline upon completion of construction to assure quality control of bends and dents and establish a base line for this segment of pipeline.

This project could not have been completed without the hard work of the project management team, design consultants, contract construction crews and NW Natural construction support. The work was completed safely, on time and within a reasonable budget.

PROJECT CHARTER

Project Title:	Christenson Bridle	**Project Number:**	200582
Project Manager:	Mark Schaefer	**Cost Center Manager:**	Steve Nelson

PROJECT DESCRIPTION

Location:	Hwy 99W, 1 mile north of Bethal Road
Plats:	2-095-023
Scope of Project:	Pig launcher and tie-in for Perrydale to Corvallis (MWF) Project
Purpose of Project:	This is part of the Mid-Willamette Feeder project and includes a gated and fenced station for tie-in and a pig launcher. Scope also includes a 12" and 10" HDD pipe bore across Hwy 99W and abandonment of the existing 10" Central Coast pipeline and casing under Highway 99W. This establishes the feed for the 12-inch Mid-Willamette Feeder pipeline.
Expected Impacts:	Minimal traffic impacts, no known environmental impacts, gas delivery impact for tie-in requires back feed from Newport LNG
Major Constraints:	Complete all work by October 31, 2012.
Items Specifically Excluded:	None
Start Date:	5/7/2012
Construction Duration:	30 days
Critical Dates:	Complete all work by October 31, 2012. Coordinate activities with pipeline contractor for the Perrydale to Rickreal phase of the project.
Funding:	System Reinforcement
Construction Overhead %:	27 %
Estimated Cost:	$684,145
Contingency ($ and %)	$68,414 (10 %)
Total Cost:	$752,560

RELATED PROJECTS

Preceding Project:	NA	**Completion Date:**		**PM:**	
Succeeding Project:	NA	**Start Date:**		**PM:**	
Parallel Project:	200581	**Completion Date:**	10/31/2012	**PM:**	Schaefer/Konrad

STAKEHOLDERS

NW Natural Stakeholders		Comments
X	Contract Services	Directional bore contract
X	Corrosion	Install electrostop corrosion isolation fittings. Coordinate with corrosion supervisor and local area corrosion technician.
	Distribution Crew	
x	Elect/Communications	Coordinate with Telecomm and Gas Control
X	Environmental/Haz Mat	Coordinate with Environmental.
X	Resource Management	Resource Management is Aware of Project and Timeline
x	Gas Supply	Coordinate resources for tie-in
x	Gasco/Mist/LNG Plants	Coordinate back feed from Newport LNG for tie-in.

x	**Major Acct. Services**	Coordinate with Larry Walker for GP Toledo.
X	**Integrity Management**	Integrity Management Has Been Involved With Project
X	**Purchasing / Stores**	Material for Project is on order
x	**Resource Center Engineer**	Coordinate with Greg Bronson for Hwy 22 feed and cut
x	**Risk and Land**	Coordinate with Land Consultant (Epic Land Solutions)
x	**Safety**	
X	**Specialty Const Crew (ROW)**	Supervisor is Aware of Project
	Station Design	
x	**Surveying**	Stake easement and construction limits
X	**Transmission Const Crew**	Crew is Aware of Project and Timeline
x	**Transmission Maint Crew**	Crew is Aware of Project and Timeline
X	**Welders**	Supervisor is Aware of Project and Resource Needs
External Stakeholders		**Comments**
	City	
x	**County**	Coordinating project activities with Polk County Planning
x	**State**	ODOT permit received. Coordinating driveway access permit with ODOT.
x	**Engineering Firm**	WHPacific and GeoEngineers
x	**Property Owners**	Christensons and Deraeve
	Other	

CHARTER APPROVAL

		Date
Project Engineer:	Mark Schaefer & Brian Konrad	3/22/2012
Engineering Manager: (Project Budget to $100K)	[signature]	5/30/12
Deliver Gas Director: (Project Budget $100K to $250K)	[signature]	5/30/12
Executive Sponsor: (Project Budget $250K to $1 Mil)	[signature]	6/5/12

PROJECT TIMELINE

Project:	Christensen Bridle
PS #:	200582
Project Manager:	Mark Schaefer/Brian Konrad
Date:	5/23/2012

Construction Duration	**8**	**Weeks**
Construction Expected Start Date	**6/4/2012**	
Construction Expected Completion Date	**7/31/2012**	
Construction Timeline	**Flexible**	

Initiation Tasks	**2/1/2012** **Required Task**	**6/4/2012** **Resp**
Complete Initiation Memo	Yes	PM
Complete Charter	Yes	PM
Complete Design Review	Yes	PM

Planning Tasks	**4/1/2012** **Required Task**	**6/4/2012** **Resp**
Request Easements	Yes	Risk
Address Environmental Issues	Yes	Envir
Request Corrosion Input	Yes	Tual Eng
RFP for Outside Services	Yes	Purch
Complete Design	Yes	Tual Eng
Station Packet	Yes	EC
Pressure Test Documentation	Yes	Tual Eng
Order Non-Stock Parts/Reserve Stock Parts	Yes	Stores
Complete Tie-in Details	Yes	Tual Eng
Finalize Design/Engineering Sketches	Yes	Tual Eng
Complete Traffic Control Plan	Yes	EC
Request Permits	Yes	EC
Notify Stakeholders Affected by Project	Yes	PM
Complete Bore Plan	Yes	Tual Eng
Draft Preliminary Procedure	Yes	Tual Eng

Executing Tasks	**5/17/2012** **Required Task**	**5/31/2012** **Resp**
Pre-Construction/Safety Meeting with Crew	Yes	Tual Eng
Install Construction Field Stakes	Yes	FET
Notifiy Stakeholders of Firm Start Dates	Yes	PM
Review Preliminary Procedure with Crew	Yes	Tual Eng

Monitoring Construction Tasks	**6/4/2012** **Required Task**	**7/31/2012** **Resp**
Monitor Schedule	Yes	PM
Monitor Budget	Yes	PM
Procedure Sign Off	Yes	Tual Eng

Closeout Tasks	**8/30/2012** **Required Task**	**9/14/2012** **Resp**
Conduct Project Learning Meeting	Yes	PM
Complete Final Report for Project	Yes	PM

COST ESTIMATE
Christenson Bridle
200582

Working Hours	300
Working Days	30
Calendar Weeks	6
Calendar Months	1.5

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
1	Internal staff charges	$65.00	80	hours	$5,200.00	
2	Porta Johns	$125.00	1	each	$187.50	
3	Traffic Control	$15.00	2	each	$9,000.00	
4	Steel plates	$125.00	12	each	$2,250.00	
5	PowerCrete	$45.50	15	each	$682.50	
6	Sideboom	$19,000.00	1	each	$28,500.00	
7	Equipment Rental - Trackhoes	$4,200.00	1	each	$6,300.00	
7	Equipment Rental - Backhoes	$46.58	1	each	$13,974.00	
8	Equipment Rental - Dozer	$8,000.00	1	each	$12,000.00	
9	Water Truck, Pigs, Pump & Hardware	$10,000.00	1	LS	$10,000.00	
10	Shoring Rental	$10,000.00	1	LS	$10,000.00	DP Nicoli
11	Drill Pipe - 10"	$45.52	120	ft	$5,462.40	
12	Other Pipe - 10"	$34.94	50	ft	$1,747.00	
13	Drill Pipe - 12"	$59.30	120	ft	$7,116.00	
14	Other Pipe - 12"	$35.00	20	ft	$700.00	
13	Dump Trucks	$80.00	80	hrs	$25,600.00	4 trucks for 80 hours
14	Haul / Dump fee (spoils)	$5.00	600	yds	$3,000.00	Includes 5' deep bore pits
14	Pee Gravel	$3.00	0	cy	$0.00	
15	Rock	$14.25	350	cy	$4,987.50	
16	Asphalt Paving	$6.00	600	sf	$3,600.00	
17	Concrete Paving	$15.25	0	sf	$0.00	
18	Sawcut	$1.00	0	lf	$0.00	
19	Sand	$15.00	150	cy	$2,250.00	
20	Elbows & Tees	$34,248.00	1	LS	$34,248.00	see material list
21	Other Misc stores	$10,000.00	1	LS	$10,000.00	misc fittings, nitrogen, weld rods, sanders, etc.
22	Valves	$40,872.00	1	LS	$40,872.00	see material list
23	Electrostops	$22,000.00	1	LS	$22,000.00	see material list
24	Painting	$10,000.00	1	LS	$10,000.00	
23	Fence and Gate	$5,000.00	1	LS	$5,000.00	

Item #	Item	Cost/Unit	Quantity	Unit	Cost	Comments
24	Pipeline supports and footings	$600.00	7	each	$4,200.00	
	Equipment/Material Total				**$278,876.90**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
25	Tual Crew Labor	$63.50	2160	hours	$137,160.00	10 hours per day 1 - 6 man crews 30 days
26	Welder - Standard	$107.00	400	hours	$42,800.00	2 welders for 20 days (contract welders)
27	Specialty Crew	$60.00	160	hours	$9,600.00	2 man crew for 8 days
28	X-Ray	$1,300.00	7	days	$9,100.00	
29	Trans Crew	$63.00	120	hours	$7,560.00	4 man crew for 3 days
30	Gas Supply	$60.00	40	hours	$2,400.00	2 man crew 2 days
31	Flatbed Truck & Operator	$80.00	40	hours	$3,200.00	Pipe and material Delivery
	Labor Total				**$211,820.00**	
Item #	**Item**	**Cost/Unit**	**Quantity**	**Unit**	**Cost**	**Comments**
32	Contract HDD Bore - Steel	$200.00	240	ft	$48,000.00	
	Contract Total				**$48,000.00**	
	Equipment/Material Total				$278,876.90	
	Labor Total				$211,820.00	
	Contract Total				$48,000.00	
	Total				**$538,696.90**	
	Construction Overhead (27% for System Reinforcement)				$145,448.16	
	Total Cost				**$684,145.06**	
	Contingency (10%)				$68,414.51	
	Total Project Cost w/ OH				**$752,559.57**	

Risk Analysis

Project:	Christensen Bridle
PS Number:	200582
Project Manager:	Mark Schaefer/Brian Konrad
Date:	5/23/2012

Risk	**Probability**	**Impact**	**Score (Probability x Impact)**	**COMMENTS (Eliminate / Mitigate)**
Acquisition of Materials	*3 Numerous Non-Stock or Specialty Items*	*2 - May Impact Project*	6	Mitigate: Order parts early, determine supply for equipment that is moving and may need repairs and determine who is responsible for repairs and how long they may take.
Land Acquisition	*3 Single or Construction Easement*	*1 - Minimal or No Impact*	3	Complete
Standard Permits	*2 Permits with Minor Conditions*	*1 - Minimal or No Impact*	2	All Permits Complete
Special Permits	*2 Permits with Minor Conditions*	*1 - Minimal or No Impact*	2	Permit complete for ODOT driveway
Environmental Impact	*3 Permits with Minor Conditions*	*2 - May Impact Project*	6	Awaiting SHPO Concurence
Ground Conditions	*1 No Concerns*	*2 - May Impact Project*	2	Drainage Conditions
Utility Conflicts	*2 Minor Utility Conflicts*	*2 - May Impact Project*	4	Tie into our Central Coast Pipeline
Weather	*1 Summer*	*1 - Minimal or No Impact*	1	
Construction Method	*1 Open Trench*	*1 - Minimal or No Impact*	1	
Bore Method	*1 Horizontal Directional Drill*	*1 - Minimal or No Impact*	1	
Resources	*1 Resources Available*	*1 - Minimal or No Impact*	1	
Working Hours	*1 No Restrictions*	*1 - Minimal or No Impact*	1	
Contract Availability	*1 Resources Available*	*1 - Minimal or No Impact*	1	Contract HDD with Brotherton Pipeline
System Impact	*3 Some Impact - Feed Issues*	*1 - Minimal or No Impact*	3	Coordinate with Newport LNG for tie-in
		Avg Score	**2.43**	**10**
				% Contingency

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Data Request Response

Request No.: UG 344 OPUC DR 292

292. Please refer to NW Natural/800, Karney/5.

a. Please provide the diameters of the Rickreall to Monmouth bare steel pipe that was replaced in 2005.

b. Please provide all analysis performed before the Rickreall to Monmouth bare steel replacement began that was used to support a 12 inch diameter.

c. Please provide the filing in which the Rickreall to Monmouth project first entered customer rates.

d. Please provide the diameters of the south of Monmouth bare steel pipe that was replaced in 2013.

e. Please provide all analysis performed before the south of Monmouth bare steel replacement began that was used to support a 12 inch diameter.

f. Please provide the filing in which the south of Monmouth project first entered customer rates.

Response:

a. The Rickreal to Monmouth pipeline replaced a predominately 6 inch bare steel pipeline.

b. Although the company is aware of a number of reasons for installing the pipe as sized, we are unable to locate the specific analysis performed to support the 12 inch diameter from before the installation of the pipeline in 2005.

c. The Rickreal to Monmouth pipeline was placed into rates as part of the Bare Steel replacement program, UM 1030.

d. The south of Monmouth pipeline replaced a predominately 6 inch bare steel pipeline.

e. Although the company is aware of a number of reasons for installing the pipe as sized, we are unable to locate the specific analysis performed to support the 12 inch diameter from before the installation of the pipeline in 2013.

f. The south of Monmouth pipeline was placed into rates as part of the System Integrity Program, UM 1406.

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Request No.: UG 344 OPUC DR 293

293. Please refer to NW Natural/800, Karney/5. For each of the four segments identified in the figure please provide the following information:

a. Original budget;
b. Final cost;
c. Project Start Sate;
d. Project Completion Date;

Response:

Perrydale to Monmouth segment – Project 200581

a. Original budget - $13,451,105

b. Final costs - $14,161,979

c. Project Start Date – November 2011

d. Project Completion Date – October 2012

Rickreal to Monmouth Bare Replacement segment

a. The Rickreal to Monmouth Bare Replacement involved the installation of approximately 5 miles of 12" steel pipe to replace an existing bare main. The pipe was placed into service and rates in 2005 as part of the Bare Steel Replacement program, UM 1030.

Monmouth Reinforcement segment – Project 200580

a. Original budget - $8,807,373

b. Final costs - $10,056,777

c. Project Start Date – February 2012

d. Project Completion Date – October 2012

South of Monmouth Bare Replacement segment – Project 200584

a. Original budget - $33,707,617

b. Final costs - $29,170,312

c. Project Start Date – July 2013

d. Project Completion Date – September 2014

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Request No.: UG 344 OPUC DR 295

295. Please refer to NW Natural/800 Karney/14.

a. Please provide the Synergi Model results for the Albany-Corvallis-Philomath area on a peak day using current firm demand, transmission and distribution.

b. Please provide the Synergi Model results for the Albany-Corvallis-Philomath area on a peak day using current firm demand, transmission and distribution but excluding the Mid Willammett Valley Feeder (MWVF), and including pipe that was removed as part of the MWVF project.

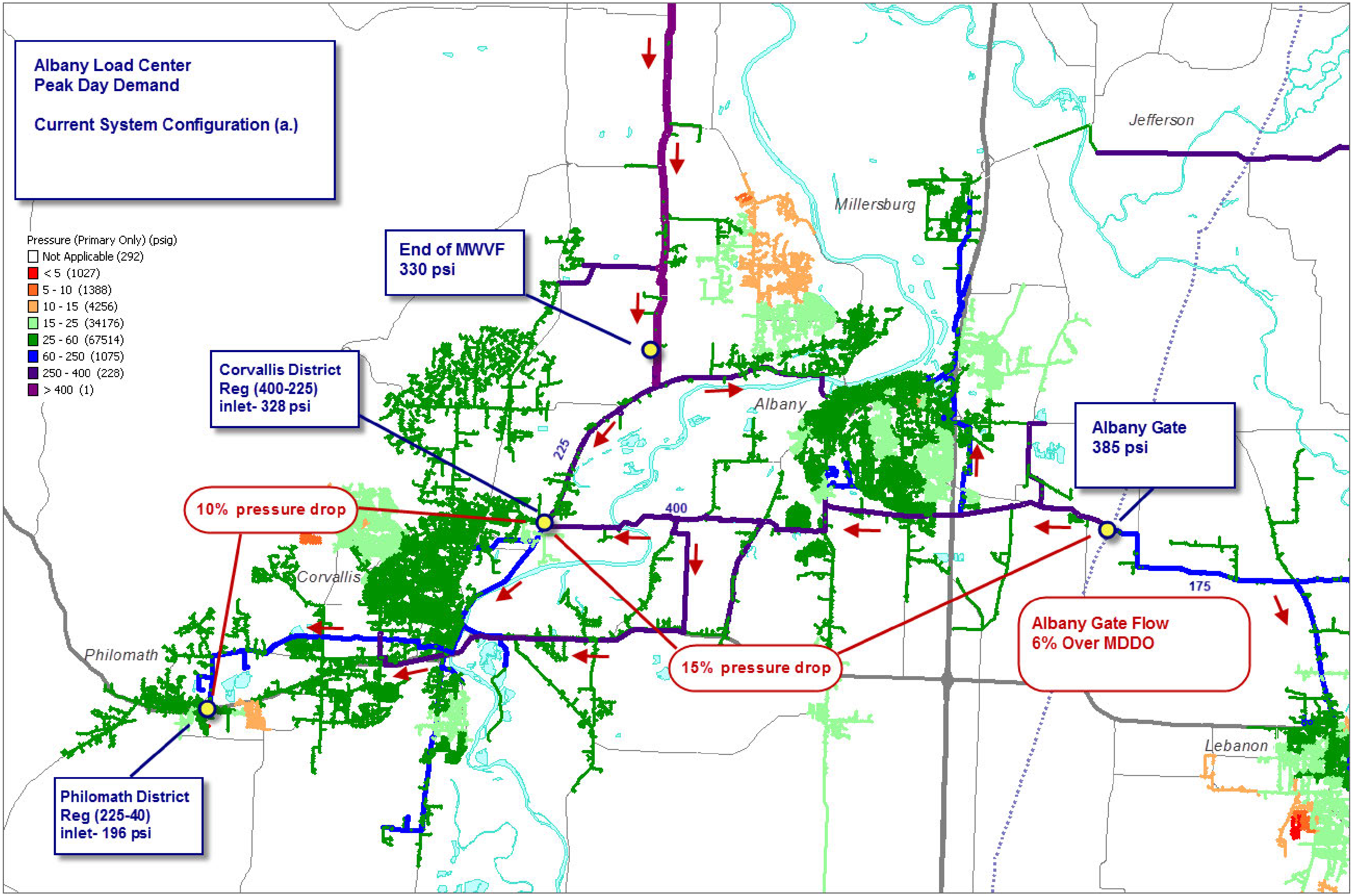
c. Please provide the Synergi Model results from part b above, but modified to exclude the Corvallis Loop, and include pipe that was removed as part of the Corvallis Loop project.

Response:

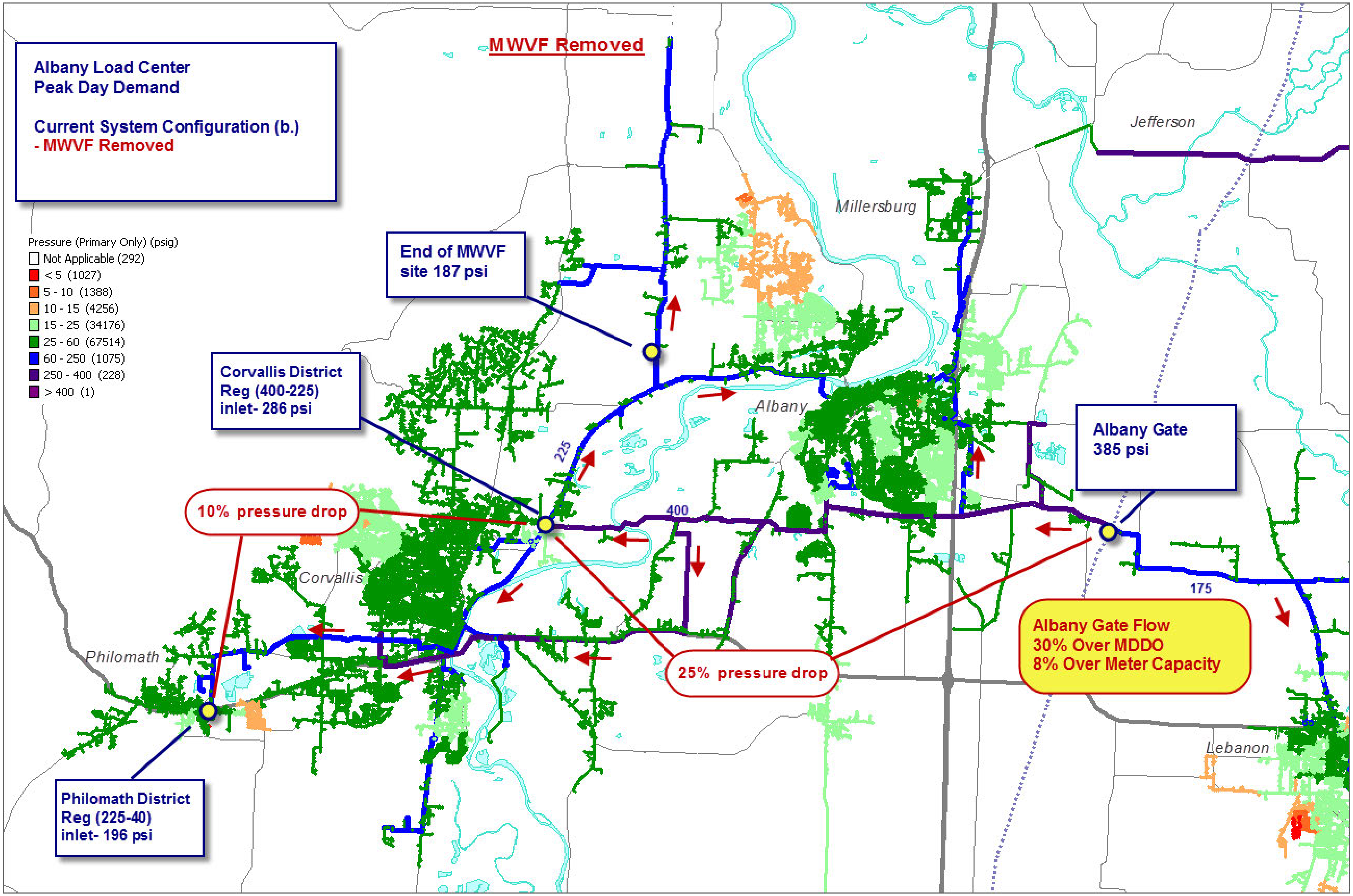
The following model scenarios are for the Albany-Corvallis-Philomath area under a peak day customer demand (based on peak hour IRP forecast for year 2017). The network piping configuration and active customers are current as of October 2017 except where stated. Interruptible customer demands have been removed as this is a peak day scenario.

a. The following Synergi Model image uses the existing system (2017) on a peak day. This includes the MWVF and Corvallis Loop projects. There are some moderately large low pressure areas in NW Corvallis, NW Albany, Lebanon, and Sweet Home (not shown). Modeling predicts less than 100 customer outages on a peak day, mainly in Lebanon and Sweet Home. These are distribution system shortcomings that will be remediated over time.

   The current Albany high pressure system is reasonably strong with the Corvallis Loop to move gas to the west and the northern connection to the MWVF as an alternate supply. There are no high pressure system issues on a peak day.

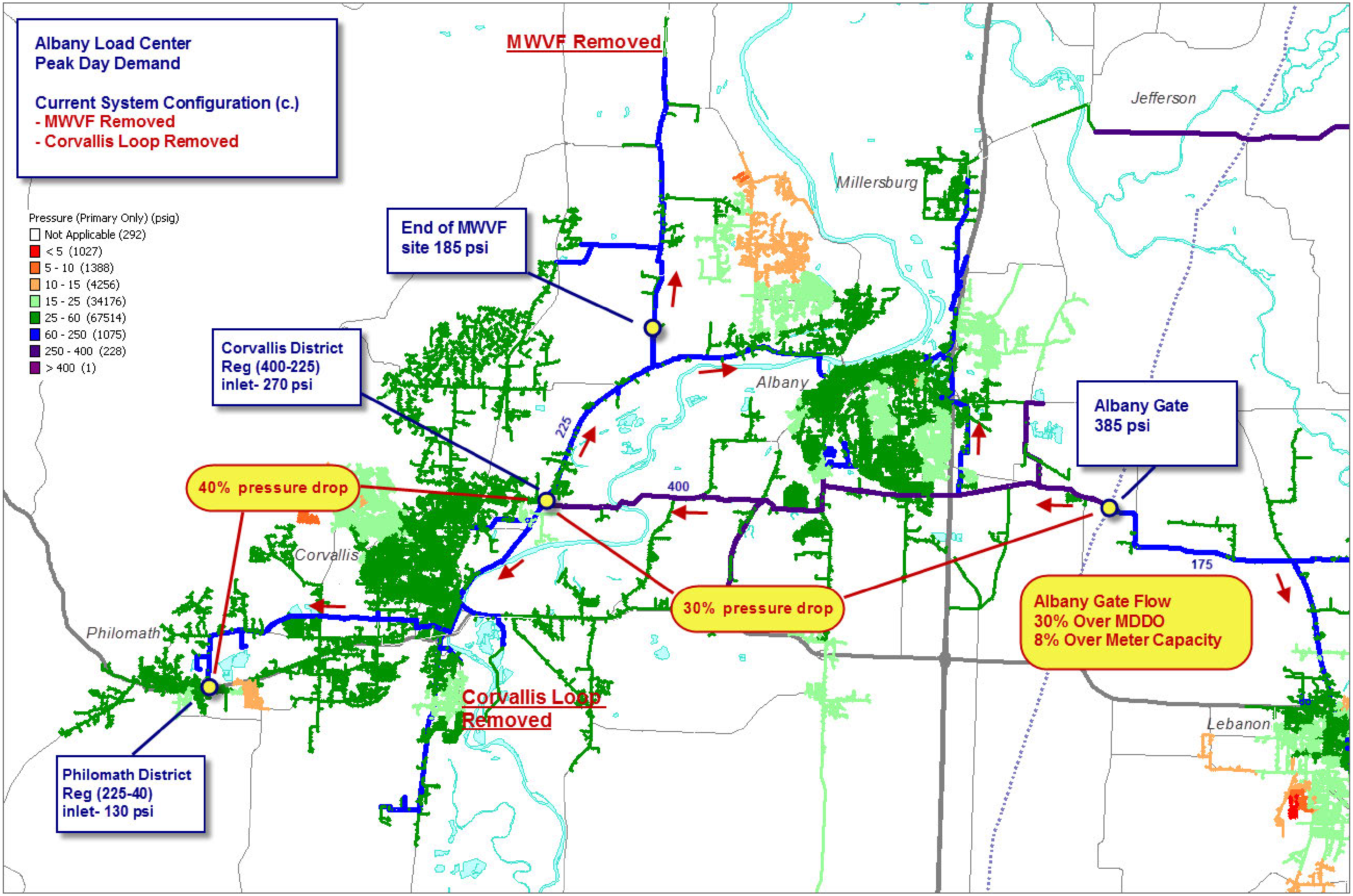

Albany Load Center
Peak Day Demand
Current System Configuration (a.)
Pressure (Primary Only) (psig)
Not Applicable (292)
< 5 (1027)
5 - 10 (1388)
10 - 15 (4256)
15 - 25 (34176)
25 - 60 (67514)
60 - 250 (1075)
250 - 400 (228)
> 400 (1)
End of MWVF
330 psi
Corvallis District
Reg (400-225)
inlet- 328 psi
10% pressure drop
15% pressure drop
Albany Gate
385 psi
Albany Gate Flow
6% Over MDDO
Philomath District
Reg (225-40)
inlet- 196 psi
Jefferson
Millersburg
Albany
Corvallis
Philomath
Lebanon
225
400
175

b. The following Synergi Model image uses the existing system (2017) on a peak day. The MWVF connection to Albany has been removed and the MAOP of the 6" line from MWVF to Corvallis District Reg has been reduced to its original 225 MAOP. Corvallis Loop project is still in place. This change has no effect on service to individual customers but it does greatly change the dynamics of the high pressure system. Albany Gate is now required to supply the additional load that is removed when the MWVF is disconnected. The stated NWPL meter capacity at Albany Gate is approximately 25k th/hr and the model requires 27k th/hr, a shortfall of 2,000 th/hr. This represents approximately 3,300 residential customers demand on a peak day. Additional NWPL capacity would have to be acquired by NW Natural if the MWVF were not in service. Problems with this scenario are highlighted with yellow balloons.


MWVF Removed
Albany Load Center
Peak Day Demand
Current System Configuration (b.)
- MWVF Removed
Pressure (Primary Only) (psig)
Not Applicable (292)
< 5 (1027)
5 - 10 (1388)
10 - 15 (4256)
15 - 25 (34176)
25 - 60 (67514)
60 - 250 (1075)
250 - 400 (228)
> 400 (1)
End of MWVF
site 187 psi
Corvallis District
Reg (400-225)
inlet- 286 psi
10% pressure drop
25% pressure drop
Albany Gate
385 psi
Albany Gate Flow
30% Over MDDO
8% Over Meter Capacity
Philomath District
Reg (225-40)
inlet- 196 psi
Jefferson
Millersburg
Albany
Corvallis
Philomath
Lebanon
225
400
175

c. The following Synergi Model image uses the existing system (2017) on a peak day. The MWVF connection to Albany has been removed and the MAOP of the 6” line from MWVF to Corvallis District Reg has been reduced to its original 225 MAOP. The Corvallis Loop project has been removed. This change has no effect on service to individual customers but it does greatly change the dynamics of the high pressure system. As in the previous case, Albany Gate is required to supply the additional load that is removed when the MWVF is disconnected. Additional NWPL capacity would have to be acquired by NW Natural if the MWVF were not in service.

The removal of the 400 MAOP Corvallis Loop places all the burden of moving Corvallis/Philomath customer gas on the 225 MAOP Corvallis Feeder. This single 8” pipeline has a 40% pressure drop under this scenario which is our trigger point for capacity evaluation and in this case would result reinforcement. The Albany Feeder from the gate station to the Corvallis District regulator also has to carry a greater burden with the Corvallis Loop removed. Its pressure drop moves to 30% which is a warning sign for capacity evaluation. Problems with this scenario are highlighted with yellow balloons.


Albany Load Center
Peak Day Demand
Current System Configuration (c.)
- MWVF Removed
- Corvallis Loop Removed
Pressure (Primary Only) (psig)
Not Applicable (292)
< 5 (1027)
5 - 10 (1388)
10 - 15 (4256)
15 - 25 (34176)
25 - 60 (67514)
60 - 250 (1075)
250 - 400 (228)
> 400 (1)
MWVF Removed
End of MWVF site 185 psi
Corvallis District Reg (400-225) inlet- 270 psi
40% pressure drop
30% pressure drop
Albany Gate 385 psi
Albany Gate Flow
30% Over MDDO
8% Over Meter Capacity
Philomath District Reg (225-40) inlet- 130 psi
Corvallis Loop Removed
Jefferson
Millersburg
Albany
Corvallis
Philomath
Lebanon
225
400
175

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Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 335

335. Please provide the following information for each main extension performed between January 1, 2012 and December 31, 2017:

a. Line extension allowance of customer requesting extension, including workpapers calculating allowance;
b. Forecasted and actual distribution margin revenue from customer from in service date to December 31, 2017;
c. New service and meter cost of customers requesting the extension;
d. Original budget, final budget, and actual cost of extension;
e. Cost analysis demonstrating the financial prudence of the project;
f. Location of extension;
g. The in-service date; and
h. If no customer requested the extension, the basis for making the extension.

Response:

NW Natural objects to this data request as overly broad and unduly burdensome. As explained below, the Company does not maintain the requested data in a manner that would allow production without manually gathering and calculating data for the approximately 1,800 main extensions that are responsive to this request. Without waiving its objection, NW Natural provides UG 344 OPUC DR 335 Attachment 1- (MX Projects 2012 – 2017) which is a list of about 1,800 main extension projects for 2013 through 2017, of which 1,428 are Oregon projects. Included in this file are estimates for therm load, margin, construction costs, and customer contributions.

Due to a lack of connections between various company systems (CRMS, CIS, and SAP), a manual process is required to associate estimated therms, margins, and project costs with actuals for main extension projects. To develop the relationships between estimates and actuals for main extension projects, the following manual process needs to be followed:

- Review project work orders in SAP using the project revision number to validate that all associated work orders have been completed.
- Review the project in MapFrame and validate in CRMS that all premises installed have been correctly attached to the project.

- If the project is a phase of a larger project, review the civil designs in Engineering's files to ensure that the proper addresses have been attached to the MapFrame view.
- Print a copy of the estimate, initial analysis, event notes, and sold date from Prospector.
- Print a copy of the MapFrame view for each project.
- Build a spreadsheet listing the revision #, Market Segment, Type of Project, premise #'s, work order #'s, and addresses that are attached to the project, list date when SOLD, list date when installed, total # of lots, percentage of lots used in financial analysis, and current percentage of completed installations. This information is gathered through queries of SAP, CRMS, MapFrame, and CIS then manually matched and combined.

UG 344 OPUC DR 335 Attachment 2, (MX Project 10 Project Analysis), contains the result of this manual matching exercise for a sample of 10 projects. This analysis builds the relationship between estimates and actuals. This manual exercise required about a week to complete using knowledgeable SMEs.

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Data Request Response

Request No.: UG 344 OPUC DR 336

336. Please provide the following information for each bare steel main replacement performed between January 1, 2012 and December 31, 2017:

a. Diameter and maximum pressure of the original main;
b. Diameter and maximum pressure of the replacement main;
c. If the diameter or maximum pressure of the replacement main exceeds the diameter of the original main:
  i. Basis for up-sizing the replacement pipe;
  ii. Diameter and maximum pressure of the connecting origin and terminal pipe.
d. Original budget, final budget, and actual cost of the replacement;
e. Cost analysis demonstrating the financial prudence of the project.

Response:

NW Natural objects to this data request as overly broad and unduly burdensome. As explained below, the Company does not maintain the requested data in a manner that would allow production without manually gathering data for the 515 Bare Steel work orders from separate systems and paper files. We estimate that it would take approximately 1,500 hours to fully respond to DR 336, 337, and 338. Without waiving its objection, NW Natural states that there were 515 Bare Steel work orders (applicant 119) performed between January 1, 2012 and December 31, 2017. UG 344 DR 336 Attachment 1 contains the Work Order, Maintenance Activity Type, Basic Finish Date, Description, Street, City, and Total Sum (actuals) for all 515 work orders for the requested time period.

Bare steel is pipe that does not have a protective coating and was installed in NW Natural's system prior to 1960. NW Natural began an accelerated bare steel replacement program in 2001 as the pipe began to fail replacing the bare steel mains and associated services with modern coated steel or polyethylene pipe.

At the March 5, 2018 rate case workshop, Staff requested further information regarding how the Company sizes pipe for Bare Steel projects. The diameter of the new main may be larger than the original main for several reasons. Our current minimum size for main installation is 2" poly, so any existing main that was less than 2" would be replaced with 2". Additionally, poly and steel pipelines of the same diameter do not have the same capacity, so an existing steel main may be replaced with a larger poly diameter main (e.g. 4" steel could be replaced with 6" poly to maintain capacity).

When replacing existing main, the system will be reviewed to understand the feed in the area and consider future growth. If the area has known pressure issues, potential growth, or known future system ties, modeling may be done to select the appropriate size of pipe, which may be larger than the existing pipe.

The major cost component of main installation is the labor cost ~70-80%. The pipe cost is a small component of the project.

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Data Request Response

Request No.: UG 344 OPUC DR 337

337. Please provide the following information for each public works project performed between January 1, 2012 and December 31, 2017:

a. Diameter and maximum pressure of the original main;
b. Diameter and maximum pressure of the replacement main;
c. If the diameter or maximum pressure of the replacement main exceeds the diameter of the original main:
 i. Basis for up-sizing the replacement pipe;
 ii. Diameter and maximum pressure of the connecting origin and terminal pipe.
d. If there was no original main explain why the main was installed.
e. Original budget, final budget, and actual cost of the replacement.
f. Cost analysis demonstrating the financial prudence of the project.

Response:

NW Natural objects to this data request as overly broad and unduly burdensome. As explained below, the Company does not maintain the requested data in a manner that would allow production without manually gathering data for the 3167 Public Works from separate systems and paper files. We estimate that it would take approximately 1,500 hours to fully respond to DR 337, 338, and 339. Without waiving its objection, NW Natural states there were 3167 Public Works, work orders (applicant 114) performed between January 1, 2012 and December 31, 2017. UG 344 OPUC DR 337 Attachment 1 contains the Work Order, Maintenance Activity Type, Basic Finish Date, Description, Street, City, and Total Sum (actuals) for all 3167 work orders for the requested time period.

Public Works projects are generated as a result of jurisdiction improvements such as repaving, road expansion, sewers, water, railroad, light rail, bridge replacement and sometimes electric work. The Company is obligated under franchise agreements and local ordinances to relocate our facilities at our expense when they are in conflict with a public works project. Projects often come to the Company over the course of a year with short lead times.

At the March 5, 2018 rate case workshop, Staff requested further information regarding how the Company sizes pipe for Bare Steel projects. The diameter of the new main may be larger than the original main for several reasons. Our current minimum size for main installation is 2” poly, so any existing main that was less than 2” would be replaced with 2”. Additionally poly and steel pipelines of the same diameter do not have the same capacity, so an existing steel main may be replaced with a larger poly diameter main (e.g. 4” steel could be replaced with 6” poly to maintain capacity).

When replacing existing main, the system will be reviewed to understand the feed in the area and consider future growth. If the area has known pressure issues, potential growth, or known future system ties, modeling may be done to select the appropriate size of pipe, which may be larger than the existing pipe.

The major cost component of main installation is the labor cost ~70-80%. The pipe cost is a small component of the project.

NW Natural®

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Request No.: UG 344 OPUC DR 338

338. Please provide the following information for each relocate/abandonment performed between January 1, 2012 and December 31, 2017:

a. Diameter and maximum pressure of the original main;
b. Diameter and maximum pressure of the replacement main;
c. If the diameter or maximum pressure of the replacement main exceeds the diameter of the original main:
   i. Basis for up-sizing the replacement pipe;
   ii. Diameter and maximum pressure of the connecting origin and terminal pipe.
d. Original budget, final budget, and actual cost of the replacement.
e. Cost analysis demonstrating the financial prudence of the project.

Response:

NW Natural objects to this data request as overly broad and unduly burdensome. As explained below, the Company does not maintain the requested data in a manner that would allow production without manually gathering data for the 2,298 Relocate/Abandonment work orders from separate systems and paper files. We estimate that it would take approximately 1,500 hours to fully respond to DR 336, 337, and 338. Without waiving its objection, the Company states that there were 2298 Relocate/Abandonment work orders (applicant 116) performed between January 1, 2012 and December 31, 2017. UG 344 OPUC DR 338 Attachment 1 contains the Work Order, Maintenance Activity Type, Basic Finish Date, Description, Street, City, and Total Sum (actuals) for all 2298 work orders for the requested time period.

Relocates/Abandonment projects are a result of customer requested relocates or as a result of requirements related to compliance, quality assurance remediation, corrosion control, underground pipe supporting the installation of a district regulator as well as general maintenance needs.

At the March 5, 2018 rate case workshop, Staff requested further information regarding how the Company sizes pipe for relocate/abandonment work orders. The diameter of the new main may be larger than the original main for several reasons. Our current minimum size for main installation is 2” poly, so any existing main that was less than 2” would be replaced with 2”. Additionally poly and steel pipelines of the same diameter do not have the same capacity, so an existing steel main may be replaced with a larger poly diameter main (e.g. 4” steel could be replaced with 6” poly to maintain capacity).

When replacing existing main, the system will be reviewed to understand the feed in the area and consider future growth. If the area has known pressure issues, potential growth, or known future system ties, modeling may be done to select the appropriate size of pipe, which may be larger than the existing pipe.

The major cost component of main installation is the labor cost ~70-80%. The pipe cost is a small component of the project.

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Request No.: UG 344 OPUC DR 339

339. Please refer to the response to OPUC DR 197 Attachment 1. Please provide a description of each capital budget category used by NW Natural from 2012 to the present.

Response:

Below is a description of the categories used for Capital Expenditures Planning:

Category 1 - New Customer Acquisitions: Capital expense mostly related to capital expenditures needed to hook up new customers. This includes extending mains and installing service lines, permitting, meters, and customer contributions.

- **Residential mains (711):** Main extensions associated with Residential Conversions.
- **Commercial and Industrial mains (712):** Main extensions associated with non-residential customers.
- **System Expansion (713):** Main extensions associated with new subdivisions.
- **Other new main projects (714):** Other miscellaneous main work.
- **Residential Services – new (721):** New construction service lines only.
- **Residential Services – conversion (722):** Residential conversions service lines only.
- **Commercial and Industrial Services (723):** Non-residential service lines only.
- **Other new services projects (724)**: Other miscellaneous service work.
- **Customer Retained Contributions (777):** Customer contributions. This is applied as a credit to overall customer acquisition capital costs.
- **Construction Permits (15):** Construction permitting costs for engineering and customer acquisition work.
- **Meter Purchases (21):** Meter purchases for new services and for replacement programs.
- **Meter Installations (23)**: Cost of installing meters for customer acquisition work done by NWN crews.

Category 2 - Replacements Supported by Revenues: Engineering work that supports System Integrity Programs (SIP). Category 2 includes the amounts, approved by the OPUC (if any) to be tracked into rates annually. Currently, NW Natural does not have a SIP tracker.

- **Bare Steel Mains and Services (119 & 319):** Program to remove all known bare steel mains and services from the gas distribution system.
- **Leakage Reconstruction Mains and Services (113 & 313):** Main and service replacements and reconstruction due to leakage.
- **Distribution System Main and Services Integrity work (120 & 320):** Programs related to the federally mandated Distribution Integrity Management Program (DIMP) as described in 49 CFR 192 subpart P. Programs include accelerated actions taken to identify and implement measures to address risk in the gas distribution system.
- **Transmission System Integrity work (112)**: Programs related to the federally mandated Transmission Integrity Management Program (TIMP) as described in 49 CFR 192 Subpart O. This work includes smart pigging to identify anomalous conditions and the remediation of anomalies and other threats on transmission pipelines.
- **Guardpost Placement (325):** An ongoing program to evaluate meters set for the likelihood of damage from vehicles or other large wheeled objects, and the installation of guard posts at identified meter sets to protect them from damage.
- **Unallowed DIMP&TIMP / Unallowed Leakage (750 and 751)**: Applicant/Line used to credit and move Category 2 lagged expense to Category 3.

Category 3 - Replacements/Betterments Not Supported by Revenues: Engineering work that includes jurisdictional requirements, relocates, system reinforcement, system gas storage and supply, and maintenance. Also included are general expenses transportation, small tools, office furniture and equipment, and other small miscellaneous expenses.

- **Public Works (114 & 314):** Public Works projects are generated as a result of jurisdiction improvements. These include grading, sewers, water, railroad, light rail, bridge replacement and sometimes electric work. The Company is obligated under franchise agreements and local ordinances to relocate our facilities at our expense when they are in conflict with a public works project. Projects often times come to Engineering over the course of a year with short lead times.
- **Relocates & Abandonments (116 & 316):** Relocates/Abandonment projects are a result of customer requested relocates or as a result of requirements related to compliance, quality assurance remediation, corrosion control, underground pipe supporting the installation of a district regulator as well as general maintenance needs.
- **The Non-Revenue Producing Leakage/Bare Steel** represents the amount deducted from Category 2 work per the SIP stipulation. The amount is deducted from Category 2 and placed in Category 3 for reporting purposes.
- **System Reinforcement (115):** System Reinforcement projects originate from the need to improve system safety and reliability.
- **CNG Internal (140):** NWN CNG (Compressed Natural Gas) installations/projects.
- **Cathodic Protection (14):** Cathodic Protection work protects the existing assets in ground bed installations.

- **Damage Reconstruction (136 & 336):** Damage Reconstruction projects originate from a need to repair our system when damage occurs. The majority of the work is unknown until the damage occurs or is found, leading to a run rate based budget.
- **District Regulators (13):** District Regulator projects are the installation or replacement of District Regulators as a result of system expansion, public works, system reinforcement, quality assurance remediation, and corrosion protection or compliance requirements.
- **Service Regulators (19):** Service Regulator projects include the installation of service regulators for system expansion or compliance requirements.
- **Gas Supply Misc (11):** Gas Supply Misc. Improvements projects include supporting and maintaining gas flow operations to gate stations, odorizers, compressors, etc.
- **Mist Storage (18):** Mist Storage projects include the work required for system support, expansion and compliance requirements.
- **Portland LNG (524):** Projects for the Portland LNG facility include the work required for system support, expansion and compliance requirements.
- **Newport LNG (529):** Projects for the Newport LNG facility include the work required for system support, expansion and compliance requirements.
- **Transportation (32):** Purchases of vehicle and vehicle set-up for needed to conduct operations.
- **Power Operated Equipment (35):** Purchases of equipment such as Back Hoes, Vacuum Trucks and Dump Trucks.
- **Small Tools (33):** The purchase of small tools for use within the company.
- **Unallocated COH (43):** Dollar amounts representing budgeted COH that has not been allocated through Capital spend to date. This amount will be zero by Dec 31st through the use of adjusted COH rates or manually assignment.
- **Office Furniture (40):** The purchase of office furniture throughout the company.
- **Office Equipment (31):** The purchase of office equipment throughout the company. Examples include Printers and Plotters.
- **Corporate Security (571):** Purchases involving security at Company facilities. Purchases involve fences, video surveillance and guard shacks.
- **Salvage (44)** represents assets liquidated by the company and generally provides information on sales of vehicle or powered equipment.

Category 4 – This category includes Information Technology and Facilities investments.

- **Radio & Electronic Improvements (17):** Purchase of radio, microwave, telemetry and other related equipment used throughout the company.
- **Computer Software/Hardware (38):** The purchase of computer software and hardware related items and related upgrades/enhancements.
- **Customer Information System (CIS) Applicant 39.** Investments related to the customer information system.
- **Land Purchases (34):** Land Purchases.

- **Structures (36):** Structures include the purchase, remodel, and maintenance of NWN Utility facilities

Category 5 - Storage: includes Utility and Non-Utility Storage activity in OR and WA.
- **Applicant 562:** Work done on the Adams Reservoir.
- **Applicant 563:** Work done on Emerald Reservoir storage projects.
- **Applicant 569:** Work done on the Deer Island Gate Station.
- **Applicant 514:** Work done on the Miller Station facility.
- **Applicant 580:** Work done on the Molalla Gate Station.
- **Applicant 581:** Work done on the Bruer/Flora Wells.

Category 6 - Unallocated Capital: Unallocated Capital budgeted in a given year; throughout the year it is absorbed by unknown projects or removed from forecast.

Category 7 - Utility Special Projects: represents special projects such as North Mist, CNG efforts, and the Low Carbon Pathway as examples.
- **North Mist Storage project (564):** Investment in the North Mist Expansion Project
- **Compressed Natural Gas (740):** CNG projects to serve external customers under schedule H
- **Carbon Solutions Program**: Includes investments related to voluntary carbon reduction programs offered under ORS 757.539. ORS 757.539 granted the OPUC the authority to allow a natural gas utility to recover costs associated with implementing programs or measures that reduce greenhouse gas emissions through the provision of natural gas.

Construction Overhead – Indirect overhead expenses associated with capital projects.

NW Natural®

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Request No.: UG 344 OPUC DR 351

351. Please refer to the response to OPUC DR 198 Attachment 1, 200363 Project Charter.PDF which is the Corvallis Loop Project Charter. The Project Objective is to "support the increasing demand of natural gas fuel consumption at the Oregon State University Energy Center."

a. Please provide the line extension allowance calculated for Oregon State University's increased demand of natural gas.

b. Is Oregon State University Energy Center a firm or interruptible customer?

c. Please provide all documents and communications between Oregon State University and NW Natural regarding the Corvallis Loop or increased gas consumption. If no such documents exist please explain how NW Natural determined that the Corvallis Loop Project was needed to support increased demand at Oregon State University.

Response:

The Project Objective from the Corvallis Loop Project Charter fully states "To supply additional natural gas capacity and support the increasing demand of natural gas fuel consumption at the Oregon State University Energy Center." The primary objective of the project was to "supply additional natural gas capacity". As described in the Proposal for Project Initiation from May 2010, attached as UG 344 OPUC DR 351 Attachment 1, the purpose of the project is stated as "To provide reinforcement to the Corvallis system."

Exhibit NWN/800 states that the Corvallis Loop was developed because there was insufficient firm capacity on the Company's system to meet its firm demand requirements in the Corvallis and Philomath area. This is evidenced by pressure drops along this feeder during the winter that exceed normal design requirements. For UG 221, "OPUC-DR-274_Attachment 1" was created and is now attached as UG 344 OPUC DR 351 Attachment 2. This attachment shows a graphic that depicts the relationship between pipeline pressure and heating degree days at the Corvallis and Philomath regulator stations using firm customer load requirements only. The analysis shows that the pressure drop occurring on the existing system will begin to exceed the design pressure drop standard at 35 heating degree days for Philomath and 45 heating degree days for Corvallis.

The investment in firm capacity from this pipeline project is lumpy and designed to meet firm capacity requirements over the life of the asset. The ability to serve the Oregon State University Energy Center as a firm customer was an added benefit.

a. Since the project's purpose was to reinforce the distribution system to meet firm customer demand, a formal line extension allowance for Oregon State University's increased demand was never finalized. At an estimated annual usage of 8 million terms, the incremental margin and associated line extension allowance would be approximately $290,000.

b. The Oregon State University Center is a firm customer.

c. Most of the communications and conversations between Oregon State and NW Natural were verbal and not documented. UG 344 OPUC DR 351 Attachment 3 and UG 344 OPUC DR 351 Attachment 4 are related to OSU transferring from interruptible to firm service.

MEMORANDUM

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

Date: May 8, 2010
To: Kerry Shampine, Andy Fortier, Joe Karney
From: Katie Gough
Subject: Proposal for Project Initiation – Corvallis Reinforcement – Design Phase

PROJECT NAME
Corvallis Reinforcement – Design Phase

PROJECT LOCATION
Connect from the existing 10” (W) Class D main in Riverside Dr (Plat 2-158-020) east of Corvallis and end in Corvallis by OSU on SW 35th Ave connecting to the existing 6” (W) Class D main (Plat 2-163-032).

PROJECT PLATS
Start at 2-158-020 and end at 2-163-032

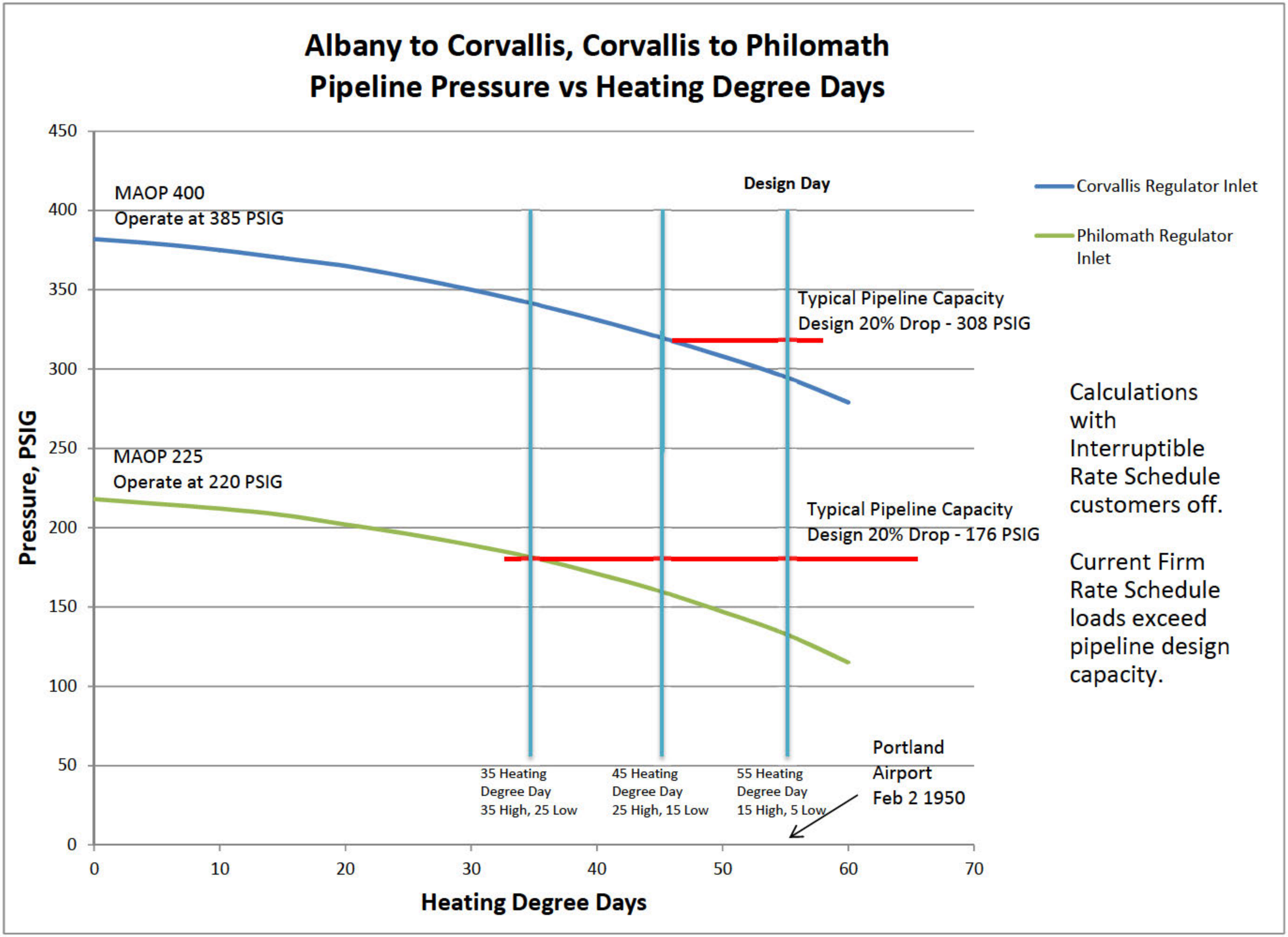
SCOPE
Installation of approximately 45,000 feet of 12” (W) Class D main.

PURPOSE
To provide reinforcement to the Corvallis system.

COST
Rough Estimated Design Cost: $50,000

FUNDING
System Reinforcement – 2010 COH 20%

SCHEDULE
Anticipated Start date: 6/1/2010 for preliminary design


Albany to Corvallis, Corvallis to Philomath
Pipeline Pressure vs Heating Degree Days
Pressure, PSIG
Heating Degree Days
450
400
350
300
250
200
150
100
50
0
10
20
30
40
50
60
70
MAOP 400
Operate at 385 PSIG
MAOP 225
Operate at 220 PSIG
Design Day
Corvallis Regulator Inlet
Philomath Regulator Inlet
Typical Pipeline Capacity
Design 20% Drop - 308 PSIG
Typical Pipeline Capacity
Design 20% Drop - 176 PSIG
Calculations with Interruptible Rate Schedule customers off.
Current Firm Rate Schedule loads exceed pipeline design capacity.
35 Heating Degree Day
35 High, 25 Low
45 Heating Degree Day
25 High, 15 Low
55 Heating Degree Day
15 High, 5 Low
Portland Airport
Feb 2 1950

NW Natural

Date/Time Received by NWN: ______________ By: ______
Original: Major Account Services Team cc: Major Accounts Manager

Out-of-Cycle Transfer Service Election Form

Customer Name: OREGON STATE UNIVERSITY

To be Completed by Company:

Service Address: 3452 S.W. JEFFERSON WAY #COGEN *Account No.:* 1985861

Combined Heat and Power Installation: (Y) / N

Current Rate Schedule: *Oregon:* *RS 3* ☐ *RS 31* ☐ *RS 32* ☒
Washington: *RS 3* ☐ *RS 41* ☐ *RS 42* ☐

Current Service Type/Option: Sales ☐ *Transportation* ☒ *Firm Peak Demand* ☐ *Firm Volumetric* ☐ *Interruptible* ☒
Combination (describe) ______ *MDDV:* ______

THE REQUESTED EFFECTIVE DATE IS: the 2nd regularly scheduled meter read following the Company's receipt of this form or 4/1/2010 ***, whichever is later.***

TO BE COMPLETED BY THE CUSTOMER -- *Indicate New Selection by checking applicable box(es):*

SERVICE TYPE SELECTION:	**RATE SCHEDULE 32 (OR) or 42 (WA)**		**RATE SCHEDULE 31 (OR) or 41 (WA)**	
SALES SERVICE:	Firm ☐	Interruptible ☐	Firm ☐	Interruptible ☐
Firm Pipeline Capacity Charge billing option	Peak Demand (MDDV) ☐	Volumetric ☐	Peak Demand (MDDV) ☐	Volumetric ☐
TRANSPORTATION SERVICE:	Firm ☒	Interruptible ☐	Firm ☐	
COMBINATION SERVICE: [1]	Firm Sales [1] + Interruptible Sales ☐		Firm Sales [1] + Interruptible Sales ☐	
	Firm Sales [1] + Firm Transportation ☐		Firm Sales [1] + Firm Transportation ☐	
	Firm Sales [1] + Interruptible Transportation ☐			
	Interruptible Sales [1] + Interruptible Transportation ☐			
	Firm Transportation [1] + Interruptible Transportation ☐			

[1] If you selected a Combination Service Type, specify the Maximum Daily Delivery Volume (MDDV) for volume to be billed first (which is always first service type named within each combination): ______ MDDV (in therms).

AUTHORIZATION: The undersigned, a representative of Customer, has verified the Customer information stated above and is authorized to make the above Service Type Selection and acknowledges having read and understood the attached Out-of-Cycle Transfer Service Election Form Information and Instructions. By executing this Service Election Form, Customer acknowledges that they understand that they are responsible for requesting information from NW Natural to permit Customer to secure service appropriate to their needs; that they are responsible for making the final selection of a rate schedule that has the most advantageous rate to meet the Customer's individual service requirements; and for how these selections apply to the Customer's service from NW Natural.

By: ______ Printed name: ______

Title: ______ Telephone #: ______ Fax #: ______

Date: ______ E-mail: ______

Approved at NW Natural by: ______ Date: ______

Return this form in person, by U.S. mail, e-mail or facsimile to:

NW Natural, Major Account Services
220 NW Second Avenue
Portland, Oregon 97209

FAX: (503) 721-2527
Phone: (503) 721-2512
E-mail: mast@nwnatural.com

F-9057 (3/9/09)

LES, PLEASE SIGN AND COMPLETE THE ABOVE SECTION

David R. Williams
Vice President
Utility Services
Tel: 503.721.2454
Fax: 503.220.2584
Toll Free: 1.800.422.4012
e-mail: dlw@nwnatural.com

NW Natural®
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
800.422.4012
www.nwnatural.com

April 4, 2013

Mr. Les Walton
Energy Operations Supervisor
Oregon State University
1500 SW Jefferson Way
Corvallis, OR 97331

Re: NW Natural/OSU Firm Transportation Gas Service

Dear Mr. Walton:

Thank you for your recent election to receive firm transportation gas service, starting November 1, 2013. As you know, NW Natural's pipeline infrastructure in the Corvallis region has been and currently is at full capacity. For this reason, NW Natural has in previous years denied previous requests by Oregon State University to obtain firm service.

As we have previously discussed, NW Natural has an infrastructure improvement project that will allow it to provide firm service to OSU while minimizing interruption events for other customers in the region. Our plan to complete under our current schedule is based on estimated gas loads for the near future, assuming that OSU remains a firm gas customer for the next five years.

The purpose of this letter is to memorialize our prior discussions and intentions. Based on your previous requests and conversations with you, we understand that OSU continues to desire to obtain firm service from NW Natural, and that your intent is to remain a firm service customer for at least five years. In return, we intend to complete the infrastructure improvement project this year. Please sign this letter and return it to me, signifying your intention that OSU will remain a firm service gas customer until at least November 1, 2018.

Yours Truly,

David R. Williams
Vice President, Utility Services

X

Les Walton
Energy Operations Supervisor
Oregon State University

NW Natural®

Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 352

352. Please refer to Order 12-408 page 4 item 3 which states "As we will more fully explain, we conclude that NW Natural has failed to demonstrate that the costs of these [MWVF] projects are prudent." Please also refer to Order 12-408 Appendix A page 2 item 10 which states "The Company has confined that the following projects have been cancelled or delayed past the rate effective date: Corvallis Reinforcement; Westside Transmission Rerate; Portland System Optimization (Phase 2); Unified Communication Phase 2; Tualatin Bioswale; Sunset Sheds; Coos Bay Retrofit; and Astoria Retrofit. NW Natural agrees to remove the amounts that were included in rate base for these projects in the Test Year, consistent with Attachment A." Please provide work papers demonstrating that the depreciation expense for these items were removed from base rates in compliance with Order 12-408. If no workpapers are available please provide the basis for the Company's statements at NW Natural/800, Karney/9 line 19.

Response:

The Company complied with Order 12-408 by deriving rates that generated the $8,716,000 in incremental revenue specified by the Commission (See Order 12-437), which is derived from Staff's revenue requirement model attached to the Order as Appendix A. In reviewing our revenue requirements model developed for compliance with the Order, it appears that it recalculates the total revenue requirement in nearly the same manner as Appendix A to Order 12-437, although a rounding adjustment in the Company model was made to match the two models. Although these projects were all removed from rate base, the Company now notes that cost components for depreciation expense are not included in the adjustment to remove the projects from the rate case in either model, and also that accumulated depreciation and deferred income taxes are likewise absent from the adjustment to rate base, which would serve to largely offset the depreciation expense.

NW Natural®

Rates & Regulatory Affairs
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Data Request Response

Request No.: UG 344 OPUC DR 353

353. Please refer to the response to OPUC DR 293.
a. Please reconcile the budgeted amounts with the amounts requested in NW Natural's initial filing for UG 221.
b. Please reconcile the actual amounts with the amounts identified in response to OPUC DR 198, OPUC DR 200 and the 2017 plant audit AIR 47.

Response:

a. The reconciled budgeted amounts and amounts requested in UG 221 for each segment of the Mid-Willamette Valley Feeder are as follows:

    i. Perrydale to Monmouth segment - Project 200581. Estimated cost in UG 221 (per GR1-OPUC-DR-175) $13,500,000. Budget amount per Project Charter - $13,451,105. The difference between the estimated cost in UG 221 and the budgeted amount in the approved project charter is due to site specific design changes that occurred as the project charter budget was finalized.
    ii. Rickereal to Monmouth segment. This project was installed and placed into rates in 2005 as part of the Bare Steel Replacement program and was not discussed in UG 221.
    iii. Monmouth Reinforcement segment – Project 200580. Estimated cost in UG 221 (per GR1-OPUC-DR-175) $8,100,000. Budget amount per Project Charter - $8,807,373. The difference between the estimated cost in UG 221 and the budgeted amount in the approved project charter is due to site specific design changes that occurred as the project charter budget was finalized.
    iv. South of Monmouth Bare – Project 200584. Estimated cost in UG 221 (per GR1-OPUC-DR-175) $14,300,000. Budget amount per Project Charter - $33,707,617. The estimated cost in UG 221 was generated in 2011 and consists of a high level estimate of replacing the 8.5 miles of bare steel in the corridor at an estimated per mile cost of $1.68 million per mile, which is consistent with the per mile installation estimates provided for the Perrydale to Monmouth and Monmouth reinforcement projects in UG 221. The budgeted amount in the approved project charter is due to detailed finalized design that was generated in 2013 for project approval.

The final design and estimate accounts for the full scope of work including all permitting, land acquisition, horizontal directional drilling (HDD), flagging, road restoration, associated service and main installation and relocations, and all other costs, as documented in the signed financial authorization. The project was placed into rates in 2013 and 2014 as part of the Bare Steel Replacement program.

b. Please see UG 344 OPUC DR 353 Attachment 1 -Reconciliation of Asset Costs to Project Costs.

Project Number	Project Description	Total Assets	Cost per DR 293	Difference	Explanation of Difference
200580	Monmouth Reinforcement segment	10,145,297	10,056,777	88,520	Difference primarily resulted from Project Trailing Charges
200581	Perrydale to Monmouth segment	14,432,484	14,161,979	270,505	Difference primarily resulted from Project Trailing Charges
200584	South of Monmouth Bare Replacement segment	27,127,612	29,170,312	(2,042,700)	Difference primarily resulted from Removal Work Orders included in Project costs, but charged to Cost of Removal and not to Assets. Removal Order 3425507, $1,959,480.

Note: The linked Project worksheets in this Excel file show the Asssts that were created as a result of each Project. The costs for each Asset were included in the Response to Plant Audit AIR 47.

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Request No.: UG 344 OPUC DR 354

354. Please provide the per foot pipe cost for each pipe size between 4" and 12".

Response:

Material Description	Price	Unit
PIPE, PE, 4" - COIL	$ 2.99	FT
PIPE, PE, 4" - STICK	$ 2.76	FT
PIPE, PE, 6" - COIL	$ 6.28	FT
PIPE, PE, 6" - STICK	$ 5.99	FT
PIPE, PE, 8", STICK, 40'	$ 10.23	FT
PIPE, STEEL, BARE, BLACK, HFW, 12"	$ 44.98	FT
PIPE, STEEL, BARE, BLACK, HFW, 4"	$ 8.25	FT
PIPE, STEEL, BARE, BLACK, HFW, 6"	$ 28.52	FT
PIPE, STEEL, FBE COATED, HFW, 10"	$ 42.95	FT
PIPE, STEEL, FBE COATED, HFW, 12"	$ 46.95	FT
PIPE, STEEL, FBE COATED, HFW, 12" .312W	$ 28.53	FT
PIPE, STEEL, FBE COATED, HFW, 4"	$ 14.09	FT
PIPE, STEEL, FBE COATED, HFW, 6"	$ 19.72	FT
PIPE, STEEL, FBE COATED, HFW, 8"	$ 34.75	FT
PIPE, STEEL, FBE COATED, HFW, 8" .250W	$ 16.69	FT
PIPE, STEEL, FBE CTD, HFW, HVY WALL, 10"	$ 78.60	FT
PIPE, STEEL, RESICOAT/FBE COATED, 4"	$ 17.88	FT
PIPE, STL, FBE/ARO CTD, HFW DD 12" .312W	$ 39.88	FT
PIPE, STL, FBE/ARO CTD, HFW, DD 8" .250W	$ 22.89	FT
PIPE, STL, FBE/ARO CTD, HFW, DIR DRL 10"	$ 36.35	FT
PIPE, STL, FBE/ARO CTD, HFW, DIR DRL, 4"	$ 17.29	FT
PIPE, STL, FBE/ARO CTD, HFW, DIR DRL, 6"	$ 24.17	FT

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Request No.: UG 344 OPUC DR 355

355. Please provide the per foot trenching and directional boring cost for each pipe size between 4” and 12” and for trenching in flat rock free loam with no obstacles or obstructions.

Response:

For poly pipe the estimated per foot trenching and directional boring costs are:

Pipe Size	Pipe Type	Pipe Installation Method	
		Open Trench	Horizontal Directional Drill
4”	MDPE, 0.391” w.t.	$15-$20 per foot	$10-$12 per foot
6”	MDPE, 0.576 w.t.	$15-$20 per foot	$17-$25 per foot
8”	MDPE, 0.750 w.t.	$20-$30 per foot	$35-$50 per foot

For steel pipe the estimated per foot trenching and directional boring costs are:

Pipe Size	Pipe Type	Pipe Installation Method	
		Open Trench	Horizontal Directional Drill
4”	FBE Steel; 0.237” w.t.	$20-$30 per foot	$60-$80 per foot
6”	FBE Steel, 0.280 w.t.	$20-$30 per foot	$90-$125 per foot
8”	FBE Steel, 0.322 w.t.	$20-$30 per foot	$140-$180 per foot
10”	FBE Steel, 0.365 w.t.	$20-$30 per foot	$170-$210 per foot
12”	FBE Steel, 0.375 w.t.	$20-$30 per foot	$220-$260 per foot

Additional Assumptions Made to Complete Estimate for Requested Costs:

• Costs reported above only include direct costs for trench excavation for pipe bury per project specifications or outside vendor horizontal directional drilling (HDD) costs;

• Costs do not include design, permitting, traffic control, gas main tie-in hole excavation, shoring, steel plates, pavement restoration, etc.;

• Work assumed to occur in open space work setting with room to side-cast trench spoils;

• Outside vendor used for HDD work:

• Trench spoils used for trench backfill (per loamy, rock free soil assumption) for all open trenching:

• Length of trench excavation or HDD installation is greater than 2,000 feet.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 362

362. Please refer to NW Natural's response to OPUC DR 154. Did NW Natural pay cash incentives to new customers in the Eugene, Albany, and Monmouth service areas in 2012 through 2017?

Response:

Yes, NW Natural paid incentives using shareholder dollars to new customers in Eugene, Albany, and Monmouth service areas. The incentives paid to these customers were available to all NW Natural customers in Oregon. Please see UG 344 OPUC DR 362 Attachment 1 for the detailed breakdown of shareholder incentives paid to customers over the 2012 to 2017 time period.

Shareholder incentives paid to new customers.

Data Request Response - UG 344 OPUC DR 362 & 363

DR #	Region		2012		2013		2014		2015		2016		2017		TOTAL	
			Qty	Total $	Qty	Total $	Qty	Total $	Qty	Total $	Qty	Total $	Qty	Total $	Qty	Total $
362	Albany		5	$1,400	11	$2,950	7	$2,850	8	$3,800	4	$2,200	7	$2,700	42	$15,900
	Monmouth		0	0	1	$200	1	$150	0	0	0	0	2	$800	4	$1,150
	Eugene		28	$5,375	43	$5,425	56	$17,825	51	$21,456	44	$25,800	74	$28,550	296	$104,431
363	South East Eugene		11	$2,100	18	$3,375	31	$9,850	33	$12,108	31	$15,200	41	$15,500	165	$58,133

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 366

366. Regarding asset numbers 6094517 South of Monmouth 12" $14,691,584 and 6106445 South of Monmouth 12" $9,846,581:

a. Please provide the following documents:
   i. Business case
   ii. Project charter
   iii. Change Orders
   iv. Project closing documents

b. Please confirm that the cost of both assets is part of the South of Monmouth Bare Replacement section shown on the map of the Mid-Willamette Valley Feeder shown in the direct testimony of Joe Karney 800/page 5.

Response:

a.

i. Both asset numbers 6094517 and 6106445 are part of the South of Monmouth Bare Steel replacement project (Project #200584). For the business case, please see section 7 of the attached Project Charters, UG 344 OPUC DR 366 Attachments 1-2 (200584 G-67 Financial Authorization.pdf and 200584 G-67 Financial Authorization 2014.pdf).

ii. The initial project charter, UG 344 OPUC DR 366 Attachment 1 (200584 G-67 Financial Authorization.pdf) is the project charter approved the project prior to the start of construction in 2013. The second project charter UG 344 OPUC DR 366 Attachments 2 (200584 G-67 Financial Authorization.pdf), was updated the charter upon completion of the 2013 construction and prior to the construction planned for 2014.

iii. There were no change orders for the project.

iv. Please see the attached final project close out document UG 344 OPUC DR 366 Attachment 3 (200584 Mid-Willamette Close Out Approved.pdf)

b. Both assets are part of the "MWVF South of Monmouth Bare Replacement (2013)" as shown in the direct testimony of Joe Karney 800/page 5.

NW Natural

South of Monmouth Bare S24 Replacement Project #200584

G-67 Financial Authorization

April 16, 2013

5/13/13

Jon Huddleston — Date
Director – Technical Services and System Operations – Sponsor

5/15/13

Jorge Moncayo — Date
Finance

5/15/13

Brody Wilson — Date
Controller

5/20/13

Alex Miller — Date
Treasurer and Vice President Regulation

(see review notes to be cleared) 5/28/2013

Steve Feltz — Date
Senior Vice President and CFO

5/29/13

Grant Yoshihara — Date
VP Utility Operations – Executive Sponsor

6/10/13

David Anderson — Date
Executive Vice President

6.10.13

Gregg Kantor — Date
President and CEO

SOUTH OF MONMOUTH BARE MAIN REPLACEMENT # 200584

Date Submitted: 4-03-2013	Facility: S24 Replacement/ Bare Main	Business Unit: Engineering/ Steve Nelson
Project Sponsor: Jon Huddleston		Executive Sponsor: Grant Yoshihara
Project Manager: Brian Konrad/ Mark Schaefer	Desired Implement Date: July 2013	Prepared By: Brian Konrad
Engineer: Mark Schaefer	Short Title: South of Monmouth Bare S24 Replacement	

1. **Project Title: South of Monmouth Bare Main Replacement**

2. **Project Description:**
The replacement of the bare S24 South of Monmouth pipeline consist of installing approximately 12 miles of 12 inch high pressure steel main on Corvallis/Independence Rd. The installation will begin on Haley Rd and will be terminating 500' north of HWY 20. The new 12 inch line will connect onto the existing 6 inch high pressure gas main (S24) that feeds North Albany and North Corvallis. The project will include distribution system upgrades eliminating services regulators, installing 2 inch poly main and replacing, reconnecting or relining existing services.

3. **Project Manager Assignment:** Mark Schaefer/Brian Konrad

4. **Project Objectives:**
- Install 12 Miles of 720 PSIG design pipeline
- Eliminate all high pressure bare main
- Minimize the impact to the local community and to enhance our customer relationship
- Assure a safe working environment for all stakeholders
- To promote good stewardship with the environment and mitigate all impacts to as good or better condition
- Manage change control
- Complete the project by November 1, 2014
- Stay within the budgetary limits.
- Lower the risk to serve and deliver product to our customers
- Create a positive relationship with the many ~~the~~ jurisdictional agencies.

5. Schedule

- Construction will start in July of 2013 and terminate November 1, 2014

Phase 1

- The first phase of construction will go out for bid and will include the installation of 3.3 miles of 12 inch pipe.
- The construction will start at Haley Rd and end north of the Lukiamute River.
- NW Natural crews will construct 9200 feet of 2 inch poly distribution improvements
- If Army Corps permits are obtained by August of 2013, then additional 2.7 miles of 12 inch will be installed south of the Lukiamute River to Springhill Rd.
- NW Natural crews will install 5500 feet of 2 inch poly on distribution system improvements.

Phase 2

- Phase 2 will consist of six miles of 12 inch steel installation starting at Springhill rd and terminate 500 feet north of HWY 20.
- NW Natural crews will install pressure reduction and reliefs to support the installation of the distribution improvements.
- Installation of 10,200 feet of 2 inch poly and the abandonment of the existing bare structure.
- Phase 2 will tie into the existing coated 6 inch high pressure line(S24) 500 feet north of Hwy 20

6. Project Cost Constraints

- The project is estimated at $ 33,707,617 this amount includes 47% COH
- The estimate for the first 3.3 miles is $10.9 million for installation.
- If NW Natural obtains the Army Corp permit in early August, the Phase 1 spend could be $16.7 million for 6 miles completed by end of 2013.
- Phase 2 is estimated @ $16.9 million.
- The estimate includes10% contingency and 47% COH.
- Other cost constraints are cost of land acquisitions, environmentally sensitive areas and cost of outsourcing the 15 directional bores.

Reason for no financial analysis. SOK

7. Business Case

- The existing 1931 high pressure bare pipe has reached its life cycle and NWN intends to install a high pressure coated steel pipeline.
- The installation will safely deliver and serve product to the Mid Willamette Valley.
- The two year approach will allow NWN crews to perform most of the work. OPUC approved SIP Cap increase over next 2 yrs.
- The impact to the agricultural community will be minimized by working in 2 dry seasons.
- NWN will construct distribution improvements while permitting the second phase of the 12" high pressure segment.

8. Deliverables:

- Communication Plan- Media and Project Team
- Obtain all land agreements
- Stay within scope of installing 12 miles of 12 inch high pressure gas main.
- Abandon existing 6 inch bare main
- Install District Regulators at South of Prather, Springhill, Palestine, Ryals and Pettibone
- Install 2 inch poly to deliver and serve the customers along the route.
- Install excess flow valves to all existing service lines within the scope of the project
- Install quality assured product
- Lower the risk to serve by replacing bare pipe with coated steel pipe
- Lower the cost to serve by eliminating the service regulators along the 12 mile route
- Follow all regulatory agencies requirements

9. Communication Plan

- The communication plan for this project is to have a conference call with the stakeholders every Wednesday morning to address any variables, deliverables, and constraints and change request.
- There will be a sponsors meeting every third Thursday to discuss progress, delays, constraints and change orders.
- Every two weeks the Project Mangers will present updates on the project to the Capital Project Manager

- On the first Tuesday of every month there is a stakeholders meeting for all Capital Projects. In attendance are stakeholders from Land Risk, Environmental, Gas Supply, Resource Management, Supply Chain, Construction and project sponsors.

Approvals.	
______ Date: 5/13/13 Project Sponsor: Jon Huddleston	______ Date: ______ Project Manager Brian Konrad
______ Date: 5/23/13 Executive Sponsor: Grant Yoshihara	______ Date: ______ Project Engineer Mark Schaefer
______ Date: 5/13/13 Business Unit: Engineering/ Steve Nelson	______ Date: ______

Items for clarification per
Steve Feltz's approval.

Project Approval Review Notes
200584 – S of Monmouth Bare Steel Replacement
5/28/13

1. Under Item 5 – please re-confirm that project deliverable for Phase 1 is to be completed by cut-off date to include in SIP tracker effective 11/1/13. All phase 1 work to be in operation "used and useful" by November 1, 2013. √SF

2. Under Item 6 – Is 10% contingency reasonable based on past experience for a Risk Score of 2.86? A 10% contingency rate was estimated for both phase 1 and 2. Based on the size of the project 10% contingency is reasonable. The project risks do not put this project in a higher contingency bracket. √SF

3. Under Item 7 – Are distribution improvements required for this bare steel replacement project? And are they automatically included in the SIP tracker? Yes distribution improvements are ~~included on~~ required by (per GRANT Y.) this project. See attached "Scope of Work" document for details which is included in the G-67 project packet. We have historically rolled in distribution improvements into the bare steel program when they were necessary. √SF

4. Under Item 8 – Is this a complete list of deliverable in project scope? Can you specify the amount of distribution poly pipe to be installed as part of the original scope? Yes, this is the complete scope of work as projected. See attached "Scope of Work" document for details on the distribution improvements. √SF

5. Can you check with Accounting to see if we can assign all of the 2009 and 2012 project costs to phase 1 that goes into service in 2013, or must some of it be prorated to Phase 2 and wait until 2014 to be put into service? It should be prorated over the project life. So we can make sure that some of the design costs are allocated to phase 1 and will be assigned when phase 1 is used and useful. Generally we have allocated the design costs based on the pipe footage. This has been done in the past. ok - √SF

6. How firm is the contract price shown as "Contract Total"? if this is a soft estimate, do we have enough contingency? The cost estimate is based on a detailed scope of work. Based on this and the risk assessment, a 10% contingency should be sufficient. ok √SF

7. Has AFUDC been included in the project cost estimate? Is conclusion that it's not material? Has project manager committed to absorbing this in project approved budget? The conclusion has been made that the AFUDC costs are not material at present. We have committed to absorbing the AFUDC costs in the budget. ok √SF

Scope of Work
South of Monmouth Bare
P200584

2013
Class B & District Regulators

- Install 14,200 feet of 2" Poly
- Eliminate 11 service regulators
- Upgrade 14 services lines (reline, replace, reconnect, EFV)
- Install 1 new district regulator

Transmission

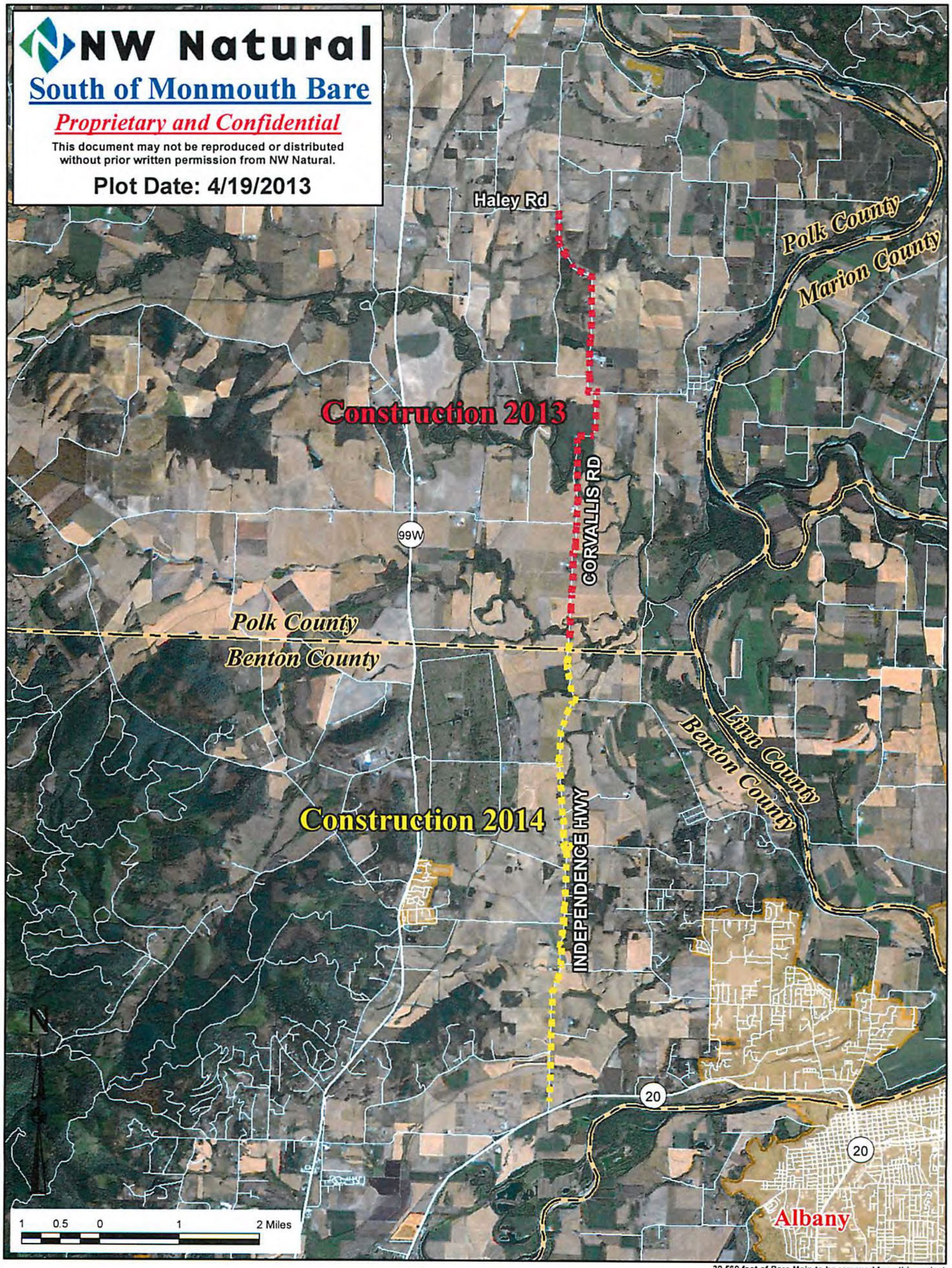
- Directional drill and install 13,250 feet of 12" pipe – 7 locations
- Open Excavate and install 18,000 feet of 12" pipe – 5 locations
- Caliper pig new 12-inch pipeline
- Install 12" Blow down bridle – 1 location
- Tie-in to existing 12" Mid-Willamette pipeline at north end (Haley Rd)
- Eliminate existing 6" high pressure bare main pipeline (1931 system)

2014
Class B & District Regulators

- Install 14,500 feet of 2" Poly
- Eliminate 18 service regulators
- Eliminate 6 district regulators
- Install 7 new district regulators
- Upgrade 19 services lines (reline, replace, reconnect, EFV)

Transmission

- Directional drill and install 19,800 feet of 12" pipe – 8 locations
- Open Excavate and install 11,350 feet of 12" pipe – 5 locations
- Directional drill and install 2,400 feet of 6" pipe – 1 location
- Hammer bore 12" pipe at street crossings - 2 locations
- Install 12" Blow down bridle – 1 location
- Caliper pig new 12-inch pipeline
- Tie-in to existing 6" S24 high pressure pipeline at south end (Hwy 20)
- Eliminate existing 6" high pressure bare main pipeline (1931 system)



30,569 feet of Bare Main to be removed from this project

Project Cost Estimate

2009 Project Actual Design Costs	
Transfer from Project 200163	$392,090
Construction Overhead (47%)	$184,282
Total 2009 Project Design w/ COH	**$576,372**

2012 Project Actual Costs	
2012 Previous Charges	$782,313
Construction Overhead (47%)	$367,687
Total 2012 Project Actual w/ COH	**$1,150,000**

Assumption on the estimate is that NWN installs the full 6 miles in 2013. Permitting is incomplete at this time.

Estimated yearly project spend for 2013 & 2014 will need to be adjusted if permitting is not complete.

THESE AMOUNTS ARE ALLOCATED TO "2013 PROJECT ESTIMATED COSTS" AND "2014 PROJECT ESTIMATED COSTS" BELOW WITH CORRESPONDING COH ON SEPARATE LINES.

2013 Project Estimated Costs	
Design/Management Total	$919,500
Equipment/Material Total	$2,141,135
Bore Labor Total	$0
Trench Labor Total	$0
Contract Support Total	$303,060
Contract Total	$5,941,510
Distribution Total	$489,220
Transfer from Project 200163	$196,045
2012 Project Actual Costs	$391,157
Total	**$10,381,627**
Construction Overhead (47%)	$4,879,364
Total Cost	$15,260,991
Contingency (10%)	$1,526,099
Total 2013 Project Cost w/ COH	**$16,787,090**

2013 Capital Budget includes $9.5M w/o COH. ✓ OK. INCREMENTAL SPEND ONLY IN BDGT. SF

Cat 2 SIP spend is down, so the remaining funds required ≈ 800k should be available.

SDG
5-15-13

2014 Project Estimated Costs	
Design/Management Total	$540,000
Equipment/Material Total	$1,890,235
Bore Labor Total	$0
Trench Labor Total	$0
Contract Support Total	$303,060
Contract Total	$6,212,850
Distribution Total	$930,800
Transfer from Project 200163	$196,045
2012 Project Actual Costs	$391,157
Total	**$10,464,147**
Construction Overhead (47%)	$4,918,149
Total Cost	$15,382,295
Contingency (10%)	$1,538,230
Total 2014 Project Cost w/ COH	**$16,920,525**

Total Project Cost w/ COH	**$33,707,615**

4/19/2013


HALEY RD
BUENA VISTA RD
OLD FORT RD
OAK HILL RD
PRATHER RD
BUENA VISTA RD
BUENA VISTA RD
POLK COUNTY
BENTON COUNTY
QUINLAN
RD
NW BUENA VISTA RD
SPRINGHILL DR
CAMP ADAIR RD
GILMOUR LN
QUINLAN
RD
NW MINT AVE
NW INDEPENDENCE HWY
NW PALESTINE AVE
NW POWERS AVE
NW RYALS AVE
NW METGE AVE
NW INDEPENDENCE HWY
NW KOUNS DR
NE PETTIBONE DR
NW ROADO ST
US-20
BENTON COUNTY
LINN COUNTY
NE GRANGER AVE
US-20

Scope of Work
South of Monmouth Bare
P200584

2013
Class B & District Regulators

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- Tie-in to existing 6" S24 high pressure pipeline at south end (Hwy 20)
- Eliminate existing 6" high pressure bare main pipeline (1931 system)

NW NATURAL

200584 South of Monmouth Bare Main Replacement

April 17, 2013

PUBLIC RELATIONS & COMMUNICATIONS PLAN

Public Relations Plan

Audiences

- Affected landowners
- Polk and Benton County Public Works
- Agricultural Businesses
- Local news media
- State regulators (OPUC)
- NW Natural employees
- Allied Waste

Strategies

1. Replacement of high pressure bare steel with 12 inch steel coated pipe to assure reliable delivery to the Mid Willamette Valley
2. Communicate our positive messages more assertively
3. Use new outlets and forums to gain positive exposure
4. Increase public awareness of the value of NW Natural to the local economy

Key messages

1. NW Natural is a valuable member of the community – we're here to stay
2. The project is about the delivering gas in a safe reliable pipeline. OLD vs NEW
3. NW Natural is using the best products and installation methods to avoid impact to local landowners and farmers.

Tactics and actions

Action Responsibility

- Scheduled meeting with Linn, Benton and Polk Counties
- Letters will be sent to all residences along the route
- News media briefings **(TBA – schedule as needed) Public Affairs**
- **Employee Communications (Ongoing, as needed) Communication**
- Public Officials & Regulatory Agencies **Govt. Relations**
- Personal contacts Regulatory Affairs
- Monthly meeting for internal stakeholders to update on project process
- Weekly meetings with key stakeholders Land and Risk, Environmental, WH Pacific, Epic Land Solutions, Geo Engineers and Engineering to discuss deliverables

Communications Plan

Communications and information exchange occur in written and verbal forms. The exchange can be formal or informal and there are processes to accommodate each type. Communication can be further broken down into internal and external to NW Natural.

Internal Communication

The most common means of internal communication for the project is through team and committee meetings. Team members are encouraged to attend bi-monthly team meetings and to meet as small groups as required. The Team meetings are intended to exchange the latest information, raise and address issues, and get team members current on the project status.

The other type of communication is in the form of presentations. There are opportunities to discuss the project with large company groups. As the project construction kicks off or when it comes to a close, there may be an opportunity to make a presentation.

Written communications are found in several different forms. Informal written communications can be provided through interoffice memos and e-mails. Formal written communications are often in the form of a drawing, report, study, or an approval document. The drawings are typically engineering design and are reviewed by several team members and approved by the Project Engineer. Reports and studies are often technical and submitted to the Engineer by consultants. The project approval documents are for gaining consent to move forward conceptually with a project.

Large audience written information exchange can also be accomplished through company communications on the HUB, FYI or Blue Flame.

External Communication

Most external communication is informal and either verbal through phone conversations or written in e-mail form. These communications are often casual and discretion needs to be used. Each team member can determine what informal correspondence warrants being saved. All team members are required to abide by Corporate Guidelines found in the **Information Management Policy** and are summarized below:

- Corporate information shall be managed to assure its accuracy, timeliness, availability, security and confidentiality, as required.
- All corporate information that is not specifically designated as public information shall be regarded as proprietary and be made available for use by employees on a business need-to-know basis only.
- Corporate information shall be managed in a manner that will satisfy the legal, regulatory, business, audit, and ethical requirements of the Company.
- It is the responsibility of all employees to assure the proper use and protection of corporate information.

Although unlikely, if the media inquires about the project, all contacts need to be directed to the Corporate Communications Department.

MEDIA SPOKESPERSONS:

24-hour pager: 503-818-9845

Melissa Moore: 503-226-4211 x2436 (office) or 503-223-2254 (cell)
Valerie White: 503-226-4211 x3515 (office) or 503-807-4236 (cell)

PROJECT TIMELINE

Project:	South Of Monmouth Bare
PS #:	200584
Date:	4/16/2013

Construction Duration	12	Months
Construction Expected Start Date	7/8/2013	
Construction Expected Completion Date	11/1/2014	
Construction Timeline	Fixed	

Initiation Tasks	1/11/2011 Required Task	4/16/2013 Resp
Complete Initiation Memo	Yes	PM
Complete Charter	Yes	PM
Complete Design Review	Yes	PM

Planning Tasks	10/12/2012 Required Task	4/16/2013 Resp
Request Easements	Yes	Risk
Address Environmental Issues	Yes	Envir
Request Corrosion Input	Yes	PM
RFP for Outside Services	Yes	Purch
Complete Design	Yes	PM
Station Packet	Yes	PM
Pressure Test Documentation	Yes	PM
Order Non-Stock Parts/Reserve Stock Parts	Yes	Stores
Complete Tie-in Details	Yes	PM
Finalize Design/Engineering Sketches	Yes	PM
Complete Traffic Control Plan	Yes	FET
Request Permits	Yes	EC
Notify Stakeholders Affected by Project	Yes	PM
Complete Bore Plan	Yes	PM
Draft Preliminary Procedure	Yes	PM

Executing Tasks	4/16/2013 Required Task	7/8/2013 Resp
Pre-Construction/Safety Meeting with Crew	Yes	PM
Install Construction Field Stakes	Yes	FET
Notify Stakeholders of Firm Start Dates	Yes	PM
Review Preliminary Procedure with Crew	Yes	PM

Monitoring Construction Tasks	4/16/2013 Required Task	11/1/2014 Resp
Monitor Schedule	Yes	PM
Monitor Budget	Yes	PM
Procedure Sign Off	Yes	PM

Closeout Tasks	12/31/2014 Required Task	1/15/2015 Resp
Conduct Project Learning Meeting	Yes	PM
Complete Final Report for Project	Yes	PM

STAKEHOLDERS

NW Natural Stakeholders		Comments
X	Contract Services	Contract Services to provide input on vendor selection
X	Corrosion	Corrosion to assess project for CP stations
X	Distribution Crew	To install and support Distribution and HP Distribution
X	Elect/Communications	Communication to support the project
X	Environmental/Haz Mat	Support the permitting and construction process
X	Resource Management	Dispatch resources needed to construct the 12".
X	Gas Supply	Gas Control and Gas Buyers
	Gasco/Mist/LNG Plants	Mist Plant personnel
X	Major Acct. Services	Notify customers of curtailment and communicate with existing and potential customers.
X	Integrity Management	Support the project with procedures and oversight of the Quality Assurance functions.
X	Purchasing / Stores	Contract preparation and supply chain
X	Resource Center Engineer	Design and manage project
X	Risk and Land	Secure easements with 25 landowners.
X	Safety	Support project with Supervision and resources.
X	Specialty Const Crew (ROW)	Supply a team to manage the coating applications
X	Station Design	Provide a design for district regulators and asset registry
X	Surveying	Recording the land agreement, defining bore entries and exits, establishing construction limits.
X	Transmission Const Crew	Provide labor for the installation of the 12" pipeline
X	Transmission Maint Crew	Provide testing of the pipeline and monitoring the product during hot tie ins.
X	Welders	Welding pipe to the 1104 specifications
External Stakeholders		**Comments**
	City	Albany, Oregon
	County	Polk and Benton Counties
	State	DSL, SHPO, ODOT ,Army Corp of Engineers, DEQ
	Engineering Firm	WH Pacific and Geo Engineers
	Property Owners	Managed by Epic Land Solutions with approvals by Land & Risk there are 25 separate landowners and the project is located within multiple tax lots.
	Other	

G-67 PROJECT PLAN - RESPONSIBILITY MATRIX

Project:	South of Monmouth Bare Steel Replacement
PS #:	200584
PM:	Brian Konrad/ Mark Schaefer

A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
PROJECT TEAM			●	●	●	●	●	●	●	●	●	●	●	●				●				●	●		●		●
INITIATION TASKS	12/20/2012	4/17/2014																									
Create Project in SAP			A																								
Create Initiation Memo			A																								
Outline Proposed Construction Dates			A	P																							
Preliminary Design Meeting			A	P			P																				
PLANNING TASKS	10/11/2012	5/15/2013																									
Identify Project Team			A																								
Create Work Orders					A																						
Assemble As Builts & Historical Documentation					A																						
Request Design Locates									A																		
Request Survey			A																								
Request Easements			A							A																	
Draft Preliminary Design			A	P	P	P		P										P									
Draft Preliminary Cost Estimate			A		A		I																				
Contract for Outside Services			A								P																
Create Design Documentation			A		P	P																					
Finalize Design			A		A		I	P										P				P					
Finalize Construction Dates			A		A		I		P																		
Create Charter or G-67 Project Plan			A																								
Charter or G-67 Project Plan Approved			A																								
Complete Engineering Sketch			P	P	A																						
Complete Traffic Control Plan			A		P																						
Request Permit					A																						
EXECUTING TASKS	4/17/2013	11/1/2014																									
Request Construction Locates			A						A																		
Install Construction Field Stakes			A		A																						
Schedule Field Resources							I		A																		
Hold Pre-Construction/Safety Meeting			A		P		P		I			P	P									P	P				
Notify Stakeholders of Firm Start Dates			A				I		I													I					

G-67 PROJECT PLAN - RESPONSIBILITY MATRIX

Project:	**South of Monmouth Bare Steel Replacement**
PS #:	**200584**
PM:	**Brian Konrad/ Mark Schaefer**

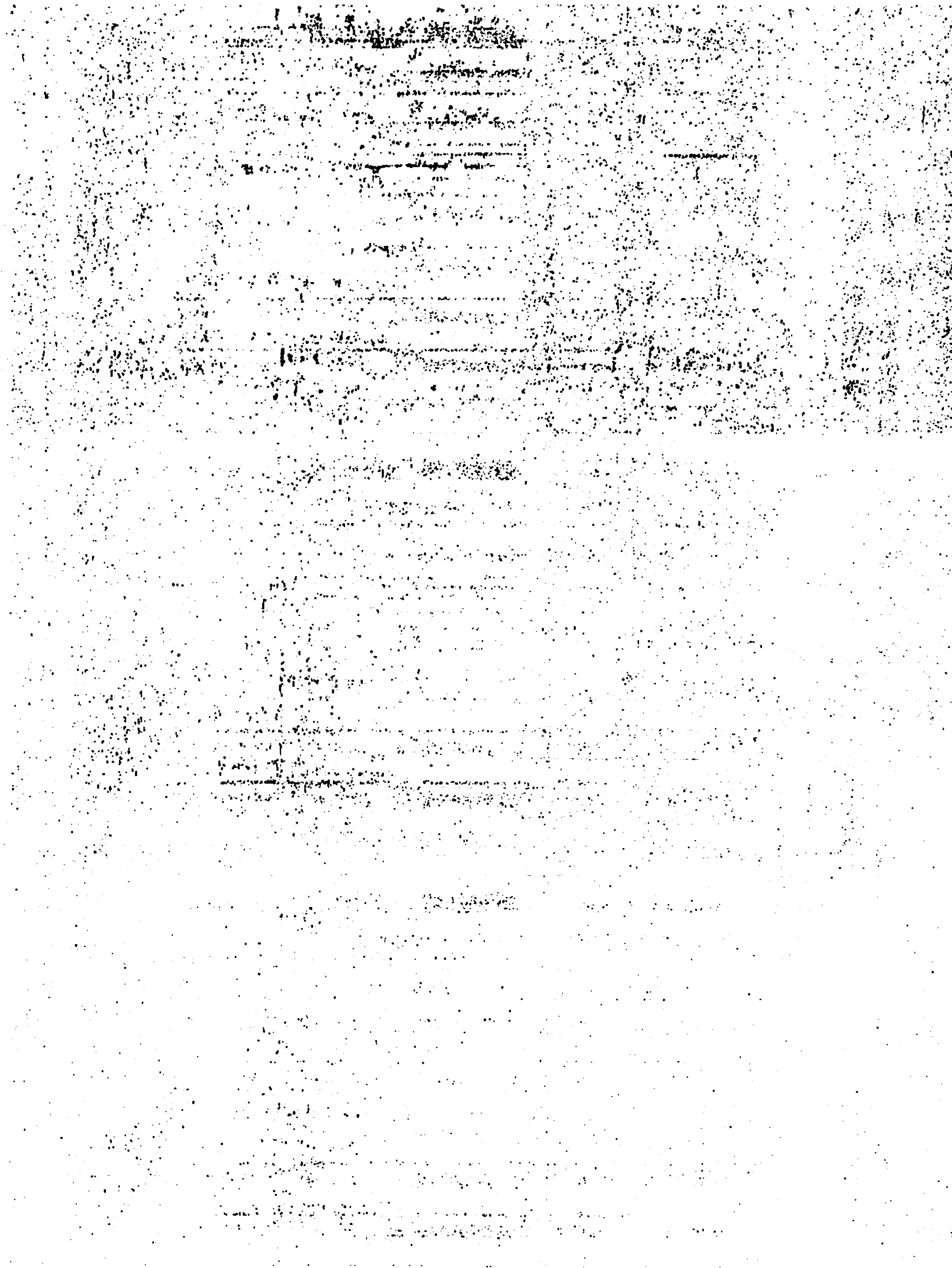
A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
MONITORING TASKS	5/17/2013	11/1/2014																									
Monitor Worksite Activities			A	P			I		P													P					
Complete and Submit Project Change Request Form as Necessary			A				I															P					
Monitor Schedule			A				P		P													P					
Monitor Budget			A				I																				
Receive & Approve all Invoices			A		A		I															I					
Coordinate Construction Activities with Stakeholders			A				P															P					
Finalize Tie-in Procedure			A		A		P							P								P	P		P		P
Tie-in Procedure Signed Off			A		A	I								I													
Schedule Tie-in and Coordinate with Support Crews			A		A		I		A					A								P					
Establish Final Punch List Items & Timeline for Completion			A		A		I															P					
CLOSEOUT TASKS	4/17/2014	11/1/2014																									
Complete As Built Packet			A		P		I				I											P					
Audit work orders and asbuilt					A																						
Complete project document review			A		A	I																					
Plat asbuilt					A	I																					
Conduct Project Learning Meeting			A	I		P	P															P					
Complete Final Report for Project			A																								

Construction Estimate Summary
MWVF -South of Monmouth Bare
Project 200584

Option 1 - Contractor installs 12 miles of 12" pipe. NWN Crews install all distribution (DB) improvements in 2013.
Option 2 - Contractor installs 12" pipe & NWN Crews install all DB, 6 miles in 2013 & 6 miles in 2014.
Option 3 - Contractor installs 12" pipe and NWN all DB, 3.3 miles in 2013, 4.2 miles in 2014, 4.5 miles in 2015.

2009 Project Actual Design Costs	Option 1	Option 2	Option 3
Transfer from Project 200163	$392,090	$392,090	$392,090
Construction Overhead (47%)	$184,282	$184,282	$184,282
Total 2009 Project Design w/ COH	**$576,372**	**$576,372**	**$576,372**
2012 Project Actual Costs			
2012 Previous Charges	$782,313	$782,313	$782,313
Construction Overhead (47%)	$367,687	$367,687	$367,687
Total 2012 Project Actual w/ COH	**$1,150,000**	**$1,150,000**	**$1,150,000**
2013 Project Estimated Costs			
Design/Management Total	$1,298,000	$919,500	$866,000
Equipment/Material Total	$3,979,555	$2,141,135	$1,390,170
Bore Labor Total	$0	$0	$0
Trench Labor Total	$0	$0	$0
Contract Support Total	$590,010	$303,060	$187,280
Contract Total	$11,530,200	$5,941,510	$3,597,173
Distribution Total	$1,420,020	$489,220	$384,500
Transfer from Project 200163	$392,090	$196,045	$107,825
2012 Project Actual Costs	$782,313	$391,157	$215,136
Total	**$19,992,188**	**$10,381,627**	**$6,748,084**
Construction Overhead (47%)	$9,396,328	$4,879,364	$3,171,599
Total Cost	$29,388,516	$15,260,991	$9,919,683
Contingency (10%)	$2,938,852	$1,526,099	$991,968
Total 2013 Project Cost w/ COH	**$32,327,368**	**$16,787,090**	**$10,911,652**
2014 Project Estimated Costs			
Design/Management Total	$0	$540,000	$425,500
Equipment/Material Total	$0	$1,890,235	$1,287,394
Bore Labor Total	$0	$0	$0
Trench Labor Total	$0	$0	$0
Contract Support Total	$0	$303,060	$277,730
Contract Total	$0	$6,212,850	$4,196,583
Distribution Total	$0	$930,800	$306,380
Transfer from Project 200163		$196,045	$137,232
2012 Project Actual Costs		$391,157	$273,810
Total	**$0**	**$10,464,147**	**$6,904,628**
Construction Overhead (47%)	$0	$4,918,149	$3,245,175
Total Cost	$0	$15,382,295	$10,149,803
Contingency (10%)	$0	$1,538,230	$1,014,980
Total 2014 Project Cost w/ COH	**$0**	**$16,920,525**	**$11,164,784**
2015 Project Estimated Costs			
Design/Management Total	$0	$0	$425,500
Equipment/Material Total	$0	$0	$1,506,394
Bore Labor Total	$0	$0	$0
Trench Labor Total	$0	$0	$0
Contract Support Total	$0	$0	$285,770
Contract Total	$0	$0	$4,916,443
Distribution Total	$0	$0	$729,140
Transfer from Project 200163			$147,034
2012 Project Actual Costs			$293,367
Total	**$0**	**$0**	**$8,303,648**
Construction Overhead (47%)	$0	$0	$3,902,715
Total Cost	$0	$0	$12,206,363
Contingency (10%)	$0	$0	$1,220,636
Total 2015 Project Cost w/ COH	**$0**	**$0**	**$13,426,999**
Total Project Cost w/ COH	**$32,327,368**	**$33,707,615**	**$35,503,434**



MWVF South of Monmouth Bare
4/19/2013

NW Natural®
project management office

000000
00-048Defining Stage000000
Project Tier Assessment

Project Name: South of Monmouth Bare

Project Requester: Brian Konrad

A. Project Impact Assessment		
Technical Complexity	**X**	**Score**
Requires New Technology		10
Requires Changes in Multiple Applications and Architecture		7
Requires Changes in Multiple Applications		5
Requires Changes within an Application		3
No Technology Impacts	X	0
Section Score		0
Public Relations	**X**	**Score**
May Result in Difficult / Challenging Perception Management		10
May Initiate Media Inquiries	X	7
Requires Pre-Planning to Manage Customer Relations		5
No Customer Impacts		0
Section Score		7
Compliance/Regulatory	**X**	**Score**
Requires Rate Case		10
Impacts SQMs / Requires Regulator or Jurisdictional Negotiation	X	7
Requires Regulator or Jurisdictional Notification		5
Impacts Tariff Elements / May be Subject to Audit		3
No Compliance Impacts		0
Section Score		7
Employee Impact	**X**	
Requires a Work Redesign for BU Employees		10
BU and NBU impact	X	7
BU Impact		3
NBU Impact Only		1
Section Score		7
Number of Work Groups Impacted	**X**	
7 or More	X	10
3-6		7
1-2		1
Section Score		10
Safety	**X**	
Requires External Expertise and Equipment		10
Hazard Mitigation for Public and Employee Safety Required	X	7
Requires Acquisition of New Safety Equipment / Training		5
Requires Changes in Safety Protocols / Training		3
No Safety Impacts		0
Section Score		7
Project FTEs (Captial and O&M)	**X**	
Requires more than 480 internal FTE hours	X	10
Requires more than 160 internal FTE hours, and possibly up to 480		7
Requires more than 40 internal FTE hours and possibly up to 160		5
Requires at least 40 internal FTE hours		3
No FTE impacts		0
Section Score		10
A. Total Project Impact Assessment Score		**48**

B. Project Estimated Budget	
Development and Implementation	
Equipment/vehicles	
Facility Costs	
Materials	
Technology (hardware and software)	
Capital internal labor	
Capital external labor	
Construction overhead (COH) 47%	~~$0~~
AFUDC	
Travel and Expenses	
Other (itemize)	
B. Total Project Estimated Budget	**$33,707,615**

TIER ASSESSMENT RATING CHART	
A. Total Project Impact Assessment Score	48
B. Total Project Estimated Budget	$33.707615.00
Tier Rating (See Key below)	Tier 3

Tier Assessment Key		
Tier Level (If Score/Estimates fall in either A or B)	**mp**	**B.Cost**
Tier 3	) -	**>$1M**
Tier 2	5 -	**$100K - $1M**
Tier 1	5 -	**$25k - $100k**

SAP Project Number
200584-01

Risk Analysis

Project:	South of Monmouth Bare S24
PS Number:	200584
Project Manager:	Brian Konrad/Mark Schaefer
Date:	4/3/2013

Risk	Probability	Impact	Score (Probability x Impact)	COMMENTS (Eliminate / Mitigate)
Acquisition of Materials	*2 Assorted Non-Stock Items*	*1 - Minimal or No Impact*	2	Mitigate: Order parts early and develop alternate supply chains if standard vendors cannot deliver in a timely manner.
Land Acquisition	*5 Multiple Easements*	*1 - Minimal or No Impact*	5	Mitigate: The project team has outside resources working on obtaining the remaining easements for 2013 and will have to obtain the remaining 16 easements for 2014
Standard Permits	*2 Permits with Minor Conditions*	*2 - May Impact Project*	4	Mitigate: Standard ROW Polk and Benton Counties with DEQ 1200C
Special Permits	*3 Permits with Major Conditions*	*3 - Major Impact to Project*	9	Mitigate: Apply for Army Corp of Engineers, Polk County Land Use, Wetland Permits early to allow enough time to construct as much as we can in 2013.
Environmental Impact	*3 Permits with Minor Conditions*	*2 - May Impact Project*	6	Mitigate: Construction in Wetlands and Agricultural fields will require the use of crane mats
Ground Conditions	*2 Moderately Rocky*	*1 - Minimal or No Impact*	2	Mitigate: The ground conditions may lead to larger excavations due to collapse and mitigation can be accomplished by planning ahead and having the proper size shoring boxes.
Utility Conflicts	*2 Minor Utility Conflicts*	*1 - Minimal or No Impact*	2	Mitigate by obtaining a job agreement with Lukiamute Water to cut service off and reconnect services after pipe has been lowered. The foot line for the project required easements to avoid conflict with overhead and underground utilities.
Weather	*1 Summer*	*2 - May Impact Project*	2	Mitigate: This project is weather sensitive in the farm lands. HDD bores maybe able to continue in inclement weather with the use of crane mats.
Construction Method	*1 Open Trench*	*2 - May Impact Project*	2	Mitigate: Plan for trench collapse.
Bore Method	*1 Horizontal Directional Drill*	*2 - May Impact Project*	2	Mitigate: Perform geotechnical analysis prior to boring and design a bore path that will mitigate frack-out concerns. The alignment is near domestic water wells and will require testing and possible mitigation of the wells.
Resources	*1 Resources Available*	*1 - Minimal or No Impact*	1	Eliminate: The first phase will require outsourcing of the installation of the 12" with NWN crew installing he Distribution improvements. The second phase is planning on using NWNG resources.
Working Hours	*1 No Restrictions*	*1 - Minimal or No Impact*	1	Mitigate: Plan to open only the amount of trench that can be backfilled by the end of the day.
Contract Availability	*1 Resources Available*	*1 - Minimal or No Impact*	1	Eliminate: Contract resources are available for this project.
System Impact	*1 No Impacts - Adequate Feed*	*1 - Minimal or No Impact*	1	Mitigate by installing the High Pressure feed first and the installing the distribution system improvements. This bare main project is not tied
		Avg Score	**2.86**	10
				% Contingency

Risk Strategy
South of Monmouth Bare
P200584

Purpose

Provide safe and reliable service to the Mid-Willamette valley customers by installing 12 miles quality assured 12-inch coated pipeline with upgrades to the existing distribution facilities and elimination of the existing 6" high pressure bare main (1931 system).

Project Approach:

- Design
  - Preliminary design started in early 2012
  - Minimize disturbance to environmentally sensitive areas
  - Coordinate with outside services for geotechnical, environmental, survey and land acquisition
- Land Acquisition
  - Phased approach to Easement Acquisition (24 land owners)
  - Coordinate with outside land consultant
- Permitting
  - Started environmental permitting process in early 2012
  - Phased approach to Environmental permitting (Archaeology, Wetlands, Floodplain, Land Use, Erosion Control
  - Meet with agencies for common understanding of expectations
- Material Procurement
  - Pipe and materials procurement process started
  - Secured 3.6 acre pipe and materials storage yard near the project
- Construction
  - Phase construction over 2 years (2013/2014) with all work completed by October 2014
  - Outsource construction in 2013 for 3.3 miles of 12-inch pipeline (with possible extension to 6 miles depending on permitting
  - NW Natural crews to install all distribution improvements

200584 South of Monmouth Bare Steel Replacement

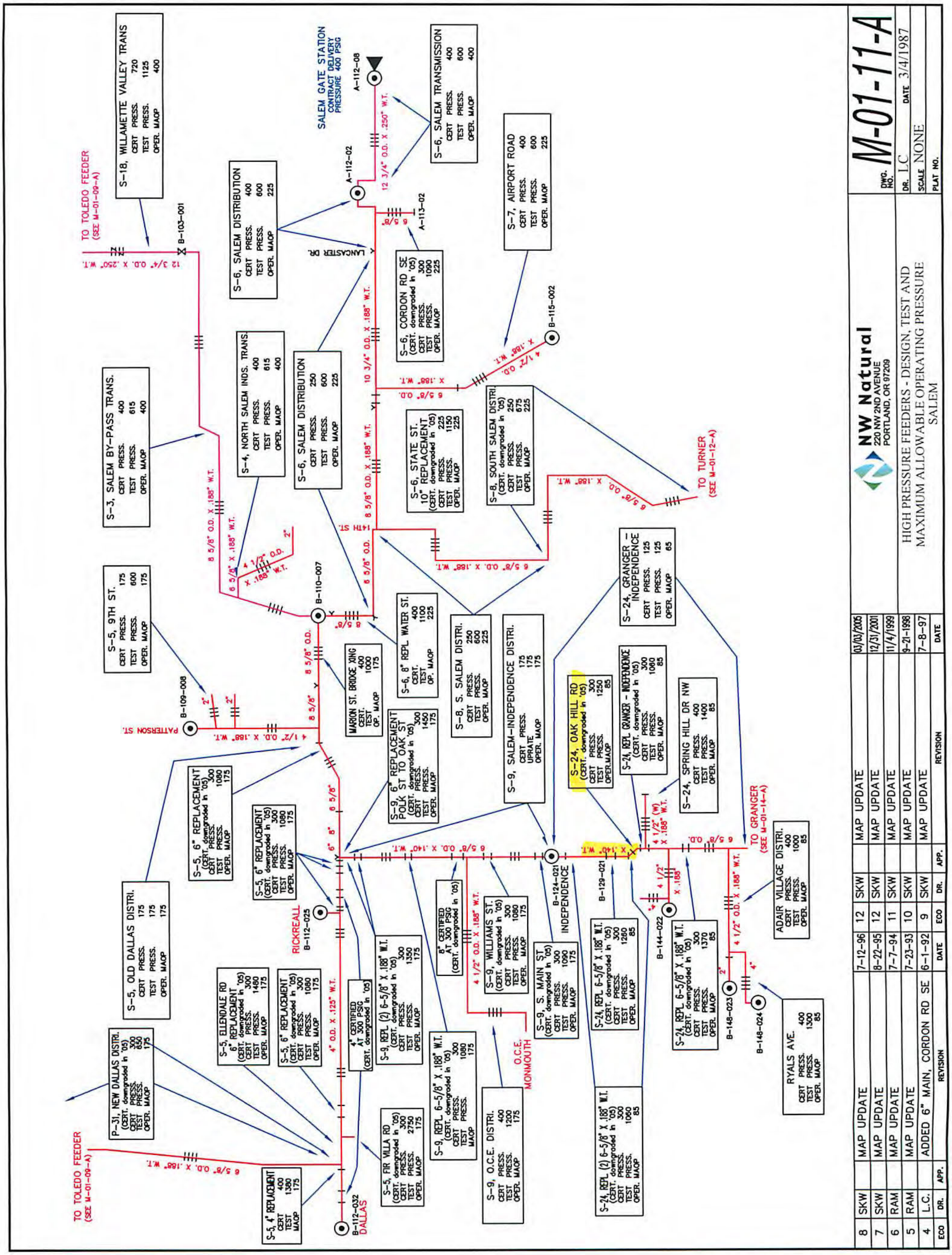
April 17, 2013

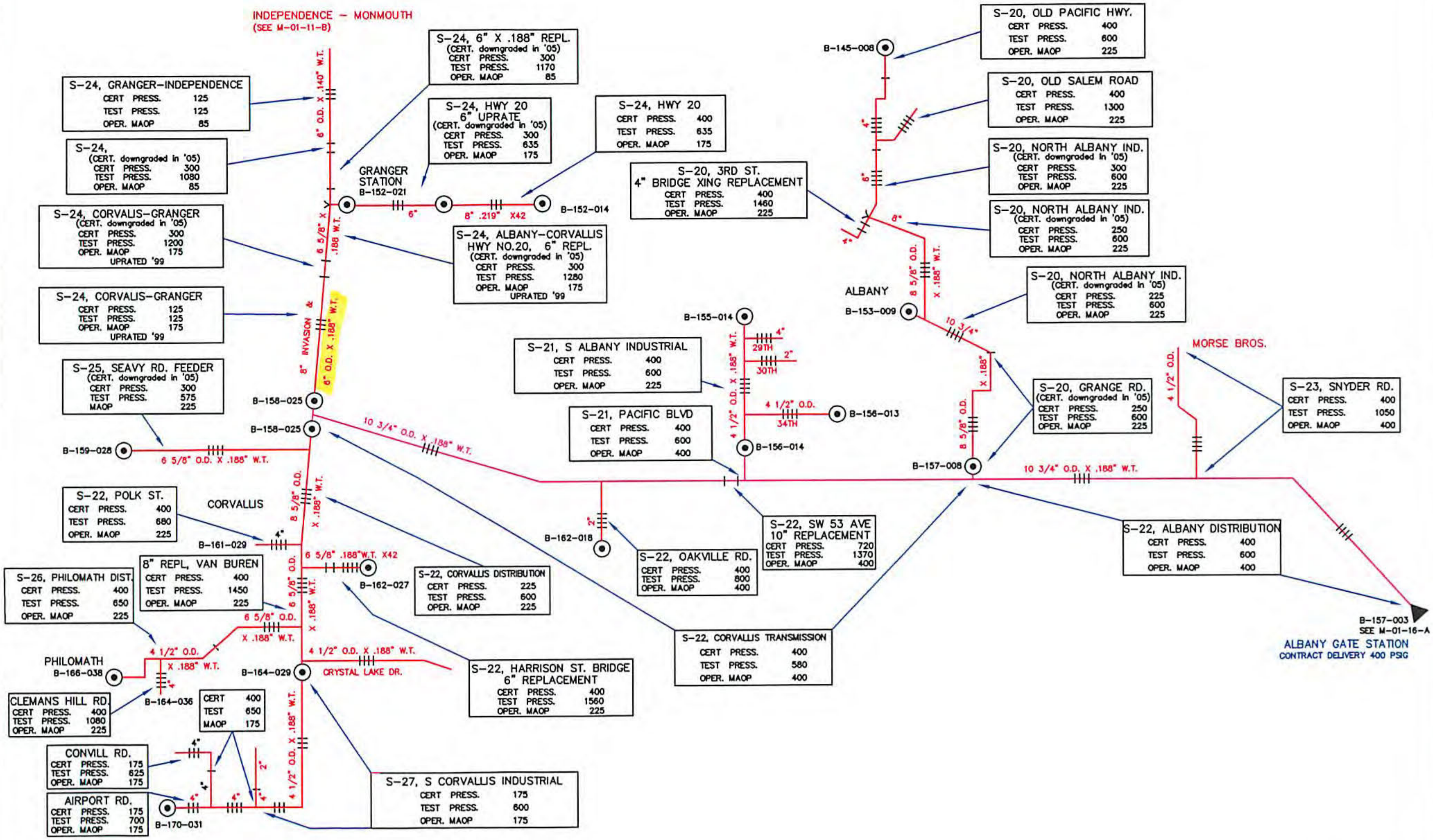
ASSUMPTIONS AND CONSTRAINTS

Assumptions:
The following items will all be addressed prior to the project start:

Land Acquisition
Environmental Impacts
Safety
Pipeline Integrity
Permitting
2 year build out – construction
Completion 11-1-2014

Constraints:
Narrow public right of way
Residential access
Traffic
Supply chain
Contractor availability
Short scheduling timeline
Resource availability
Environmental permitting process and protocols


M-01-11-A
NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
HIGH PRESSURE FEEDERS - DESIGN, TEST AND MAXIMUM ALLOWABLE OPERATING PRESSURE
SALEM
DWG. NO.
DR. LC
SCALE NONE
DATE 3/4/1987
PLAT NO.
SALEM GATE STATION
CONTRACT DELIVERY PRESSURE 400 PSIG
S-18, WILLAMETTE VALLEY TRANS
CERT PRESS. 720
TEST PRESS. 1125
OPER. MAOP 400
S-6, SALEM TRANSMISSION
CERT PRESS. 400
TEST PRESS. 600
OPER. MAOP 400
S-6, SALEM DISTRIBUTION
CERT PRESS. 400
TEST PRESS. 600
OPER. MAOP 225
S-7, AIRPORT ROAD
CERT PRESS. 400
TEST PRESS. 600
OPER. MAOP 225
S-3, SALEM BY-PASS TRANS.
CERT PRESS. 400
TEST PRESS. 615
OPER. MAOP 400
S-4, NORTH SALEM INDS. TRANS.
CERT PRESS. 400
TEST PRESS. 615
OPER. MAOP 400
S-5, 9TH ST.
CERT PRESS. 175
TEST PRESS. 600
OPER. MAOP 175
S-5, OLD DALLAS DISTRI.
CERT PRESS. 175
TEST PRESS. 175
OPER. MAOP 175
S-9, SALEM-INDEPENDENCE DISTRI.
CERT PRESS. 175
UPRATE 175
OPER. MAOP 175
S-24, GRANGER - INDEPENDENCE
CERT PRESS. 125
TEST PRESS. 125
OPER. MAOP 85
S-24, OAK HILL RD
S-24, SPRING HILL DR NW
S-9, O.C.E. DISTRI.
RYALS AVE.
ADAIR VILLAGE DISTRI.
TO TOLEDO FEEDER (SEE M-01-09-A)
TO TURNER (SEE M-01-12-A)
TO GRANGER (SEE M-01-14-A)
LANCASTER DR.
PATTERSON ST.
14TH ST.
RICKREALL
DALLAS
INDEPENDENCE
O.C.E. MONMOUTH
A-112-08
A-112-02
A-113-02
B-103-001
B-115-002
B-110-007
B-109-008
B-112-025
B-112-032
B-124-021
B-129-021
B-144-022
B-148-023
B-148-024
8 SKW MAP UPDATE 03/03/2005
7 SKW MAP UPDATE 12/31/2001
6 RAM MAP UPDATE 11/4/1999
5 RAM MAP UPDATE 9-21-1998
4 L.C. ADDED 6" MAIN, CORDON RD SE 7-8-97
12 SKW MAP UPDATE 7-12-96
12 SKW MAP UPDATE 8-22-95
11 SKW MAP UPDATE 7-7-94
10 SKW MAP UPDATE 7-23-93
9 SKW MAP UPDATE 6-1-92
ECO DR. APP. REVISION DATE



ECO	DR.	APP.	REVISION	DATE	ECO	DR.	APP.	REVISION	DATE
5	SKW		MAP UPDATE	7-7-97					
4	SKW		MAP UPDATE	7-12-96					
3	RAM		MAP UPDATE	7-23-93	8	SKW		MAP UPDATE	03/03/2005
2	L.C.		ADD 6" REPL, ADD UPDATE	6-7-88	7	SKW		MAP UPDATE	11/8/1999
1	L.C.		INITIAL RELEASE	3-2-87	6	SKW		MAP UPDATE	9-21-1998

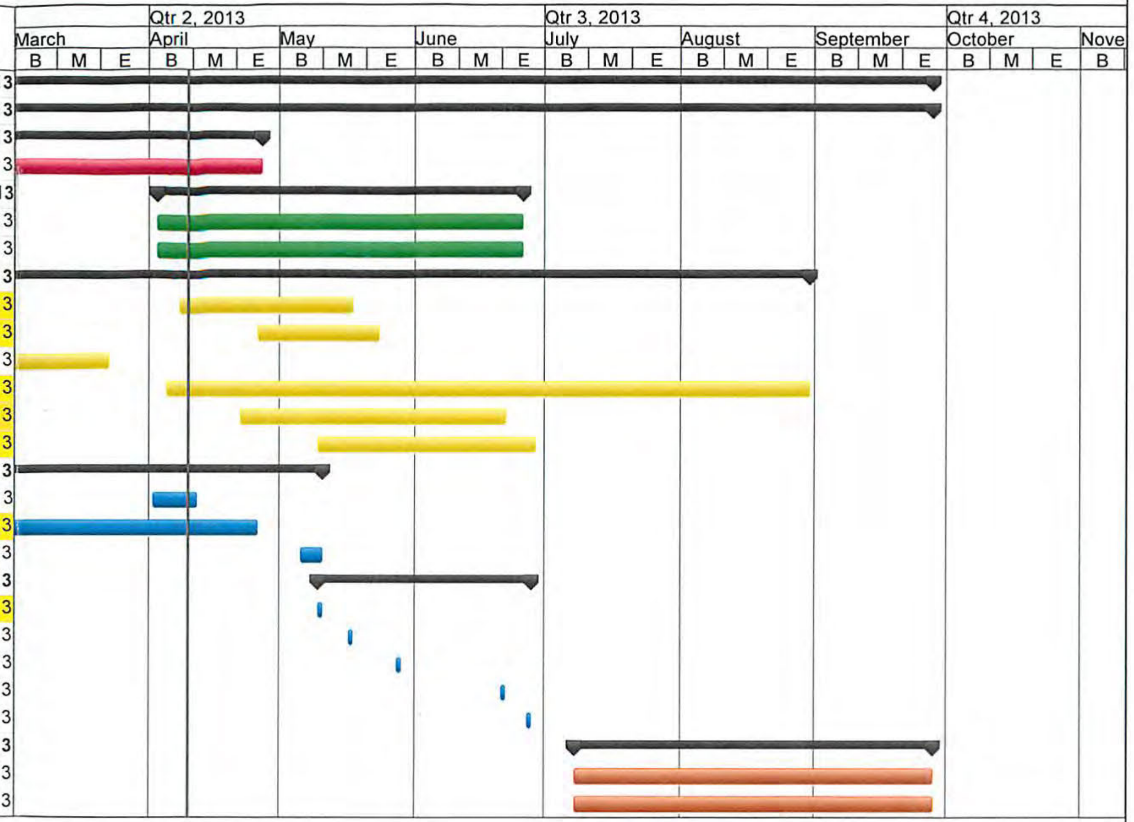
NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209

HIGH PRESSURE FEEDERS - DESIGN, TEST AND MAXIMUM ALLOWABLE OPERATING PRESSURE
ALBANY

DWG. NO. M-01-14-A
DR. LC DATE 3/2/1987
SCALE NONE
PLAT NO.

Mid-Willamette Feeder

ID		Task Name	Duration	Start	Finish
1		**Mid-Willamette Feeder - Phase 3A**	**330 days**	**Mon 6/25/12**	**Fri 9/27/13**
2		**Phase 3- South of Monmouth Bare (P200584)**	**330 days**	**Mon 6/25/12**	**Fri 9/27/13**
3		**Design**	**80 days**	**Mon 1/7/13**	**Fri 4/26/13**
4		Final Designs	80 days	Mon 1/7/13	Fri 4/26/13
5		**Material**	**60 days**	**Wed 4/3/13**	**Tue 6/25/13**
6		Order Pipe	60 days	Wed 4/3/13	Tue 6/25/13
7		Procure Materials	60 days	Wed 4/3/13	Tue 6/25/13
8		**Permitting**	**310 days**	**Mon 6/25/12**	**Fri 8/30/13**
9		* Polk County - Land Use	30 days	Mon 4/8/13	Fri 5/17/13
10		* Polk County - ROW	20 days	Fri 4/26/13	Thu 5/23/13
11		DSL - Wetland Concurrence	195 days	Mon 6/25/12	Fri 3/22/13
12		Joint Permit - DSL / Corps of Engineers	106 days	Fri 4/5/13	Fri 8/30/13
13		* DEQ 1200C	45 days	Mon 4/22/13	Fri 6/21/13
14		* SHPO Concurrence	36 days	Fri 5/10/13	Fri 6/28/13
15		**Land Acquistion**	**200 days**	**Mon 8/6/12**	**Fri 5/10/13**
16		* Obtain Final Land Owner Signature -Land Use	8 days	Tue 4/2/13	Thu 4/11/13
17		* Easements & Workspaces	189 days	Mon 8/6/12	Thu 4/25/13
18		Property Owner Notificatons (Risk & Land)	5 days	Mon 5/6/13	Fri 5/10/13
19		**Construction Pre Work**	**35 days**	**Fri 5/10/13**	**Thu 6/27/13**
20		* RFP	1 day	Fri 5/10/13	Fri 5/10/13
21		Job Walk	1 day	Fri 5/17/13	Fri 5/17/13
22		Bids Due	1 day	Tue 5/28/13	Tue 5/28/13
23		Award	1 day	Fri 6/21/13	Fri 6/21/13
24		Preconstruction meeting	1 day	Thu 6/27/13	Thu 6/27/13
25		**Construction (3.3 miles of pipeline)**	**60 days**	**Mon 7/8/13**	**Fri 9/27/13**
26		Construction of 12-inch	60 days	Mon 7/8/13	Fri 9/27/13
27		Construction of 2" poly	60 days	Mon 7/8/13	Fri 9/27/13



Wed 4/10/13

*** Key Deliverables**

Assumes that supply chain (pipe & materials) is available by start of construction

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 367

367. Please refer to Docket No. UG 221 NWN/600 Yoshihara/4 which estimates the Corvallis loop to have a capital cost of $12.8 million. Please also refer to the response to OPUC DR 198 Attachment 1, 200363 Project Charter.PDF which estimates the Corvallis loop to have a project cost of $15.9.

a. Please reconcile the two forecasted costs for the Corvallis Loop.
b. Please provide all change orders for the Corvallis Loop.
c. Please explain why the final cost of Corvallis Loop, at 28.4 million, exceeded the UG 221 estimate by more than 120 percent.

Response:

a. The estimate for the Corvallis loop in UG 221 testimony is an estimated cost based on historical per mile installation costs for similar pipeline projects. The initial project initiation memo for the Corvallis Reinforcement project discusses the installation of approximately 45,000 feet of 12" welded steel main. At an estimated $1.5 million per mile of installed pipe yields an estimate of $12.8 million. The estimate in the project charter is based on the site specific design. The project charter estimate is $17.7 million with project contingency and is outlined on page 11 of UG 344 OPUC DR 367 Attachment 1.

b. Please see attached UG 344 OPUC DR 367 Attachment 2 and UG 344 OPUC DR 367 Attachment 3.

c. Page 2 in the attached UG 344 OPUC DR 367 Attachment 2 details the net increase in costs for design and permitting, land acquisition, installation costs, use of HDD installation method, pipe material costs, and project overheads that increased the project cost by $9.1 million. UG 344 OPUC DR 367 Attachment 3 discusses the additional $1.1 million cost due to the increased vendor pricing for seven HDD bores on the project. The project charter estimate of $17.7 million, plus the two change orders of $9.1 million and $1.1 million, and the addition of $0.4 million in additional construction overhead make up the total final cost of the Corvallis loop project.

NW Natural

Corvallis Loop Project
Project #200363
G-67 Financial Authorization
June 2011

Grant Yoshihara
Executive Sponsor

6/8/11
Date

Jon Huddleston
Sponsor

6/6/11
Date

John Soh
Finance

6/15/2011
Date

Alex Miller
Director, Rates/Regulatory Compliance

6/16/2011
Date

Steve Feltz
Treasurer/Controller

6/17/2011
Date

David Anderson
Senior VP, Finance and CFO

6/23/11
Date

Gregg Kantor
President and CEO

7/1/11
Date

CORVALLIS LOOP PROJECT - PROJECT 200363

Date Submitted: May 20, 2011	Facility: S22.01	Business Unit: Engineering
Project Sponsor: Steve Nelson		Executive Sponsor: Grant Yoshihara
Project Manager: Mark Schaefer	Desired Implement Date: June 2011	Prepared By: Mark Schaefer
Engineer: Mark Schaefer	Short Title: Corvallis Loop Project Project #: 200363	

1. **Project Title:** Corvallis Loop Project

2. **Project Description:**
The scope of this project includes two phases. The first phase is for installation of approximately 12,700 feet of 12-inch steel natural gas pipeline tested and certified at a Maximum Allowable Operating Pressure (MAOP) of 720 psig. This pipeline will connect to the existing 10-inch Corvallis – Albany Transmission line (S22 pipeline) located on Riverside Drive in Linn County and extends south to State Highway 34. This section of pipeline will be designed to the parameters of the future Mid-Willamette Valley Pipeline in anticipation of future expansion north to the Perrydale Station (P30 pipeline) and south to Eugene. Considerations for future pressure regulation will be provided at either end of the pipeline. The second phase is for installation of approximately 39,300 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 400 psig. This pipeline will connect to the first phase pipeline at State Highway 34 and extend west to the Campus Energy Center at Oregon State University located on SW 35th Avenue in Corvallis, Oregon.

3. **Project Manager Assignment:** Mark Schaefer

4. **Project Objectives:**
To supply additional natural gas capacity and support the increasing demand of natural gas fuel consumption at the Oregon State University Energy Center.

5. **Schedule**
NW Natural construction crews and the directional drill bore contractor will mobilize in July once the pipeline easements have been acquired and the environmental permits have been received on the private land parcels between Riverside Drive and State Highway 34. Expected completion will be by October 2012.

6. **Cost Constraints**
   - Project is estimated at $15,939,000 with a 10% contingency ($1,594,000) amounts to $17,703,000 requested budget.
   - Project funding is on the System Reinforcement account ~~116.~~ 115
   - The Construction Overhead rate for this project is 27%.

   Other cost constraints include:
   - Easement and workspace acquisitions.
   - Work restriction due to environmental permitting including wetland delineation and erosion control and sedimentation plans.
   - Haul off and disposal of spoils and bore fluid from directional drill activity.
   - ODOT limitation of work hours and permit requirements for traffic control and restoration on State Hwy 34 and State Hwy 20.

7. **Business Case**
   - This project will provide additional reinforcement to OSU and increase the delivery of gas capacity to the area. Although the project will provide improved service to some area customers in the short term, multiple system improvements still need to be considered for long term system reliability. These improvements include extension of the Mid-Willamette Valley Feeder pipeline from the Central Coast Feeder (P30 pipeline) at Perrydale Station to the Albany-Corvallis Feeder (S22 pipeline) and multiple distribution and transmission system improvements throughout the area.

8. **Project Deliverables**
   - Install 12,700 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 720 psig.
   - Install 39,300 feet of 12-inch steel natural gas pipeline tested and certified at a MAOP of 400 psig.
   - Rebuild the gas supply meter set at the OSU Energy Center and tie the existing service over to the new 12-inch (400 MAOP) pipeline.

- Install a new district regulator at SW 35th Avenue and Washington Way and connect the new 12-inch (400 MAOP) pipeline to the existing 6-inch (225 MAOP) S26 pipeline.

9. Communication Plan

The Communication Plan for this project is to specifically discuss the project at the Capital Projects Meetings scheduled on a bi-monthly basis. These meetings serve the function of communicating any project related management issues and addressing them in a small team environment. Key stakeholders regularly attending the meeting include Construction Supervisors, Resource Management Coordinator, Integrity Management Supervisor, Capital Project Manager, Project Engineer and Field Engineering. Outside stakeholders will be communicated with as necessary.

Approvals.			
Mark Schaefer	Date: 5/20/11		Date: 6/17/11
	Date: 6/6/11		Date: 6/17/2011
	Date: 6/6/11		Date: 6/23/11
	Date: 6/15/2011		

Scope of Work
Corvallis Loop Project
P200363

2011

- Procure 31,000 of 12" Directional Drill pipe
- Procure 21,000 of 12" Green coated pipe
- Procure all stock and non-stock materials
- Obtain approximately 21,000 L.F. of pipeline easements
- Directional drill and install 12,920 feet of 12" pipe – 5 locations
- Open Excavate and install 11,700 feet of 12"pipe – 3 locations

---

2012

- Directional drill and install 15,080 feet of 12" pipe – 5 locations
- Open Excavate and install 12,300 feet of 12" pipe – 5 locations
- Clean, inspect and caliper pig new 12" pipeline
- Install new bridles – 3 locations
- Rebuild gas supply meter set at OSU Energy Center
- Install new district regulator at SW 35th Avenue

FINANCIAL ANALYSIS

Project Title:	Corvallis Loop Project	**Project Number:**	200363
Project Manager:	Mark Schaefer	**Cost Center Manager:**	Steve Nelson

Funding:	**System Reinforcement**
Act Type:	11~~5~~6 System Reinforcement Category 3 (COH 27% 5/2011)
Total Cost:	2010 $170,000 (actual) 2011 $9,916,821 2012 $7,615,878 **TOTAL $17,702,699**
Contingency ($ and %)	Contingency used is 10% based on the Risk Analysis for the project.Total contingency for this project is $1,593,882.
Project Justification:	This project will be funded by the System Reinforcement account. The project will supply additional capacity and support increasing demand of natural gas fuel consumption at the Oregon State University Energy Center. The project has been included in the Annual Capital Budget for 2011.

PROJECT TIMELINE

Project:	Corvallis Loop
PS #:	200363
Project Manager:	Mark Schaefer
Date:	5/20/2011

Construction Duration	**15**	**Months**
Construction Expected Start Date	**6/20/2011**	
Construction Expected Completion Date	**9/28/2012**	
Construction Timeline	**Fixed**	

Initiation Tasks	**5/8/2010** **Required Task**	**5/3/2011** **Resp**
Complete Initiation Memo	Yes	PM
Complete Charter	Yes	PM
Complete Design Review	Yes	PM

Planning Tasks	**3/7/2011** **Required Task**	**9/2/2011** **Resp**
Request Easements	Yes	Risk
Address Environmental Issues	Yes	Envir
Request Corrosion Input	Yes	PM
RFP for Outside Services	Yes	Purch
Complete Design	Yes	PM
Station Packet	Yes	PM
Pressure Test Documentation	Yes	PM
Order Non-Stock Parts/Reserve Stock Parts	Yes	Stores
Complete Tie-in Details	Yes	Tual Eng
Finalize Design/Engineering Sketches	Yes	Tual Eng
Complete Traffic Control Plan	Yes	FET
Request Permits	Yes	EC
Notify Stakeholders Affected by Project	Yes	PM
Complete Bore Plan	Yes	Tual Eng
Draft Preliminary Procedure	Yes	Tual Eng

Executing Tasks	**6/20/2011** **Required Task**	**9/28/2012** **Resp**
Pre-Construction/Safety Meeting with Crew	Yes	Tual Eng
Install Construction Field Stakes	Yes	FET
Notifiy Stakeholders of Firm Start Dates	Yes	PM
Review Preliminary Procedure with Crew	Yes	Tual Eng

Monitoring Construction Tasks	**6/20/2011** **Required Task**	**9/28/2012** **Resp**
Monitor Schedule	Yes	PM
Monitor Budget	Yes	PM
Procedure Sign Off	Yes	Tual Eng

Closeout Tasks	**11/27/2012** **Required Task**	**12/12/2012** **Resp**
Conduct Project Learning Meeting	Yes	PM
Complete Final Report for Project	Yes	PM

Risk Analysis

Project:	Corvallis Loop
PS Number:	200363
Project Manager:	Mark Schaefer
Cost Center Manager:	Steve Nelson
Date:	5/20/2011

Risk	**Probability**	**Impact**	**Score (Probability x Impact)**	**COMMENTS (Eliminate / Mitigate)**
Acquisition of Materials	*2 Assorted Non-Stock Items*	*1 - Minimal or No Impact*	2	Assemble list and order non-stock parts in advance
Land Acquisition	*5 Multiple Easements*	*3 - Major Impact to Project*	15	Hire contract Land Agent and meet with landowners early on in the project
Standard Permits	*2 Permits with Minor Conditions*	*1 - Minimal or No Impact*	2	Schedule pre-planning meeting with ODOT and City of Corvallis
Special Permits	*2 Permits with Minor Conditions*	*1 - Minimal or No Impact*	2	Hire contract Engineering Consultant and coordinate with agencies early
Environmental Impact	*3 Permits with Minor Conditions*	*2 - May Impact Project*	6	Hire contract Environmental Consultant and coordinate with agencies early
Ground Conditions	*1 No Concerns*	*2 - May Impact Project*	2	
Utility Conflicts	*2 Minor Utility Conflicts*	*1 - Minimal or No Impact*	2	Field survey and locate utilities during design and incorporate into plans
Weather	*2 Spring/Fall*	*2 - May Impact Project*	4	Schedule Construction activities in wet areas during dry months. Maintain pumps for groundwater for excavation.
Construction Method	*1 Open Trench*	*2 - May Impact Project*	2	Schedule Construction activities in wet areas during dry months
Bore Method	*1 Horizontal Directional Drill*	*2 - May Impact Project*	2	Develop HDD Design plans, undertake geotechnical subsurface borings in advance and secure HDD contractor
Resources	*1 Resources Available*	*1 - Minimal or No Impact*	1	Coordinate timeline and construction schedule with RMC and impacted work groups
Working Hours	*2 Hours Restricted*	*1 - Minimal or No Impact*	2	Coordinate construction schedule with ODOT and City of Corvallis
Contract Availability	*1 Resources Available*	*1 - Minimal or No Impact*	1	Coordinate schedule with outside vendors and work with purchasing to secure HDD contractor
System Impact	*1 No Impacts - Adequate Feed*	*1 - Minimal or No Impact*	1	
		Avg Score	**3.14**	**10**
				% Contingency

Staff/702
Kaufman/168

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

Project:	Corvallis Loop
PS #:	200363
PM:	Project Manager

A = Accountable
P = Participant
I = Input/Review

Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
PROJECT TEAM			●	●	●	●	●		●	●	●	●	●	●								●	●		●		●
INITIATION TASKS																											
Create Project in SAP	5/8/10	5/8/10	A																								
Create Initiation Memo	5/8/10	5/8/10	A																								
Outline Proposed Construction Dates	3/1/11	6/1/11	A	P																I							
Preliminary Design Meeting	4/25/11	4/25/11	A	P		P	P													P							
PLANNING TASKS																											
Identify Project Team	5/8/10	10/1/10	A																								
Create Work Orders	6/27/11	7/8/11			A																						
Assemble As Builts & Historical Documentation	3/1/11	7/8/11			A																						
Request Design Locates	11/5/10	12/2/10							A																		
Request Survey	11/5/10	12/24/10	A																	P							
Request Easements	5/9/11	9/2/11	A							P										P							
Draft Preliminary Design	3/1/11	5/2/11	A	P	P	P														P							
Draft Preliminary Cost Estimate	1/4/11	1/4/11	A	P		P	P													I							
Contract for Outside Services	5/8/10	10/1/10	A								P																
Create Design Documentation	6/3/11	6/10/11	A		P	P																					
Finalize Design	6/20/11	6/20/11	A			I	I													P		I					
Finalize Construction Dates	6/6/11	6/6/11	A	P			P		P											I							
Create Charter or G-67 Project Plan	4/28/11	5/4/11	A																								
Charter or G-67 Project Plan Approved	5/4/11	6/3/11	A																								
Complete Engineering Sketch	5/20/11	9/2/11	P	P	A																						
Complete Traffic Control Plan	6/10/11	9/2/11		A																A							
Request Permit	5/6/11	9/2/11			A															A							
EXECUTING TASKS																											
Request Construction Locates	6/20/11	8/2/12							A																		
Install Construction Field Stakes	6/13/11	8/2/12		A																P							
Schedule Field Resources	6/20/11	9/29/12					I		A																		
Hold Pre-Construction/Safety Meeting	6/27/11	6/27/11	A	P		P	P		I			P	P									P	P				P
Notify Stakeholders of Firm Start Dates	6/20/11	6/1/11	A				I		I											I		I					

G-67 PROJECT PLAN - RESPONSIBLITY MATRIX

Project:	Corvallis Loop
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Tasks	Task Start	Task End	Project Manager	FET	Engineering	Integrity Management	Transmission Const. Supervisors	Station Design	Resource Management	Risk & Land	Purchasing / Stores	Environmental / HazMat	Safety	Gas Supply	Gas Plants	Major Acct. Services	Electrical/ Communications	Corrosion	Municipalities	Private Eng. Firm	Other	Transmission Construction	Welders	Distribution Crew	Specialty Const. Crew (ROW)	Transmission Maintenance Crew	Gas Supply Crew
MONITORING TASKS																											
Monitor Worksite Activities	6/20/11	9/29/12	P	P		P	A		P													A					
Complete and Submit Project Change Request Form as Necessary	6/20/11	9/29/12	A				I																				
Monitor Schedule	6/20/11	9/29/12	A				P		P													P					
Monitor Budget	6/20/11	9/29/12	A				P																				
Receive & Approve all Invoices	6/20/11	9/29/12	A				A																				
Coordinate Construction Activities with Stakeholders	6/20/11	9/29/12	A				A													I		A					
Finalize Tie-in Procedure	8/24/12	8/24/12	A			I	P							I								P	P		P		P
Tie-in Procedure Signed Off	8/31/12	8/31/12	A		I	I	I							I													
Schedule Tie-in and Coordinate with Support Crews	8/31/12	9/21/12	I			I	I		A					I								I					
Establish Final Punch List Items & Timeline for Completion	9/24/12	10/12/12	A				A															A					
CLOSEOUT TASKS																											
Complete As Built Packet	9/21/12	10/12/12					I													P		A					
Audit work orders and asbuilt	9/21/12	10/12/12			A																						
Complete project document review	9/21/12	10/12/12			A	I																					
Plat asbuilt	10/15/12	10/29/12			A	I														I							
Conduct Project Learning Meeting	12/1/12	12/1/12	A	P		P	P													I							
Complete Final Report for Project	10/29/12	12/1/12	A																								

Construction Estimate
Corvallis Loop Project
Project 200363

2010 Project Actual Costs - Corvallis	
2010 Previous Charges	$170,000
Total 2010 Project Actual Costs w/ COH	**$170,000**

2011 Project Estimated Costs - Corvallis	
Equipment/Material Total	$5,000,800
Labor Total	$1,279,500
Contract Total	$1,292,000
Total	**$7,572,300**
Construction Overhead (27% for System Reinforcement)	$2,044,521
Total Cost	$9,616,821
Contingency (10%)	$300,000
Total 2011 Project Cost w/ COH	**$9,916,821**

2012 Project Estimated Costs - Corvallis	
Equipment/Material Total	$1,898,450
Labor Total	$1,471,500
Contract Total	$1,608,000
Total	**$4,977,950**
Construction Overhead (27% for System Reinforcement)	$1,344,047
Total Cost	$6,321,997
Contingency (10%)	$1,293,882
Total 2012 Project Cost w/ COH	**$7,615,878**

Total Project Contingency	**$1,593,882**
Total Project Cost w/ COH 2010-2012	**$17,702,699**

NW Natural – Corvallis Loop

Project Permit Listing

WHPacific File No. 209.035901

PERMIT / REPORT	JURISDICTION	CONTACT	Anticipated Review Period	NOTES / COMMENTS
Wetland Delineation	Oregon Division of State lands (DSL)	Linn County Resource Coordinator, Gloria Kiryuta 503-986-5226 Jevra Brown (503-986-5297) File number is **WD 2011-0188.**	Up to 120 days	5/31/11 - Wetland delineation was submitted on 5/26/11 6/1/11 - The report has been assigned to Jevra Brown (503-986-5297) for review. The file number is **WD 2011-0188**
Joint permit Application (JPA)	DSL & Oregon Corps of Engineers (COE)	Northwestern Division – Portland Linn County, Shelly Hanson @ Eugene Office 541-465-6878	30 days completeness – 120 day review period (includes 30 day public notice)	5/31/11 – JPA has been prepared and we are awaiting Owners signatures to submit. Mike Hayward to confirm ability to submit under nationwide status.
Land Use Application (TBD)	City of Corvallis	Brian Latta, Associate Planner 541-766-6908 ext 5020 Brian.latta@ci.corvallis.or.us	Up to 120 days	5/31/11 - Recent updates now require City permitting – City Staff is determining application process
Land Use Compatibility Statement (LUCS)	City of Corvallis	Brian Latta, Associate Planner 541-766-6908 ext 5020 Brian.latta@ci.corvallis.or.us	30 days after application completeness (typically 30 days)	5/31/11 – Submitted to City and in review (see comments above)

Permit Application for Franchise Utilities to Occupy or Perform Operations Within Public ROW	City of Corvallis	Mark Bauer 541-766-6729 ext 5079 Mark.bauer@ci.corvallis.or.us	Within 30 days of submittal…	5/31/11 - To be submitted 6 months prior to construction
Excavation & Grading/Erosion Prevention & Sediment Control Permit Application	City of Corvallis	Development Services Division 541-766-6929	TBD	5/31/11 – Currently submitted to Development Services but City is not clear on why it is needed – awaiting verification from Mark Bauer…
DEQ 1200C Permit (Intergovernmental Agreement with DEQ)	City of Corvallis (City has authority to issue permit)	Michael O'Connor, Erosion Control Specialist 541-752-7522 ext 5109 Mike.oconnor@ci.corvallis.or.us	Within 2 weeks after evidence of DEQ 1200C	6/1/11 – Talked with Michael – all OK, send in final DEQ permit and the City will also issue permit. Permit good for 180 days and then extended with each inspection for an additional 180 days.
Conditional Use permit – Rural Resource Zoning District	Linn County	Deborah Pinkerton, Sr. Planner 541-967-3816 ext 2367 dpinkerton@co.linn.or.us	Up to 120 days	5/31/11 – Awaiting Owners signatures for submittal
Conditional Use Permit – Willamette River Greenway Review	Linn County	Deborah Pinkerton, Sr. Planner 541-967-3816 ext 2367 dpinkerton@co.linn.or.us	Up to 120 days	5/31/11 – Awaiting Owners signatures for submittal
Land Use Compatibility Statement (LUCS)	Linn County	Deborah Pinkerton, Sr. Planner 541-967-3816 ext 2367 dpinkerton@co.linn.or.us	30 days after application completeness	5/31/11 – Awaiting Owners signatures for submittal

			(typically 30 days)	
Application for ROW Encroachment	Linn County	Linn County Roads Department Katy McGowan, ROW Specialist 541-967-3919	15 - 30 days	5/31/11 - One page application form – 3 sets of drawings (follow directions on form)
DEQ 1200C Permit	Oregon State Department of Environmental Quality	Kathy Jacobson Eugene Office 541-687-7326	Up to 120 days	5/31/11 – Requires land Use Compatibility Statements from City of Corvallis and Linn County - Requires Owners signatures and land use applications to be submitted
Easement for Willamette River Crossing	Division of State Lands	Mr. Cy Young, Property Manager 503-986-5245 Jim Grimes 503986-5233	TBD	5/31/11 – Contact made with Jim Grimes at DSL 503-986-5233 and it was determined that an easement will be required
Easement for Mary's River Crossing	Division of State Lands	Mr. Cy Young, Property Manager 503-986-5245	TBD	5/31/11 – **Easement not required** per Jim Grimes – "State ownership is undetermined"...
ODOT Right of Way Permitting & Traffic Control Plans	State of Oregon	Ken lamb 541-757-4182 Kenneth.e.lamb@odot.state.or.us	Up to 30 days	5/31/11 – Ken Lamb on vacation – call into him to determine ROW permitting process... 6/6/11 – Left another message
Oregon State Historic Preservation Office (SHPO) Clearance / Permitting	State of Oregon	Dr. Dennis Griffin, State Archeologist 503-986-0674 Dennis.griffin@state.or.us	TBD	5/31/11 - Mike Hayward to research SHPO requirements...

Railroad Crossing Permits (2)		Portland & Western Railroad Willamette & Pacific Railroad Document Custody c/o Kuenzi & Co., LLC 650 Hawthorne Ave. SE, #100 Salem, OR (&#)! Marsha Dunn 503-779-1043 mdunn@kuenzicpas.com Dennis Hannas, Field Engineer 503-508-7440	30 – 60 days	5/31/11 – Railroads' representatives contacted and forms obtained...

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PROJECT CHANGE ORDER

Project Name	Project Number
Corvallis Loop	200363-01
Change Order No.	**Change Request No**
1	
Project Manager	**Date**
Brian Konrad	4-11-2013

Description of Change

- Budgetary lift to complete the construction of Corvallis Loop
- Original estimate from G-67 financial approval $ 17.7 million
- Revision to the G-67 financial approval for an additional $9 million for a total of $ 26.7 million

Reason for Change

- Original budget is at 93% and the construction progress is at 44%.
- Project has had difficulties obtaining land acquisition and permits
- Complex route selection to avoid environmental impacts
- The project is located in a culturally rich area and consumed time and budget
- Multi agency permitting process
- The geology of the area consists of gravel beds over clays. This composition has created design changes, unsuccessful HDD bores, contamination of domestic water wells and changes in contractor cost.
- NWN committed to additional HDD bores to secure the land acquisitions
- The project will require a high risk bore across the Willamette and Marys Rivers.

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PROJECT CHANGE ORDER

Net Change Summary:

(1) Increase costs of design and permitting.	$ 1.2
(2) Increase costs of land acquisitions.	$ 0.8
(3) Increase in installation costs.	$ 5.2
(4) Increase in HDD pipe footage & installation price.	$ 0.3
(5) Increase in pipe material quantities and cost.	$ 0.6
(6) Increase in projects overheads	$ 1.0
Total in millions	$ 9.1

Change Details:

Recovery Plan

NWN crews will construct the remaining 5.8 miles

Obtain concurrence from SHPO before moving forward

Obtain all land owner agreements before we award any contracts

Modify all designs and construction practices to mitigate environmental risk

NWN will manage the contracts with the HDD contractors

NWN will employ third party observation on the high risk HDD bores to minimize risk.

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PROJECT CHANGE ORDER

Impact Detail	
Budget Impacts	Original Budget: $17,702,698.97 Change (+ or -): + $ 9,048,930.78 Adjusted Budget: $ 26,751,629.75 Details: See attachments;
Schedule Impact	Expected completion was end of October 2012 and now is the first of November 2013. One year adjustment.
Scope Impacts	
Resource Impacts	Project team has met with the Construction Managers and they do not feel that constructing this project this year will negatively impact the response to core business needs.
Quality Impact	
Other Impacts	The desired outcome is still to increase system reliability and reinforcement in the Corvallis/ Philomath service territories.

Signatures:

4/25/13
4/25/13
4/25/13

Executive Sponsor | Date

4/25/13

Project Sponsor | Date

Project Manager | Date

Net Change

Net Change 0.7 miles of 12" Pipeline

Item	Cost/Unit	Qty	Unit	Cost
Design and Permitting (1)(6)(7)			LS	$1,202,729.00
Workspace & Easements (2)(6)(7)			LS	$770,623.00
NWN Labor			hrs	-$449,727.60
Pipeline Contractor (3)(7)			LS	$5,572,781.00
Contract HDD Bore Services (4)(6)(7)	$39.13		ft	$316,512.00
X-ray (NDT) (3)(6)(7)	$557.19	313	days	$625,875.67
Caliper Pig			ea	$0.00
Drill Pipe (4)(6)(7)	$2.43	14377	ft	$788,572.97
FBE Pipe	$2.53	-7458	ft	-$209,988.24
Pipe Materials (5)			LS	$497,771.00
NWN Equipment & Material			LS	-$1,002,136.00
Total				**$8,113,012.80**
Construction Overhead				$1,568,762.83
Total				**$9,682,775.63**
Contingency				$633,844.85
Total Project Cost w/ OH				**$9,048,930.78**

Install Cost/ft **$103.58**
Excludes Design, Permitting, Workspace & Easements
Includes Actual Pipe installed only

Net Change 0.7 miles of 12" Pipeline

Net Change Summary:

(1) Increase costs of design and permitting.

(2) Increase costs of land acquistion.

(3) Increase in installation costs.

(4) Increase in HDD pipe footage & material and installation price.

(5) Increase in pipe material quantities and cost.

(6) Increase length of project by 0.7 miles.

(7) Increase in project duration

Total (Actual & Projections)

Total (Actual + Projected)
Total Install 10.5 miles of 12" Pipeline

Item #	Item	Cost/Unit	Qty	Unit	Cost
1, 2	Design and Permitting	$2,289,729.00	1	LS	$2,589,729.00
3	Workspace & Easements	$795,623.00	1	LS	$970,623.00
33-58	NWN Labor		1	hrs	$2,223,117.20
-	Pipeline Contractor	$5,572,781.00	1	LS	$5,572,781.00
46	Contract HDD Bore Services	$139.13	22400	ft	$3,116,512.00
21	X-ray (NDT)	$1,857.19	393	days	$729,875.67
59	Caliper Pig	$100,000.00	1	ea	$100,000.00
29	Drill Pipe	$49.61	45377	ft	$2,251,152.97
30	FBE Pipe	$35.28	13542	ft	$477,761.76
32	Pipe Materials	$833,271.00	1	LS	$833,271.00
4-28, 66	NWN Equipment & Material	$1,884,204.00	1	LS	$1,968,439.00
	Total				**$20,833,262.60**
	Construction Overhead				$4,958,330.28
	Total				**$25,188,342.88**
	Contingency				$960,036.87
	Total Project Cost w/ OH				**$26,751,629.75**

Install Cost/ft **$418.31**
Excludes Design, Permitting, Workspace & Easements
Includes Actual Pipe installed only

Total Length of Pipeline = 10.5 Miles

Financial Cost Analysis:

* Revised total estimated project costs. Includes actual costs to date and estimated costs for remaining installation.

Phase 1, 3A & 3B (Projections)

Projected to finish
Install 3.5 miles of 12" Pipeline (Phase 1)
Install 2.3 miles of 12" Pipeline (Phases 3A & 3B)

Item #	Item	Cost/Unit	Qty	Unit	Cost
1, 2	Design & Permitting (2)(4)(5)(6)	$752,425.00	1	LS	$752,425.00
3	Workspace & Easements (3)(5)	$444,000.00	1	LS	$444,000.00
33-58	NWN Labor (1) (7)	$84.33	19640	hrs	$1,656,241.20
-	Pipeline Contractor	$0.00	1	LS	$0.00
46	Contract HDD Bore Services (5)(6)(8)	$139.13	22400	ft	$3,116,512.00
21	X-ray (NDT) (7)	$1,857.19	123	days	$228,434.37
59	Caliper Pig	$100,000.00	1	ea	$100,000.00
29	Drill Pipe (5) (9)	$49.61	-3650	ft	-$181,076.50
30	FBE Pipe (9)	$35.28	-5170	ft	-$182,397.60
32	Pipe Materials	$20,000.00	1	LS	$20,000.00
4-28, 66	NWN Equipment & Material (1)	$1,520,972.00	1	LS	$1,605,207.00
	Total				**$7,559,345.47**
	Construction Overhead (27%)				$2,041,023.28
	Total				**$9,600,368.75**
	Contingency (10%)				$960,036.88
	Total Project Cost w/ OH				**$10,560,405.63**

Install Cost/ft **$363.40**
Excludes Design, Permitting, Workspace & Easements
Includes Actual Pipe installed only

Total Length of Pipeline = 5.8 Miles

Recovery Plan:

(1) NW Natural to construct project due to high risk of installation through farmland and environmentally sensitive areas.

(2) Permitting process still incomplete. Working with SHPO to obtain completeness.

(3) Acquistion process still incomplete due to design changes. Working with land owners to secure final easements and workspaces.

(4) Gathering additional geotechnical data and revising HDD Bore plans.

(5) Modified design to avoid and mitigate environmentally sensitive areas.

(6) Contract with consultant to oversee HDD field installations.

(7) Decrease inspection costs by self performing installation.

(8) NW Natural to directly contract with HDD bore contractors.

(9) Credit pipe charges to project for extra pipe ordered but not installed.

Phase 2 & 3C (Actual)

Actual to date (as of March 21, 2013)
Installed 3.7 miles of 12" Pipeline (Phase 2)
Installed 1.0 mile of 12" pipeline (Phase 3C)

Item	Cost/Unit	Qty	Unit	Cost
Design and Permitting (2) (3)	$1,837,304.00	1	LS	$1,837,304.00
Workspace & Easements (3)	$526,623.00	1	LS	$526,623.00
NWN Labor (4) (6)			hrs	$566,876.00
*Pipeline Contractor (1) (2) (5)	$5,572,781.00	1	LS	$5,572,781.00
**Contract HDD Bore Services	$0.00	0	ft	$0.00
X-ray (NDT) (6)	$1,857.19	270	days	$501,441.30
Caliper Pig	$0.00	0	ea	$0.00
Drill Pipe (3) (7)	$49.61	49027	ft	$2,432,229.47
FBE Pipe (7)	$35.28	18712	ft	$660,159.36
Pipe Materials (8)	$813,271.00	1	LS	$813,271.00
NWN Equipment & Material	$363,232.00	1	LS	$363,232.00
Total				**$13,273,917.13**
*Construction Overhead (22% Actual)				$2,917,307.00
Total				**$16,191,224.13**
* Includes $475,000 yet to be received				
** HDD Services included in Pipeline Contractor costs				
Total Project Cost w/ OH				**$16,191,224.13**

Install Cost/ft **$476.16**
Excludes Design, Permitting, Workspace & Easements
Includes Actual Pipe installed only

Total Length of Pipeline = 4.7 Miles

Engagement Discoveries:

(1) Outsource construction labor

(2) Permitting delays due to land owner negotations and agency completeness process

(3) Higher cost of land acquistion with public and private land owners that exceeded estimated values.

(4) Construction installation process modified to avoid environmental sensitive areas

(5) Undiscovered geological conditions caused schedule delays and change orders

(6) Inspection costs increased due to outsourcing

(7) Cost of pipe increase

(8) Increase in pipe material spend due to design changes

G67 Charter - June 2011 (Estimate)

Original Estimate (2011)
Install 9.8 miles of 12" Pipeline

Item	Cost/Unit	Qty	Unit	Cost
Design and Permitting (3)	$1,217,000.00	1	LS	$1,217,000.00
Workspace & Easements (2)	$200,000.00	1	LS	$200,000.00
NWN Labor (1)	$79.36	33680	hrs	$2,672,844.80
Pipeline Contractor	$0.00	0	LS	$0.00
Contract HDD Bore Services (4)	$100.00	28000	ft	$2,800,000.00
X-ray (NDT)	$1,300.00	80	days	$104,000.00
Caliper Pig	$100,000.00	1	ea	$100,000.00
Drill Pipe (4)	$47.18	31000	ft	$1,462,580.00
FBE Pipe (3)	$32.75	21000	ft	$687,750.00
Pipe Materials	$335,500.00	1	LS	$335,500.00
NWN Equipment & Material (1)	$3,015,670.00	1	LS	$2,970,575.00
Total				**$12,550,249.80**
Construction Overhead (27% for System Reinforcement)				$3,388,567.45
Total				**$15,938,817.25**
Contingency (10%)				$1,593,881.72
2010 Previous Charges				$170,000.00
Total Project Cost w/ OH (5)				**$17,702,698.97**

Install Cost/ft **$314.74**
Excludes Design, Permitting, Workspace & Easements

Total Length of Pipeline = 9.8 Miles

Base Assumptions:

(1) Project to be constructed by NW Natural Crews

(2) Farmland and City property to be low cost of acquistion

(3) Open excavation through farmland with low environmental impacts

(4) Minimize installation by HDD bore method with moderate to low risk installations.

(5) Construction to be completed in one season

Construction Estimate Summary - Feb 2013
Corvallis Loop
Project 200363

2010-2012 Project Actual Costs	
2010 Actual Charges	$169,311
2011 Actual Charges	$4,285,769
2012 Actual Charges	$10,569,034
Total 2010-2012 Project Actual Costs w/ OH	**$15,024,114**

2013 Project Estimated Costs		
Actual Charges (as of Feb 25, 2013)	$	294,881.00
Projected Costs - Phase 3C (City to OSU)	$	1,016,000.00
Projected Costs - Extra Pipe to be Transferred	$	(475,000.00)
Phase 1 (Riverside Drive to Hwy 34)		
Design/Management Total	$	339,975.00
Equipment/Material Total	$	1,021,317.50
Bore Labor Total	$	744,892.00
Trench Labor Total	$	77,300.00
Contract Support Total	$	60,480.00
Contract Total	$	1,255,100.00
Total	$	3,499,064.50
Construction Overhead (27%)	$	944,747.42
Total Cost	$	4,443,811.92
Contingency (10%)	$	444,381.19
Total Cost w/ OH - Phase 1	**$**	**4,888,193.11**

Phase 3A (Hwy 34 / Hwy 20 Bypass)		
Design/Management Total	$	249,975.00
Equipment/Material Total	$	609,946.75
Bore Labor Total	$	136,936.00
Trench Labor Total	$	288,824.00
Contract Support Total	$	46,080.00
Contract Total	$	246,600.00
Total	$	1,578,361.75
Construction Overhead (27%)	$	426,157.67
Total Cost	$	2,004,519.42
Contingency (10%)	$	200,451.94
Total Cost w/ OH - Phase 3A	**$**	**2,204,971.36**

Phase 3B (Willamette & Mary's River)		
Design/Management Total	$	162,475.00
Equipment/Material Total	$	366,909.00
Bore Labor Total	$	415,556.00
Trench Labor Total	$	-
Contract Support Total	$	46,080.00
Contract Total	$	1,728,000.00
Total	$	2,719,020.00
Construction Overhead (27%)	$	734,135.40
Total Cost	$	3,453,155.40
Contingency (10%)	$	345,315.54
Total Cost w/ OH - Phase 3B	**$**	**3,798,470.94**
2013 Total Cost w/ OH	**$**	**11,727,516.41**

Total Project Cost w/ OH 2010-2013	**$26,751,630**

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PROJECT CHANGE ORDER

Project Name	Project Number
Corvallis Loop	200363-01
Change Order No.	**Change Request No**
2	
Project Manager	**Date**
Brian Konrad	6-5-2013

Description of Change
G-67 financial approval to increase the project budget by $ 1.1 million. The adjustment is due to the 40% increase in vendor pricing of the 7 HDD bores on the Corvallis Loop project. The bores are required due to avoidance of wetlands, waterways, highways and cultural sensitive areas.
Reason for Change
Change Order # 1 for $ 9 million did not include final bid values for the HDD bores on the project. The contractors have been interviewed and questioned why there has been such a price adjustment. They stated due to the experience from the last couple of years they are unable to make profit at the $85.00 range. They are experiencing increases in the amount of time it takes to perform a bore due to the soil conditions in the area. They have to clean out the heavy clay tailings/cuttings on the bore path that block the return path. This includes retracting the bore rod completely out of the bore path and returning the bore rod back into the bore path. This process takes the contractor days to perform. Maintaining returns to avoid hydro fracture of the down hole formation is crucial for the success of the bore. This is necessary so they do not contaminate the aquifer that is above the drill path. The bidding process produced only two companies that could meet the experience qualification and completion schedule. The work has been awarded to the HHD Company and Brotherton Pipeline Company.
Change Details:

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PROJECT CHANGE ORDER

*The bid prices exceed the contingency for the whole project. The budget adjustment will allow for a 5% contingency rather than a 10% as the cost variance risk has decreased with the final HDD values.

The HDD process is a significant part of the construction process and we project that minimal change will occur during the project construction.

The NWN insurance requirement for the Willamette/Marys River bore (Bore #8) is $50 Million dollars and was a pass through line item cost to the company. The cost of the insurance is $ 191,004.00. This was not included in the original estimate and is being requested by NWN outside broker services and supported by NWN Risk and Land Department.

Bore prices were estimated based on recent HDD bore projects cost per foot data. Bore prices for similar areas to Phase 1 have been consistently priced at $85/foot over the last 2 years. Phase 1 was previously bid last year and the cost per foot bid was $85/foot. NWN did not execute the contract due to the inability to obtain land and permits. We expected that the Phase 1 bore would have come in closer to that number. The estimates were based on the assumptions that the price would be (7) $100 per foot and (8) $270 per foot based on historical data from similar projects. The actuals are bore (7) $121 and bore (8) $294.14. The 10% contingency would have covered the increases for this phase but would not leave any margin for extras or changes. With all the HDD bores exceeding the estimated value, the contingency value is not enough to cover the increase.

Corvallis Loop

Change Order #2 Cost Variance

June 5, 2013

Phase 3 - Contract HDD Bore

NWN Estimate				Actual Bid			Change	
	ft	$ / ft	Total	ft	$ / ft	Total	$	%
Bore #7	1900	100	$ 190,000	1764	121	$ 213,444	$ 23,444	12%
Bore #8	6400	270	$ 1,728,000	6425	294.14	$ 1,889,823	$ 161,823	9%
Liability Insurance $50M						$ 191,004	$ 191,004	
Phase 3 Total			**$ 1,918,000**			**$ 2,294,271**	**$ 376,271**	20%

Phase 1 - Contract HDD Bore

NWN Estimate				Actual Bid			Change	
	ft	$ / ft	Total	ft	$ / ft	Total	$	%

Bore #1A	1491	85	$ 126,735.00	1491	153	$ 228,123.00	$ 101,388.00	80%
Bore#1B	1633	85	$ 138,805.00	1810	142	$ 257,020.00	$ 118,215.00	85%
Bore #1C	1093	85	$ 92,905.00	1093	153	$ 167,229.00	$ 74,324.00	80%
Bore #2	4669	85	$ 396,865.00	4669	143.77	$ 671,247.98	$ 274,382.98	69%
Bore #3	5214	85	$ 443,190.00	5214	143.58	$ 748,638.00	$ 305,448.00	69%
Phase 1 Total			**$ 1,198,500.00**			**$ 2,072,257.98**	**$ 873,757.98**	73%

Summary

	NWN Estimate		Bid Totals	Net Change	%
Phase 1 & 3 Totals	**$ 3,116,500.00**		**$ 4,366,529.48**	$ 1,250,029.48	
COH (27%)	$ 841,455.00		$ 1,178,962.96	$ 337,507.96	
Total w/ COH	**$ 3,957,955.00**		**$ 5,545,492.44**	$ 1,587,537.44	40%
		Total Net Change w/COH		$ 1,587,537.44	
		Project Contingency -(10%)		$ (960,036.87)	
		Balance		$ 627,500.57	
		Remaining Contingency		$0	

Change Order #2

Balance (Contract HDD Bore)	$ 627,500.57	
Contingency (5%)	$ 480,018.44	5% of $9,600,368.75 (remaining spend estimate 4/12/13)
Total w/COH	**$ 1,107,519.01**	
Approved Budget	$ 26,751,630	As of 4/25/13
Change Order #2	$ 1,107,519	
Total Project Cost w/COH	**$ 27,859,149**	

Impact Detail	
Budget Impacts	Original Budget: 26,751,629.75 Change (+ or -): 1,107,519.01 Adjusted Budget: 27,859,148.76 Details: Budget Adjustment reflects increase in Contractor pricing.

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PROJECT CHANGE ORDER

Schedule Impact	None
Scope Impacts	None
Resource Impacts	None
Quality Impact	Positive impact on the quality of tracking and documentation of the installation
Other Impacts	

Signatures:

Executive Sponsor Date

Project Sponsor Date

Project Manager Date

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 703

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 18-002

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

Exhibits in Support
Of Opening Testimony

April 20, 2018

Diameter (Inches)	4	6	12
INGAA			
$ per inch-mile	28829	24164	68219
$ per Mile	115316	144984	818628
31.6 miles	3,643,986	4,581,494	25,868,645
NWN Average			
$ per-foot	$234	242	289
$ per Mile	1,235,520	1,277,760	1,525,920
31.6 Miles	39,042,432	40,377,216	48,219,072
Gate Station	1,000,000	1,000,000	1,000,000
Total Cost Low	4,643,986	5,581,494	26,868,645
Total Cost High	40,042,432	41,377,216	49,219,072
Percent Depreciated	81%	81%	81%
Equivalent Life Cost	$32,615,207	$33,702,410	$40,089,728

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 705

Exhibits in Support
Of Opening Testimony

April 20, 2018

UG 344 OPUC DR 197	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	Total	Total Mains
	$	$	$	$	$	$	$	$
COMPANY TOTALS	138,260,859	130,167,520	85,579,499	81,575,606	90,361,546	115,661,167	641,605,334	223,674,492
Category 1-4 Total	137,038,039	129,930,504	84,375,307	82,126,390	93,853,821	114,641,698	641,964,896	223,674,492
Category 5 (Storage) Total	1,222,820	237,016	1,204,193	(550,784)	(3,492,275)	1,019,468	(359,562)	-
1. NEW CUSTOMER ACQUISITIONS	27,310,946	33,813,186	21,317,847	24,309,619	26,834,177	33,335,630	166,921,407	32,449,359
NEW MAINS	3,759,067	4,845,718	3,563,015	4,852,893	6,651,299	8,777,367	32,449,359	32,449,359
MAIN EXTENSION RESIDENTIAL	107,264	1,180,723	710,373	844,005	811,878	1,763,565	5,417,809	
MAIN EXTENSION COMMERCIAL & INDUSTRIAL	2,294,476	1,235,369	906,020	786,295	1,510,695	1,339,438	8,072,293	
MAIN EXTENSIONS SYSTEM EXPANSION	1,391,013	2,417,128	1,955,345	3,182,754	4,322,763	5,315,349	18,584,352	
OTHER	(33,686)	12,499	(8,723)	39,838	5,963	359,014	374,905	
NEW SERVICES	15,631,009	20,053,280	12,234,252	12,141,538	13,726,356	17,051,844	90,838,279	-
NEW RESIDENTIAL SERVICE	4,931,048	6,926,630	4,928,464	5,523,247	6,432,286	7,281,402	36,023,077	
CONVERSION RESIDENTIAL SERVICE	7,925,580	10,859,237	5,900,904	4,860,568	5,107,198	7,146,479	41,799,966	
COMMERCIAL & INDUSTRIAL SERVICE	2,774,380	2,223,131	1,320,687	1,730,556	2,148,217	2,569,278	12,766,249	
OTHER	1	44,282	84,197	27,167	38,655	54,684	248,987	
RETAINED CONTRIBUTIONS	(525,084)	(806,521)	-	-			(1,331,605)	
CONSTRUCTION PERMITS-15	623,750	722,396	1,310,837	1,338,490	1,130,012	1,128,901	6,254,386	
BANDON FEEDER - PRELIMINARY SURVEY	(17,794)	3,663	(9,298)				(23,429)	
METERS	7,839,998	8,994,650	4,219,041	5,976,698	5,326,511	6,377,519	38,734,417	-
2. REPLACEMENTS SUPPORTED BY REVENUES	9,331,985	21,762,042	17,147,487	6,000,000	-	-	54,241,514	37,092,791
TOTAL BARE STEEL	2,921,159	16,004,549	11,704,825	5,450,603	582,586	358,628	37,022,350	33,574,725
BARE STEEL-MAINS-119	2,473,633	15,579,141	11,172,767	3,937,421	117,345	294,418	33,574,725	33,574,725
BARE STEEL-SERVICES 319	447,526	425,408	532,058	1,513,182	465,241	64,210	3,447,625	
TOTAL LEAKAGE	1,083,145	1,954,297	2,684,136	1,818,447	506,514	676,638	8,723,178	-
LEAKAGE RECONSTRUCTION - MAINS	967,772	1,743,320	2,362,562	1,539,474	328,549	348,762	7,290,438	
LEAKAGE RECONSTRUCT - SERVICES	115,373	210,978	321,574	278,973	177,966	327,876	1,432,740	
LESS: UNALLOWED LEAKAGE/BARE STEEL	(3,000,000)	(3,750,000)	(3,750,000)				(10,500,000)	
DISTRIBUTION INTEGRITY - MAINS (DIMP)	1,564,351	791,351	410,279	87,306	154,177	510,603	3,518,067	3,518,067
DISTRIBUTION INTEGRITY - SERVICES (DIMP)	658,731	1,350,562	1,223,500	735,004	360,739	314,014	4,642,549	

TRANSMISSION INTEGRITY (TIMP)	6,354,599	5,661,282	5,124,748	4,460,286	3,749,325	4,385,889	29,736,129	
GUARDPOST PLACEMENT					65,078	146,039	211,117	
LESS: UNALLOWED DIMP & TIMP	(250,000)	(250,000)	(250,000)	(6,551,646)	(5,418,418)	(6,391,812)	(19,111,876)	
3. REPLACEMENTS / BETTERMENTS NOT SUPPORTED BY REVENUES	**69,271,700**	**49,905,357**	**30,746,517**	**38,871,076**	**54,674,028**	**61,653,405**	**305,122,083**	**154,132,342**
PUBLIC WORKS	12,296,268	13,635,195	10,399,537	10,412,882	9,663,828	10,076,185	66,483,895	60,488,100
PUBLIC WORKS - MAINS	11,365,466	12,156,907	9,457,283	9,704,032	8,522,692	9,281,720	60,488,100	60,488,100
PUBLIC WORKS - SERVICES	930,802	1,478,288	942,254	708,850	1,141,137	792,645	5,993,975	
PUBLIC WORKS - FIELD DATA						1,820	1,820	
RELOCATES/ABANDONMENTS	7,710,601	6,070,041	5,592,430	5,621,916	7,681,294	7,950,329	40,626,611	18,374,180
RELOCATES/ABANDONMENTS-MAINS-116	3,432,398	2,249,009	2,639,818	2,425,701	4,194,039	3,433,215	18,374,180	18,374,180
RELOCATES/ABANDONMENTS-SERV-316	4,278,203	3,821,032	2,952,611	3,196,215	3,487,256	4,517,114	22,252,431	
NON REVENUE PRODUCING LEAKAGE/BARE STEEL	3,250,000	4,000,000	4,000,000	6,551,646	5,418,418	6,391,812	29,611,876	
SYSTEM REINFORCEMENT	36,369,956	16,641,029	4,713,179	956,053	8,037,959	8,085,938	74,804,113	74,804,113
CNG - INTERNAL USE		1,332,049	301,707	166,000	840		1,800,595	
CATHODIC PROTECTION-14	161,121	230,835	2,237	13,137	23,156	(21,881)	408,604	
DAMAGE RECONSTRUCTION - MAINS	163,350	50,525	77,017	91,791	(58,873)	142,139	465,949	465,949
DAMAGE RECONSTRUCTION - SERVICES	135,598	225,238	199,772	240,018	180,211	152,772	1,133,608	
METER RELOCATIONS-SERVICES-317	3			14,006	46		14,055	
CUT-OFFS SERVICES-318	3						3	
REGULATORS	1,455,518	1,591,657	1,164,562	1,004,927	1,422,532	1,193,298	7,832,493	-
DISTRICT REGULATORS-13	1,368,068	1,401,373	1,011,285	829,575	1,305,786	1,024,944	6,941,030	
SERVICE REGULATORS-19	87,450	190,284	153,277	175,352	116,746	168,354	891,463	
SYSTEM BETTERMENTS	1,635,613	1,710,065	1,554,560	7,610,096	15,329,958	19,591,331	47,431,623	-
MISC IMPROVEMENTS-GAS SUPPLY-11	1,030,821	234,153	175,819	641,529	1,021,807	1,878,747	4,982,875	
BETTERMENTS-ENGINEERING-12							-	
MIST MISC BETTERMENTS-18	23,918	808,226	103,962	570,425	247,758	8,336,941	10,091,231	
PORTLAND LNG-524	264,620	34,487	164,244	1,112,668	2,447,738	3,031,901	7,055,659	
NEWPORT LNG-529	316,254	633,199	1,110,534	5,285,475	11,612,654	6,343,742	25,301,858	
GENERAL	6,093,669	4,418,724	2,741,517	6,188,604	6,974,659	8,091,483	34,508,656	-
4. INVESTMENTS REQUIRING ECONOMIC JUSTIFICATION	**31,123,408**	**24,449,918**	**15,163,455**	**12,945,695**	**12,345,616**	**19,652,663**	**115,679,892**	**-**
5. STORAGE	**1,222,820**	**237,016**	**1,204,193**	**(550,784)**	**(3,492,275)**	**1,019,468**	**(359,562)**	**-**

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 706

Exhibits in Support
Of Opening Testimony

April 20, 2018

	Column Labels			
	Installed		Abandoned	
Row Labels	Sum of Feet	Cost	Sum of Feet	Cost
Woodburn	17,205	2,304,884	9,631	96,437

Basic fin. date	Description	Street	City	TotSum (actual)
10/21/2016	Lower 3 valve frames due to grading - va	Highway 99E & Young St	Woodburn	14,158.65
11/03/2014	For Platting Purposes	Country Club Rd & Evergreen Rd	Woodburn	0.00
10/03/2014	Lower 6' of 4" (P) main	Evergreen Rd	Woodburn	3,736.24
09/03/2014	Lower 2 test risers	Woodland Ave @ Hillsboro-Silverton Hwy	Woodburn	-968.42
08/01/2014	Raise KD box to sidewalk elevation	Woodland Ave	Woodburn	790.94
06/30/2014	Install 97' of 4" (W) main	Broughton Way	Woodburn	5,052.35
06/30/2014	Abandon 90' of 4" (W) main	Broughton Way	Woodburn	2,841.36
06/30/2014	Ph 1 - Abandon 712' of 2" (W) main	Chalet Dr, PUE - Country Club Ter	Woodburn	0.00
06/30/2014	Ph 3 - Abandon 124' of 6" (P) main	Evergreen Rd	Woodburn	4,309.25
06/30/2014	Ph 3 - 5,506` of main OUT OF SERVICE	Highway 214	Woodburn	63,253.11
06/30/2014	Abandon 143' of 1" (W) main	Highway 214	Woodburn	0.00
06/30/2014	Abandon 30' of 2" (W) main	Highway 214	Woodburn	0.00
06/30/2014	Install 2,151' of 2" (P) main	Highway 214, Lawson St & Stacy Allison Way	Woodburn	41,411.94
06/30/2014	Order created per Dan Kizer for potholin	WOODBURN INTERCHANGE - HWY 214	Woodburn	103.01
06/24/2014	Install 30-50 of 4" (P) main to lower	Highway 214 & Country Club Rd	Woodburn	9,511.80
05/09/2014	Ph 1B - Abandon 35' of 6" (W) OOS main	Highway 214	Woodburn	4,321.98
04/15/2014	Ph 4 - Install 6862' of 6" (W) main	Boones Ferry Rd & Parr Rd	Woodburn	1,214,974.86
04/15/2014	Ph 4 Install 6' (W)Class B Outlet Piping	Evergreen Rd, Yard Main S of	Woodburn	10,959.49
04/15/2014	Ph 4 - Install 2" (W) HP inlet piping	Evergreen Rd, Yard Main S of	Woodburn	10,482.34
04/15/2014	Ph 4 - Install 3/4" (W) test risers	Evergreen Rd, Yard Main S of	Woodburn	1,770.69
04/15/2014	Ph 1B - Relocate C-P Wires & Test Leads	Woodland Ave	Woodburn	0.00
03/31/2014	Ph 1B - install 4" PE valve	Evergreen Rd	Woodburn	7,884.89
02/28/2014	Ph 1B - Abandon 2930' of 6" (W) main	Highway 214	Woodburn	25,759.73
02/28/2014	PH 1B - Intall 838' of 4" (P) main	Highway 214 & Country Club Rd	Woodburn	89,336.50
02/28/2014	Ph 1B - Abandon 260' of 2" (W) main	Highway 214 & Country Club Rd	Woodburn	5,986.07
02/28/2014	Ph 1B - Install 652' of 2" (P) main	Highway 214 & Evergreen Rd	Woodburn	49,819.41
02/28/2014	Ph 1B - Abandon 130' of 6" (P) main	Highway 214 & Evergreen Rd	Woodburn	4,400.44
02/28/2014	Ph 1B - Abandon 385' of 1" (W) main	Highway 214 & N Cascade Dr	Woodburn	13,819.52
02/28/2014	Ph 1B - Install 80' of 2" elec conduit	Princeton Rd & Highway 214	Woodburn	-1,277.49
02/18/2014	Ph 1 B install 72' of 2" (p) main	N Cascade Dr	Woodburn	33,984.45
01/10/2014	Ph 1B - Install 126' of 4' (W) main	Broughton Way	Woodburn	52,702.23
01/10/2014	Ph 1B - Abandon 120' of 4" (W) main	Broughton Way	Woodburn	4,287.56
12/31/2013	install 988' 4" (p) main	Arney Rd NE	Woodburn	46,192.34
12/31/2013	abandon 157' 2" (p) main	Arney Rd NE	Woodburn	2,814.46
12/31/2013	abandon 945' 4" (p) main	Arney Rd NE	Woodburn	2,227.42
12/31/2013	abandon 5' 4" (w) main	Hillsboro-Silverton Hwy	Woodburn	288.35
12/31/2013	abandon 125' 4" (p) main	Hillsboro-Silverton Hwy	Woodburn	0.00

12/31/2013	Abandoned 502' of 6"(W) per L2C on this	Hillsboro-Silverton Hwy	Woodburn	0.00
12/31/2013	Abandoned 2100' of 6"(W) per L2C on this	Hillsboro-Silverton Hwy	Woodburn	0.00
12/31/2013	install 877' 4" (p) main	Hillyer/Hillsboro Silverton Hwy	Woodburn	75,688.16
12/31/2013	Install 854' of 6"(W) main	Interstate 5 and Highway 214	Woodburn	223,416.25
12/31/2013	Abandon 123' of 1 1/4 (P) main	Lawson St	Woodburn	1,870.76
12/31/2013	Install 55' of 6" (P) main	Stacy Allison Way	Woodburn	49,911.24
12/31/2013	Install Rectifier & Anode Bed	Willow Ave	Woodburn	136,135.30
12/31/2013	install 135' 2" (w) main	Woodland Ave	Woodburn	39,173.75
12/31/2013	abandon 135' 2" (w) main	Woodland Ave	Woodburn	7,146.69
12/31/2013	Install 10' of 4" (P) main	Woodland Ave NW	Woodburn	10,236.26
12/31/2013	Crew Abandoned 10' of 6" (P) main	Woodland Ave NW	Woodburn	64.75
12/31/2013	Crew Abandoned 10' of 4" (P) main	Woodland Ave NW	Woodburn	22.48
12/20/2013	Install 929' of 2" (P) main	1390 Commerce Way #A	Woodburn	27,501.45
12/20/2013	Abandon 32' of 1" (W) main	Commerce Way	Woodburn	303.48
10/07/2013	Relocate 2" (P) main for catch basin	Country Club Rd & Evergreen Rd	Woodburn	3,117.17
10/01/2013	Install 145' of 2" (W) main	Country Club Ter	Woodburn	6,636.82
06/30/2013	Abandon 161' of 1" (W) main	Country Club Ct	Woodburn	13,682.38
04/30/2013	Abandon 564' of 1" (W) main	Main N of Rainier Rd & Frontage Rd	Woodburn	649.55
02/29/2012	Abandon 205' of 1" (W) main	Geschwill Ln	Woodburn	610.17
02/29/2012	Abandon 228' of 2" (W) main	Highway 99E	Woodburn	13,263.02
02/29/2012	Abandon 85' of 1 1/4" (P) main	Highway 99E	Woodburn	0.00
02/29/2012	Install 955' of 2" (P) main	Highway 99E & Geschwill Ln	Woodburn	60,922.88
02/29/2012	Abandon 652' of 2" (P) main	Highway 99E & Geschwill Ln	Woodburn	244.38
03/07/2009	CITY OF WOODBURN	N FRONT ST/HARDCASTLE-LINCOLN	WOODBURN	5,788.23

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 707

Exhibits in Support
Of Opening Testimony

April 20, 2018

Basic fin. date	Description	Street	City	TotSum (actual)
12/30/2013	Aban 3/4" (W) service	#10055 Oak Hill Rd.	Independe	317.52
12/30/2013	Aban 3/4" (W) service	#10195 Oak Hill Rd.	Independe	317.52
12/30/2013	Aban 3/4" (W) service	#10395 Oak Hill Rd.	Independe	317.52
12/30/2013	Aban 3/4" (W) service	#9999 Oak Hill Rd.	Independe	317.52
10/31/2013	Aban 3/4" (W)	12050 Independence Granger rd	Monmouth	317.52
10/31/2013	Aban 3/4" (W)	12070 Independence Granger Rd	Monmouth	693.64
08/09/2011	Aban 3/4" (W)	13530 Independence Granger Rd	Monmouth	680.63
10/31/2013	Aban 3/4" (W)	13605 Independence Granger Rd	Monmouth	317.52
10/31/2013	Aban 3/4" (W)	14280 Independence Granger Rd	Monmouth	317.52
10/31/2013	Aban 3/4" (W)	14465 Independence Granger Rd	Monmouth	317.52
06/30/2014	Abandon 162' of 1" (W) main	3rd St & Main St NE	Aurora	12,484.00
06/30/2014	Abandon 188' of 2" (W) OOS Main	3rd St NE	Aurora	12,299.91
06/11/2012	Abandon 118' of 1" (W) main	3rd St	Salem	1,786.32
09/07/2012	Abandon 1"(W) main	ALLEY BTWEN UNION-MARION COMMERCIAL-LIBERTY	Salem	8,900.92
11/29/2013	Abandon 1"(W)/(B) main	Bonham Ave S	Salem	15,109.98
10/31/2015	Abandon 1" (W) Main	Campus Way	Corvallis	2,065.36
09/28/2012	Abandon 150' of 1" (W) main	D St, Monmouth St, Alley bet 6th & 5th	Independe	2,398.65
12/31/2012	Abandon 725' of 4" (W) main	Division St NE	Salem	8,734.66
12/31/2012	Abandon approx 1267' of 1" (W) main	Division St, Liberty St, & Alleys	Salem	4,188.19
07/03/2013	Abandon 200' of 2"(W)	F St, E 10th/11th Alley	The Dalles	1,164.29
07/19/2013	Abandon 50' of 1"(W) bare main	F St, N/O E. 10th St	The Dalles	23.84
12/31/2012	Abandon 980' of 2" (W) main	Front St	Salem	969.24
06/29/2012	Abandon 71' of 1" (W) main	G St, 4th St - 3rd St	Hubbard	34.18
06/29/2012	Abandon 26' of 1 1/4" (P) main	G St, 4th St - 3rd St	Hubbard	733.25
10/31/2015	Abandon 8725' 4"(B) & (W)	HWY 223 (Ellendale Ave - Rickreall Rd.)	Dallas	5,470.83
10/31/2013	Aban 6"(B) & 6"(W) S. Mon Bare	Independence-Granger Rd.		11,433.44
12/01/2012	Abandon 1" (W) main	John St S, S of Rural Ave S	Salem	71.77
10/31/2013	Abandon 65' of 1" (W) main	La Branch St SE	Salem	0.00
12/28/2012	Abandon xx' of 1"(W) main	Laughlin St/btwn 8th & 9th St	The Dalles	0.00
03/29/2013	Abandon 332' of 1" (W) main	Laughlin/9th/10th Alley	The Dalles	2,651.65
09/15/2015	Abandon 2" (W) Main --See Attached Sketc	N Basin Ave	Portland	23,487.90
10/31/2014	Abandon 16" (W) Main	N Edgewater Ave	Portland	47,056.40
10/31/2014	Abandon 6" (W) Main	N Edgewater Ave	Portland	0.00
10/31/2014	Abandon 10' of 8" (W) Main	N Edgewater Ave	Portland	0.00

12/29/2009	Abandon 2" (W) Main	N Lombard St	Portland	2,944.81
10/15/2013	Abandon 6" (W) Main	NW Front Ave	Portland	58,425.64
10/31/2014	Aban ft 6" (W)	NW Independence Hwy	Albany	4,849.42
06/01/2015	Abandon 1002' of 2"(P) main	Rickreall Rd	Independe	12,410.73
04/26/2013	Abandon 26' of 2" (P) 1983	Saxon Dr S	Salem	572.21
12/31/2012	Abandon 222' of 1" (W) main	SE Ash St & Alley S of Ash St	Dallas	4,320.63
12/31/2013	Abandon 1" (B) and (W) Main	SE Division St	Portland	16,566.92
06/14/2013	Abandon 2" (W) Main	SE Holgate Blvd	Portland	2,420.93
10/31/2013	Abandon 225' of 1" (W) main	SE Oak St	Dallas	600.66
09/01/2014	Abandon XX' of 1" (W) Main	SE Stark St	Portland	0.00
10/31/2014	Abandon Approx 80' of 1" (W) main	SEVER CT	Portland	68.39
08/31/2013	Abandon 1" (W) Main on SW 63rd Dr	SW 63rd Dr	Portland	0.00
12/31/2013	Abandon 1" (W) Main	SW Buddington St	Portland	6,584.05
11/25/2011	Abandoned 1”(W) per asbuilt found in pla	SW Vermont St / SW Chestnut St	Portland	0.00
10/10/2014	Abandon 17' of 2"(P) main	Union St/btwn 13th St & 14th St	The Dalles	4,247.90
10/31/2013	Abandon 1"(W) and 1"(B) main	W BERKLEY ST	PORLAND	790.46
03/01/2013	Abandon 130' of 1 1/4" (P) main	Yew St SE	Salem	2,594.47
Total			**$**	**282,376**

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 708

Exhibits in Support
Of Opening Testimony

April 20, 2018

07 FEB 2018

DHI Group, Inc. Reports Fourth Quarter and Full Year 2017 Results

NEW YORK, Feb. 7, 2018 /PRNewswire/ --

- Fourth quarter 2017 total revenues of $50.9 million, net income of $11.8 million and diluted EPS of $0.24, including $0.18 net benefit to EPS from unusual items impacting comparability to previous periods
- Cash flows from operations of $7.2 million in the fourth quarter; Adjusted EBITDA of $11.4 million including $1.8 million net benefit from unusual items impacting comparability to previous periods
- Completed the disposition of Health eCareers for $15.0 million, resulting in a $6.7 million pre-tax gain

DHI Group, Inc. (NYSE: DHX) ("DHI" or the "Company"), a leading online career resource and talent acquisition platform for technology professionals and other select professional communities, today reported financial results for the quarter and year ended December 31, 2017.

"We accomplished a number of things in the fourth quarter, including having all the senior leaders of the functional areas in place, so the organization can execute on our strategy and our product roadmap. The early results are encouraging and the cadence that we established in the fourth quarter has set a strong foundation for 2018," said Michael Durney, President and Chief Executive Officer of DHI Group, Inc. "We initiated a number of product features and enhancements in the quarter and in the new year that we feel really good about. Given the favorable fundamentals of tech career services and the strong competitive environment, it's critical we move to capture market opportunity and ultimately work to return our business to growth."

Q4 2017 Tech-Focused Product and Business Highlights

Notable achievements as part of the tech-focused strategy:

- Launched several product features and improvements, including a new homepage and search functionality for eFinancialCareers, our new Dice homepage in beta that has reduced bounce rates and increased application rates, and a new salary tool which has improved user engagement
- Completed a Company-wide migration to a cloud-based platform, which will drive cost savings, improve SEO, result in faster response time, and accelerate product development and experimentation
- "Open Web First" go-to-market strategy drove 51% year-over-year growth in Dice customers with Open Web, increasing penetration of Dice recruitment package customers to 39% as of December 31, 2017, up from 24% a year ago
- On-boarded 80 additional search API clients and now have more than 950 customers with API integrations as of December 31, 2017, a 50% increase year-over-year
- Dice Careers app cumulative downloads were 58% higher than December 31, 2016

Q4 and Fiscal Y ear 2017 Segment Financial Highlights

"Fourth quarter results met our expectation of continuing modest top line trend improvement, and our continued focus on efficiency allowed us to maintain our levels of investment in product and marketing, without unduly impacting profitability," said Luc Grégoire, Chief Financial Officer. "We begin 2018 well positioned to execute our tech-focused strategy and realize the significant opportunity in the growing online tech recruitment market. While it may take a bit more time for our product roadmap to gain momentum and improve financial performance, initial feedback on product initiatives gives us confidence we are on the right path."

The Company's two reportable segments are Tech-focused and Healthcare. The Tech-focused segment includes Dice, Dice Europe, ClearanceJobs, eFinancialCareers, and Brightmatter (absorbed into Tech-focused in the third quarter of 2017). The Healthcare segment includes Health eCareers, which was sold on December 4, 2017. Corporate and other includes Hcareers, Rigzone, BioSpace (transferred to BioSpace management effective January 31, 2018), as well as Slashdot Media (sold in January 2016) and getTalent, which has been discontinued.

The following tables summarize Revenues, Net Income, Adjusted EBITDA and Adjusted EBITDA Margin results for the quarters and years ended December 31, 2017 and 2016 ($ in millions). A reconciliation of Operating Income (Loss) to Adjusted EBITDA is included toward the end of this press release.

	Q4 2017	Q4 2016	Change	Fx Impact	FY 2017	FY 2016	Change	Fx Impact
Revenues								
Tech-focused	$ 39.8	$ 41.7	(5)%	$ 0.5	$ 158.4	$ 170.6	(7)%	$ (1.2)
Healthcare (1)	4.6	6.4	(28)%	—	24.4	27.1	(10)%	—
Corporate & Other	6.5	6.8	(4)%	—	25.2	29.3	(14)%	(0.1)
Total Revenues	$ 50.9	$ 54.9	(7)%	$ 0.5	$ 208.0	$ 227.0	(8)%	$ (1.3)
Net Income (loss) (2)	$ 11.8	$ 5.5	115%		$ 16.0	$ (5.4)	n.m.	
Diluted earnings (loss) per share (2)	$ 0.24	$ 0.11	118%		$ 0.33	$ (0.11)	n.m.	

(1) Sold on December 4, 2017.

(2) Unusual items impacting comparability to previous periods increased net income by $8.8 million, including a tax benefit of $4.7 million related to certain discrete tax items, or $0.18 per share in Q4 2017, and increased net income $0.7 million, related to a tax benefit of $0.8 million from certain discrete tax items in Q4 2016. For Q4 2017 these items included: disposition related and other costs, gain on sale of business, restitution payment, and certain legal costs.

				Adjusted EBITDA Margin					Adjus EBIT Marg
Adjusted EBITDA	Q4 2017	Q4 2016	Change	2017	2016	FY 2017	FY 2016	Change	2017
Tech-focused	$ 10.6	$ 17.1	(38)%	27%	41%	$ 48.9	$ 67.8	(28)%	31%
Healthcare (1)	0.3	0.4	(25)%	7%	6%	1.4	2.5	(44)%	6%
Corporate & Other	0.5	(3.6)	114%	8%	n.m.	(8.9)	(12.6)	29%	n.m.
Total Adjusted EBITDA (2) (3)	$ 11.4	$ 13.9	(18)%	22%	25%	$ 41.4	$ 57.7	(28)%	20%

(1) Sold on December 4, 2017.

(2) Unusual items impacting comparability to previous periods increased adjusted EBITDA by $1.8 million in Q4 2017 and decreased adjusted EBITDA by $0.2 millio 2016. For Q4 2017 these items included: disposition related and others costs, proceeds from restitution award, and certain legal costs. Q4 2016 included certain lega

(3) Reconciliations of Net Income and Operating Income to Adjusted EBITDA and of Operating Cash Flows to Adjusted EBITDA are included toward the end of this p release.

Business Outlook

For 2018, the Company expects current top line trends to continue initially, with improvement later in the year as new products gain adoption with tech professionals and recruiters. Investments in marketing will continue at fourth quarter run rates and product development will increase, funded with efficiency gains in other functional areas. This outlook results in an Adjusted EBITDA margin that is in line with our 2017 Adjusted EBITDA margin, excluding items that impact comparability to prior periods, and excluding the impact of the upcoming new revenue recognition accounting changes. On today's conference call, management will discuss additional details of its tech-focused strategy, including context around the financial impact of the Company's 2018 strategic objectives and operational plans.

Update on Divestiture of Non-Core Assets

As previously announced, on December 4, 2017 the Company completed the sale of Health eCareers for $15.0 million, resulting in a $6.7 million pre-tax gain.

The Company has progressed on its strategy for the remainder of its non-tech portfolio. The Company expects to finalize a deal to sell the data services division of the Rigzone business in the first quarter. The career services division of Rigzone will remain a part of DHI. The Company continues to respond to interest in the Hcareers business and is exploring a possible deal for the brand. Ownership of the BioSpace business has recently been transferred to BioSpace management, with DHI retaining a minority stake.

Conference Call Information

The Company will host a conference call accompanied by a presentation of supporting materials to discuss fourth quarter and full year results today at 8:30 a.m. Eastern Time. Hosting the call will be Michael Durney, President and Chief Executive Officer, and Luc Grégoire, Chief Financial Officer.

The conference call and presentation will be available live through the Company's website in the Investor Relations section under Presentations & Events at www.dhigroupinc.com. The conference call can also be accessed by dialing 1-844-890-1790 or for international callers by dialing 1-412-380-7407. Please ask to be joined to the DHI Group, Inc. call. A replay will be available one hour after the call and can be accessed by dialing 1-877-344-7529 or 1-412-317-0088 for international callers; the replay passcode is 10116344. The replay will be available until February 14, 2018.

The call will also be webcast live from the Company's website at www.dhigroupinc.com under the Investor Relations section.

Media & Investor Contact

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Director, Corporate Communications
DHI Group, Inc.
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About DHI Group, Inc.

DHI Group, Inc. (NYSE: DHX) is a leading provider of data, insights and employment connections through our specialized services for technology professionals and other select online communities. Our mission is to empower tech professionals and organizations to compete and win through expert insights and relevant employment connections. Employers and recruiters use our websites and services to source, hire and connect with the most qualified and highly-skilled tech professionals, while professionals use our websites and services to find ideal employment opportunities, relevant job advice and tailored career-related data. For over 25 years, we have built our Company on providing employers and professionals with career connections, news, tools and information. Today, we serve multiple markets located throughout North America, Europe, the Middle East and the Asia Pacific region. Find out more at www.dhigroupinc.com.

Notes Regarding the Use of Non-GAAP Financial Measures

The Company has provided certain non-GAAP financial information as additional information for its operating results. These measures are not in accordance with, or an alternative for, generally accepted accounting principles in the United States ("GAAP") and may be different from similarly titled non-GAAP measures reported by other companies. The Company believes that its presentation of non-GAAP measures, such as adjusted earnings before interest, taxes, depreciation, amortization, non-cash stock based compensation expense, other non-recurring income or expense ("Adjusted

EBITDA") and Adjusted EBITDA margin provides useful information to management and investors regarding certain financial and business trends relating to its financial condition and results of operations. In addition, the Company's management uses these measures for reviewing the financial results of the Company and for budgeting and planning purposes. The non-GAAP measures apply to consolidated results and results by segment or other measures as shown within this document. The Company has provided required reconciliations to the most comparable GAAP measures elsewhere in the document.

Adjusted EBITDA and Adjusted EBITDA Margin

Adjusted EBITDA and Adjusted EBITDA Margin are non-GAAP metrics used by management to measure operating performance. Management uses Adjusted EBITDA as a performance measure for internal monitoring and planning, including preparation of annual budgets, analyzing investment decisions and evaluating profitability and performance comparisons between us and our competitors. The Company also uses this measure to calculate amounts of performance based compensation under the senior management incentive bonus program. Adjusted EBITDA, as defined in our Credit Agreement, represents net income plus (to the extent deducted in calculating such net income) interest expense, income tax expense, depreciation and amortization, non-cash stock option expenses, losses resulting from certain dispositions outside the ordinary course of business, certain writeoffs in connection with indebtedness, impairment charges with respect to long-lived assets, expenses incurred in connection with an equity offering, extraordinary or non-recurring non-cash expenses or losses, transaction costs in connection with the Credit Agreement up to $250,000, deferred revenues written off in connection with acquisition purchase accounting adjustments, writeoff of non-cash stock compensation expense, and business interruption insurance proceeds, minus (to the extent included in calculating such net income) non-cash income or gains, interest income, and any income or gain resulting from certain dispositions outside the ordinary course of business.

We present Adjusted EBITDA as a supplemental performance measure because we believe that this measure provides our board of directors, management and investors with additional information to measure our performance, provide comparisons from period to period and company to company by excluding potential differences caused by variations in capital structures (affecting interest expense) and tax positions (such as the impact on periods or companies of changes in effective tax rates or net operating losses), and to estimate our value.

We also present Adjusted EBITDA because covenants in our Credit Agreement contain ratios based on this measure. Our Credit Agreement is material to us because it is one of our primary sources of liquidity. If our Adjusted EBITDA were to decline below certain levels, covenants in our Credit Agreement that are based on Adjusted EBITDA may be violated and could cause a default and acceleration of payment obligations under our Credit Agreement.

Adjusted EBITDA Margin is computed as Adjusted EBITDA divided by Revenues. Adjusted EBITDA and Adjusted EBITDA Margin are not measurements of our financial performance under GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with GAAP as a measure of our profitability.

Forward-Looking Statements

This press release and oral statements made from time to time by our representatives contain forward-looking statements. You should not place undue reliance on those statements because they are subject to numerous uncertainties and factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control. Forward-looking statements include, without limitation, information concerning our possible or assumed future results of operations. These statements often include words such as "may," "will," "should," "believe," "expect," "anticipate," "intend," "plan," "estimate" or similar expressions. These statements are based on assumptions that we have made in light of our experience in the industry as well as our perceptions of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. Although we believe that these forward-looking statements are based on reasonable assumptions, you should be aware that many factors could affect our actual financial results or results of operations and could cause actual results to differ materially from those in the forward-looking statements. These factors include, but are not limited to, our review of strategic alternatives from time to time, our ability to execute our tech-focused strategy, the review of potential dispositions of certain of our businesses and the terms and timing of any such transactions, the results and timing of our search for a new Chief Executive Officer, competition from existing and future competitors in the highly competitive market in which we operate, failure to adapt our business model to keep pace with rapid changes in the recruiting and career services business, failure to maintain and develop our reputation and brand recognition, failure to increase or maintain the number of customers who purchase recruitment packages, cyclicality or downturns in the economy or industries we serve, the uncertainty surrounding the United Kingdom's future departure from the European Union, including uncertainty in respect of the regulation of data protection and data privacy, failure to attract qualified professionals to our websites or grow the number of qualified professionals who use our websites, failure to successfully identify or integrate acquisitions, U.S. and foreign government regulation of the Internet and taxation, our ability to borrow funds under our revolving credit facility or refinance our indebtedness and restrictions on our current and future operations under such indebtedness. These factors and others are discussed in more detail in the Company's filings with the Securities and Exchange Commission (the "SEC"), all of which are available on the Investors page of our website at www.dhigroupinc.com, including the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 to be filed with the SEC, under the headings "Risk Factors," "Forward- Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

You should keep in mind that any forward-looking statement made by the Company or its representatives herein, or elsewhere, speaks only as of the date on which it is made. New risks and uncertainties come up from time to time, and it is impossible to predict these events or how they may affect us. We have no obligation to update any forward-looking statements after the date hereof, except as required by applicable law.

DHI GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(in thousands except per share amounts)

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	2017	2016
Revenues	$ 50,936	$ 54,938	$ 207,950	$ 226,970
Operating expenses:				
Cost of revenues	7,293	7,569	29,974	32,126
Product development	5,754	6,391	24,984	25,714
Sales and marketing	20,870	18,878	80,508	77,451
General and administrative	9,970	10,862	40,749	43,684
Depreciation	2,049	2,210	9,752	9,849
Amortization of intangible assets	452	681	2,138	6,787
Impairment of goodwill & intangible assets	—	—	2,226	24,621
Disposition related and other costs	2,510	—	4,746	3,347
Total operating expenses	48,898	46,591	195,077	223,579
Other Operating Income:				
Gain on sale of business	6,699	—	6,699	—
Proceeds from restitution payment	3,293	—	3,293	—

globalpayments

Global Payments Reports 2017 Earnings, Establishes 2018 Growth Targets and Announces Partnership with HSBC Mexico

February 15, 2018

ATLANTA--(BUSINESS WIRE)--Feb. 15, 2018-- Global Payments Inc. (NYSE:GPN) today announced results forthe fourth quarter and year ended December 31, 2017.

"We finished 2017 the way we started it: We generated double digit organic growth across our markets in the fourth quarter. 2017 was a terrific year by any measure, and we delivered the fastest rates of organic adjusted net revenue growth, margin enhancement and adjusted earnings per share growth in our history," said Jeff Sloan, Chief Executive Officer. "We also furthered our strategic objectives to expand our presence in faster growth markets with our agreement today to create a new joint venture with HSBC in Mexico.

"The combination of our technology-enabled distribution with the continuing expansion of our faster growth geographic markets positions us well to continue our exceptional track record of market leading growth," Sloan continued. "Finally, we are pleased to raise our growth targets in light of the progress we have made in evolving our business mix over the last several years."

Full-Year 2017 Summary

- GAAP revenues were $3.98 billion, compared to $3.37 billion in 2016; diluted earnings per share were $3.01 compared to $1.37 in the prior year; and operating margin was 14.1% compared to 10.6% in 2016.
- Adjusted net revenue grew 24% to $3.52 billion, compared to $2.84 billion in 2016.
- Adjusted earnings per share grew 26% to $4.01, compared to $3.19 in 2016.
- Adjusted operating margin expanded 120 basis points to 29.9%.

Fourth Quarter 2017 Summary

- GAAP revenues were $1,054.3 million, compared to $950.2 million in the fourth quarter of 2016; diluted earnings per share were $1.51 compared to $0.16 in the prior year; and operating margin was 14.2% compared to 8.4% in the fourth quarter of 2016.
- Adjusted net revenue grew 15% to $939.0 million, compared to $819.7 million in the fourth quarter of 2016.
- Adjusted earnings per share grew 23% to $1.07, compared to $0.87 in the fourth quarter of 2016.
- Adjusted operating margin expanded 170 basis points to 30.3%.

ASC 606

Global Payments will adopt Accounting Standards Codification Topic 606, *Revenue from Contracts with Customers* ("ASC 606"), effective January 1, 2018. Under ASC 606, GAAP revenues will now be reported net of fees paid to payment networks rather than on a gross basis with these amounts being reflected as a cost of service as they have been historically. In addition, GAAP revenues associated with our gaming cash advance products will now be reported net of associated commissions paid to casinos. These changes in presentation reduce revenues and operating expenses by the same amount and have no effect on operating income or earnings per share.

In addition to reporting GAAP results on this basis going forward, we will also report an adjusted net revenue plus network fees metric, which we believe better reflects how we manage our business and is largely consistent with our historical non-GAAP adjusted net revenue reporting convention, except with respect to the netting of gaming cash advance commissions. The netting of casino commissions reduces 2017 reported amounts by approximately $68 million and is expected to impact 2018 by an estimated $73 million. In addition, we will report adjusted operating margin based on the adjusted net revenue plus network fees metric, which again is largely consistent with our historical reporting convention.

2018 Outlook

"We could not be more pleased with our strong financial performance for 2017, and we remain excited about the momentum we have entering 2018," stated Cameron Bready, Senior Executive Vice President and Chief Financial Officer. "As a result of this performance, for 2018 the company expects adjusted net revenue plus network fees to range from $3.88 billion to $3.97 billion, reflecting growth of 12% to 15% over comparable 2017 results and adjusted earnings per share to be in a range of $4.95 to $5.15, reflecting growth of 23% to 28% over 2017. Annual adjusted operating margin for 2018 is expected to expand by up to 110 basis points over comparable 2017 adjusted operating margin of 30.4%."

Capital Allocation

Global Payments' Board of Directors approved a dividend of $0.01 per share payable March 30, 2018 to shareholders of record as of March 16, 2018. The board also approved an increase to the company's existing share repurchase program authorization, raising the total available authorization to $600 million.

Conference Call

Global Payments' management will host a conference call today, February 15, 2018 at 8:00 a.m. ET to discuss financial results and business highlights. Callers may access the conference call via the investor relations page of the company's website at www.globalpaymentsinc.com; or callers in North America may dial 877-674-6428 and callers outside North America may dial 970-315-0457. A replay of the call will be archived on the company's website within two hours of the live call.

Non-GAAP Financial Measures

Global Payments supplemented revenues, income and earnings per share information determined in accordance with GAAP by providing those measures on an adjusted basis, and other measures, in this earnings release to assist with evaluating performance. In addition to GAAP measures, management uses these non-GAAP measures to focus on the factors the company believes are pertinent to the daily management of our operations.

Reconciliations of the non-GAAP measures to the most directly comparable GAAP measure are included in the schedules to this release.

Staff/708
Kaufman/7

Robert Half International Inc (NYSE:RHI) Operating Margin %: 9.53% (As of Dec. 2017)

=GURUF("NYSE:RHI","Operating Margin %") (/excel_Add_in.php)

Operating Margin % (/term/operatingmargin/NYSE:RHI/Operating-Margin-/Robert-Half-International-Inc) is calculated as Operating Income (/term/Operating+Income/NYSE:RHI/Operating-Income/Robert-Half-International-Inc) divided by its Revenue (/term/Revenue/NYSE:RHI/Revenue/Robert-Half-International-Inc). Robert Half International Inc's Operating Income (/term/Operating+Income/NYSE:RHI/Operating-Income/Robert-Half-International-Inc) for the three months ended in Dec. 2017 was $128 Mil. Robert Half International Inc's Revenue (/term/Revenue/NYSE:RHI/Revenue/Robert-Half-International-Inc) for the three months ended in Dec. 2017 was $1,346 Mil. Therefore, Robert Half International Inc's Operating Margin % (/term/operatingmargin/NYSE:RHI/Operating-Margin-/Robert-Half-International-Inc) for the quarter that ended in Dec. 2017 was 9.53%.

Good Sign:

```
Robert Half International Inc operating margin is expanding. Margin expansion is usually a good sign.
```

NYSE:RHI' s Operating Margin % Range Over the Past 10 Years
Min: 2.25 Max: 1 1.39
Current: 9.79
2.25 11.39

NYSE:RHI's Operating Margin % is ranked higher than
74% of the 151 (/screener/#&industry=31057) Companies
in the Global (/screener/#&industry=31057) industry.

(Industry Median: 4.25 vs. NYSE:RHI: 9.79)

Robert Half International Inc's 5-Year Average operating margin Growth Rate was 3.60% per year.

Robert Half International Inc's Operating Income (/term/Operating+Income/NYSE:RHI/Operating-Income/Robert-Half-International-Inc) for the three months ended in Dec. 2017 was $128 Mil. Its operating income for the trailing twelve months (TTM) ended in Dec. 2017 was $516 Mil.

Historical Data

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 709

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 709

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CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 710

Exhibits in Support
Of Opening Testimony

April 20, 2018

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CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 711

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff/711
Kaufman/1

Natural Gas Equipment for Businesses

From heating to special processes, natural gas equipment can be the best solution to your business needs.

Food Service

An extensive look at ranges, cooktops, deep fat fryers, ovens, and ventilation, including safety tips.

Cook like the pros »

Heating & Cooling

A quick guide to heating and cooling options for business.

See the difference »

Water Heating

Covers tank and tankless water heaters, as well as boilers.

See the difference »

Other gas applications —Facts on natural gas applications, building dry-outs, cutting torches and dryers/ironers.

Staff/711
Kaufman/2

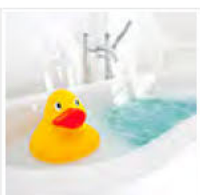
Natural Gas Equipment

Natural gas brings comfort and convenience to your home, while reducing your environmental footprint.

Gas Furnaces and Heating

Learn how the quality of your home's heating system can directly impact how comfortable you and your family are in your home.

Feel the warmth »



Gas Water Heaters

Have peace of mind. Enjoy plenty of hot water. Lower your energy bills. You get all that with a high-efficiency natural gas water heater.

See the difference »

Gas Fireplaces

Flip a switch and set the mood with a relaxing fire.

Create ambiance »

Gas Cooktops and ovens —Cooking with natural gas is preferred by restaurant chefs across the country. Find out why.

Gas Dryers —People are looking for ways to save time, add convenience and protect their clothing when it comes to doing the laundry. Try a natural gas dryer.

Gas Grill and patio —Create an outdoor kitchen and living space.

Combination systems —What exactly is a combination system?

NW Natural Appliance Center —Check out the retail sales showroom, offering a great selection of natural gas products.

NW Natural®

Gas Fireplaces

Flip a switch and set the mood with a relaxing fire.

All across North America, natural gas fireplaces are rapidly replacing wood-burning appliances. That's because natural gas burns cleaner than wood and is often less expensive than wood or wood pellets, easy to operate, and more convenient.

Convenience and safety of a natural gas fireplace

You can have a fire when you want, for as long as you want. Starting a natural gas fireplace is as fast and simple as turning a knob or flicking a switch. Some models even come with thermostats and remote controls. Because natural gas fireplaces also turn off just as easily, you never have to leave a fire burning when you leave your home or go to bed.

With natural gas, you don't have to worry about creosote build-up or chimney fires.

No popping coals, ashes or sparks.

Operation is safe, clean and simple.

Not only do you avoid the preparation of hauling, chopping, and stacking wood, you no longer have to clean up. Even if you have only the last hour of the day to relax, you can enjoy the warmth and beauty of a fire and switch it off when you're ready to turn in.

Residential wood burning is a source of local air pollution and local health problems, such as asthma and other respiratory ailments. By installing a high-efficiency natural gas fireplace, you'll also help improve air quality because it burns cleaner.

Low-cost operation of a natural gas fireplace

Gas fireplaces can save money over using purchased firewood.

Masonry fireplaces are 10 to 25 percent efficient, compared with efficiencies as high as 80 percent for natural gas fireplaces.

Heat the room you live in most for about $0.50 an hour, and turn down the thermostat in the outer rooms.

No need to change out your current heating system.

Choosing the right product

First, consider how you want to use your new natural gas fireplace. If you simply want the decorative beauty of a fire, then a log set will work fine for you. If you want to enjoy a beautiful flame as well as the warmth of an efficient heating device, a gas fireplace insert or a designated built-in fireplace is the right choice.

Varying models offer switch, remote control or thermostat operation. The large selection of models allows you to decide where you wan your new gas fireplace product installed. You can remake a room by installing a natural gas fireplace against an outer wall, creating a hearth where none existed before. There are a variety of styles and efficiency levels of today’s gas fireplace products.

NW Natural

Gas does it better

For many business purposes, nothing beats natural gas.

From heating to special processes, natural gas equipment can be the best solution to your business needs.

Comfort and convenience

Whether you run an office operation, a restaurant, a retail shop or another type of business, you want your employees to be comfortable. That's why high-efficiency gas equipment is your best bet during a Northwest winter.

And if your customers come in to eat, shop or meet, greet them with an inviting natural gas fireplace on a cold day. Nothing is more welcoming – or easier to use. Today's remote or timer controlled equipment guarantees that you have the comfort of a hearth when you want it.

Equipment for your business

A professional chef wants a natural gas cooktop. A building contractor wants natural gas for dry-outs. An industrial food processor wants boilers, dryers and ovens for processing. And the owner of a commercial laundry wants gas dryers to keep the business working efficiently and effectively.

Natural gas equipment —Learn more about heating, water heating, food service equipment, and other gas applications.

NW Natural®

Staff/711
Kaufman/6

Food Service

An extensive look at ranges, cooktops, deep fat fryers, ovens, and ventilation, including safety tips.

Professional chefs prefer natural gas for the speed and control it gives them when preparing food. Plus, gas equipment is more cost effective to operate than electric appliances.

Contact Tom Simpson for all of your restaurant equipment questions, at 503-721-2458 or send him an email.

Ranges

Natural gas ranges are a practical marriage of cooktop and oven in the same appliance. They can be easily accommodated in smaller kitchen areas. Commercial models are manufactured in 30, 36, 48 and 60-inch widths, and have special installation requirements.

Cooktops

Nothing gives you control like a natural gas cooktop because today's models deliver the precise heat you need. New designs have ports on the inside of the burner to distribute the flame more evenly and provide a higher concentration of heat.

There are so many mix-and-match cooktop features: grills, wok rings, thermostatically controlled griddles, steamers, rotisseries, deep fryers, and lift out grease wells. A new oblong burner ideal for poaching fish is on the market. And there are models with electrical LED readouts that indicate the power level of the gas flame for each burner. Many ranges will relight automatically if the flame blows out accidentally.

New, different-sized burners

> Standard gas burners provide between 9,000 and 10,000 BTUs worth of energy (A BTU is a British Thermal Unit, or the amoun of heat required to raise one pound of water one degree Fahrenheit).
>
> Many cooktops have three 9,000 BTU burners and one 12,000 BTU burner, a power burner. It is used for boiling, stir frying, anc other uses where high heat is required.
>
> Other cooktop models offer the standard burners, a power burner and a lower-BTU burner (about 5,000 BTUs) for simmering sauces and other low temperature uses.

Sealed burners

> Prevent spills from seeping under the cooktop, making cleanup a lot easier.

Quick cooking tip

Remember to place the pot or pan you use on the appropriate-sized burner head. If the flame licks around the outside of the bottom of the cookware, the heat isn't being concentrated properly.

Deep fat fryers

Floor Models: Gas fryers are one of the most widely used pieces of equipment in the food service industry. In selecting a fryer, production capacity are important considerations.

> Immersion tube type fryer: Manufacturers using this design contend that immersing the burners in fat contributes to fryer efficiency by completely surrounding the heat transfer surface (the tubes) with the hot frying medium.
>
> V-shaped fry pot: In this case, burners are located under the fry pot and the curved bottom surface serves as the heat transfer surface. This design offers good accessibility to both the fry pot and the burners located under the cabinet.

Counter Top Models: With the current trend towards downsized restaurant formats, there is a greater selection of gas counter top fryers than ever before.

New 15-inch high units: These units are compatible with other equipment(earlier models generally had working heights higher than the rest of the cookline).

Volume cooking: Many of the new gas counter top fryers offer volume cooking capabilities that rival top, heavy duty floor models.

Hood requirements: When selecting counter top equipment, it should be noted that hood requirements are dictated by the by-products of the cooking process and not by the fuel used.

Ovens

Nothing bakes, broils or bastes like a natural gas oven because they provide the precise, moist heat that cooktops offer.

Gas ovens: Come in radiant heat or convection models.

Radiant heat provides a steady heat that is ideal for baking and broiling. It heats the food, not just the air surrounding it, and locks in the juices and nutrients.

Fan-forced convection ovens circulate hot air around the food for even heating and browning at lower temperatures. Fan forced convection ovens cook food the same no matter which oven shelf it sits upon, and can roast food 25 percent faster than conventional ovens.

Combination Ovens: Combination ovens are designed to provide food service operators with a choice of three basic cooking functions with a single oven cavity.

The oven creates two primary heat transfer sources: pressure-less convection steam and convection hot air. These two heat sources may be utilized individually or in combination, creating three primary cooking modes.

A single piece of equipment doing a multitude of cooking tasks can improve the efficiency of your entire production and service system while saving labor costs.

Getting the most from your oven

Size: Ovens come in 24, 27 and 30-inch widths, and in single or double oven configurations.

Digital controls: Help keep the temperature exact by limiting temperature swings as much as possible.

Broiling: Natural gas broiling is virtually smokeless. The splatter goes up into the flame and is consumed, so you can broil with the door shut. That can be an advantage in the summer, because it reduces the amount of heat in the kitchen. Electric broilers produce more smoke that can build up unless it's vented out of your kitchen.

Ventilation

Do not underestimate the importance of a high performance ventilation system for your cooking equipment. It will draw grease, odor, heat, steam and smoke away from you and your commercial kitchen.

There are two methods: updraft or downdraft systems. Consumers need to ask for an updraft or downdraft model with at least 300 CFM rating to ensure that they're getting their money's worth.

Updraft systems: Consumers shopping for an updraft hood should pay more attention to power than to noise, because any vent set on "high" will make noise. The key is drawing power and how well the hood will operate on a "medium" setting.

To be truly effective, a hood should move air at 300 cubic feet per minute (CFM).

Downdraft systems: There's no question that a downdraft system is a wonderful option, especially when an updraft system is impractical. Downdrafts produce a current of air that travels over the surface of the cooktop, drawing the smoke and odors into the exhaust duct.

Retractable models rise up from the back of the cooktop and, at the touch of a button, will stay on for five minutes after you're done cooking to further eliminate kitchen odors.

Some models will remind you when it's time to clean the filters.

Many models are powerful, exceeding ratings of 600 CFM.

Gas booster water heaters

A booster water heater is used to increase the temperature of general purpose hot water to 180 degrees F. This reduces the amount of chemicals needed for the sterilization of dishes and utensils.

Natural gas boosters offer several advantages over the other alternatives:

- 45-50 percent savings in operating costs over electric
- Superior performance over chemical/low temp process
- Quicker cycle times
- More friendly to the environment
- Uses less water

Gas warewashers

Generally speaking, there are four categories of gas warewasher; flight type, rack conveyor, stationary door, and specialty machines.

Warewasher types: For lower volume operations stationary machines are most often used, while conveyer and flight type machines are best suited for high volume and institutional type operations. Specialty washers are designed for cleaning pots and pans and other items that would require hand washing.

> Sanitation and cost savings: Gas warewashers are designed to provide a high level of sanitation on a consistent basis and to offer significant cost of operation savings compared to electric models.

There is a large selection of gas-fired warewashers that will not only facilitate compliance with health codes and increase customer satisfaction, but also fit the operator's kitchen space, equipment budget, and production requirements.

- Finance your restaurant equipment purchase —Become an iBank small business member and network with one of their iBank lenders to work out a financing deal.

- Food equipment dealers —Search the comprehensive list of dealers for your natural gas equipment needs.

Staff/711
Kaufman/9

Comfort and Convenience

Natural gas is always there when you need it.

The comfort and convenience of natural gas are at your fingers with the flip of a button. Forget the wood-chopping, hauling and messiness that come with owning a wood-burning fireplace. Don't worry about running out of propane or charcoal briquettes. Natural gas is ready to perform when you need it.

Reliable

A properly maintained natural gas furnace will provide about 20 years of reliable service.

Efficient performance

Natural gas provides instant heat with an adjustable temperature that can be controlled on gas cook tops or ranges and by thermostats

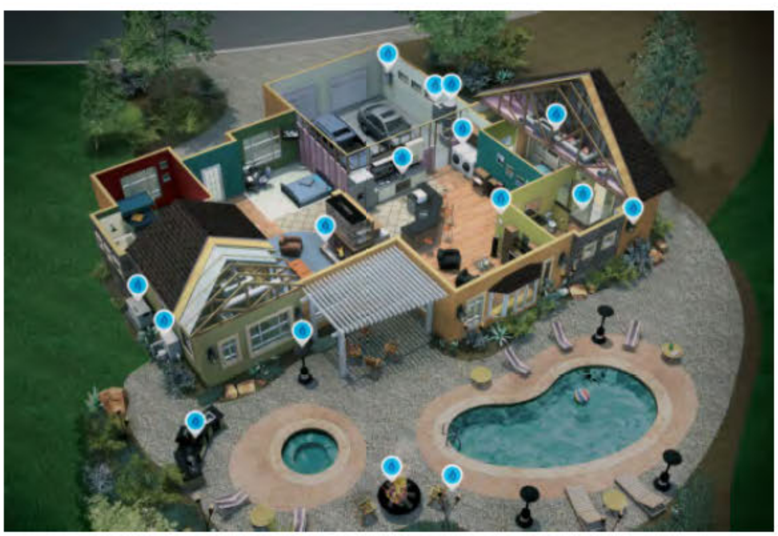
Natural gas water heaters reheat water about twice as fast as electric models-an economical approach that also means less waiting for hot showers in the mornings.

Comfortable

The temperature of gas heat at the register is between 110 and 120 degrees Fahrenheit, which warms your home quickly and efficiently.

Natural gas in your home

Endless hot water, high-efficiency heating and cooking indoors and outdoors are just some of the benefits of natural gas. Visit this virtual doll house to learn about the variety of natural gas uses in a home.



Power outage? —Most natural gas appliances allow you to bathe, cook or stay warm without interruption. See why.

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 712

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff/712
Kaufman/1

Delivering More Natural Gas Capacity to Oregon's Willamette Valley

POSTED ON SEPTEMBER 15, 2012 | POSTED IN: ALL NEWS FEED

GeoEngineers is providing a full suite of services for Northwest Natural's Mid-Willamette Valley Feeder project. The company's ambitious natural gas pipeline improvements will increase capacity of a major pipeline by 25 percent to serve the energy needs of the rapidly growing population of Oregon's Willamette Valley. Stretching 150 miles south from Portland to Eugene, this scenic region is known for lush agricultural lands and award-winning vineyards, and also encompasses the state's largest population centers.

The Mid-Willamette Valley Feeder project was the cover story of the autumn 2012 issue of *Underground Utilities* magazine. The article describes the geological characteristics that GeoEngineers' studies revealed and details the pipeline installation techniques being employed for each stage of the project.

Led by Pipeline Group Manager and Principal Engineer Trevor Hoyles, PE, LEG (Salt Lake City, UT) and Project Manager and Senior Geologist Brian Ranney, RG, CEG, LG, LEG (Portland, OR), a team of specialists from GeoEngineers' Portland office have provided geologic hazard assessments, pipeline routing support, HDD design and feasibility, erosion-control plans and permitting services. CAD Technician Ben Lane (Springfield, MO) has generated all of the AutoCAD® drawings for the project and assisted with HDD design support. Staff from the Spokane and Redmond (WA) offices and the Springfield (MO) office also assisted during the subsurface exploration phase.

In addition to the geologic hazard studies, routing support and HDD feasibility services the team completed at the start of the project, they have contributed their expertise to every segment of the pipeline. Their work has included subsurface investigations, lab testing, and wetland- and erosion-control plan development. For the Perrydale segment, they also provided Polk County flood plain permitting support.

For the final Willamette crossing segment now in progress, GeoEngineers' team is designing three HDD crossings of Highway 20, existing rock quarries and the Willamette River. When all is said and done, the improved pipeline will include 32 Geo-Engineers-designed HDD crossings under roadways, railroads, streams, rivers and wetlands.

Staff/712
Kaufman/2

The Mid-Willamette Valley Feeder project began in 2009 and will wrap up in 2013. Reflecting on its challenges and successes to date, Brain Ranney said, "It has been a pleasure working with NW Natural and other members of the design team to solve challenging pipeline installation problems where the pipeline crosses culturally and environmentally sensitive areas as well as to use the HDD method of construction to lessen the impact to the environment and landowners along the alignment. To date, approximately 15 miles of pipeline have been installed, including 14 HDD segments ranging from 675 feet to 5,500 feet in length. I have a great sense of satisfaction knowing that GeoEngineers was instrumental in helping NW Natural achieve their pipeline installation goals thus far."

‹ PREVIOUS NEXT ›

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 713

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff/713
Kaufman1

Contemporary Project Management

Timothy J. Kloppenborg

Third Edition

organize / plan / perform

WILLAMETTE UNIVERSITY | MBA

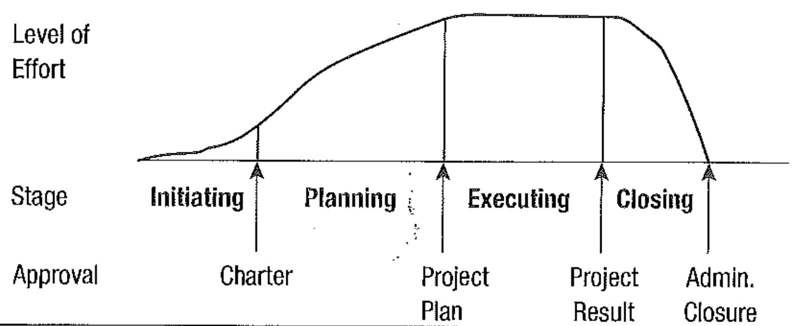
9-2b Accuracy and Timing of Cost Estimates

Project managers need to understand when cost estimates should be developed, how accurate they need to be, and how they will be used. During project initiation, many project managers need to develop cost estimates to have their project charters approved. At this point, very little detail is understood regarding the project, so the estimates are only approximate. However, as the scope becomes well defined in the work breakdown structure (WBS), schedules are planned, and specific resources are assigned, the project manager knows much more and can estimate more precisely. Many organizations have specific names and guidance for their estimates and these vary widely. Normally, estimates should be documented, and the level of confidence in the estimate should be described. Exhibit 9.4 shows several points regarding different types of project cost estimates.

ORDER OF MAGNITUDE ESTIMATES Several things should be noted from these comparisons. First, estimates go by several different names. For example, order of magnitude estimates that are often used to seek initial charter approval are also sometimes called "ball park," "conceptual," "initial," or "level-one" estimates. These early estimates are often created during the project initiating stage when very little detail is known about the project. At this point, a very rough order of magnitude estimate that could underestimate the project by as much as 100 percent (that is, the final cost could be double the initial estimate) may be the only possible estimate. There is no way to really know how accurate an estimate is until the project has been completed, but with less detailed knowledge concerning the project in the initiating stage, there is likely to be a larger margin of error. Order of magnitude cost estimates and the parallel high-level looks at each of the other planning areas can quickly give enough information to decide whether to approve the project charter and begin to invest time and money into detailed planning.

EXHIBIT 9.4

PROJECT COST ESTIMATE COMPARISONS



Estimate Name	Order of Magnitude	Budget	Definitive
Accuracy Level	−40% to +100%	−30% to +50%	−10% to +15%
Possible Method	Analogous	Parametric	Bottom-Up

← Rolling Wave →

CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 714

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 714

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CASE: UG 344
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 715

Exhibits in Support
Of Opening Testimony

April 20, 2018

Staff Adjustment NWN
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019

		TEST YEAR			TEST YEAR			Staff Adjustment
	Normalized Therm Deliveries	Average Class Price Per Therm	Normalized Revenues and Margin	Normalized Therm Deliveries	Average Class Price Per Therm	Normalized Revenues and Margin		Normalized Revenues and Margin
	(d)	(e)	(f)	(d)	(e)	(f)		(g)
Revenues								
Sales Volumes and Revenues								
1 **Residential**	385,050,429	1.00706	$387,770,097	381,736,948	1.00838	$384,934,521		($2,835,576)
2 **Commercial**	232,141,965	0.78444	$182,100,457	250,157,593	0.76645	$191,734,252		$9,633,796
3 **Industrial Firm**	32,708,089	0.61644	$20,162,497	34,959,579	0.61311	$21,434,145		$1,271,649
4 **Interruptible**	51,150,158	0.39066	$19,982,556	54,671,124	0.38938	$21,287,822		$1,305,266
5 **Total Sales of Gas Revenues**	701,050,641		$610,015,606	721,525,244		$619,390,741		$9,375,134
Transportation Volumes and Revenues								
6 **Firm**	96,582,618	0.08970	$8,663,501	103,230,968	0.08743	$9,024,973		$361,472
7 **Interruptible**	196,967,402	0.03145	$6,194,584	210,525,826	0.03114	$6,556,047		$361,463
8 **Special Contracts - Firm**	60,875,713	0.02403	$1,462,735	65,066,146	0.02248	$1,462,735		$0
9 **Special Contracts - Interruptible**	18,288,504	0.01783	$326,133	19,547,409	0.01668	$326,133		$0
10 **Total Transportation**	372,714,237		$16,646,954	398,370,348		$17,369,888		$722,935
11 **Total Deliveries and Revenues**	1,073,764,878		$626,662,560	1,119,895,592		$636,760,629		$10,098,069
12 **Decoupling**			$12,068,346			$12,204,664		$136,318
13 **WARM Base Period**								
14 **Total Revenue**			$638,730,906			$648,965,293		$10,234,386
Gas Costs								
15 **Demand Charges**			$76,015,833			$78,028,966		$2,013,133
16 **Commodity Charges**			200,837,676			206,730,088		5,892,412
17 **Total Cost of Gas**			$276,853,509			$284,759,054		$7,905,545
18 **Total Margin**			$361,877,397			$364,206,239		$2,328,841

CASE: UG 344
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

April 20, 2018

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to specific issues in Northwest Natural Gas Company's request for general rate revision. I present Staff's recommendations regarding the rate treatment of the following expenses: gas storage; working gas supply; plant maintenance; distribution O&M; research and development; and customer service expense; and the environmental rider.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/801, my witness qualification statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your recommendations regarding each of these issues.

A. The following table summarizes the Company request and Staff's proposed adjustment for each issue:

Table 1 (000's of Dollars).

	Issue	Company Request	Staff Adjustment
1	Gas Storage (non-labor O&M))	$1,719	($122)
2	Working Gas Inventory (rate base)	$35,373	$0
3	Plant Maintenance (non-labor O&M)	$2,087	($93)
3	Distribution O & M (non-labor O&M)	$13,086	($2,148)
5	Research and Development	$661	$0
6	Customer Accounts Expense	$5,320	($357)

ISSUE 1. Gas Storage Expense

Q. What is gas storage expense?

A. For purposes of this testimony, gas storage expense is expense recorded in FERC Accounts 814 (operation supervision and engineering), 816 (wells expenses), 818 (compressor station expenses), 819 (compressor station fuel and power), 820 (measuring and regulating station expenses), 821(purification expenses), 832 (maintenance of reservoirs and wells), 840 (operation, supervision and engineering – other storage), 845 (power/fuel/rents – other storage), and 847 (maintenance – LNG terminal and processing).

Q. Please summarize Northwest Natural's proposal related to gas storage expense.

A. As with all of its operations and maintenance expense, the Company proposes to begin with the total gas storage operating expense from actual expenses incurred January through October of 2017 in addition to a forecast of the expenses for the remaining three months of 2017 to develop the total base year expenses.[1]

Q. Please summarize the Commission's historical treatment of gas storage operating expense.

A. I was unable to find a Commission order specifically addressing how to determine the proper amount of gas storage operating expense that should be included in the revenue requirement.

Q. What is your recommendation?

[1] NW Natural/600, Moncayo/2.

A. My recommendation is based on my review of NW Natural's actual gas storage operating expense for the previous three years.

Q. Please summarize your analysis.

A. I reviewed the Company's response to the Standard Data Requests (SDRs) 57 and 58. SDR 57 requested a transactional detail including these accounts, and SDR 58 requested expenses at the FERC account level for both non-labor expenses and total expenses including labor costs. I also reviewed the Company's responses to Staff DRs 183 and 315, which requested historical FERC account level detail going back to 2010.

In reviewing the transaction level detail in response to SDR 57, I discovered that a significant amount of transaction description detail was missing, and therefore I could not identify what many of the expenditures are for. The Company responded by supplying most of the missing detail. It should be noted that a significant portion of Northwest Natural's gas storage operating expenses is for items related to meals, entertainment, travel and gifts. These expense categories in all FERC expense accounts are reviewed and adjusted by Staff witness Kathy Zarate in Exhibit 1000, so I do not address them here. After reviewing individual transaction detail and excluding the meals, entertainment, travel, and gifts categories, I determined that the remainder of the spending appeared to be appropriately related to operating expense.

Next I looked at the expenditures in terms of total expense vs. non-labor expense. Total expenditures for gas storage and operating expense decreased slightly from the $2.87 million 2017 actual expense 2017 to the $2.70 million forecast for the test year. Labor costs across the Company are addressed separately by Staff witness Marianne Gardner in Exhibit 100. Therefore I focused my adjustment on non-labor expenses. Non-labor expenses are projected to increase from $1,649,464 in the base year to $1,719,484 in the test year, an increase of approximately four percent.

Q. Please summarize your proposed adjustment to gas storage operating expense.

A. I propose to reduce Northwest Natural's gas storage operating expense by $122,000, from $1,719,000 to $1,600,000. The $1,600,000 reflects a three-year moving average value.

<u>Issue 2. Gas Storage in Rate Base</u>

Q. Please describe the gas storage in rate base at issue.

A. Storage gas consists of two components, "cushion gas" and "working gas inventory." Cushion gas is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. Working gas inventory is the gas that flows in and out of the storage reservoir (or Liquid Natural Gas (LNG) tank) to serve customer loads.

Q. Please summarize Northwest Natural's and your proposed rate treatment of the Company's gas storage costs.

A. Northwest Natural includes $35,373,000 for gas storage in its rate base.[2] This component of rate base is based on a 13-month average of stored gas

[2] Exhibit NW Natural/202, McVay/1.

supplies of both cushion and working gas. Northwest Natural derived its test year inventory by starting with the October 31, 2017 storage volume and price balances and then modeling the injections and withdrawals on a monthly basis through the end of the test year. Staff supports including the cost of working gas inventory in rate base. Staff does not recommend an adjustment to the amount included in rate base as proposed by Northwest Natural.

Q. Please summarize the Commission's historical treatment of gas storage in rate base.

A. Staff has previously testified that its "analysis in Docket No. UM 1651 showed that year-to-year variations in average annual gas storage are caused by variations in weather from that forecasted and spot market gas prices falling below the average cost of gas in storage."[3] Staff's analysis in that docket and this one shows that the amount of gas a utility may include in rate base should be calculated using average working gas inventory balances for a recent or a forecasted 12-month time period. Staff supports using the most recent three-year moving average to calculate average annual gas storage.

Q. Did you issue data requests to Northwest Natural about the working gas inventory issue?

A. Yes. Staff issued DR No. 184 to the Company regarding monthly storage inventory levels as well as the monthly storage guideline for each storage facility. Based upon Northwest Natural's responses to DR No.184, the gas is valued at its cost when placed in the reservoir.

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[3] *In the Matter of Avista Corporation,* OPUC Docket No. UG 288 Staff/700, Colville/4.

Q. Please summarize Staff's analysis.

A. Staff's recommendation is based on review of Northwest Natural's actual gas storage in rate base for the previous three years. The most recent three-year moving average value is $47,788,270, which is significantly more than the amount of $35,373,000 Northwest Natural proposes to include in the test year. As a result, I do not recommend an adjustment.

Issue 3. Distribution O&M and General Plant Maintenance

Q. Please describe "distribution O&M and general plant maintenance.

A. Distribution O&M (operations and maintenance) refers to those expenses and activities recorded in FERC accounts 870-894, and include operation, supervision and engineering, distribution load dispatching, compressor station and regulator station expenses and customer installations expenses. General plant maintenance refers to expenses recorded in FERC account 935 and contains costs associated with customer accounts, sales and administrative, as well as labor and materials used in the maintenance of general property such as structures and improvements, office furniture and equipment.

Q. Please summarize Northwest Natural's proposal related to distribution O&M and general plant maintenance.

A. The Company proposes to include $47.55 million in distribution O&M expenses in the test year. Excluding labor expense, the Company proposes to include $13.09 million, an increase of 5.71 percent over the base year non-labor expense of $12.40 million. For general plant maintenance, the Company includes $4.50 million total expense, and $2.1 million in non-labor expense.

This represents a 4.0 percent increase over the $2.0 million base year expenditure.

Q. Please summarize your review of distribution O&M and plant maintenance expense.

A. First, I reviewed the line-item transaction detail the Company provided in its response to SDR No. 57. As with the gas storage expense accounts, these accounts were also missing a significant amount of descriptive detail. Once the Company supplemented its response, I was able to review the expenses and determine that – except for meals, entertainment and gifts categories addressed by Kathy Zarate in Staff Exhibit 1000 – the itemized expenses appear to be appropriate to the Company's operation. Next, I reviewed long-term and three-year trends of these expenses.

Q. What is your recommendation for these expense accounts?

A. The three-year average for distribution O&M is approximately $10.9 million. I recommend adjusting the Company's proposed test year expenses by $2.1 million to reflect this three-year average. The three-year average for plant maintenance is approximately $2 million. I recommend adjusting the Company's proposed test year expenses by $113,000 to reflect this three-year average.

Issue 4. Research and Development

Q. Please describe research and development and explain the Company's proposal.

A. Research and development (R&D) expenses are recorded in FERC account 930. Northwest Natural partners with non-profit utility organizations that conduct research, development and testing projects to develop and improve a variety of energy-efficient, cost-effective technologies to serve gas customers. For the 2018 test year, the Company projects $661,375 expenses in contributing to these projects, which include seismic preparedness research, compressor testing, gas hydrogen production projects.

Q Describe Staff's review of these expenses.

A. I reviewed the Company's response to Staff DR No. 320 requesting identification of all R&D expenses and justification for their inclusion in customer rates. The Company provided descriptions of all the projects and expenses, and explanation of the non-profit trade R&D groups they participate in. I also reviewed the last three years' expenses.

Q. What is your recommendation regarding R&D expenses?

A. I do not recommend any adjustment to the Company's proposal. The inclusion of $661,375 in 2018 test year expenses is below the most recent three-year average expenditure of $700,587. Further, the projects being funded appear to be appropriate in terms of providing value and benefit to gas customers.

Issue 5. Customer Accounts Expense

Q. Describe customer accounts expense.

A. Customer accounts expenses are recorded in FERC accounts 901-903. These accounts are associated with the labor and supervision of customer accounting and collecting activities.

Q. Summarize the Company's proposal and Staff's review.

A. The Company includes approximately $18.2 million total expense in its 2018 test year, a 4.5 percent decrease over 2017 base year expenses. However for the non-labor portion of expense, the amount of $5.32 million test year expense represents a four percent increase over the base year expense. The most recent three-year average for non-labor expense is approximately $4.964 million.

Q. What is Staff's recommendation regarding customer accounts expense?

A. I recommend a reduction of $356,517 to the test year expense to reflect the most recent three-year average.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 344
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

April 20, 2018

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

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's proposed adjustment to NW Natural's dues and memberships expenses. The proposed adjustment I recommend is derived from review of multiple data requests, analysis of NW Natural's 2017 Operation and Maintenance non-labor transactions, and Commission dues and memberships policy.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/902, my electronic workpaper that supports my adjustment.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. DUES AND MEMBERSHIPS

Q. Please summarize your adjustment.

A. I recommend the following adjustment (Oregon-allocated):

Dues and Memberships ($451,525)

Q. What expense does NW Natural include in test year expense for dues and memberships?

A. NW Natural's test year expense for dues and memberships is based on NW Natural's actual expense for 2017 and escalated for 2018 and the first ten months of 2019.

Q. What is the basis of your adjustment to this non-labor operation and maintenance expense?

A. This adjustment to non-labor operation and maintenance expenses is regularly proposed by Staff in general rate cases, and its purpose is to share membership and dues expenses between stockholders and ratepayers.

Q. Please explain the dues and memberships adjustment.

A. This adjustment is to NW Natural's dues and memberships expenses recorded to non-labor FERC accounts 832 through 935 provided in electronic spreadsheet format by NW Natural in its confidential response to Staff Data Request No. 57, Attachment 1 Supplement 3, 2017 OM Transactions.[1] Staff used NW Natural's 2017 transactional expenses for the Oregon allocated non-labor expense for each FERC account and then escalated to

[1] The data in the Company's confidential response to Staff Data Request No. 57 is too voluminous to include as an exhibit. However, Staff does include data showing the FERC account totals for each account as Exhibit Staff/902, Rossow/1.

approximate the test year expense by applying the Company's escalators. Staff first escalated by 2.3 percent for twelve months, which is the escalation factor for the year 2018. Staff further escalated these amounts by 2.0 percent (2.4% x 10/12) to arrive at the test year amount. Both of these CPI escalation factors were referenced by the Company in its response to Staff Data Request No. 382.[2]

Then Staff searched for dues and memberships by using the cost element name and descriptions provided by the Company in its confidential response to Staff's Standard Data Request No. 57. Staff sorted these expenses by cost element and description.

Keeping with Commission policy regarding dues and memberships for organizations in the energy utility industry, Staff recognized all the expenses associated with industry research organizations. The Gas Technology Institute is one such organization.

Staff recognized a disallowance of 25 percent of the expenses associated with national and regional industry organizations on the basis that certain levels of activities are lobbying or promotional in nature, or otherwise do not benefit ratepayers. This represents a sharing of interests between stockholders and ratepayers in these organizations. An example of this type of organization is the American Gas Association, which advocates and promotes the benefits of natural gas.

[2] *See* Company's response to Staff Data Request No. 382 (the CPI escalated factors used can be found on Page 43 of the Portland-Salem Consumer Price Index reported in the September 2017 Oregon Economic and Revenue Forecast published by the Oregon Office of Economic Analysis).

Finally, Staff applied a 100 percent disallowance of the expenses associated with technical, professional, commercial, trade, community affairs, and economic development organizations.

Table 1 summarizes the cost elements that were identified, the total Oregon allocated amount for FERC accounts 832 through 935, and the disallowed amount:

Table 1. Cost Elements Adjustment by Staff

Cost Element	Total $ Oregon Allocated Amount	Disallowed Amount
Dues/Membership	943,656	428,761
Dues and Memberships that are not recorded to the Dues/Membership Cost Element	611,976	22,764
Total	1,555,632	451,525

Table 2 below indicates the proposed amount to be disallowed from each FERC Account.

Table 2. Disallowed Amounts by FERC Account

FERC Account #	Proposed Disallowance ($)
832	26
844	94
856	3
870	10,621
874	118
879	1,100
885	5,986
887	336
889	47
903	40,080
908	20,451
909	3,241
911	402
912	17,090
913	1,411
921	287,840
925	48
926	992
930	61,108
935	531
Total	451,525

These calculations resulted in an Oregon allocated test year adjustment of ($451,525).

Q. Is it possible that Staff will have an adjustment to PGE's escalation of costs?

A. Yes. Staff witness Gardner is examining the escalation rates used by the Company and may propose an escalation adjustment.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 344
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources & Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem OR 97301
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, and UM 1818. I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UG 344
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 902

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CASE: UG 344
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

April 20, 2018

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

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Staff adjustments to the expense Northwest Natural Gas Company (NW Natural, NWN, or the Company) includes in the test year for meals and entertainment, travel, and awards and any gains on sales of utility property that the Company includes in rate base.

Q. What exhibits do you include as part of your testimony?

A. I have prepared the following exhibits:

Exhibit 1001—Witness Qualifications Statement
Exhibit 1002—Company response to Staff Data Request No. 57, regarding meals and entertainment.
Exhibit 1003—Company response to Staff Data Request Nos. 133-135, regarding any gain or loss on a property sale and how such gains or loss could benefit or harm of Oregon Customers.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MEALS, TRAVEL AND AWARDS

Q. Please discuss your review of meals, travel, and awards expense.

A. The Company's 2018 test-year estimate for meals, travel, and awards (MTA) expense is based on the 2017 unadjusted expenditures of $ 2,614,689. Staff reviewed the unadjusted expenses incurred by the Company in 2017, to identify expenses of the type that should not be included in retail rates. Expenses that are discretionary and are not required to provide safe and adequate service to customers are typically excluded from rates.

Q. Please discuss how you reviewed meal, travel, and award expenses.

A. Staff reviewed the Company's response to Staff's Standard Data Request No. 57 and created a Spending Summary for categories of expense, including account numbers[1] and object descriptions, to aid in Staff's analysis of meals and entertainment (meals), awards, and travel expense. The results are summarized in Table 1.

[1] Exhibit Staff/1002 Work Paper.

Table 1. Meals, Travel, and Awards Expenses (A&G and O&M)

Spending by Cost Element		
Element		Spending
Meals and Entertain	$	495,599.56
Meal Tickets	$	171,735.31
Meal Tickets ZTSFO	$	(40,003.56)
Refreshments	$	116,112.96
Employee Awards	$	393,365.05
Employee Awards MLS &	$	97,346.49
Non Employee Gifts	$	5,054.88
Business Travel	$	320,574.73
Conference Travel	$	553,222.88
Mileage Reimb STFSO	$	(30,498.03)
Mileage Reimburse	$	205,609.48
Mileage Reimbursemnt	$	17,823.97
Travel in Territory	$	193,036.71
Sub-Total	$	2,498,980.42

Additional Spending by Keyword	
Keyword	Spending
Meal	1,133.44
Snack	1,129.14
Coffee	24,044.15
Breakfast	2,947.14
Lunch	25,239.40
Dinner	9,479.06
Award	6,844.39
Gift	32,478.52
Prize	1,419.89
Travel	4,589.68
Airport	6,403.95
Sub-Total	115,708.75

Q. Please discuss your review of award expenses.

A. Staff removed the entire expense amount of $536,509 related to awards, gifts and prizes consistent with Staff's practice in previous rate cases.

Q. How does Commission policy typically treat meal expense?

A. Commission policy regarding expense for meals requires a 50 percent sharing between customers and shareholders because such expenses are discretionary and not required to provide safe and adequate service to customers.[2] Therefore, Staff recommends a 50/50 sharing adjustment to the Company's meals expense, resulting in the net adjustment (Oregon-allocated) of $506,673 as shown in Table 3.

Q. How did Staff analyze travel expenses?

A. Staff filtered spending by cost element - business travel, conference travel, and travel in territory - and then filtered by vendor to review entries that were charged to PCards, as these typically contained clear descriptions of spending. These results were sorted into two categories: Travel entries over $1000 and travel entries under $1000. Entries over $1000 were allowed by Staff based on Staff's judgment of whether the description of the entry supported its inclusion in rates.

Due to the large number of travel entries under $1000, Staff took a random sampling of 35 entries and determined the portion of that sample containing a description that supported the entry's inclusion in rates. Based on the initial sampling, Staff determined that 13 percent of the travel entries did not support inclusion in rates. Staff applied the 13 percent adjustment for all PCard spending for travel under $1000, for each cost element.

After completing this process for travel entries charged to PCards, Staff Staff excluded PCard entries and conducted similar analysis on the remaining travel spending. The entries for items not charged to PCards were far less consistent in having descriptions that supported inclusion in rates. The same random sampling method referenced above resulted in 95 percent of entries

[2] *See* OPUC Order No. 09-020 at 21.

not supporting inclusion into rates. Therefore, those entries over $1,000 lacking sufficient business description were disallowed at 100 percent. Those under $1,000, absent clear evidence of misuse of funds, Staff does not believe it is reasonable to assume 95 percent of all entries are incorrect, and recommends a flat adjustment of 50 percent for these entries.

Staff repeated this analysis for each cost element related to travel. The results of the analysis are summarized in Exhibit Staff1002. Staff recommends adjusting the Company's test year travel expense of $1,066,834 downward by $305,775, as detailed in Table 3 below.

Q. Please provide a summary table showing the Staff's adjustment to travel expense.

A. Staff's summary table of the travel expense adjustment is below.

Table 2. Travel Expenses (A&G and O&M)

Cost Element/Filter	Total Spending	Oregon Allocated	Adjustment %	Staff Adjustment	Oregon Allocated
Business Travel (Descriptive > $1K via PCard)	$ 40,939.32	$ 36,869.76	NA	$ -	$ -
Business Travel (Non-Descriptive > $1K via PCard)	$ 1,490.76	$ 1,330.57	100%	$ 1,490.76	$ 1,330.57
Business Travel (Total < $1K via PCard)	$ 127,295.70	$ 114,911.30	13%	$ 16,548.44	$ 14,938.47
Business Travel (Descriptive > $1K via Manual Entry)	$ 24,943.34	$ 22,310.43	NA	$ -	$ -
Business Travel (Non-Descriptive > $1K via Manual Entry)	$ 102,050.17	$ 91,693.28	100%	$ 102,050.17	$ 91,693.28
Business Travel (Total < $1K via Manual Entry)	$ 59,519.55	$ 53,459.39	50%	$ 29,759.78	$ 26,729.70
Conference Travel (Descriptive > $1K via PCard)	$ 170,675.97	$ 152,909.85	NA	NA	NA
Conference Travel (Non-Descriptive > $1K via PCard)	$ 2,201.49	$ 2,040.83	100%	$ 2,201.49	$ 2,040.83
Conference Travel (Total < $1K via PCard)	$ 257,648.82	$ 231,374.04	13%	$ 33,494.35	$ 30,078.63
Conference Travel (Descriptive > $1K via Manual Entry)	$ -	$ -	NA	$ -	$ -
Conference Travel (Non-Descriptive > $1K via Manual Entry)	$ 27,624.34	$ 24,779.06	100%	$ 27,624.34	$ 24,779.06
Conference Travel (Total < $1K via Manual Entry)	$ 157,792.34	$ 142,119.10	50%	$ 78,896.17	$ 71,059.55
Travel In Territory (Descriptive > $1K via PCard)	$ 42,416.72	$ 37,901.56	NA	$ -	$ -
Travel In Territory (Non-Descriptive > $1K via PCard)	$ 1,043.00	$ 930.51	100%	$ 1,043.00	$ 930.51
Travel In Territory (Total < $1K via PCard)	$ 127,786.32	$ 115,248.12	13%	$ 16,612.22	$ 14,982.26
Travel In Territory (Descriptive > $1K via Manual Entry)	$ 2,167.30	$ 1,934.42	NA	$ -	$ -
Travel In Territory (Non-Descriptive > $1K via Manual Entry)	$ 19,232.96	$ 17,402.97	100%	$ 19,232.96	$ 17,402.97
Travel In Territory (Total < $1K via Manual Entry)	$ 21,758.86	$ 19,619.14	50%	$ 10,879.43	$ 9,809.57
Total Travel Spending	**$ 1,186,586.96**	**$ 1,066,834.33**		**$ 339,833.11**	**$ 305,775.40**

Q. Please provide a summary table showing the total MTA adjustment.

A. Staff's summary table of the MTA expense adjustment is below.

Table 3. Meals, Travel, and Awards Expenses (A&G and O&M)

		Adjustment Summary				
		Total Spending by Company	**Staff proposed disallowance**		**Total Staff Adjusment**	
					2,614,689.17	
Meal Spending		1,011,345.63	50%	505,672.82	-505,672.82	
Travel Spending		1,066,834.33	Mixed	305,775.40	-305,775.40	
Awards Spending		536,509.21	100%	536,509.21	-536,509.21	
	Total	2,614,689.17		1,347,957.43		
					$1,266,732	

ISSUE 2. GAINS ON SALES OF UTILITY PROPERTY

Q. Please discuss your review of gains on sales of utility property

A. For my review of NWN's treatment of gains on utility property sales within this general rate case filing, I took several actions. I reviewed NW Natural's recent history of property sales filings before the OPUC, spoke with NW Natural personnel, and sent four formal Staff Data Requests. I note that NW Natural's responses to my data requests were on time, responsive to the questions asked, and comported with the independent review that I conducted.

Q. What is the historical treatment for property sales?

A. In the order approving the acquisition by, what is now, NW Natural of CP National's Oregon territory, the OPUC authorized NW Natural to use any gains from property sales to reduce its acquisition adjustment (merger premium). This relatively unique authorization ended in 2012. For property sales since 2012, the appropriate treatment is to pass property sales gains directly to customers.

NW Natural has had only one property sales transaction since 2016. NWN explained in a response to a Staff Data Request that it has already returned the net gain to customer through the Schedule 178 "Regulatory Adjustment Rate."[3] Staff confirmed that this return had in fact occurred. Therefore, no adjustment is required for this issue.

Q. Did you make any adjustments to NW Natural Company's test-year to account for gains on property sales?

[3] *See* Staff/1003, NWN Response to Staff DR No. 134.

A. No. As discussed above, none was required.

Q. Does this include your testimony?

A. Yes.

CASE: UG 344
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals. I have approximately 10 years of professional experience in contracting and audit review work, including: • Six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft.

CASE: UG 344
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 1002

PROVIDED IN ELECTRONIC FORMAT ONLY

CASE: UG 344
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 133

133. Has the Company sold any utility property since the effective date for rates in the last rate case? If so, please describe the transaction and provide any gain or loss on a property sale and the account in which it was recorded.

Response:

The Company has sold four utility properties since the effective date for the last rate case:

1. South Center Resource Center
2. Tualatin Resource Center
3. A portion of the Central Property (Portland)
4. 1,250 square feet of improved land on NW 30th Avenue (Portland)

Please see OPUC Order No. 12-299 (Docket UP 280) for a description of the transaction and treatment of the gains associated with the sale of the Company's South Center Resource Center.

Please see OPUC Order 13-196 (Docket UP 287) for a description of the transaction and treatment of the gains associated with the sale of the Company's Tualatin Resource Center properties.

Please see OPUC Order No. 13-358 (Docket UP 290) for a description of the transaction and treatment of the gains associated with the sale of a portion of the Company's Central Property in Portland.

Please see Docket UPN 24, for a description of the transaction and the treatment of the gains associated with the sale of the improved land on 30th Ave. The net gain on the property sale was booked to a regulatory deferred account, Account 254305.

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 135

135. For any net gains identified in the Company's response to the two data request above, please note whether and to what extent each of such gains from the respective transactions were used to reduce plant in service or otherwise provided to the benefit of Oregon customers. If not, for each such transaction, explain why such gains were not flowed through to the benefit of Oregon customers.

Response:

Please see OPUC Order No. 12-299 (Docket UP 280) and OPUC Order No. 13-196 (Docket UP 287) for the treatment of the gains associated with the sale of the Company's South Center Resource Center and Tualatin Resource Center properties.

Please see OPUC Order No. 13-358 (Docket UP 290) for the treatment of the gains associated with the sale of a portion of the Company's Central Property in Portland.

Please reference Docket UPN 24 for the treatment of the gains associated with the sale of Company property in NW Portland.

In each case where there was a gain on property sale, NW Natural returned the net gain to customers through the Schedule 178 "Regulatory Adjustment Rate" in the annual Purchase Gas Adjustment (PGA) mechanism filing for the gas year following the sale.

CASE: UG 344
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

April 20, 2018

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

A. My name is Ming Peng. I am a Senior Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. I discuss my review of the depreciation expense and accumulated depreciation (depreciation reserve) portions of Northwest Natural Gas Company's (NW Natural or Company) revenue requirement for this rate case as documented by the Company witness Kevin McVay in NW Natural/200. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. What exhibits are included as part of your testimony?

A. I have prepared the following exhibits: Exhibit Staff/1101, witness qualification statement, and Exhibit Staff/1102, NW Natural Response to Staff Data Request (DR) Nos. 218-222.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ANALYSIS OF DEPRECIATION FROM A RATEMAKING PERSPECTIVE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

The statement above defines "depreciation" from a valuation perspective. From an accounting perspective, "depreciation" is a capital recovery concept. It is the allocation of the cost of fixed assets less net salvage to accounting periods. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep

[1] NARUC, *Public Utility Depreciation Practices*, p.318 (1996).

> such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate (1) the combination of survivor curve-service life (Curve-Life) of utility property, and (2) Net Salvage (gross salvage – cost of removal) ratio. Depreciation rates are based on these two fundamental depreciation parameters and other required elements, such as asset value, asset remaining life, and depreciation method.

OAR 860-027-0350(2) requires that each energy utility file a new depreciation study with the Commission no less frequently than once every five years. NW Natural filed its most recent depreciation study in 2017, which the Commission reviewed in Docket No. UM 1808. At the conclusion of that docket, the Commission issued Order No. 18-007 authorizing the Curve-Life and Net Salvage parameters for "each plant account" (FERC account), from which depreciation rates are derived for each account.

Q. What depreciation rates did NW Natural use in its test year revenue requirement?

A. NWN used two sets of depreciation rates in this filing. For the period ending October 31, 2018, the Company used depreciation rates based on parameters established in Order 08-578 from Docket No. UM 1335. For the period starting on November 1, 2018, the Company used the rates based on the depreciation study reviewed by the Commission in Docket No. UM 1808.

Q. Why did NWN use two different sets of depreciation rates?

A. NWN explained that it used November 2018 as the effective date for its new depreciation rates "per Commission Order 18-007," in Docket No. UM 1808, which states "NW Natural agrees to change its depreciation rates on its books and move the depreciation rates into customer rates at the same time rates are effective in the company's next general rate case, which NW Natural filed on December 29, 2017, docket UG 344."[2] NW Natural explains that "[g]iven a 10-month rate case process, the effective date of rates in UG 344 is expected to be November 1, 2018."[3]

Q. Does Staff agree the Company appropriately used two sets of depreciation rates?

A. Yes.

Q. How did you analyze the Company's proposed depreciation expense, and what information did you review?

A. To confirm that the depreciation expense was properly calculated using the authorized depreciation parameters in Commission Order 18-007, Staff sent the Company data requests asking NWN to insert data links to its Excel work paper 200, to enable Staff to verify such data as (1) plant balance, (2) depreciation rates, (3) depreciation expense, (4) depreciation reserve, and (5)

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2 See Staff/1102, NWN Response to Staff DR No. 219.

3 Staff/1102, NWN Response to Staff DR No. 219.

Oregon allocation factors, all of which tie to the revenue requirement model, to allow Staff to trace the data calculation from proposed data sources.[4]

Upon receiving the Company's responses, Staff verified the Company's calculations by reviewing:

(1) the Excel-files and checking the reference links, formulae, and calculations provided in these files;

(2) how the Company calculated depreciation expense using the depreciation parameters authorized in Order 18-007; and

(3) how the Company calculated the depreciation expense and depreciation reserve adjustments.

Staff also conducted several phone conferences with Company witness Kevin McVay to gain a better understanding of NW Natural's depreciation adjustments.

Q. Are there any errors in the Company's original filing with respect to depreciation?

A. Yes. In preparing its response to Staff DR No. 218, the Company detected depreciation rate data entry errors and other plant balance and amortization related mistakes when it tried to link the data and calculation references from the Company's original filing. After several conference meetings with NWN, the Company sent a "DR 218 Update Narrative" on March 23, 2018, and explained that two types of data errors were identified in original filing. The first type of data errors was the use of incorrect depreciation rates. For example,

[4] See Staff/1102.

the FERC account 391.2 - Computers, mistakenly used four percent instead of the authorized 20 percent. Also, some other data entry errors were detected when applying the new depreciation rates from the Order 18-007.

The second type of data errors related to the implementation of the amortization method for twelve FERC account categories in the General Plant area. For example, the amortization included negative adjustments (negative means over amortized expense and should reduce the rate base) shown on page 13 of the Appendix A attached to the Order in UM 1808 (Order 18-007). Those adjustments totaling $1,241,386 annually are included as a reduction in depreciation expense as shown on the “Expense” tab of Attachment 2 (lines 158 to 170), and the monthly amounts are included as reductions starting in November 2018.

In its response to Staff DR No. 218, the Company provided a corrected version of linked files (“UG 344 OPUC DR 218 Attachment 1 Revenue Requirements Model – Linked”; “UG 344 OPUC DR 218 Attachment 2 – Gross Plant and Accum Deprec – Linked”; “UG 344 OPUC DR 218 Attachment 3-Allocation Factors– Linked”). The Company explained that “Gross Plant and Accum Deprec, Depreciation Rates, and Depreciation Expense files referenced above have now been combined into a single file named ‘UG 344 OPUC DR 218 Attachment 2– Gross Plant and Accum Deprec – Linked’”.

NWN also provided in its Staff DR No. 218 response a table showing the difference between NWN’s filed case and the corrected case.

in $ 000		NWN Filed			NWN Corrected	
Description/ Account No.		Total Oregon	Adj.to base year		Total Oregon	Adj.to base year
Expense						
Depreciation & Amortization		$73,605	$2,193		$76,371	$5,009
Rate Base						
Accumulated Depr. & Amort.		$1,257,248	$114,192		$1,244,909	$101,861

Q. Has the Company made adjustments to its filing to correct the errors?

A. Yes. On March 22, 2018, NWN filed supplemental direct testimony that addressed the depreciation errors and updated its initially filed revenue requirement.

In summary, resulting from the data corrections from the supplemental filing, the Oregon test year "depreciation expense" will increase by $2.19 million from the originally filed $73.60 million to $76.37 million, and the Oregon test year "accumulated depreciation" will decrease by $12.34 million from originally the filed $1,257.25 million to $1,244.91 million.

Q. Did you identify additional errors after the Company's re-calculation of depreciation in its supplemental filing?

A. No. I did not find additional errors in the Company's calculation after the updated data information was submitted in its supplemental filing.

ISSUE 2. DEPRECIATION EFFECT ON REVENUE REQUIREMENT

Q. Describe the depreciation effect on the revenue requirement of a utility.

A. NARUC, in its "Public Utility Depreciation Practices" manual on "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[5]

Q. What is the relationship between depreciation and revenue requirement?

A. Under cost of service regulation, revenue requirement refers to the revenues the utility earns to recover the cost of providing service and to earn a reasonable return on its investment. To compute the revenue requirement (RR) (RR is measured by cost-of-service), a basic formula is followed:[6]

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

Depreciation is one of the largest items in the cost of service; therefore, depreciation is important as both an annual expense and as a reduction of rate base.

[5] NARUC, *Public Utility Depreciation Practices,* p.195 (1996).
[6] Federal Energy Regulatory Commission, *Cost-of-Service Rates Manual*, pp. 6-7 (1999), www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc

Q. How are depreciation parameters used in determining the utility's revenue requirement?

A. In a general rate case, the depreciation expense is calculated by using the Commission's authorized depreciation parameters, from which depreciation rates are derived, and traditional FERC classification of generation, transmission, distribution, and general plant assets.

Accumulated depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as depreciation expense. Accordingly, the depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the net book plant. The net book plant represents the portion of gross plant that is undepreciated.

Q. How is depreciation expense calculated in revenue requirement?

A. Depreciation expense, in revenue requirement, is determined by three factors: (1) depreciation rates, (2) plant in service, and (3) Oregon cost allocation factor. Depreciation rates were determined in OPUC Oregon Order No.18-007 in UM 1808.

Q. Please explain if the depreciation expense adjustment in this testimony is final.

A. The given depreciation rates are authorized under the Order No. 18-007. However, if any adjustments are made to test year plant in service or cost allocation factors, the final depreciation expense and accumulated depreciation would be changed accordingly.

ISSUE 3. REGULATORY CAPITALIZATION POLICY

Q. What is AFUDC?

A. AFUDC is Allowance for Funds Used During Construction and is defined as the cost of money used during construction. AFUDC is capitalized as part of Plant in Service.

Q. What is FERC AFUDC Capitalization Policy?

A. On March 18, 2010, in FERC Docket No. AI11-1-000, Accounting Release Number 5 (AR-5) (Revised), FERC,

> revised its AFUDC accrual policy to allow natural gas pipeline companies to begin accruing AFUDC on construction projects when the following two conditions are met: (1) capital expenditures for the project have been incurred; and (2) activities that are necessary to get the construction project ready for its intended use are in progress (AFUDC policy conditions).

FERC also explained that "AFUDC capitalization shall continue as long as these two conditions are present."

Q. Have you reviewed Northwest Natural's Capital Policy 83?

A. Yes. I reviewed Northwest Natural's Capital Policy 83.

Q. Please describe if NWN complied with guidance regarding the capitalization of assets based on FERC's and the OPUC's regulations in this filing?

A. In response of Staff DR Nos. 220-222, the Company provided detailed information about AFUDC and its accounting practices related to AFUDC contained in its Capital Asset Policy No. 83, effective October 6, 2016. On page 1, the policy states:

> This Policy outlines the Company's policy for budgeting, acquiring, and accounting for capital assets and provides guidance regarding the capitalization of assets based on the Federal Energy Regulatory Commission's (FERC) regulations and other related regulatory body guidelines (e.g. the Oregon Public Utilities Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC).

Page 3 of the policy states

> AFUDC is an allowance for interest and, if applicable, a return on equity to be capitalized on capital construction projects before they are put in service. AFUDC is a cost of capital rate that includes short term borrowing rates and, to the extent average annual construction work in progress costs exceed the average annual short-term borrowing amounts, long term borrowing rates and equity cost rates. The AFUDC debt and equity rates are calculated monthly using prescribed FERC calculations. Refer to FERC class of accounts in CFR Title 18 for more details.

Staff's DR No. 221 asked if the Company complied with FERC's Capitalization of AFUDC policy and meets two conditions of accruing AFUDC on construction projects. In the Company's data response, NWN stated that the Company has complied with FERC's Capitalization of AFUDC, and has met the two conditions of accruing AFUDC on all of its construction projects. NWN verified that AFUDC is only charged to the project when 1) capital expenditures for the project have been incurred, and 2) activities that are necessary to get the construction project ready for its intended use are in progress.

ISSUE 4. FERC AFUDC REQUIREMENTS

Q. Please describe the FERC formulas for calculating AFUDC.

A. The FERC AFUDC rate formulas are set forth in Electric Plant Instruction 3(17) in the FERC's Uniform System of Accounts Prescribed for Public Utilities and Licensees (18 C.F.R. Part 101). FERC has prescribed two formulas for calculating maximum allowable AFUDC rates. One formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes. The second formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes. The rates derived from each formula, added together, provide the total maximum allowable rate that can be used to capitalize AFUDC.

Q. Have you reviewed the Company calculation of its AFUDC rate?

A. Yes. I reviewed the Company's calculation of its AFUDC rate. I sent out DR Nos. 220-222 and asked the Company to explain in details whether the Company's calculation of its AFUDC rates complies with the FERC AFUDC rate formulas and accounting requirements.

Q. From your review, please describe how the Company's AFUDC rate calculations are conducted?

A. In response to Staff DR No. 220, NWN states: "AFUDC is a cost of capital rate that includes short term borrowing rates and, to the extent average annual construction work in progress costs exceed the average annual short-term borrowing amounts, long term borrowing rates and equity cost rates. The

AFUDC debt and equity rates are calculated monthly using prescribed FERC calculations."[7]

Along with providing the Excel calculation files, UG 344 OPUC DR 220-Attachment 1 and 2, NWN further explained that "[i]n the calendar years 2013 through 2016, and 2019 the average annual construction work in progress costs did not exceed the average annual short-term borrowing amounts."[8] NWN already provided data for 2017 and 2018. "As a result, the AFUDC Rate for those months reflects the monthly average short- term debt interest rate." NWN stated in its data response that "[t]he Company's calculation of its monthly AFUDC rates complies with the FERC AFUDC rate formulas and accounting requirements."[9]

Q. Do you think the Company's calculation of its AFUDC rates is in a manner consistent with FERC rules?

A. Yes. Staff reviewed Excel spreadsheet files with reference links and calculation formulas, and found that the Company's calculation of its AFUDC rates follow the FERC AFUDC rate formulas without deviation. The calculations assume that short-term debt is the first source of construction funding. If construction funding requirements exceed the balance of short-term debt, NWN assumes the requirements are met proportionally from long-term debt, preferred stock (if any) and common equity.

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[7] Staff/1102.
[8] Staff/1102.
[9] Staff/1102.

Q. Has the OPUC conducted a financial audit of the company's AFUDC accounting practices? Did the OPUC audit include a review of the company's AFUDC accounting practices?

A. Yes. I reviewed the Staff audit report. Staff auditors examined the Company's AFUDC rate calculations in their 2010 audit report and did not note a deficiency in its practices or any recommendations for corrective action to those practices.

Q. Have you made adjustment to NWN's AFUDC rate?

A. No. The Company's AFUDC policy and calculation are consistent with regulatory guidance.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 344
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION & TRAINING:
M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

300+ credit hours on 30+ topics trainings in public utility industry

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 18.5 years since January 1999. My roles include:
Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst
I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

Principal Analyst & Case Manager, Settlement Leader/Negotiator for Depreciation and Ratemaking:
For the "Depreciation Rate Determination" (fixed cost capital recovery), I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) and monitoring a significant piece of the revenue requirement for past 10 years.

In this position, I investigate, analyze and calculate "Energy Asset Retirement Cost & Impact" and "Power Plant Decommissioning Cost & Impact" on Customer Rates. I review, calculate, analyze fixed asset depreciation and propose depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on are Steam/Coal, Hydraulic, Natural Gas, Wind, Solar and Geothermal.

My analyses of "Power-Plant-Shutdown" activities include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215),
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316)
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809)

I conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for cost of capital, mainly debt capital analysis for nine years. My responsibilities included: review and analyze regulatory policy on Cost of Capital and Market Risks from utility's financial applications for their Derivative Instruments & Hedging Activities and Capital Raising Activities.

I advised the Commission on over 60 Financial Dockets and obtained the Commission Orders.

I passed the certification test offered by "Society of Utility and Regulatory Financial Analysts", become a "Certified Rate of Return Analyst" in 2002.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of "PacifiCorp vs. MidAmerican Energy Company" (a subsidiary of Berkshire Hathaway Energy) in UM 1209. My reviews on Energy Merger & Acquisition also include "PacifiCorp vs. Scottish Power", "PGE vs. Enron".

Clean Energy – Dollar Impact on Customer Rates: I performed analyses of "Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in Rates".

General Rate Case and Other Cases: I testified and conducted analyses on some subjects in the revenue requirement. I testified on Depreciation and Reserve, Cost of Debt Capital, Fuel Price Forecasting Regarding Property Sales; I reviewed Load Forecasting, Weather Normalization, Integrated Resource Planning (IRP).

Statistical Sampling Design & Procedure Design: My work functions have also included the Statistical Sampling Design & Procedure Design, and I testified on Revenue Issues (UM 1288) by presenting the sampling results.

Utility Auditing: I conducted Energy Utility Auditing for cost of capital component on energy companies and also preformed utility operational auditing. I have conducted "Interest Rate and Late Payment Charge" Survey and Analysis annually for state of Oregon (UM 779).

Telecom Market Survey Analysis: I conducted Telecommunications "Market Competition and Economic Policy Survey Analysis" and write report for House Bill 2577, the report has been published on OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My "Mentoring Topics" were focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in US and "Price-Cap" in Europe; Cost of Capital, Energy Demand and Price Forecasting Models; Least Cost Planning; and Regulatory Policy & Renewable Energy issues affecting Utility Rates.

CASE: UG 344
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

(WORKPAPERS)

Exhibits in Support
Of Opening Testimony

April 20, 2018

STAFF EXHIBIT 1102

WORKPAPER

PROVIDED IN ELECTRONIC FORMAT ONLY

CASE: UG 344
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

April 20, 2018

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

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon (OPUC) since March of 2007. I am a Senior Economist (half-time) within the Energy, Rates, Finance, and Audits Division. My business address is 201 High St., Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. This testimony addresses the long-run-incremental-cost (LRIC) cost analyses for the Northwest Natural Gas Company (NW Natural, NWN, or Company).

Q. Have you other exhibits for this docket?

A. Two. Page 1 of Exhibit Staff/1202 is Staff's primary alternative to the Company's primary LRIC study results as contained in Exhibit NW Natural/1101, Speer/1. It employs a system mains cost figure provided by NWN in response to Staff's Data Request No. 350—replicated as Exhibit Staff/1203. Page 2 of Exhibit Staff/1202 substitutes an Avista figure for the one supplied by NWN. To facilitate ease of making comparisons, page 3 of Staff/1202 is a replication of the NWN Exhibit 1101. It provided a key input to my LRIC study.

Q. How is your testimony organized?

A. This testimony is organized as follows:

Q. Please explain what LRIC is used for.

A. LRIC studies inform both how a utility's prices are to be set and how its costs are to be allocated among the utility's customer classes—residential, commercial and industrial. Allocation among classes is called "rate spread"; pricing is referred to as "rate design". I use the term "inform" to denote the fact that other considerations besides LRIC study results are typically brought to bear in both the rate spread and rate design functions. The testimony of Scott Gibbens (Staff/600) contains Staff's rate spread recommendations for this docket.

Q. Please provide some detail regarding how LRIC studies are performed.

A. The first step is to compartmentalize the utility costs among several functional categories. Cost-wise the largest gas utility function consists of the distribution mains themselves, which in turn are divided between local mains, or "main extensions," that traverse the neighborhoods, and "system mains," which take the gas into the neighborhoods. Customers' on-premise meters and the service lines that connect them to the local mains in the streets constitute the next-costliest plant category. Far less costly functions are scheduling and planning, meter reading, and billing.

The second step involves a combination of a) estimating what it would cost, in test period revenue requirement terms, to replace the functional elements on a current cost (LRIC) basis, and b) allocating those cost to the various customer classes/schedules.

If the functional element's costs can be decomposed and isolated among the different customer classes, a bottom-up approach can be used for this second step. Consider the case of meters and services. Each customer has its own meter and service line, and the per-customer average LRIC cost for each customer class is readily distinguishable. Each schedule's LRIC for this function is established by multiplying the per-customer average LRIC by the number of customers in the schedule. A total LRIC for this function is then established by summing all the schedules' LRICs for the function.

If the functional element's costs can*not* be decomposed and isolated among the different customer classes, a top-down approach comes into play for this second step. Consider the case of system mains, which together and simultaneously transport gas to *all* the customer classes. Before system mains costs can be allocated, their system total LRIC must first be estimated on a current costs, total replacement basis. Since a major cost driver of these large-diameter mains is meeting the peak demand, the key here is the estimation of each customer schedule's own peak day load. The schedules' peak-day loads, combined with a component involving their annual through-puts, are then used to allocate the system mains LRIC among all the customer schedules.

The third and final step involves the utility's embedded, or historic accounting-booked-and-depreciated, costs for each designated functional category. Comparisons of each schedule's LRIC for a particular function to the total LRIC for that function are used to establish an allocation ratio for each schedule and function, which are then applied to allocate the embedded costs. In other words, the embedded costs for each function are allocated to each customer schedule in proportion to that schedule's percentage share of the total LRIC for the function.

Q. I understand the objectives of wanting to allocate embedded costs so as to reflect both cost causation and the benefits received by the various customer classes, but why can't we simply rely upon your final step, i.e., without going through the LRIC process?

A. The utilities' accounting books and records generally lack the granularity to reveal the individual customer information just described. And partly to place everything onto the same vintage, i.e., the present, the customer classes are sampled and replication-cost studies produced whose outputs can then be aggregated and disaggregated as described in my previous answer.

Q. Please explain how an LRIC study can affect rate design,

A. The typical gas utility pricing structure is limited to a flat customer charge and a volumetric charge. In Oregon the former is informed by LRIC costs pertaining to billing, metering, and the service line; the latter covers the balance of the distribution costs plus the gas commodity cost. For comparison, electric pricing structures are more granular, with separate volumetric prices covering generation, transmission, and non-customer-related distribution costs. In all cases the LRIC studies help separate those categories of costs from each other.

Q. Please provide an overview of your LRIC analyses.

A. The sums of the customer classes' LRIC estimates of shares of local mains and system mains costs are used to allocate the embedded "core mains" costs category. The customer classes' LRIC shares of *all* the embedded cost categories, less the cost of the gas commodity itself, combine to form the "LRIC-Based Target Margin"[1] for each of those customer classes.

The Company has understated system main costs by a major degree. Utilizing data response (DR) information supplied by the Company, I obtained a more accurate estimate of system mains LRIC. I then allocated the revised estimate among the customer classes using a methodology similar to what has been stipulated to in recent Avista general rate cases.

In general the effect of my results is to dampen the Company's results, with costs shifted away from the residential class and over to the larger commercial, industrial, and transportation customers.[2] Examples: NWN's LRIC-based "target" percentage margin revenue increase for the firm residential class is 27 percent while mine is 17 percent; and while NWN's commercial sales firm class (32 CSF) target adjustment is minus 78 percent, my figure is minus 2 percent. The reason for the shift is that my model corrects for the very small system mains costs amount in the Company model.

[1] Total costs include the cost of the gas purchased from the interstate pipeline suppliers; "margin" costs pertain to everything else, i.e., the gas utility's "own" costs. General rate cases only establish revenue requirements dedicated to covering the utility's own costs.

[2] "Transportation" customers obtain their gas commodity directly from a third-party supplier instead of from NW Natural, which acts solely as the distribution service provider in these instances.

Topic 1: An Alternative Approach to Allocating System Mains Costs

Q. What are "system mains" versus "local mains"?

A. Most of a gas utility's plant consists of the "local mains" (or "main extensions") that run up or down neighborhood streets. The primary cost driver is the per-customer average length of those mains. The average diameters of main extensions also vary by customer class, with industrial customers' average mains being larger and longer.

"System mains" are the larger-diameter mains that transport gas from the interstate pipeline interconnection to the neighborhoods and areas were customers are served.

Q. On an LRIC basis, how would the magnitude of system mains costs compare with that of the local mains?

A. NWN's response to my DR No. 350 (reproduced as Exhibit Staff/1203) puts the relative share at above 75 percent. Caveat: Because we have been cautioned that system mains total replacement costs are "not developed in [NWN's] normal course of business,"[3] some modesty can be expected with how far we can rely on the related LRIC study results. Adding some perspective to this matter is the fact that in the most recent Avista general rate case (2016 Docket UG 325), system mains are about 33 percent of local mains in terms of their LRIC magnitudes.[4] In contrast, the NWN ratio is only 1.5 percent.[5] Page 2 of Exhibit

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[3] *See* Staff/1203, NW Natural's Response to Staff DR No. 350.
[4] *See* UG 325 Avista/801, Miller/1, lines 11 – 15.
[5] *See* NW Natural/1101, Speer/1, lines 10 and 13.

Staff/1202 employs the 33 percent figure to help assess the overall LRIC cost sensitivity to system mains costs.

Q. What approach did the Company employ to estimate system mains costs in this case?

A. Their basis for calculating what they refer to as the "incremental system capacity and commodity main investment" was "incremental system reinforcement costs."[6] That approach understates the system mains long run incremental costs.

Q. On what grounds do you say that?

A. There seems to be perfectly understandable confusion regarding the meaning of "incremental" in the context of our long-run-incremental-cost analyses. Oregon's regulatory use of the term refers to replicating the existing system as if it were entirely new.[7] So, for example, the base LRIC cost estimate for residential local mains is obtained by taking the per-customer average length of mains in residential neighborhoods, multiplying that average by the current unit linear cost of those mains, *and then multiplying that product by the total number of residential customers*. What we get is an estimate of the total costs of serving all of the residential customers with brand new local mains.

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[6] *See* NW Natural/1100, Speer/11, lines 11 – 20.

[7] An excellent current example of the use of new replacement costs in LRIC studies is found in PGE's UE 335 testimony by Robert Macfarlane and Jacob Goodspeed (Exhibit 1200, pages 7 and 8). The closest equivalent to a gas utility's system mains are what are referred to by electric utilities as "distribution feeders," or simply "feeders." In answering, "How do you calculate the marginal unit feeder costs?" PGE's response is, "Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars."

By contrast, instead of estimating what it would cost to replicate the entire systems mains network with brand new equipment, etc., the Company used an average of yearly "incremental," or *reinforcement*, investments. Clearly the cost of reinforcement of existing mains will be of a very much smaller magnitude than the cost of replicating all those mains as if new. If only for consistency purposes, the same LRIC study utilizing full replication of local mains should also make use of a full replication of system mains.

Q. You have made the case for using a much larger system mains dollar figure than came in NWN's application. Aside from the magnitude of what should be allocated among the customer classes, would you agree with how the Company performed that allocation?

A. I would agree in part and disagree in part. As indicated by the associated system mains label, "capacity and commodity main investment," cost attribution in this context carries both a peak capacity and a commodity, or annual throughput, component. The Company's analysis only employed the peak capacity component.

Q. Please elaborate briefly regarding the peak capacity cost driver.

A. While local mains are a fixed/standard size, largely depending upon the nature of customer group being served,[8] larger-diameter system mains must be sized to meet the annual peak day demands that are aggregated over all the

[8] For instance, residential local mains tend to be two inches in diameter regardless of the local customers' peak day demand or annual throughput.

customer groups served by those mains. Accordingly, system mains costs are driven in large measure by system peak day demands.

Q. What is the underlying justification for considering an annual throughput component when allocating system main costs?

A. Achieving safety constitutes a major cost driver, with the attributed costs being allocated by shares of annual throughput as a proxy for the magnitudes of benefits received from the safety-driven costs. Also, much of installation costs, e.g., permitting, trenching, and tunneling, are not particularly sensitive to whether, for example, the pipe being laid is ten inches in diameter or four inches. Arbitrarily (admittedly), the non-capacity-based costs can be, and generally are, allocated and priced on a commodity or volumetric/throughput basis.

Q. Given the two cost allocation components, capacity and throughput, how much weight should each be given?

A. As far back as I can remember in my regulatory career, which suggests that this treatment actually pre-dates my career, the average-and-excess demand (A&E) method has been used when allocations combine a mix of capacity and throughput (or demand and energy in the electricity vernacular). The A&E method considers a utility's or customer group's load factor, and allocates the load factor[9] percentage of the total of system mains costs on the basis of

[9] The gas industry load factor is defined as the average daily throughput (i.e., the annual throughput divided by 365) divided by the peak day's throughput. NWN's load factor is 27 percent. (Exhibit Staff/1202, Compton/1, line 3d).

throughput and allocates the balance of the system mains costs on the basis of the demand measure shares.

Q. Does your Exhibit Staff/1202 reflect the A&E and other specifics that you have described that relate to your recommended approach to allocating system mains costs?

A. Yes, lines 3a – 3d display the development of the system load factor; lines 10a – 10c display the system mains LRIC allocations; the remainder of the lines that are bolded display the study outcomes that incorporate Staff's alternative system mains allocations approach.

Topic 2: General LRIC Study Conclusions

Q. What general conclusions do you have regarding NWN's LRIC study?

A. NWN's LRIC study is vastly improved compared to the one filed as part of UG 221 (2012). As I said earlier, most of a gas utility's plant consists of the local mains (or "main extensions") that run up or down neighborhood streets. The primary cost driver is the per-customer average length of those mains. The average diameters and lengths of main extensions vary by customer class, with industrial customers' average mains being larger and longer. The LRIC study used in the prior rate case did not distinguish among the rate classes in those regards. In order to come up with a basis for allocating main extensions costs, Staff was forced to use varying average service line costs as a correlated proxy for the costs of the local mains themselves. In the current case the Company appropriately breaks the costs down by pipe size and average mains lengths according to the respective customer classes.

Q. You stated in your overview that the effect of your LRIC analysis was to shift costs over to "the larger commercial, industrial, and transportation customers." Please explain why that would be the case.

A. System mains account for a substantial share of LRIC costs. Except for the LRIC allocation of system mains costs and storage costs (with the latter being a very small magnitude), none of the other cost categories have a volumetric component in their allocations. Reflecting volumetric cost causation factors, system mains costs are allocated on the basis both of peak day and yearly volumes. In this arena, large consumption volumes are associated with large cost allocations.

Q. In scanning the two sets of LRIC results I observe that while the Company's would suggest a substantial margin rates *reduction* for the transportation firm schedule 32TF (Transmission Firm), your results call for a 27 percent *increase*. Please explain the disparity.

A. My rather large cost allocation increases to the larger customer schedules generally shrinks what remains as a net target rates reduction for many of those schedules. But for Schedule 32 F, an increase of comparable relative magnitude led to a net target rates increase. To provide perspective I added line 28 to my exhibit. It calculates the target margin level on a per-unit-of-annual-throughput basis. Consider Industrial Transportation Firm 31ITF, where the indicated target margin percentage *reduction* is 49 percent (line 27A). After incorporating the indicated margin cost reduction, the per-unit target margin cost for these customers comes out to be $0.13 per therm (line 28). On the other hand, while the indicated target *increase* for Transportation Firm 32TF is 18 percent (line 27A), the target margin unit cost for this schedule is still "only" $0.10 per therm (line 28). So, as expected, the larger customer would still reap scale benefits even though he would see a target margin increase rather than a decrease. For added perspective note from that same line 28 that the target margin cost per therm for Firm Residential Sales is $0.71.

Q. In your overview you referred to the distinction between the target margin increase as a percent of present *total* revenue (line 27) and as a percent of the present *margin* revenue (line 27A). Please elaborate.

A. The average, i.e., residential, sales customer is concerned about the prospective increase to his monthly gas bill – which is a total of the cost of the gas commodity itself plus the margin portion. To address that average customers' concern, overall/total bill percentage increases are publicized. Transportation customers' bills only pertain to the margin, since they buy their commodity from a third party.[10] So it makes no sense to compare percentage increases for sales customers' total bills with the percentage increases of transportation customers' "total" bills because from the utility's perspective the latter does not include the commodity cost of gas. For that reason, the bottom

[10] It is noteworthy that about one-third of NWN's annual throughput is comprised of third-party gas obtained by transportation customers.

line comparisons – i.e., line 27A on both Staff's and NWN's primary exhibits – refer to percentage *margin* increases.[11]

Q. In the overview to this testimony you said that correcting for the understatement of the system mains costs in the Company model shifted LRIC cost estimates away from the residential and small commercial schedules and toward the transportation, industrial, and larger commercial schedules. Please present us now with a summary table that displays numerically what I just described.

A. It follows below:

LRIC RESULTS SUMMARY TABLE

Schedule	Annual Throughput MM Therms	Target Margin % Change NWN	Target Margin % Change Staff	Staff's Target Margin Per Therm
Residential	385	+27	+17	$0.71
Sm. Comm. 3CSF	166	+29	+27	$0.54
Lg. Comm. 32CSF	39	-78	-28	$0.16
Firm Trans. 32TF	93	-84	+27	$0.10
Interruptible Trans.	197	-82	+5	$0.03

Q. Does that conclude your direct testimony?

A. Yes.

[11] Staff/1202, Compton/1 and 3.

CASE: UG 344
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

April 20, 2018

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street, SE., Suite 100
Salem, OR. 97301

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UG 344
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural

Oregon Jurisdictional Rate Case

Test Year Twelve Months Ended October 31, 2019

Long-Run Incremental Cost Study

Summary of Results

Staff LRIC Results

Assuming a $245,000,000 annual System Mains Revenue Requirement

Line No.	CUSTOMER CLASS / SERVICE TYPE / RATE SCHEDULE	Totals	Residential Sales Firm 02	Commercial Sales Firm 03CSF	Industrial Sales Firm 03ISF	Commercial Sales Firm 27CSF	Commercial Sales Firm 31CSF	Commercial Transportation Firm 31CTF	Industrial Sales Firm 31ISF
	STATISTICS								
1	2019 ANNUAL THERM DELIVERIES	1,073,764,878	385,050,429	166,461,516	4,874,416	1,197,618	25,390,021	3,496,586	14,010,541
2	2019 CUSTOMERS	673,269	610,273	58,752	355	1,962	740	74	217
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		631	2,833	13,731	610	34,311	47,251	64,565
3a	**ESTIMATED DESIGN DAY LOAD FACTOR**		**27%**	**20%**	**37%**	**27%**	**34%**	**28%**	**48%**
3b	**Average Firm Daily Deliveries**	**2,045,159**	**1,054,933**	**456,059**	**13,355**	**3,281**	**69,562**	**9,580**	**38,385**
3c	**Peak Firm Day Deliveries**	**7,521,024**	**3,867,055**	**2,321,162**	**36,017**	**12,028**	**207,093**	**34,285**	**79,790**
3d	**System Firm Load Factor**	**27%**							
4	Demand Charges	$76,015,833	$44,619,642	$19,289,561	$564,846	$138,779	$2,942,198	$0	$1,623,544
5	Cost of Gas	$198,888,064	$109,238,807	$47,225,131	$1,382,872	$339,765	$7,203,149	$0	$3,974,789
6	Total Cost of Gas	$274,903,897	$153,858,449	$66,514,692	$1,947,718	$478,544	$10,145,347	$0	$5,598,333
7	Account Services (Meter Reading, Billing, etc.)	$26,500,696	$23,676,365	$2,361,734	$14,270	$76,118	$143,459	$14,397	$42,068
	Customer Capital Investment LRIC Costs								
8	Meter & Regulators	$31,271,274	$23,199,887	$6,259,399	$156,723	$78,040	$398,513	$39,725	$174,291
9	Services	$234,118,449	$213,913,778	$18,100,185	$260,111	$687,723	$417,002	$40,236	$125,210
10	Main Extensions	$315,808,952	$218,871,639	$90,254,775	$545,348	$703,662	$1,136,782	$113,678	$1,209,835
10a	**System Mains Replacement Rev. Req.**	**$245,000,000**							
10b	**System Mains – Annual Through-Put Allocated**	**$66,621,781**	**$25,792,005**	**$11,150,166**	**$326,505**	**$80,221**	**$1,700,711**	**$234,213**	**$938,474**
10c	**System Mains – Firm Demand Allocated**	**$178,378,219**	**$91,716,029**	**$55,051,637**	**$854,236**	**$285,263**	**$4,911,685**	**$813,157**	**$1,892,393**
11	Storage Costs	$2,166,814	$1,110,217	$666,276	$10,340	$3,451	$59,451	$0	$22,906
12	Total Customer Capital Investment Costs	$1,073,365,488	$574,603,554	$181,482,438	$2,153,264	$1,838,360	$8,624,144	$1,241,010	$4,363,110
13	Total System Reinforcement Cost	$3,759,945	$1,901,185	$1,140,999	$17,709	$5,909	$101,808	$16,856	$39,226
14	Long Run Incremental Distribution Cost	$1,378,530,027	$754,039,553	$251,499,862	$4,132,960	$2,398,932	$19,014,758	$1,272,263	$10,042,737
	Proposed Cost by Functional Classification								
15	Cost of Gas Commodity	$276,853,509	$154,949,610	$66,986,413	$1,961,531	$481,938	$10,217,298	$0	$5,638,036
16	Account Services (Meter Reading, Billing, etc.) Costs	$48,358,722	$43,204,855	$4,309,714	$26,041	$138,902	$261,785	$26,272	$76,767
17	Meters & Services Costs	$68,997,521	$61,646,152	$6,333,142	$108,371	$199,088	$212,022	$20,789	$72,866
18	**Core Main Costs**	$262,906,879	**$157,694,576**	**$73,346,744**	**$809,190**	**$501,215**	**$3,632,810**	**$544,299**	**$1,894,279**
19	Storage Costs	$20,203,532	$10,351,744	$6,212,408	$96,409	$32,173	$554,326	$0	$213,573
20	Proposed Cost	$679,109,030	$427,846,936	$157,188,421	$3,001,541	$1,353,315	$14,878,241	$591,359	$7,900,521
21	LRIC Based Target Margin	$402,255,521	**$272,897,327**	**$90,202,009**	**$1,040,010**	**$871,377**	**$4,660,943**	**$591,359**	**$2,262,484**
22	Revenue at Current Rates	$626,662,560	$387,770,097	$137,975,522	$3,740,132	$1,038,854	$18,521,031	$1,113,636	$8,813,710
23	**Margin Revenue at Current Rates**	$351,758,663	$233,911,648	$71,460,830	$1,792,414	$560,310	$8,375,684	$1,113,636	$3,215,377
24	Current Revenue to Proposed Cost (Includes Cost of Gas)	0.92	0.91	0.88	1.25	0.77	1.24	1.88	1.12
25	Current Margin Revenue to LRIC Based Target Margin	0.87	0.86	0.79	1.72	0.64	1.80	1.88	1.42
25A	**Relative Margin to Cost at Present Rates**	1.00	0.96	0.91	1.97	0.74	2.05	2.15	1.63
26	Component LRIC Target Increase by Schedule	$52,446,470	$40,076,839	$19,212,899	($718,590)	$314,461	($3,642,790)	($522,277)	($913,189)
27	Target Increase as Percent of Total Present Revenue	8.37%	10.34%	13.92%	-19.75%	30.27%	-19.67%	-46.90%	-10.36%
27A	Target Increase as Percent of Present Margin Revenue	14.91%	**17.13%**	**26.89%**	**-41.21%**	**56.12%**	**-43.49%**	**-46.90%**	**-28.40%**
28	**Target Margin Per Delivered Therm**	**$0.37**	**$0.71**	**$0.54**	**$0.21**	**$0.73**	**$0.18**	**$0.17**	**$0.16**

Line No.	CUSTOMER CLASS / SERVICE TYPE / RATE SCHEDULE	Industrial Transportation Firm 31ITF	Commercial Sales Firm 32 CSF	Industrial Sales Firm 32ISF	Transportation Firm 32TF	Commercial Sales Interruptible 32CSI	Industrial Sales Interruptible 32ISI	Transportation Interruptible 32TI	Transportation 33T	Special Contracts
	STATISTICS									
1	2019 ANNUAL THERM DELIVERIES	383,568	39,092,810	13,823,132	92,722,465	23,733,673	27,416,484	196,967,402	-	79,164,217
2	2019 CUSTOMERS	5	433	62	178	58	68	85	-	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER	72,714	90,284	222,954	520,913	409,201	403,184	2,317,264	-	11,309,174
3a	**ESTIMATED DESIGN DAY LOAD FACTOR**	**61%**	**33%**	**37%**	**47%**	**26%**	**21%**	**35%**		**35%**
3b	**Average Firm Daily Deliveries**	**996**	**107,104**	**37,872**	**254,034**	-	-	-	-	**216,888**
3c	**Peak Firm Day Deliveries**	**1,628**	**322,952**	**102,298**	**536,716**	-	-	-		**621,093**
3d	**System Firm Load Factor**									
4	Demand Charges	$0	$4,530,076	$1,601,827	$0	$327,287	$378,073	$0	$0	$0
5	Cost of Gas	$0	$11,090,630	$3,921,623	$0	$6,733,242	$7,778,056	$0	$0	$0
6	Total Cost of Gas	$0	$15,620,706	$5,523,450	$0	$7,060,529	$8,156,129	$0	$0	$0
7	Account Services (Meter Reading, Billing, etc.)	$973	$83,943	$12,020	$34,234	$11,244	$13,334	$16,537	$0	$1,362
	Customer Capital Investment LRIC Costs									
8	Meter & Regulators	$3,648	$415,271	$85,920	$201,874	$83,708	$34,530	$139,745	$0	$11,508
9	Services	$2,981	$266,931	$34,696	$118,399	$45,969	$40,826	$64,401	$0	$5,304
10	Main Extensions	$27,876	$665,171	$345,667	$992,400	$89,099	$379,119	$473,899	$0	$39,027
10a	**System Mains Replacement Rev. Req.**									
10b	**System Mains – Annual Through-Put Allocated**	**$24,353**	**$2,618,571**	**$925,921**	**$6,210,870**	**$1,589,763**	**$1,836,451**	**$13,193,556**	**$0**	**$0**
10c	**System Mains – Firm Demand Allocated**	**$38,602**	**$7,659,543**	**$2,426,237**	**$12,729,438**	**$0**	**$0**	**$0**	**$0**	**$0**
11	Storage Costs	$0	$92,711	$29,367	$0	$70,795	$101,301	$0	$0	$0
12	Total Customer Capital Investment Costs	$97,460	$11,718,198	$3,847,808	$20,252,981	$1,879,335	$2,392,226	$13,871,600	$0	$55,839
13	Total System Reinforcement Cost	$800	$158,766	$50,299	$263,830	$0	$0	$0	$0	$62,558
14	Long Run Incremental Distribution Cost	$99,233	$27,581,613	$9,433,577	$20,551,045	$8,951,108	$10,561,689	$13,888,137	$0	$119,759
	Proposed Cost by Functional Classification									
15	Cost of Gas Commodity	$0	$15,731,488	$5,562,622	$0	$7,110,602	$8,213,972	$0	$0	$0
16	Account Services (Meter Reading, Billing, etc.) Costs	$1,775	$153,180	$21,933	$62,470	$20,518	$24,333	$30,177	$0	$48,819
17	Meters & Services Costs	$1,723	$177,363	$31,358	$83,266	$33,714	$19,591	$53,075	$0	$85,882
18	**Core Main Costs**	**$42,582**	**$5,130,205**	**$1,733,538**	**$9,344,441**	**$787,050**	**$1,038,658**	**$6,407,294**	**$0**	$1,654,166
19	Storage Costs	$0	$864,444	$273,821	$0	$660,100	$944,535	$0	$0	$0
20	Proposed Cost	$46,080	$22,056,679	$7,623,273	$9,490,177	$8,611,984	$10,241,088	$6,490,546	$0	$1,788,868
21	LRIC Based Target Margin	**$46,080**	**$6,325,192**	**$2,060,651**	**$9,490,177**	**$1,501,382**	**$2,027,117**	**$6,490,546**	$0	$1,788,868
22	Revenue at Current Rates	$89,844	$24,565,050	$7,608,655	$7,460,021	$9,271,906	$10,710,650	$6,194,584	$0	$1,788,868
23	**Margin Revenue at Current Rates**	$89,844	$8,944,344	$2,085,205	$7,460,021	$2,211,377	$2,554,521	$6,194,584	$0	$1,788,868
24	Current Revenue to Proposed Cost (Includes Cost of Gas)	1.95	1.11	1.00	0.79	1.08	1.05	0.95	-	-
25	Current Margin Revenue to LRIC Based Target Margin	1.95	1.41	1.01	0.79	1.47	1.26	0.95	-	-
25A	**Relative Margin to Cost at Present Rates**	2.23	1.62	1.16	0.90	1.68	1.44	1.09	-	-
26	Component LRIC Target Increase by Schedule	($43,764)	($2,508,372)	$14,618	$2,030,156	($659,922)	($469,562)	$295,961	$0	$0
27	Target Increase as Percent of Total Present Revenue	-48.71%	-10.21%	0.19%	27.21%	-7.12%	-4.38%	4.78%	0.00%	0.00%
27A	Target Increase as Percent of Present Margin Revenue	**-48.71%**	**-28.04%**	**0.70%**	**27.21%**	**-29.84%**	**-18.38%**	**4.78%**	0.00%	0.00%
28	**Target Margin Per Delivered Therm**	**$0.13**	**$0.16**	**$0.15**	**$0.10**	**$0.06**	**$0.07**	**$0.03**		**$0.02**

Note: Bolded figures represent Staff inputs/calculations.

Note: Except for Line 13, the Totals figures for Lines 7 - 19 exclude Special Contracts amounts.

Note: Average & Excess Demand principle used to allocate system mains costs between through-put and demand components. Line 13 information was not used except to "Indicate" Special Contracts' Line 14 LRIC.

NW Natural

Oregon Jurisdictional Rate Case

Test Year Twelve Months Ended October 31, 2019

Long-Run Incremental Cost Study

Summary of Results

Staff LRIC Results

Assuming a $105,000,000 annual System Mains Revenue Requirement

Line No.	CUSTOMER CLASS SERVICE TYPE / RATE SCHEDULE		Residential Sales Firm 02	Commercial Sales Firm 03CSF	Industrial Sales Firm 03ISF	Commercial Sales Firm 27CSF	Commercial Sales Firm 31CSF	Commercial Transportation Firm 31CTF	Industrial Sales Firm 31ISF	Industrial Transportation Firm 31ITF	Commercial Sales Firm 32 CSF	Industrial Sales Firm 32ISF	Transportation Firm 32TF	Commercial Sales Interruptible 32CSI	Industrial Sales Interruptible 32ISI	Transportation Interruptible 32TI	Transportation 33T	Special Contracts
	STATISTICS	Totals																
1	2019 ANNUAL THERM DELIVERIES	1,073,764,878	385,050,429	166,461,516	4,874,416	1,197,618	25,390,021	3,496,586	14,010,541	363,568	39,092,810	13,823,132	92,722,465	23,733,673	27,416,484	196,967,402	-	79,164,217
2	2019 CUSTOMERS	673,269	610,273	58,752	355	1,962	740	74	217	5	433	62	178	58	68	85	-	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		631	2,833	13,731	610	34,311	47,251	64,565	72,714	90,284	222,954	520,913	409,201	403,184	2,317,264	-	11,309,174
3a	**ESTIMATED DESIGN DAY LOAD FACTOR**		**27%**	**20%**	**37%**	**27%**	**34%**	**28%**	**48%**	**61%**	**33%**	**37%**	**47%**	**26%**	**21%**	**35%**		**35%**
3b	**Average Firm Daily Deliveries**	**2,045,159**	**1,054,933**	**456,059**	**13,355**	**3,281**	**69,562**	**9,580**	**38,385**	**996**	**107,104**	**37,872**	**254,034**	-	-	-	-	**216,888**
3c	**Peak Firm Day Deliveries**	**7,521,024**	**3,867,055**	**2,321,162**	**36,017**	**12,028**	**207,093**	**34,285**	**79,790**	**1,628**	**322,952**	**102,298**	**536,716**	-	-	-		**621,093**
3d	**System Firm Load Factor**	**27%**																
4	Demand Charges	$76,015,833	$44,619,642	$19,289,561	$564,846	$138,779	$2,942,198	$0	$1,623,544	$0	$4,530,076	$1,601,827	$0	$327,287	$378,073	$0	$0	$0
5	Cost of Gas	$198,888,064	$109,238,807	$47,225,131	$1,382,872	$339,765	$7,203,149	$0	$3,974,789	$0	$11,090,630	$3,921,623	$0	$6,733,242	$7,778,056	$0	$0	$0
6	Total Cost of Gas	$274,903,897	$153,858,449	$66,514,692	$1,947,718	$478,544	$10,145,347	$0	$5,598,333	$0	$15,620,706	$5,523,450	$0	$7,060,529	$8,156,129	$0	$0	$0
7	Account Services (Meter Reading, Billing, etc.)	$26,500,696	$23,676,365	$2,361,734	$14,270	$76,118	$143,459	$14,397	$42,068	$973	$83,943	$12,020	$34,234	$11,244	$13,334	$16,537	$0	$1,362
	Customer Capital Investment LRIC Costs																	
8	Meter & Regulators	$31,271,274	$23,199,887	$6,259,399	$156,723	$78,040	$398,513	$39,725	$174,291	$3,648	$415,271	$85,920	$201,874	$83,708	$34,530	$139,745	$0	$11,508
9	Services	$234,118,449	$213,913,778	$18,100,185	$260,111	$687,723	$417,002	$40,236	$125,210	$2,981	$266,931	$34,696	$118,399	$45,969	$40,826	$64,401	$0	$5,304
10	Main Extensions	$315,808,952	$218,871,639	$90,254,775	$545,348	$703,662	$1,136,782	$113,678	$1,209,835	$27,876	$665,171	$345,667	$992,400	$89,099	$379,119	3473,899	$0	$39,027
10a	**System Mains Replacement Rev. Req.**	**$105,000,000**																
10b	**System Mains -- Annual Through-Put Allocated**	**$28,552,192**	**$11,053,716**	**$4,778,643**	**$139,931**	**$34,380**	**$728,876**	**$100,377**	**$402,203**	**$10,437**	**$1,122,245**	**$396,823**	**$2,661,802**	**$681,327**	**$787,050**	**$5,654,381**	**$0**	**$0**
10c	**System Mains -- Firm Demand Allocated**	**$76,447,808**	**$39,306,869**	**$23,593,559**	**$366,101**	**$122,256**	**$2,105,008**	**$348,496**	**$811,026**	**$16,544**	**$3,282,661**	**$1,039,816**	**$5,455,473**	**$0**	**$0**	**$0**	**$0**	**$0**
11	Storage Costs	$2,166,814	$1,110,217	$666,276	$10,340	$3,451	$59,451	$0	$22,906	$0	$92,711	$29,367	$0	$70,795	$101,301	$0	$0	$0
12	Total Customer Capital Investment Costs	$793,365,488	$507,456,107	$143,652,836	$1,478,554	$1,629,512	$4,845,632	$642,512	$2,745,471	$61,486	$5,844,990	$1,932,289	$9,429,948	$970,899	$1,342,826	$6,332,425	$0	$55,839
13	Total System Reinforcement Cost	$3,759,945	$1,901,185	$1,140,999	$17,709	$5,909	$101,808	$16,856	$39,226	$800	$158,766	$50,299	$263,830	$0	$0	$0	$0	$62,558
14	Long Run Incremental Distribution Cost	$1,098,530,027	$686,892,105	$213,670,261	$3,458,251	$2,190,084	$15,236,246	$673,765	$8,425,099	$63,259	$21,708,405	$7,518,058	$9,728,012	$8,042,672	$9,512,289	$6,348,962	$0	$119,759
	Proposed Cost by Functional Classification																	
15	Cost of Gas Commodity	$276,853,509	$154,949,610	$66,986,413	$1,961,531	$481,938	$10,217,298	$0	$5,638,036	$0	$15,731,488	$5,562,622	$0	$7,110,602	$8,213,972	$0	$0	$0
16	Account Services (Meter Reading, Billing, etc.) Costs	$48,358,722	$43,204,855	$4,309,714	$26,041	$138,902	$261,785	$26,272	$76,767	$1,775	$153,180	$21,933	$62,470	$20,518	$24,333	$30,177	$0	$48,819
17	Meters & Services Costs	$68,997,521	$61,646,152	$6,333,142	$108,371	$199,088	$212,022	$20,789	$77,866	$1,723	$177,363	$31,358	$83,266	$33,714	$19,591	$53,075	$0	$85,882
18	**Core Main Costs**	$262,906,879	$168,206,982	$74,114,032	$656,866	$537,485	$2,480,735	$351,463	$1,513,847	$34,273	$3,167,609	$1,113,523	$5,691,410	$481,336	$728,582	$3,828,737	$0	$1,654,166
19	Storage Costs	$20,203,532	$10,351,744	$6,212,408	$96,409	$32,173	$554,326	$0	$213,573	$0	$864,444	$273,821	$0	$660,100	$944,535	$0	$0	$0
20	Proposed Cost	$679,109,030	$438,359,342	$157,955,709	$2,849,218	$1,389,585	$13,726,166	$398,523	$7,520,089	$37,771	$20,094,083	$7,003,258	$5,837,146	$8,306,270	$9,931,013	$3,911,989	$0	$1,788,868
21	**LRIC Based Target Margin**	$402,255,521	$283,409,733	$90,969,297	$887,687	$907,647	$3,508,868	$398,523	$1,882,052	$37,771	$4,362,596	$1,440,636	$5,837,146	$1,195,668	$1,717,041	$3,911,989	$0	$1,788,868
22	Revenue at Current Rates	$626,662,560	$387,770,097	$137,975,522	$3,740,132	$1,038,854	$18,521,031	$1,113,636	$8,813,710	$89,844	$24,565,050	$7,608,655	$7,460,021	$9,271,906	$10,710,650	$6,194,584	$0	$1,788,868
23	**Margin Revenue at Current Rates**	$351,758,663	$233,911,648	$71,460,830	$1,792,414	$560,310	$8,375,684	$1,113,636	$3,215,377	$89,844	$8,944,344	$2,085,205	$7,460,021	$2,211,377	$2,554,521	$6,194,584	$0	$1,788,868
24	Current Revenue to Proposed Cost (Includes Cost of Gas)	0.92	0.88	0.87	1.31	0.75	1.35	2.79	1.17	2.38	1.22	1.09	1.28	1.12	1.08	1.58	-	-
25	Current Margin Revenue to LRIC Based Target Margin	0.87	0.83	0.79	2.02	0.62	2.39	2.79	1.71	2.38	2.05	1.45	1.28	1.85	1.49	1.58	-	-
	25A Relative Margin to Cost at Present Rates	1.00	0.94	0.90	2.31	0.71	2.73	3.20	1.95	2.72	2.34	1.66	1.46	2.11	1.70	1.81	-	-
26	Component LRIC Target Increase by Schedule	$52,446,470	$50,589,245	$19,980,187	($890,914)	$350,711	($4,794,865)	($715,113)	($1,293,621)	($52,073)	($4,470,962)	($605,397)	($1,622,875)	($965,636)	($779,637)	($2,282,595)	$0	$0
27	Target Increase as Percent of Total Present Revenue	8.37%	13.05%	14.48%	-23.82%	33.76%	-25.89%	-64.21%	-14.68%	-57.96%	-18.20%	-7.96%	-21.75%	-10.41%	-7.28%	-36.85%		0.00%
	27A Target Increase as Percent of Present Margin Revenue	14.91%	21.63%	27.96%	-49.70%	62.60%	-57.25%	-64.21%	-40.23%	-57.96%	-49.99%	-29.03%	-21.75%	-43.67%	-30.52%	-36.85%	0.00%	0.00%
28	**Target Margin Per Delivered Therm**	$0.37	$0.74	$0.55	$0.18	$0.76	$0.14	$0.11	$0.13	$0.10	$0.11	$0.10	$0.06	$0.05	$0.06	$0.02		$0.02

Note: Bolded figures represent Staff inputs/calculations.

Note: Except for Line 13, the Totals figures for Lines 7 - 19 exclude Special Contracts amounts.

Note: Average & Excess Demand principle used to allocate system mains costs between through-put and demand components. Line 13 information was not used except to "indicate" Special Contracts' Line 14 LRIC.

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2019
Long-Run Incremental Cost Study
Summary of Results

NWN LRIC Results

Line No.	CUSTOMER CLASS / SERVICE TYPE / RATE SCHEDULE	Totals	Residential Sales Firm 02	Commercial Sales Firm 03CSF	Industrial Sales Firm 03ISF	Commercial Sales Firm 27CSF	Commercial Sales Firm 31CSF	Commercial Transportation Firm 31CTF	Industrial Sales Firm 31ISF	Industrial Transportation Firm 31ITF	Commercial Sales Firm 32 CSF	Industrial Sales Firm 32ISF	Transportation Firm 32TF	Commercial Sales Interruptible 32CSI	Industrial Sales Interruptible 32ISI	Transportation Interruptible 32TI	Transportation 33T	Special Contracts
	STATISTICS																	
1	2019 ANNUAL THERM DELIVERIES	1,073,764,878	385,050,429	166,461,516	4,874,416	1,197,618	25,390,021	3,496,586	14,010,541	363,568	39,092,810	13,823,132	92,722,465	23,733,673	27,416,484	196,967,402	-	79,164,217
2	2019 CUSTOMERS	673,269	610,273	58,752	355	1,962	740	74	217	5	433	62	178	58	68	85	-	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		631	2,833	13,731	610	34,311	47,251	64,565	72,714	90,284	222,954	520,913	409,201	403,184	2,317,264	-	11,309,174
4	Demand Charges	$76,015,833	$44,619,642	$19,289,561	$564,846	$138,779	$2,942,198	$0	$1,623,544	$0	$4,530,076	$1,601,827	$0	$327,287	$378,073	$0	$0	$0
5	Cost of Gas	$198,888,064	$109,238,807	$47,225,131	$1,382,872	$339,765	$7,203,149	$0	$3,974,789	$0	$11,090,630	$3,921,623	$0	$6,733,242	$7,778,056	$0	$0	$0
6	Total Cost of Gas	$274,903,897	$153,858,449	$66,514,692	$1,947,718	$478,544	$10,145,347	$0	$5,598,333	$0	$15,620,706	$5,523,450	$0	$7,060,529	$8,156,129	$0	$0	$0
7	Account Services (Motor Reading, Billing, etc.)	$26,500,696	$23,676,365	$2,361,734	$14,270	$76,118	$143,459	$14,397	$42,068	$973	$83,943	$12,020	$34,234	$11,244	$13,334	$16,537	$0	$1,362
	Customer Capital Investment Costs																	
8	Meter & Regulators	$31,271,274	$23,199,887	$6,259,399	$156,723	$78,040	$398,513	$39,725	$174,291	$3,648	$415,271	$85,920	$201,874	$83,708	$54,530	$139,745	$0	$11,508
9	Services	$234,118,449	$213,913,778	$18,100,185	$260,111	$687,723	$417,002	$40,236	$125,210	$2,981	$266,931	$34,696	$118,399	$45,969	$40,826	$64,401	$0	$5,304
10	Main Extensions	$315,808,952	$218,871,639	$90,254,775	$545,348	$703,662	$1,136,782	$113,678	$1,209,835	$27,876	$665,171	$345,667	$992,400	$89,099	$379,119	$473,899	$0	$39,027
11	Storage Costs	$2,166,814	$1,110,217	$666,276	$10,340	$3,451	$59,451	$0	$22,906	$0	$92,711	$29,367	$0	$70,795	$101,301	$0	$0	$0
12	Total Customer Capital Investment Costs	$583,365,488	$457,095,521	$115,280,635	$972,523	$1,472,877	$2,011,748	$193,639	$1,532,242	$34,505	$1,440,084	$495,650	$1,312,673	$289,572	$555,776	$678,044	$0	$55,839
13	Total System Reinforcement Cost	$4,751,743	$1,901,185	$1,140,999	$17,709	$5,909	$101,808	$16,856	$39,226	$800	$158,766	$50,299	$263,830	$121,228	$173,495	$759,633	$0	$62,558
14	Long Run Incremental Distribution Cost	$889,521,824	$636,531,520	$185,298,060	$2,952,220	$2,033,448	$12,402,362	$224,892	$7,211,870	$36,278	$17,303,499	$6,081,419	$1,610,737	$7,482,573	$8,898,734	$1,454,214	$0	$119,759
	Proposed Cost by Functional Classification																	
15	Cost of Gas Commodity	$276,853,509	$154,949,610	$66,986,413	$1,961,531	$481,938	$10,217,298	$0	$5,638,036	$0	$15,731,488	$5,562,622	$0	$7,110,602	$8,213,972	$0	$0	$0
16	Account Services (Meter Reading, Billing, etc.) Costs	$48,358,722	$43,204,855	$4,309,714	$26,041	$138,902	$261,785	$26,272	$76,767	$1,775	$153,180	$21,933	$62,470	$20,518	$24,333	$30,177	$0	$48,819
17	Meters & Services Costs	$68,997,521	$61,646,152	$6,333,142	$108,371	$199,088	$212,022	$20,789	$77,866	$1,723	$177,363	$31,358	$83,266	$33,714	$19,591	$53,075	$0	$85,882
18	System Core Main Costs	$262,906,879	$181,066,160	$74,957,966	$461,789	$581,953	$1,015,826	$107,057	$1,024,414	$23,519	$675,750	$324,751	$1,030,293	$172,499	$453,225	$1,011,677	$0	$1,654,166
19	Storage Costs	$20,203,532	$10,351,744	$6,212,408	$96,409	$32,173	$554,326	$0	$213,573	$0	$864,444	$273,821	$0	$660,100	$944,535	$0	$0	$0
20	Proposed Cost	$677,320,162	$451,218,520	$158,799,643	$2,654,141	$1,434,053	$12,261,256	$154,118	$7,030,656	$27,018	$17,602,224	$6,214,485	$1,176,029	$7,997,434	$9,655,656	$1,094,929	$0	$1,788,868
21	**LRIC Based Target Margin**	$400,466,653	$296,268,911	$91,818,231	$692,610	$952,115	$2,043,959	$154,118	$1,392,620	$27,018	$1,870,737	$651,863	$1,176,029	$886,891	$1,441,684	$1,094,929	$0	$1,788,868
22	Revenue at Current Rates	$624,873,692	$387,770,097	$137,975,522	$3,740,132	$1,038,854	$18,521,091	$1,113,636	$8,813,710	$89,844	$24,565,050	$7,608,655	$7,460,021	$9,271,906	$10,710,650	$6,194,584	$0	$1,788,868
23	**Margin Revenue at Current Rates**	$351,758,663	$233,911,648	$71,460,830	$1,792,414	$560,310	$8,375,684	$1,113,636	$3,215,377	$89,844	$8,944,344	$2,085,205	$7,460,021	$2,211,877	$2,554,521	$6,194,584	$0	$1,788,868
24	Current Revenue to Proposed Cost (includes Cost of Gas)	0.92	0.86	0.87	1.41	0.72	1.51	7.23	1.25	3.33	1.40	1.22	6.34	1.16	1.11	5.66	-	-
25	Current Margin Revenue to LRIC Based Target Margin	0.88	0.79	0.78	2.59	0.59	4.10	7.23	2.31	3.33	4.78	3.20	6.34	2.49	1.77	5.66	-	-
25A	**Relative Margin to Cost at Present Rates**	1.00	0.90	0.89	2.95	0.67	4.67	8.21	2.63	3.79	5.44	3.64	7.22	2.84	2.02	6.44	-	-
26	Component LRIC Target Increase by Schedule	$52,446,470	$63,448,423	$20,824,121	($1,085,990)	$395,199	($6,259,775)	($959,518)	($1,783,054)	($62,827)	($6,962,826)	($1,394,170)	($6,283,992)	($1,274,472)	($1,054,994)	($5,099,656)	$0	$0
27	Target Increase as Percent of Total Present Revenue	8.39%	16.36%	15.09%	-29.04%	38.04%	-33.80%	-86.16%	-20.23%	-69.93%	-28.34%	-18.32%	-84.24%	-13.75%	-9.85%	-82.32%	0.00%	0.00%
27A	Target Increase as Percent of Present Margin Revenue	14.91%	27.12%	29.14%	-60.59%	70.53%	-74.74%	-86.16%	-55.45%	-69.93%	-77.85%	-66.86%	-84.24%	-57.63%	-41.30%	-82.32%	0.00%	0.00%
28	**Target Margin per Delivered Therm**	$0.37	$0.77	$0.55	$0.14	$0.80	$0.08	$0.04	$0.10	$0.07	$0.05	$0.05	$0.01	$0.04	$0.05	$0.01	$0.00	$0.02

CASE: UG 344
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibits in Support
Of Opening Testimony

April 20, 2018

NW Natural®

Rates & Regulatory Affairs
UG 344
2017 General Rate Revision
Data Request Response

Request No.: UG 344 OPUC DR 350

Nomenclature protocol for the following question: "Main Extensions" run up and down neighborhood streets; "System Core Mains" constitute the balance of the distribution system, i.e., the larger-diameter mains that go out to the neighborhoods and in from the pipeline delivery point(s).

350. Line No. 10 of NW Natural/1101 Speer/Page 1 of 1 indicates that the annual revenue requirement for "Main Extensions" on a total replacement cost basis would be $315,808,952. What is the Company's best estimate of total replacement costs revenue requirement for "System Core Mains."? Comment: AVISTA's Core Main to Total Mains revenue requirement ratio is about 17%.

Response:

The Company does not forecast the replacement costs for "System Core Mains" as a normal process in the course of business; however, for purposes of this data request the Company estimates that the total replacement costs revenue requirement for "System Core Mains" is approximately $245,000,000. Because the estimate of the replacement costs for "System Core Mains" is not developed in our normal course of business and instead was developed specifically for this request, we reserve the right to challenge the use or application of this estimate in this proceeding.