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April 18, 2024

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UG 490 – In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.

Attached for Opening Testimony filing are the following exhibits:
Exh 100-109 Muldoon Redacted
Exh 200-202 Mondragon Redacted
Exh 300-301 Scala
Exh 400-402 Nottingham
Exh 500-502 Abraham
Exh 600-601 Anderson
Exh 700-702 Beitzel Redacted
Exh 800-805 Chipanera Redacted
Exh 900-907 Dlouhy Redacted
Exh 1000-1003 Dyck Redacted
Exh 1100-1102 Kim Redacted
Exh 1200-1204 Lockwood
Exh 1300-1303 Moore Redacted
Exh 1400-1402 Peng
Exh 1500-1501 Peterson
Exh 1600-1602 Pileggi
Exh 1700-1704 Rossow
Exh 1800-1803 Shierman
Exh 1900-1901 Stevens
Exh 2000-2004 Yamada Redacted
Exh 2100-2100 Hennessy

Highly Confidential and non-confidential Excel exhibits included with this filing are:
Highly Confidential exhibits:
Exh 2004 (3)

Non-Confidential exhibits:
Exh 101, 102, 103, 104, and 105
Exh 106
Exh 107
Exh 202 (4)
Exh 502
Exh 904
Exh 1002 (5)
Exh 1202
Exh 1203
Exh 2002 (3)

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CERTIFICATE OF SERVICE

UG 490

I certify that this day I served the foregoing document upon all the following parties or attorneys of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid or by electronic mail pursuant to OAR 860-001-0180 (which may include a link to a secure shared file service).

Dated this 18th day of April, 2024, at Salem, Oregon.

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CASE: UG 490
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

REDACTED
OPENING TESTIMONY
Overview and Return on Equity
Subject to Protective Order No. 23-480

April 18, 2024

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

A. My name is Matt Muldoon. I am a manager employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Stipulating Parties/101.

Q. What is the purpose of your testimony?

A. I introduce Staff-sponsored adjustments and issues regarding the Northwest Natural Gas Company (NW Natural, NWN, or Company) request for a general rate revision, docketed as Docket No. UG 490 and articulate some of Staff's overarching concerns regarding the frequency and aggregate magnitude of the Company's proposed increases in this rate case and in recent years. I also address NW Naturals Pensions and Post Retirement Medical Expenses, Cost of Capital components and overall Rate of Return (ROR), going into greater detail regarding Return on Common Equity (ROE).

Further detail on Capital Structure is found in Rose Pileggi's testimony in Exhibit Staff/1200. NW Natural's cost of Long-Term Debt is addressed in a Stipulation executed by Staff and other parties.[1]

Q. Are other Staff witnesses submitting testimony?

A. Yes. Each Staff assigned to Docket No. UG 490 is submitting separate testimony. My testimony introduces the Staff witnesses and their respective

[1] See Stipulating Parties/100, Kravitz, Muldoon, Jenks, Mullins/1-6.

assignments and estimates the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. Additional detail about revenue, expense, and rate base components of Staff's proposed adjustments is found in Luz Mondragon's testimony in Exhibit Staff/200. The issues identified in Staff testimony are those identified to date. Staff's recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Did you prepare exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared the following exhibits:

Other Supporting Exhibits

1. REVENUE REQUIREMENT IMPACT BY STAFF TOPIC

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

A. See Table 1 below:

TABLE 1 – STAFF RATE CASE TOPICS

Staff Issues Summary Table - ($000) for Test Year Ending October 31, 2025					
Total Incremental Revenue Requirement on the Company's Filed General Rate Case				$154,913	$154,913
Exhibit	**Issue**	**Staff**	**Staff Issues and Proposed Adjustments**	**Revenue Requirement @ROE 8.9%**	**Revenue Requirement @ROE 9.3%**
100	1	Muldoon	Introduction	-	-
	2		Concerns	-	-
	3		Return on Equity (ROE) - **Range** (**Floor to Ceiling**)	**(18,819)**	**(12,770)**
	4		Pensions and Post Retirement Medical Expense	-	-
	5		Physical and Cyber Security	-	-
200	1	Mondragon	Revenue Requirement Summary	-	-
	2a		Customer Service(CS) , and Operations and Maintenance (O&M) Non-Labor (NL)	(11)	(11)
	2b		Sales Expense Dealer Relations	(88)	(88)
	2c		Sales Expense, Consumer Price Index (CPI) Adjustment	(6)	(6)
	3		ARAM Excess Deferred Income Tax (EDIT)	(140)	(140)
	4		Interest Synchronization	-	-
	6		Budget to Actuals	-	-
300	1	Scala	Energy Justice Overview	-	-
400	1	Nottingham	Overview of Public Comments Received to Date	-	-
	2		How Falling Natural Gas Prices Can Help NWN Customers	-	-
500	1	Abraham	Gas Storage Operating Expense	(275)	(275)
	2		Gas Storage in Rate Base	-	-
	3		New Major Gas Storage Projects	-	-
600	1	Anderson	Utility Plant in Service	-	-
	2		Gains on Sale of Utility Property	-	-
	3		Test Year Rate Base, Discrete vs Non Discrete Investments	-	-
	4		New Major Plant Distribution Projects North Coast Feeder B	**(601)**	**(619)**
	5		New Plant - Resource Centers	-	-
	6		Attestations and Other Project Adjustments	-	-
700	1	Beitzel	Non-Medical Insurance and Risk	-	-
	2		Directors and Officers (D&O) Insurance (**CONFIDENTIAL**)	[redacted]	[redacted]
800	1	Chipanera	Escalations	-	-
	2		Cash Working Capital	**(45)**	**(46)**
	3		Regulatory Fees	194	194
	4		Income Taxes	-	-
	5		Leasehold Improvements	-	-
	6		Other Related Topics	-	-
900	1	Dlouhy	Climate Protection Program (CPP)	-	-
	2		Renewable Natural Gas Automatic (RNG) Adjustment Clause (AAC)	-	-
	3		Residential Line Extension Allowance (LEA)	-	-
	4		Meter Modernization Program (MMP)	**(814)**	**(841)**

Continued on Next Page

Concluded

1000	1	Dyck	Information Technology and Security (IT&S) projects, and Cloud-Based Software - Genesis Contingency	**(319)**	**(329)**
	2a		A&G Expense NL, Office Supplies & CPI Adjustment	(975)	(975)
	2b		Admin. Expenses with CPI Adjustment	147	147
	2c		Shareholder Meeting with CPI Adjustment	(287)	(287)
	2d		Rents with CPI Adjusments	(43)	(43)
1100	1	Kim	Long-Term Natural Gas Price Hedging	-	-
	2		Schedule H	-	-
1200	1	Lockwood	Uncollectible Accounts	(2,926)	(2,926)
	2		NW Natural's Bill Discount Program	-	-
1300	1	Moore	Distribution O&M Expense	(6,371)	(6,371)
	2		Materials and Supplies	**(352)**	**(363)**
	3		Customer Accounts	(2,184)	(2,184)
	4		Affiliated Interests	-	-
	5		Atmospheric Testing	-	-
1400	1	Peng	Depreciation Expense	-	-
	2		Ammortization Expense	-	-
	3		Depreciation Reserve	-	-
	4		Ammortization Reserve	-	-
	5		Allowance for Funds Used During Construction (AFUDC)	-	-
1500	1	Peterson	Current Medical and Health Insurance	(542)	(542)
	2		Current Pension Costs	-	-
1600	1	Pileggi	Capital Structure	-	-
1700	1	Rossow	Political Activities and Office Supplies	(12)	(12)
	2		Advertising	(169)	(169)
	3		Memberships Dues and Donations	(499)	(499)
	4		Meals, Entertainment and Travel	(364)	(364)
1800	1	Shierman	Marginal Cost	-	-
	2		Rate Spread	-	-
	3		Rate Design	-	-
1900	1	Stevens	Load Forecasting	-	-
	2		Decoupling	-	-
	3		Rate Base Calculations	-	-
2000	1a	Yamada	Wage and Salaries (W&S) - O&M	(6,657)	(6,657)
	1b		W&S Capital	**(279)**	**(288)**
	2		Incentives	-	-
	3		Full Time Equivalents (FTE)	-	-
	4		Related Issues	-	-
2100	1	Hennessy	Safety and Insepction Programs	-	-
			Total Staff Proposed Adjustments (Base Rates) (**CONFIDENTIAL**):	[redacted]	[redacted]
			Staff-Calculated Revenue Requirements Change (Base Rates) (**CONFIDENTIAL**):	[redacted]	[redacted]

2. INTRODUCTION TO OTHER STAFF'S OPENING TESTIMONY

Q. Please describe the opening testimony submitted by Staff in this rate case.

A. The Staff exhibit number, respective Staff witness, and topics published on this date are presented below.

Topics addressed in Opening Testimony published April 18, 2024:

In **Exhibit 200, Luz Mondragon**, Senior Financial Analyst, reviews revenue requirements, customer service sales expense, operations and maintenance (O&M) non-labor (NL), excess deferred income taxes, interest synchronization, and budget to actuals.

In **Exhibit 300, Michell Scala**, Energy Justice Program Manager, provides an Energy Justice overview for this general rate case and discusses energy justice foci.

In **Exhibit 400, Melissa Nottingham** summarizes public comments received by the Commission as of March 12, 2024. She also provides an overview of how falling natural gas commodity costs may help control costs in another rate proceeding outside this general rate case: the Company's annual Purchase Gas Adjustment (PGA); and in aggregate reduce total rate increases for changes effective November 1, 2024.

In **Exhibit 500, David Abraham**, Senior Economist, discusses the Company's gas storage operating expense, gas storage in rate base, and new major storage gas projects.

In **Exhibit 600, Laurel Anderson**, Senior Financial Analyst, discusses utility plant in service, gains on sale of utility property, test year rate base discrete vs, non-discrete investments, new plant major distribution projects, new plant resource centers, attestations, and Staff-proposed project adjustments.

In **Exhibit 700 Russ Beitzel**, Program Manager of the Rates and Telecommunications Section reviews non-medical insurance and risk, and Directors and Officers (D&O) insurance.

In **Exhibit 800, Itayi Chipanera**, Senior Financial Analyst, discusses escalations, cash working capital, regulatory fees, income taxes, leasehold improvements, and related topics.

In **Exhibit 900, Dr. Curtis Dlouhy**, Senior Economic and Policy Analyst, reviews NW Natural's proposals regarding the Climate Protection Program (CPP), Renewable Natural Gas Automatic (RNG) Adjustment Clause (AAC), Residential Line Extension Allowance (LEA), and Meter Modernization Program (MMP).

In **Exhibit 1000, Julie Dyck**, Senior Economist and Utility Analyst, reviews NW Natural's information technology and security (IT&S) projects, cloud-based software, and A&G (NL) expense.

In **Exhibit 1100, Anna Kim**, Energy Costs Section Manager, reviews the Company's Long-Term Hedging, and Schedule H.

In **Exhibit 1200, Charles Lockwood**, Utility Analyst, analyzes uncollectible accounts, and the Company's bill discount program.

In **Exhibit 1300, Mitch Moore**, Senior Utility Analyst, analyzes distribution O&M expense, materials and supplies, customer accounts, affiliated interests, and the Company's atmospheric testing.

In **Exhibit 1400, Ming Peng**, Senior Economist, analyzes depreciation expense, amortization expense, depreciation reserve, amortization reserve, and Allowance for Funds Used During Construction (AFUDC).

In **Exhibit 1500, Nicola Peterson**, Senior Telecom Analyst, analyzes current medical and health insurance, and Current Pension Costs.

In **Exhibit 1600, Rose Pileggi**, Senior Utility Analyst, analyzes NW Natural's capital structure.

In **Exhibit 1700, Paul Rossow**, Utility Analyst, reviews NW Natural's expense related to political activities, advertising, memberships, dues, donations, meals, entertainments, and travel.

In **Exhibit 1800, Eric Shierman**, Senior Utility Analyst, analyzes NW Natural's marginal cost, rate spread, and rate design.

In **Exhibit 1900, Dr. Bret Stevens, Ph.D.**, Senior Economist, analyzes the Company's load forecasting, decoupling, and rate base calculations.

In **Exhibit 2000, Steph Yamada**, Senior Utility Analyst examines NW Natural's wages and salaries, incentives, full time equivalents (FTE), and other related issues.

In **Exhibit 2100, Kervin Hennessy**, Senior Utility Analyst examines NW Natural's safety and inspection programs.

3. CONCERN – FREQUENCY AND AGGREGATE AMOUNT OF INCREASES

Q. Are there any issues that appear in the case that you would like to highlight?

A. Yes. Staff is concerned that the aggregate rate impacts of this general rate case, deferrals, and power costs may constitute an unreasonably energy burden for NW Natural's Oregon utility customers outpacing Oregon wages. According to the Wall Street Journal (WSJ), necessities like food have become much more expensive in recent years.[2] Further, the U.S. Federal Reserve (Fed) is tightening monetary policy to control high inflation.[3] This increases the cost of borrowing for utility rate payers as well as the cost of debt for utilities.

Q. Can you give a general idea of the mindset you would prefer NW Natural executives avoid when considering cost controls and capital project best management practices?

A. Yes. In the news articles cited above, some food company executives have said that "shoppers will adjust over time to higher prices, as they have in the past". This mind set presumes that consumers of goods and services who have finite resources will either consume less or otherwise shift their spending to deal with higher prices on necessities.

While energy efficiency is generally praiseworthy, Staff expects utility leadership to control costs to the extent practicable throttle the frequency and

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2 See Exhibit Staff/109 Muldoon/21 for "It's Been 30 Years Since Food Ate Up This Much of Your Income" by Jesse Newman and Heather Haddon of the WSJ – Feb 26, 2024. Also see Exhibit Staff/109 Muldoon/22 for "How Far $100 Goes at the Grocery Store After Five Years of Food Inflation" by Stephanie Stamm and Jesse Newman of the WSJ – April 4, 2024.

3 See Exhibit Staff/109 Muldoon/26 for Fed activity on interest rates.

amount of rate increase, and to avoid the presumption that if energy prices rise faster than wages, they utility customers will just need to “adjust” to that new reality.

Q. Please show the approximate impact on residential customer rates were the Company’s rate increase implemented as requested.

A. Staff cautions that it is still early in this proceeding and the following depiction reflects a point estimate prior to Staff’s filing its Opening Testimony:

Table 2

Current Residential	Avg. Useage/Mo.	Residential Avg. Basic Charge $/Mo.	Residential Avg. Bill $/Mo.
Single Family	55	$ 8.00	$ 79.43
Multi-Family	55	$ 8.00	$ 79.43

	Nov. 1, 2024 Increase	Scenario if increase were $154.9 M*			
NWN Proposed [1]		New Residential Basic Charge $/Mo.	New Residential Avg. Bill $/Mo.	Increase $/Mo	% Increase
Single Family	$154.9 Million*	$ 10.00	$ 93.81	$ 14.38	18.10%
NP Single Family		$ 26.25	$ 66.54	n/a	n/a
Multi-Family		$ 8.00	$ 91.82	$ 12.39	15.60%
NP Multi-Family		$ 24.25	$ 63.92	n/a	n/a

* Oregon jurisdictional revenues overall increase of 16.62 percent

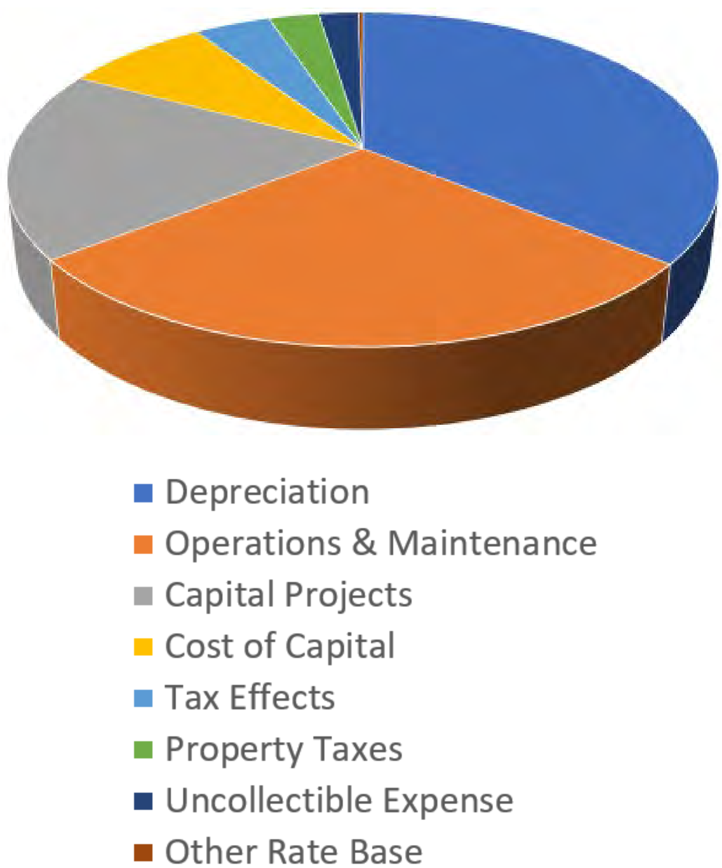
[1] Margin revenues for existing and **new premise** (NP) were designed to generate an equal amount. Monthly bill is driven by usage differences.

This information does not yet reflect recommendations offered by Staff and intervenors for Commission consideration, which if adopted, would reduce the impact of NW Natural’s proposed rate increase.

Q. What does the Company identify as key cost drivers when describing this rate case to investors and analysts?

A. With the caution that this is at a very general level, and importantly without showing NW Natural's offsetting revenues and cost controls, the largest drivers of costs in this general rate increase are shown below.

Table 3



Cost Drivers	%
Depreciation	35.92%
Operations & Maintenance	28.57%
Capital Projects	18.36%
Cost of Capital	7.90%
Tax Effects	4.12%
Property Taxes	2.72%
Uncollectible Expense	2.14%
Other Rate Base	0.26%
	100.00%

Rate Case Cost Drivers	Approximate NWN Proposed Oregon Revenue Requirement	
	$ Millions	**Percent**
Driver 1: Capital Projects [1] (Examples Below) Current Rate Base $1,755,679 Million (UG 435); Proposed Rate Base $2,136,361 million	**32,948**	21.27%
Central Resource Center	788	0.51%
Meter Modernization	4,559	2.94%
Incremental Cloud Capital (replace end of life software)	3,100	2.00%
Storage Investments for Winter Peak	4,765	3.08%
Other	19,736	12.74%
Driver 2: Cost of Capital (as requested) 10.1% ROE, 50% Equity, 4.712% Cost LT Debt	**14,167**	9.15%
Driver 3: Depreciation	**64,453**	41.61%
Depreciation Study	35,403	22.85%
Increased Capital	29,050	18.75%
Driver 4: O&M	**51,273**	33.10%
2 Years of Wages and Salaries	19,389	12.52%
Customer Payment Processing	1,333	0.86%
Locating Services	2,997	1.93%
IT&S (software licenses)	4,650	3.00%
Other (inflationary pressures across all costs)	22,904	14.79%
Driver 5: Gross Up	**7,401**	4.78%
Federal Income Taxes	1,151	0.74%
State Income Taxes	1,073	0.69%
Franchise Taxes	4,572	2.95%
Corporate Activity Tax	605	0.39%
Driver 6: Uncollectible Expense	**3,848**	2.48%
Driver 7: Property Taxes	**4,888**	3.16%
Driver 8: Other Rate Base	**463**	0.30%
Driver 9: Revenue (net of Cost of Gas)	**-24,531**	-15.84%
Customer Growth	-24,531	-15.84%
Total	**154,910**	100.00%

Staff's testimony will provide more detail on the above costs. Note that the information above does not capture all the Company's tax offsets and offsetting operating revenues as well as cost controls that reduce the impact to customers rates.

Q. What could the Commission do to address general rate increases of the magnitude proposed by NW Natural in this general rate case?

A. One solution proposed by Bob Jenks of the Oregon Citizens' Utility Board (CUB) on that organization's website is for the Commission to set the utility's profit margin at the lowest reasonable point.[4]

Q. Does Staff agree with CUB that this is the Commission's best option?

A. Staff analyzing Cost of Capital (CoC) in this general rate case would not use terms like "allowable profit margins" interchangeably with allowed Return on Equity (ROE). Staff also think holistically about Cost of Capital considering credit ratings and the financial health of Commission jurisdictional energy utilities and their relative strength in financial markets in comparison to their peer or similarly situated like utilities.

However, in advance of reading any testimony by CUB in this general rate case, Staff agrees that the Commission could consider any ROE in Staff's range of reasonable ROE's for Commission Authorized ROE in its final order in this general rate case.

Q. Are there other ways that the Commission could look at using ROE to mitigate the magnitude and frequency of general rate cases?

A. Yes. The Commission could consider using ROE as a throttle to control the frequency of general rate cases. For example, were a utility to file three

[4] Posted January 25, 2024, on https://oregoncub.org/ this proposal within "Is Oregon Utility Regulation Part of the Problem?" by Bob Jenks is reproduced with some small editing changes to fit a written rather than on-screen format at Exhibit Staff/109 Muldoon/13 to capture the context in which the suggestion was made. Also see Exhibit Staff/109 Muldoon/14-16.

general rate cases in a five-year period, the Commission might consider that activity sufficient to reduce regulatory lag and reduce financial risk in terms of metrics like ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt, in a form meaningful to credit rating agencies.

Q. Would that last approach be immediately applicable in this general rate case?

A. That is uncertain. Persons concerned about the frequency and aggregate magnitude of energy utility rate increases in Oregon are sharing ideas on possible solutions. Consideration of recommendations raised in this general rate case could give the Commission tools to mitigate the impact of frequent rate cases on jurisdictional utility customers. Staff will continue to monitor suggestions on intervenors in this case and closely review the analysis and justifications provided to support such recommendations to the Commission.

The Commission's evaluation of such proposals is consistent with public comments and posting by intervenors asking that the Commission consider impacts on utility customers in its determination of most appropriate just and reasonable outcomes in this case.

Q. Are utility customers helped by falling natural gas prices?

A. Yes. Please see Exhibit Staff/400 Nottingham's discussion of how natural gas prices falling in the first quarter of this year could help control Purchase Gas Adjustment (PGA) and rate case aggregate rate changes on November 1.[5]

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5 NYMEX Natural Gas Prices fell 29.87 percent in the first quarter of 2024. See Exhibit Staff/109, Muldoon/44, "Track the Markets: Quarterly Winners and Losers" published in the Wall Street Journal on April 1, 2024.

4. OVERALL RATE OF RETURN (ROR)

Q. What did NW Natural include in its initial filing for its overall Rate of Return?

A. The Company. proposes a rate of return of 7.807 percent, with a capital structure comprised of 51 percent equity and 49 percent debt, a 5.104 percent cost of debt, and a 10.40 percent return on equity.

Q. Did you prepare tables showing NW Natural's current Commission-authorized, Company-filed, and Staff-calculated RORs?

A. Yes. The following three tables provide that information.

TABLE 4

NWN Current OPUC Authorized (UG 435 Order No. 22-388, 22-437)			NWN
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long-Term Debt	50.0%	4.271%	2.136%
Preferred Stock	0.0%	0.0%	0.000%
Common Stock	50.0%	9.40%	4.700%
	100.00%	**ROR**	**6.836%**

TABLE 5[6]

NWN Requested – UG 490		NWN Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	50%	**4.712%**	2.356%	**0.571%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	50%	**10.10%**	5.050%	
	100.00%	**ROR**	**7.406%**	

6 NW Natural/300, Wilson/3.

TABLE 6

Staff Proposed – UG 490		Staff Opening Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long-Term Debt	**50.00%**	**4.712%**	2.356%	**0.070%**
Preferred Stock	0%	0.0%	0.000%	
Common Stock	**50.00%**	**9.10%**	4.550%	
	100.00%	**ROR**	**6.906%**	

CAPITAL STRUCTURE

Q. Has the Commission recently considered a preferred target capital structure?

A. Yes. In PacifiCorp's 2020 GRC, the Commission adopted a notional 50 percent equity capital structure. The Commission noted that "[w]e consider all components to the company's cost of capital that will result in a fair and reasonable rate of return, 'to strike a balance between the interests of ratepayers and the interests of investors [,]" and that 50/50 capital structure was an optimal structure for ratemaking.[7]

Q. Does NW Natural continue to target a 50 percent Common Equity / 50 percent LT Debt capital structure?

A. Yes.[8] See Staff/1600 Pileggi for further discussion on capital structure.

COST OF LONG-TERM DEBT

Q. Did parties address Cost of Long-Term Debt in a partial settlement?

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7 *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 374, Order No. 20-473, p. 24 (December 18, 2020).

8 See NW Natural/300, Wilson/3.

A. Yes. As earlier mentioned in this testimony NW Natural, Staff, the Alliance of Western Energy Consumers, and CUB recommend the Commission adopt a 4.712 percent Cost of Long-Term Debt.

5. RETURN ON EQUITY (ROE)

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

A. Staff observes a range of reasonable ROEs of 8.9 percent to 9.3 percent, with a mean ROE of 9.1, derived from Staff's two separate Three-Stage Discounted-Cash-Flow (DCF) models. Staff does not have a recommended point ROE estimate in this case, which is a departure from its typical practice.

Q. Did you perform a check on the results of Staff's Three-Stage DCF models?

A. Yes. Staff employed two simpler models to check the reasonableness of its findings:

1. A Single-Stage DCF or Gordon Growth Model; and,
2. A Capital Asset Pricing Model (CAPM).

Q. What results did these models generate?

A. The Gordon Growth Model generated a mean ROE of 7.5 percent using Staff's peer electric utilities and 7.7 percent with the Company's peer electric utilities. This model points to the lower end of Staff's three-stage discounted cash flow results.

The CAPM using Staff's usual inputs and methodology generated a mean ROE of 9.2 percent using Staff's peer electric utilities and 9.3 percent with the Company's peer electric utilities. This model supports an ROE at the middle to high end of Staff's three-stage discounted cash flow results.

Based on these checks, Staff utilizes the midpoint estimate of 9.1 percent for ROE in Table 6 above. However, any point within Staff's range of reasonable ROEs from 8.9 percent to 9.3 percent (rounded up) would be support of a just and reasonable ROE.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The range or reasonable ROEs Staff recommends is appropriate for overall rates that are reflective of forward looking conditions in conjunction with Staff's adjustments and meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040.[9] Staff recommendations are consistent with establishing "fair and reasonable rates" that are both, "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[10] However, a higher point within Staff's range would be more supportive of current NW Natural credit ratings and financial market expectations.

PEER SCREEN

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

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

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

10 *See* ORS 756.040(1)(a) and (b).

1. Covered by Value Line (VL) as an electric utility;
2. Forecasted by VL to have positive dividend growth;
3. LT Issuer Credit Rating greater than or equal to Baa3 from Moody's and greater than or equal to BBB- from S&P;[11]
4. No decline in annual dividend in last five years based on VL;
5. Has heavily regulated electric utility revenue;
6. Has LT Debt from 40 percent to 60 percent inclusive in VL Capital Structure; and[12]
7. Has no recent merger and acquisition activity representing a large portion of the utilities capitalization.[13]

Q. What peer groups of electric utilities did Staff and Company ROE modeling primarily depend on, and were there similarities?

A. The Company and Staff recommended regulated natural gas utility peer groups both drew from pertinent electric utilities covered by VL and with one exception, chose the same peer group. Staff did not select New Jersey Resources Corporation based on how much of its operational cash flows are regulated and that the credit rating coverage for the Company was withdrawn by Moody's and Standard & Poor's. Otherwise Table 7 shows the overlap between NW Natural's and Staff's peer groups.

Q. Did the Company apply some different criteria?

[11] See Exhibit Staff/101 Muldoon/1 for a table showing how Moody's and S&P ratings compare with each other.

[12] Staff also performs sensitivity analysis looking at a peer screen of 40 percent to 60 percent long-term debt in capital structure. Sensitivity analysis does not impact Staff's modeling results but does answer questions looking at alternative inputs and scenarios.

[13] See Staff/109, Muldoon/36-39 for examples of financial news on mergers monitored by Staff.

A. Yes. However, there was much overlap between NW Natural's and Staff's screening criteria. For example neither Staff nor NW Natural chose UGI Corporation as it primarily sells propane rather than natural gas.

TABLE 7[14]

UG 490 Company	UG 490 Staff
Yes	Yes
No	No
Yes	No
Yes	Yes
Yes	Yes
Yes	Yes
No	No
Yes	Yes
Yes	Yes
No	No

A comparison of the peer groups used by Staff and NW Natural are set forth in Table 9 above. Staff excluded some of the companies used by NW Natural based on the Staff screening criteria described above. Six companies were relied upon by both Staff and NW Natural.

Q. Is the set of Natural Gas utilities followed by Value Line relatively small.

A. Yes. Staff is also doing sensitivity modeling so that the Commission can consider over time whether publicly traded water utilities should be considered in the future as a second combined water and natural gas utilities peer group for a second set of recommendations regarding ROE. In this publication Staff

[14] See Exhibit Staff 102, Muldoon/2 for the full peer screening table.

just upgraded its natural gas utility information to bring its recommendations current with financial markets. Unfortunately Value Line has not yet made its forward-looking updates for water utilities so readers will have to wait for Staff's Rebuttal Testimony to see that modeling. However, because water utility information and modeling are provided only as a sensitivity and will not impact or change Staff's recommendations.

Q. Does NW Natural also offer a larger second peer group for the Commission's consideration?

A. Yes. NW Natural offers select electric utilities as a potential way to expand its natural gas peer group.[15] While Staff does not think this approach is informative for the Commission, the Company is considering ideas on how to address the relatively small group of publicly traded natural gas companies that are like NW Natural.

Bringing such ideas to the Commission may be helpful over the long run. The Commission may not have a best approach in mind now, but then again might not know exactly what it would like to see until it sees it.

MODEL RESULTS

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

A. See Table 8 below for the results from Staff's Three-Stage DCF modeling.

[15] See NW Natural/400 Coyne-Nelson/22 Figure 6.

TABLE 8 – RESULTS OF STAFF'S 3-STAGE DCF MODELING[16]

	8.9%	**to**	**9.3%**
	Midpoint	**9.1%**	**ROE**

Supporting Exhibit Staff/403, Muldoon/1 shows step-by-step how Staff's Hamada adjusted[17] Three-Stage DCF modeling, using Staff peers and growth rates, generates a higher recommended ROE than using NW Natural's peer electric utility group. Note that Staff rounds upward to generate a top of range value of 9.3 percent.

Q. Does Staff agree with the NW Natural's assertion that the Company's requested ROE of 10.1 percent is reasonable?

A. No. NW Natural comes up with a range of 10.0 percent to 10.6 percent with a recommended point estimate of 10.10 percent.[18] This is a very interesting range as most of the Company's similarly situated and sized (in terms of capitalization) utilities have ROE's authorized within the last two years that are below even the lowest point of this range. According to Regulatory Research Associates (RRA), an affiliate of S&P, the average ROE authorized for electric utilities rose to 9.54 percent for rate cases decided in 2022 from the 9.38 percent average for cases decided in 2021.[19]

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16 See Exhibit Staff/103, Muldoon/1 for the results of Staff three-stage DCF modeling.
17 As Staff explains in more detail below, Staff applies the Hamada equation to better compare companies with different capital structures.
18 See NW Natural/403, Coyne-Nelson/1.
19 See Exhibit Staff/109, Muldoon/1 for Average Authorized ROEs in 2023 by Lisa Fontanella, RRA.

Staff invites the Company to explain further in its Reply Testimony why its results exceed recent state commission authorized ROE's for its modeling peers.

Q. Based on the information you have reviewed can you explain why NW Natural's results appear unreasonably high?

A. Yes. NW Natural inputs unreasonably high assumptions regarding future markets into its financial models. These unreasonably high assumptions, coupled with the relatively simple nature of the models relied on most heavily by NW Natural, leads inexorably to high estimates of what return is necessary to attract investors in today's market.

Q. Please provide an example of an extreme input used in the Company's modeling.

A. Example 1 below shows how important inputs are to ROE modeling. Looking at the difference between NW Natural and Staff inputs, one can see how use of an inflated market return can skew results upward.

Example 1 – NOT a Staff Recommendation:

NWN	4.42%	Rf Rate as shown in Exhibit NWN/400 Coyne-Nelson/13 @31
Opening	13.31%	NWN Mkt Return
Testimony	8.89%	NWN Mkt Risk Premium (MRP) as shown in Exhibit NWN/400 Coyne-Nelson/13 @30
Staff	4.555%	R_f as April 5, 2024 30 Yr UST Yields WSJ Bonds & Rates (wsj.com)
	9.90%	S&P 500 Market Return 1993 thru 2023
	5.35%	Staff Mkt Risk Premium MRP)

Q. Please show a Capital Asset Pricing Model with Staff's and other more inflated inputs that may be preferred by the Company.

A. In Table 9 below, one can see how applying inputs from the table above to all the peer utilities changes ROE results of CAPM modeling.

Table 9 – Capital Asset Pricing Model (CAPM) Examples

	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	VL Q1 2024 Beta	ROE w VL Beta CAPM	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	0.85	9.10%	1	1
2	3	New Jersey	Yes	No	No	NJR	0.95	9.63%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	0.90	9.37%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	0.85	9.10%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	0.85	9.10%	6	5
6	8	Southwest Ga	Yes	Yes	Yes	SWX	0.90	9.37%	8	6
7	9	Spire	Yes	Yes	Yes	SR	0.85	9.10%	9	7
8	10	American Wa	No	No	Yes	AWK	0.95	9.63%	10	8
9	11	California Wa	No	No	Yes	CWT	0.75	8.56%	11	9
10	12	Middlesex W	No	No	Yes	MSEX	0.75	8.56%	12	10
11	13	SJW	No	No	Yes	SJW	0.85	9.10%	13	11
		No. of Peers:	7	6	10			VL Betas		
					Company Screen		Mean	9.3%	ROE	
					Staff Gas and Water Sensitivity Screen		Mean	9.1%	ROE	
					Staff Screen		Mean	9.2%	ROE	

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.

Staff usually relies on a U.S. Treasury (UST) thirty-year bond as reported by the Wall Street Journal (WSJ) and 30-year monthly geometric returns for the Standard and Poor's (S&P) 500 index as a proxy for market returns. If one instead uses **an extreme arithmetic market return,** one can inflate the results of a CAPM model with few inputs.[20] One can also boost results by using a starting point for data collection in the Great Depression and then including World War II era boom times unlikely to be repeated in the U.S. economy.

Q. Is calculation of a market risk premium calculated from 1926-2003 a good predictor of future U.S. stock returns?

A. No. Since returns over the last thirty years are lower than those experienced earlier in the Country's history, which includes post-World-War II economic

[20] See Staff/104, Muldoon/1 for this CAPM modeling example.

expansion in the U.S, expectations should mirror the recent 30-year returns. According to Ibbotson, reliance on a date range like NW Natural's would overstate likely future market returns.[21]

Q. Is Staff suggesting that CAPM is not a good model to check results of other modeling Staff performs, as advised by the Commission?

A. No. Rather, Staff shows why the Commission accepts CAPM only as a check on ROE modeling and demonstrates how one can abuse the model. If one eliminates unreasonable modeling inputs, selects only peer electric utilities most like NW Natural using Staff's standard screening methods, and eliminates unreasonable inputs, you arrive at a result equal to Staff's ROE recommendations.[22]

STAFF MODELS

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

A. Staff's first model is a conventional three-stage discounted dividend model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). This model captures the thinking of a money manager at a pension fund or insurance company, or other institutional investor, who expects to keep the Company's stock indefinitely and use the dividend cash flow to meet future obligations.

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21 See "The Equity Risk Premium" by William N. Goetzmann and Roger G. Ibbotson available on Amazon.com.

22 Exhibits Staff/101-105 show how Staff's recommendations are generated.

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

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

For a smooth transition, Staff steps the rate of dividend growth between the near-term (the next five years) and that of long-run expectations.

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

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

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

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

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

Q. How do you address dividend timing?[23]

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

The second set of calculations assumes the investor receives dividends

[23] See Exhibit Staff/108 for Value Line (VL) information relied on in this testimony regarding publicly traded natural gas and water utilities.

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

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

A. Staff used the average of closing prices for each utility from the first trading day in February 2024, March 2024, and April 2024, to represent a reasonable snapshot of utility stock prices.

GROWTH RATES USED IN THIRD STAGE OF DCF MODELS[24,25]

Q. What long-term growth rates did you use in Staff's two three-stage DCF models?[26,27]

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

The first method uses the U.S. Congressional Budget Office's (CBO) 4.46 percent nominal 20-year GDP growth rate estimate.

Staff's second Composite Growth Rate applies a 20 percent weight to each of the following referent entities long-term growth rates: EIA, Organization for Economic Co-operation and Development (OECD), the U.S. Social Security

24 See Exhibit Staff/106, Muldoon1 for BEA historical GDP growth rates.

25 See Exhibit Staff/107 Muldoon1 for TIPS implied long-run inflation rates.

26 Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. *See*, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, Exhibit Staff/800, Storm/46 – 52. Growth rates relied upon by Staff are also shown in Exhibit Staff/104, Muldoon/1.

27 See three-stage DCF models X and Y in Exhibit Staff/103.

Administration (SSA), the Congressional Budget Office's (CBO), with the remaining 20 percent as the average annual historical real GDP growth rate, established using regression analysis of U.S. Bureau of Economic Analysis (BEA) Nominal Historical,1980 Q1 – 2022 Q4, for the period 1980 through 2021, to which we apply a TIPS implied inflation forecast. These growth rates are shown below in Table 10.

Staff's third Composite Growth Rate is BEA Nominal Historical,1980 Q1–2023 Q4. These growth rates are shown below in Table 10.

TABLE 10
GROWTH RATES STAFF RELIED UPON

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	2.24%	2.39%	4.69%	20.0%	0.94%	
Organization for Economic Co-operation and Development (OECD)ggridlines	1.81%	2.39%	4.24%	20.0%	0.85%	
Social Security Administration (SSA)	1.95%	2.39%	4.39%	20.0%	0.88%	
Congressional Budget Office (CBO)	2.02%	2.39%	4.46%	20.0%	0.89%	
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	20.0%	1.02%	
Composite				100%	4.58%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			3.80%	100.0%	4.46%	CBO
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	100.0%	5.10%	Historical

Q. Did your analysis reflect a synthetic forward curve?

A. Yes. Staff utilized synthetic forward curve using UST Treasury Inflation Protected Securities (TIPS) break-even points. This reflects implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Staff assumes for purposes of its three-stage DCF modeling that LDC utility growth is bounded by the growth of the U.S. economy, and more specifically impacted by challenges regarding U.S. population, workforce participation, and productivity in the long-run (20-year) modeling period.

Q. How do your methods employed in this case differ from those utilized by Staff in recent general rate cases?

A. Staff's methods and modeling parallel those employed by Staff in recent electric utility general rate cases. Staff continues to look primarily to referent federal sources for long-term GDP growth rates which weight long-run population, workforce participation, and productivity higher than current financial market events and global events with shorter if not transitory effects. Nevertheless, Staff monitors current financial news, and this testimony is informed by such.[28]

Q. Do you capture both the perspective of a buy and hold investor and an investor who plans to sell in the future?

A. Yes. Staff's recommended 8.9 to 9.3 percent range of reasonable ROEs is consistent with findings modeling the perspectives of both types of investors through Staff's two different three-stage DCF models.

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

A. Yes.

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

[28] See Exhibit Staff/109, Muldoon/1-47 for news that investors in electric utilities are seeing.

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

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

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

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

A. Yes. Over-extrapolating a snapshot of short-term data undermines confidence in modeling results. For example, Value Line, Blue Chip, and a variety of other financial resources focus primarily on the next five years. The next five years may be affected by recent events. Over the long run, population and productivity are the key drivers of economic growth. This is of concern with declines in the rate of growth of America's population.[29]

Q. In Staff's two different three-stage DCF models, Staff is looking for growth rates for a period between 10 and 30 years in the future, or an average of 20-years out. Why not just use a five- or ten-year projection?

A. Staff could use a five- or ten-year projection, but there is better information available. If a primary concern is whether enough Americans are both working

[29] See Exhibit Staff/109, Muldoon for concerns about Oregon population growth.

and highly productive to support a robustly growing economy 30 years from now, 10-year data will not be the most useful. This is because 10-year data is not yet impacted by retirement of persons born in 1960 or persons not immigrating and not being born to U.S. families now. A better solution is to use data that is projected with those difficulties in mind, i.e., 30-year data.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at NW NATURAL's target capital structure increases required ROE. Why is this adjustment reasonable?

A. Staff employs the Hamada Equation to better compare companies with different capital structures driven by differing amounts of outstanding debt. As earlier discussed, Staff applied screening criteria already identify peers that have a very close capital structure to the Company. Use of the Hamada-adjusted results helps ensure that Staff has captured all material risk in our analysis because it captures additional risk associated with varying capital structure.

Within the confines of Staff's testimony, one can see the steps to un-lever and re-lever a peer company's capital structure as the equivalent of removing debt of peer companies with varying capital structures, and then adding enough debt back to equal the Company's balanced target capital structure in this general rate case.

Q. What accounts for differences in peer capital structures?

A. Each of the two models employs the Hamada equation[30] to calculate an adjustment for differences in capital structure between each peer utility and the Staff-proposed capital structure for the Company. When few peer utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. Why is it important to consider capital structure when modeling ROE?

A. Different amounts of debt financing along with different tax rates result in disparate risk profiles among peer utilities used in ROE modeling to approximate the unknown appropriate ROE for the utility examined. All else equal, with more debt in a capital structure, investors require higher expected equity returns to compensate for the increased risk. Debt has a higher call on the company's available cash, and so less cash is available for equity holders. Staff uses the Hamada equation, named after Robert Hamada, to separate the financial risk of a levered firm from its business risk, and adjust the results of peer utilities to have results as though they had the same capital structure as the utility for whom an appropriate ROE is sought.

Q. Did Staff use a capital structure peer group screen with 40 percent to 60 percent debt, carrying more interest rate risk than NW Natural?

[30] Dr. Robert Hamada's Equation as used in Staff/404 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

A. Yes. Inclusive of Hamada adjustments, the higher debt sensitivity peer group would decrease Staff's recommended ROE by 24 basis points. In general, the Hamada equation addresses the capital structure itself to a certain degree, companies taking on more debt may also be taking on more risk in other areas than finance.

Q. Did Staff use robust and proven analytical methodologies?

A. Yes. Staff's methods are robust, proven, and parallel Staff's work for many years. The Commission, for example, expressly relies on the multi-stage DCF to determine the range of ROEs and relies on CAPM and risk premium models to check the reasonableness of results. This can be seen in Order No. 22-129 in Portland General Electric Company's GRC (Docket No. UE 394) as well as in Order No. 20-473 in PacifiCorp's GRC (Docket No. UE 374).

Q. Describe how you performed your analysis.

A. Using the cohort of proxy companies that met our screens, Staff ran each of Staff's two three-stage DCF models three times, each time using a different long-term growth rate.

Q. Was your analysis consistent with a range of reasonable ROE's from 8.9 percent to 9.3 percent?

A. Yes.

<u>**Balanced Approach to ROE**</u>

Q. Is picking a best fit ROE within Staff's suggested range of reasonable ROE's an easy decision for the Commission.

A. No. On the one hand, a lower ROE would reduce the impact of this general rate increase on NW Natural's utility customers in Oregon. This thought is likely foremost for CUB members and employees based on the earlier cited statement by Director Bob Jenks.

On the other hand, a higher ROE is more supportive of the Company's credit ratings, which are under pressure based on financial metrics and from those who would like to migrate from natural gas for space heating and other purposes to greater reliance on renewably generated electricity or other alternatives to natural gas. Also the Oregon overall regulatory environment is a very large part of rating agency decision making. And these ratings influence the Company's borrowing cost in a period of significant spending for plant additions. A utility customer might think of this like buying the same house at low or high interest / mortgage rates.

Balancing these and other considerations is necessary for the Commission to make decisions consistent with the Hope and Bluefield legal decisions mentioned earlier.

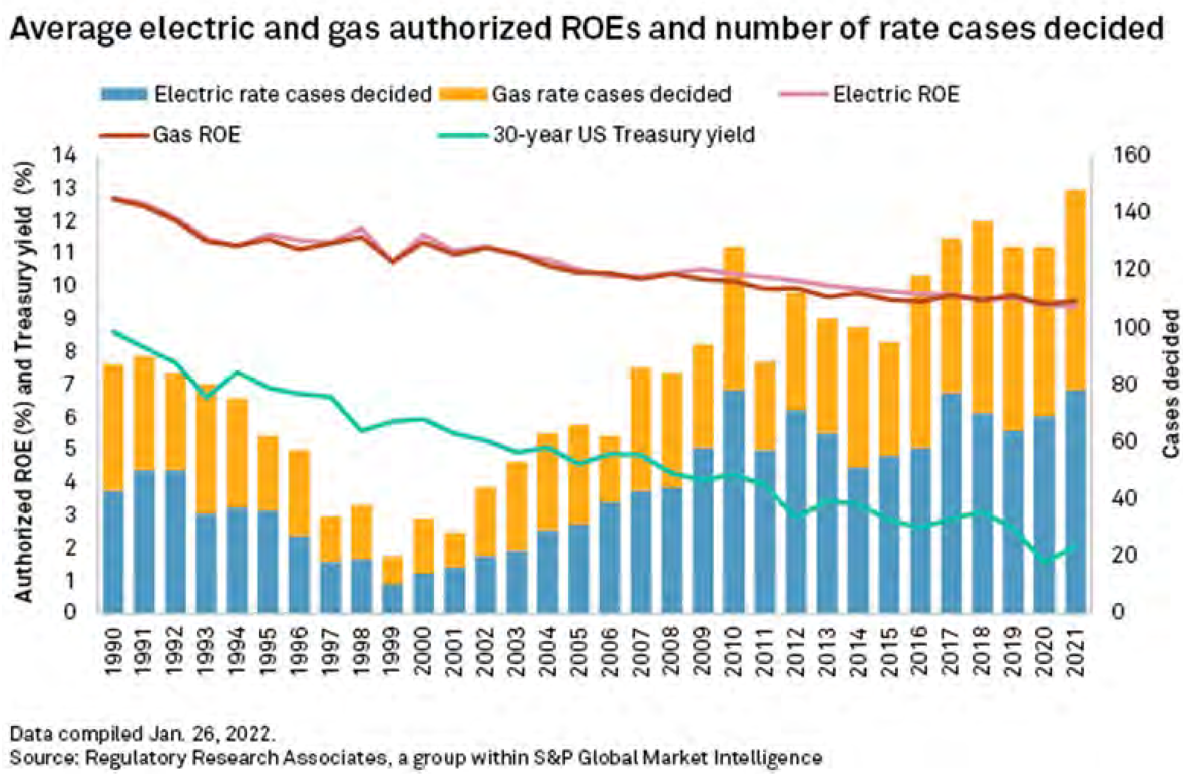
Q. Are we in a rising interest rate environment that compels higher ROEs?

A. No. The U.S. Federal Reserve expects to lower interest rates in the next two years.[31] Further interest rates and ROEs are both declining when looked at over a 30-year time frame. The downward glide path for ROE in Figure 1 below is not linear and may fluctuate through these uncertainties, but long-run

[31] See Staff/109, Muldoon/26.

GDP growth rates are mostly determined by the long future U.S. working age population and its productivity. These are downward pressures on GDP growth.

FIGURE 1 – Downward Glide Path of Utility ROES[32]



Q. What trend is Staff seeing?

A. Since 1990, according to Regulatory Research Associates (RRA), Electric and Electric Utility authorized ROEs have declined as the 30-year US Treasury (UST) has also declined. While the Fed recently raised interest rates, the Fed now anticipates loosening money supply soon.

[32] Published by Regulatory Research Associates (RRA), an affiliate of S&P Global Market Intelligence on Feb. 10, 2022.

GORDON GROWTH MODEL – As Check on ROE Findings

Q. What is the Gordon Growth model?

A. The Gordon Growth model (or Single Stage DCF model), similarly to the Three-Stage DCF model, is based on the principle that a company's value is equal to the net present value (NPV) of all its future cash flows and the company's current stock price. The Single-Stage DCF uses simpler assumptions than other models however, with dividend payments representing the only cash flow, and an assumption that growth will remain constant in perpetuity.[33]

Q. What are the positive aspects and potential shortfalls of the DCF model?

A. The most positive aspect of the Single-Stage model is its simplicity. An analyst can use this model to calculate a rudimentary cost of equity valuations without needing complex inputs or analysis, beyond selecting a trusted source for the next quarter's expected dividends. In fact, after some algebraic simplification, the return can be expressed by:

$$R = \frac{D_1}{P_0} + g$$

Where $\boldsymbol{R}$ is estimated ROE, $\boldsymbol{D_1}$ is the first dividend paid after stock purchase, $\boldsymbol{P_0}$ is the stock price, and $\boldsymbol{g}$ is the growth rate.

Caution and discretion must be used when sourcing inputs to the model; for example, growth rates should be based on well vetted and

[33] See Docket No. UG 347, Staff/1300, Muldoon Watson/31 – 39, for further discussion of the Single-Stage DCF model, and the Commission's historical treatment of its results.

reliable sources, as opposed to sell-side marketing information used by investment advisors to entice new investors. This is important to bear in mind when considering the results of any Single-Stage model, as reliance on overly optimistic inputs or use of outboard after-the-fact adjustments can have a large impact on the model output.

The Single-Stage model is based on simple principles and serves as a rough estimation of investor required ROE. It cannot incorporate known, measurable, and material information about the future usually built into Three-Stage DCF analysis. For this reason, Staff, consistent with Commission precedent, has traditionally only relied on it as a sensitivity check when rate making.

Q. How does Staff determine the dividend flow and growth rate for the single-stage DCF?

A. Much like Staff's Multi-Stage DCF, Staff sources its expected dividends from Value Line. We calculate the average dividend growth rate by comparing the expected dividend by Value Line and actual dividend for each for each company in the peer screen.

Q. What inputs does Staff use to build Staff's single-stage DCF model?

A. Staff uses the same representative draw of stock prices to build its single-stage DCF model as it uses in the three-stage DCF model. Current dividends and anticipated dividend growth are sourced from Value Line.

Q. What are the results of Staff's Gordon Growth model?

A. Using Staff's peer utility screen, the average required ROE under Staff's Gordon Growth model is 7.5 percent.

TABLE 11[34]

		1	2	3	4	5	6	7	8	9	11 =9+10	13	14	15
	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	116.00	2.6%	3.22	2.8%	7.3%	10.1%	1	1
2	3	New Jersey	Yes	No	No	NJR	42.43	3.7%	1.68	4.0%	5.0%	8.9%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	26.97	3.7%	1.06	3.9%	4.2%	8.1%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	33.46	5.8%	1.95	5.8%	0.4%	6.2%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	62.62	4.2%	2.64	4.2%	2.4%	6.7%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	SWX	72.94	3.4%	2.48	3.4%	1.1%	4.5%	8	6
7	9	Spire	Yes	Yes	Yes	SR	60.01	4.8%	3.02	5.0%	4.7%	9.7%	9	7
8	10	American Water	No	No	Yes	AWK	119.76	2.3%	3.00	2.5%	-100.0%	-97.5%	10	8
9	11	California Water	No	No	Yes	CWT	46.04	2.3%	1.12	2.4%	-100.0%	-97.6%	11	9
10	12	Middlesex Water	No	No	Yes	MSEX	50.55	2.5%	1.32	2.6%	-100.0%	-97.4%	12	10
11	13	SJW	No	No	Yes	SJW	55.37	2.7%	1.60	2.9%	-100.0%	-97.1%	13	11
		No. of Peers:	7	6	10							Mean		
											Company Screen	7.7%	ROE	
											Staff Gas and Water Sensitivity Screen	N/A	ROE	
											Staff Screen	7.5%	ROE	

Findings in Table 11 above support selection in the lower end of Staff's range of reasonable ROEs.

34 See Exhibit Staff/105, Muldoon/1 for Staff's full Gordon Growth Model.

CAPM – As Check on ROE Findings

Q. What is the Capital Asset Pricing Model (CAPM)?

A. The CAPM assumes that a stock's return on equity is a function of a risk-free return and a risk premium and that the risk premium should be augmented by a company's level of risk relative to the market, which is captured by Beta or β. All told, CAPM takes the form:

$$\boldsymbol{Required\ Return} = \boldsymbol{r_f} + \boldsymbol{\beta}(\boldsymbol{r_m} - \boldsymbol{r_f})$$

Where $\boldsymbol{r_f}$ is the risk-free rate and $\boldsymbol{r_m}$ is the market return. Generally, the risk-free rate is assumed to be the rate of return on bonds. Taking cues from long-standing financial modelling, Staff calculates its CAPM using the yield on 30-year and 10-year US Treasury bonds as stand-ins the risk-free rate.

Q. Should the Commission scrutinize CAPM carefully?

A. Yes. CAPM only relies on a few inputs. In this case, there are three inputs: the risk-free rate, the market return, and the choice of Beta. Although it is generally agreed that the rate of return on US Treasury bonds is the proper choice for the risk-free rate, there is much discussion about what maturity should be used for Beta and the market return.

There are a variety of sources to find or calculate both Beta and the market return. Because there are so many sources for two inputs into this simple model, an uninformed or malicious investigator could use unrepresentative values to motivate abnormal required returns. It is therefore of the utmost importance to be thoughtful and consistent in choosing CAPM parameters. In Commission activities, we have standardized on Value Line

(VL) Betas that are broadly used to give apples-to-apples modeling output comparisons. Staff has used CAPM for validation rather than rate setting in past cases.

Q. Where do you find information on companies' Beta estimates?

A. Estimates of Beta can be found from many sources including Bloomberg, Yahoo Finance, and VL. Traditionally, the Commission has relied on Value Line's Beta estimates to conduct analysis to maintain consistency in regulation between rate cases. The perils of switching between Beta estimates, known as "Beta shopping," will be addressed later in this testimony.

Q. Where do you find information on market returns?

A. Market returns can also be found or calculated from a variety of places. Two common sources for market returns are historical returns on stock market indices and projections for future growth. As earlier discussed, care should be taken in selecting a market return due to the volatile nature of the stock market.

Q. What issues can arise from an improper market return selection?

A. For any company with a positive Beta, a higher market return translates directly into a higher required return according to the CAPM formula. Overstating market returns, a required return estimate can vary by up to three percent for a typical regulated utility.

Q. How does Staff recommend that market returns be calculated?

A. Staff recommends that market returns be calculated based off the historic long-run growth rates of stocks and an up-to-date measure of the risk-free rate. By using historical averages, a modeler does not run the risk of a large shock in one period unnecessarily augmenting estimated returns, much like the large negative shock caused by the COVID-19 pandemic, the roaring economic recovery post-pandemic, or the ongoing conflict in Ukraine.

As has been done in past rate cases, Staff uses the market risk premium calculated by Ibbotson and the implied market risk premium from Morningstar's Stocks, Bonds, Bills, and Inflation 2015 Classic Yearbook, which measures average returns since 1926. These two sources imply that the risk premium would be 4.5 percent and 6.0 percent, respectively. Staff also calculates market risk premiums as described herein using annualized monthly data for 30 years of geometric S&P 500 returns paired with current 30-year UST yields.

Q. What recommendations do you have for the maximum authorized ROE according to CAPM?

A. As stated previously, Staff only uses CAPM for validation rather than rate setting due to its historic unreliability. Within Staff's peer utility screen, the estimated ROEs from Staff's CAPM under Staff assumptions average 9.2 percent. Using the Company's peer screen and Staff's methods, the average estimated ROE observed is 9.3 percent. If one uses the Company's inflated market risk premium, one can boost results to 12.4 percent like that found as underlying averaged components in NW Natural's testimony.

Q. Has the Commission determined that CAPM should not be relied upon as a stand-alone modeling method?

A. Yes. The Commission made this determination in two general rate cases in 2001 with the issuance of Order No. 01-777 and Order No. 01-787, but still permits use of the CAPM as a check on other modeling methods employed.[35]

DIFFERENCES IN NW NATURAL ROE MODELING FROM STAFFS

Q. What are other differences in the Company's modeling that lead to different ROE modeling results.

A. Staff relies on Value Line data, which generally avoids benchmark shopping.

Q. What is benchmark shopping?

A. Benchmark shopping is performing a review of different data sources with different calculation methods and taking from that cross section certain benchmark data that is then argued before the Commission is most appropriate for this instance of use. The Commission then gets to hear exhaustive arguments on subjects such as the reversion to mean calculations behind Value Line, Bloomberg, and various other potential benchmarks. After an exhaustive examination, the use of alternate benchmarks can be usually determined by the Commission to be obfuscation that detracts from the exercise or modeling at hand.

Q. What are other ways that NW Natural's testimony on ROE might be considered off target?

A. In the Company's discussion of its selection of Risk-Free Rate in CAPM analysis, the Company offers various methods and then averages them.

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[35] *In the Matter of Portland General Electric*, Docket No. UE 115, Order No. 01-777 at 32; *In the Matter of PacifiCorp*, Docket No. UE 116, Order No. 01-787 at 21 (September 7, 2001).

What the Company does not mention is that it is averaging a variety of methods of inflating estimation of market results and market risk premium (MRP). For example, averaging super optimistic future projections of market returns with overly-long 90-year market returns does not yield a conservative MRP likely to reflect the near future. Think of this like trying to estimate the weight of your cat or dog. One could take the average weight of a whale, and the average weight of an elephant (both mammals) and suggest that would be an excellent proxy for the weight of your pet. The first estimate for the whale is too large. The second estimate of the elephant is also too large and not reflective of a conservative estimate because though it is smaller than that of the whale, it is still not a good estimate of the weight of your pet.

Q. What other misdirection might the Commission watch for?

A. The Commission should be vigilant for the substitution of five- to ten-year growth rates and other near-term data for 20- to 30-year data and projections from referent entities. Depending on the context, five- to ten-year data can be characterized as "long-term." But, for purposes of the analysis to estimate ROEs, long-term means 20-30 years in the future.

Generally, Value Line and Blue-Chip type resources focus on the next one to five years and call a future projection five to ten years into the future their long-tern projection. In contrast the U.S.: Social Security Administration, the Congressional Budget Office, the Bureau of Economic Analysis, Energy Information Administration, and other federal referent bodies mean 20-30 years into the future when they say "long-term".

Q. Why is that important in the context of ROE modeling?

A. Over the next few years, the United States still has a large working age population, despite the graying of America. Productivity has declined in recent years, but near-term GDP growth is still relatively strong.

But looking out 20-30 years, many Americans will be retired, and various other challenges cause referent entities to project lower GDP growth. So averaging a set of near-term growth numbers and using that average in lieu of long-run numbers from referent entities talking about 20-30 years in the future also boosts ROE modeling results.

Q. When will Staff provide more detailed examples of these approaches in NW Natural's ROE modeling?

A. Because Staff has just updated its natural gas utility peer market information to be current as of April, Staff will have time to illustrate how some of the above techniques are used in the Company's ROE modeling to present the appearance of conservative model building while inflating ROE model results.

Q. What was the result of Staff's updating its ROE modeling to incorporate most current market data?

A. Staff's top end of its ROE modeling results dropped 10 basis points from the modeling Staff did based on January 2024 market information.

6. PENSIONS AND POST RETIRMENT MEDICAL EXPENSE

Q. Does Staff recommend an adjustment to the Company's pensions and post-retirement medical expense in this general rate case?

A. No.

Q. Did Staff carefully analyze the Expected Return on Assets for each of the Company's pensions and post-retirement medical expense?

A. Yes. Staff performed its usual robust analysis, discussed these issues in detail at a workshop with the Company on March 5, 2024, and issued follow-up data requests, the responses to which corroborated Staff's findings. Staff found the Company's actuarial work consistent with the Company's benchmarks inclusive of EROA for Oregon Public Employee Retirement System (PERS), CA PERS, and California State Teachers' Retirement System.

Q. Did Staff carefully analyze the discount rate assumptions for each of the Company's pensions and post-retirement medical expense?

A. Yes. Staff also calibrated the revenue requirement impact of each of the above factors and confirmed that in aggregate the Company's work in this area was reasonable and no adjustment is required in this general rate case.

7. PHYSICAL AND CYBER SECURITY

Q. Does Staff recommend an adjustment to Information Technology (IT) and Security (IT&S) projects?

A. Please see Exhibit Staff/1000 Dyck for detail on Staff review of IT&S Projects that go into service in the test year.

Q. Does Staff Review the Company's project management performance and cost controls in compliance with TSA Security Directive 2 and updates thereto?

A. Yes. The Commission's RSUP group including Accounting and Finance, Safety, and Energy Costs Staff are reviewing the Company's investments in both physical and cyber security on an ongoing basis.

Q. Will Staff discuss the Companies practices and detailed costs of certain projects herein?

A. No. The Commission's RSUP group including X Accounting and Finance, Safety, and Energy Costs Staff are reviewing the Company's investments in both physical and cyber security on an ongoing basis to comply with U.S. Transportation Security Administration (TSA) and other agencies directives and to protect critical infrastructure in general.

Q. Why is this information on a "Federal Need to Know Basis"?

A. Proper handling of highly confidential critical infrastructure information protects the lives, livelihood, and modern standard of life for Oregonians.

Q. When federal agencies mandate the Company comply with new or updated directive does that give NW Natural a blank check to spend

whatever it takes and take a "cost is no object" approach to physical and cyber security?

A. No. Like all other project management the Commission reviews, NW Natural must consider less costly next best alternatives to its physical and cyber security capital spending and other initiatives. The Company must practice prudent project management and cost controls based on what is known and knowable at the time of NW Natural's decisions.

Q. What sort of risks does the Company have to consider in prudently managing its expenditures?

A. In general, the Company must consider two main types of risk. The first type is protection against something that is relatively likely to happen. One might think of this as a focus on the 95 percent of risks most likely to materialize.

But then a Commission jurisdictional energy utility must also consider and protect against High-Impact Low-Frequency (HILF) events. These are unlikely to happen, but if they do happen, outcomes could be catastrophic.

Q. Why does Staff look at these issues on an ongoing, open-ended basis?

A. Directives, standards, and best practices regarding physical and cyber security that the Company must comply with are regularly changing to address emerging concerns. Rather than a one-and-done review, Staff teams of financial and safety professionals, and engineers must vigilantly review incremental new Company initiatives and expenditures.

Just as utility customers cannot make necessary purchases at any price or only consider the most expensive options in life, utilities must frugally put in place assets and processes that get the job done effectively at reasonable cost.

8. CONCLUSION

Q. What is Staff's recommendation regarding ROE?

A. Staff recommends that the Commission select a point ROE from within Staff's range of reasonable ROE's from 8.9 percent to 9.3 percent (after rounding). This is a difficult decision balancing financial market criteria and credit ratings on the one hand against reducing energy burden for Oregon customers of NW Natural on the other.

Q. What Rate of Return (ROR) is generated by the Staff's aggregated Cost of Capital recommendations on Capital Structure, ROE, and Cost of Long-Term Debt?

A. Staff provides an illustrative 6.906 percent Overall Rate of Return (ROR), based on the midpoint of Staff's range of reasonable ROEs of 9.10 percent, a 50 percent equity layer Capital Structure, and the settled 4.712 percent Cost of Long-Term Debt.

Q. What recommendation does Staff have regarding a point estimate within Staff's range of reasonable ROEs?

A. Staff finds that recommending a range is appropriate rather than any single point estimate. The range is from 8.9 percent to 9.3 percent. The range provides values from which the Commission can use to balance the interests of shareholders and energy affordability for Oregon utility customers and still meet statutory requirements to provide for a fair return on equity.

Q. Does Staff recommend an adjustment to pensions and post-retirement expense in this general rate case?

A. No. Staff's usual robust analysis found the Company's work on these issues to be reasonable and in aggregate consistent with Staff's benchmarks.

Q. Does Staff recommend incremental adjustments in this testimony over those provided IN Exhibit Staff/1000 Dyck for IT&S projects?

A. No.

Q. Does that conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

ROE – Three-Stage DCF: Peer Screen, Dividends, Earnings per Share (EPS), and Hamada Equation

April 18, 2024

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+	C	CCC	C	CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC				CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

Natural Gas

NWN UG 490

Screen:	6	VL Gas Utilities passing Staff Peer Screen
Sensitivities:	8	VL Gas Utilities passing Co. Screen

80% Mid Cap

Gas Group

1 #	2 Abbreviated Utility	3 UG 490 Company	4 UG 490 Staff	5 VL Corporate Name Gas Utility	6 NYSE Ticker	7 VL Cap Small Mid Large	8 S&P Global Market Intelligence MI Key	9 SPCIQ Key	10 IRS EIN	11 SEC File	12 VL 3/28/2024 Beta <1	13 Yahoo Fin. 3/28/2024 Beta	14 Yahoo Fin. 3/28/2024 Mkt Cap $ Billions	15 VL 3/28/2024 Mkt Cap $ Billions	16 Value Line N-Gas Utility w VL Beta < 1 3/28/2024	17 VL No Div Declines 5 years	18 Either / Or: S&P Local LT 3/28/2024 Rating ≥ BBB-	19 Either / Or: Moody's Local LT 2/2/2024 Rating ≥ Baa3	20 Last 10-K Highly Regulated LDC Revenue	21 VL 2024 LT Debt ≥ 40% ≤ 60% of Capital	22 VL 2027-2029 LT Debt % of Capital	23 VL 2024 Common Equity % of Capital	24 VL 2024 Preferred Stock of Capital
1	Atmos	Yes	Yes	Atmos Energy Corporation	ATO	L	4057157	252684	75-1743247	1-10042	0.85	0.66	17.87	17.20	Yes	Pass	A-	A1	R	40.0%	40.0%	60.0%	0.0%
2	Chesapeake	No	No	Chesapeake Utilities Corporation	CPK	S	4057113	260346	51-0064146	1-11590	0.80	0.60	2.39	1.90	Yes	Pass	W	W	M	42.0%	40.0%	58.0%	0.0%
3	New Jersey	Yes	No	New Jersey Resources Corporation	NJR	M	4057128	291335	22-2376465	1-08359	0.95	0.65	4.21	4.10	Yes	Pass	W	W	M	57.0%	55.0%	42.5%	0.5%
4	NiSource	Yes	Yes	NiSource Inc.	NI	L	4057051	292092	35-1719974	1-09779	0.90	0.48	12.32	10.60	Yes	Pass	BBB+	Baa2	R	57.5%	55.0%	35.0%	7.5%
5	NW Natural	Yes	Yes	Northwest Natural Gas Corporation	NWN	S	4057132	292047	93-0256722	1-15973	0.85	0.56	1.39	1.30	Yes	Pass	A+	Baa1	R	52.5%	50.0%	47.5%	0.0%
6	ONE Gas	Yes	Yes	ONE Gas, Inc.	OGS	M	4427129	243685856	46-3561936	1-36108	0.85	0.64	3.64	3.50	Yes	Pass	A-	A3	R	45.0%	51.0%	55.0%	0.0%
7	South Jersey	No	No	South Jersey Industries, Inc.	SJI	M	4057145	303963	22-1901645	1-06364	0.90	N/A	N/A	4.20	Yes	Pass	W	N/A	M	60.0%	60.0%	40.0%	0.0%
8	Southwest Gas	Yes	Yes	Southwest Gas Holdings, Inc.	SWX	M	4884928	304227	81-3881866	1-37976	0.90	0.35	5.42	4.30	Yes	Pass	BBB-	Baa2	R	58.0%	57.0%	42.0%	0.0%
9	Spire	Yes	Yes	Spire, Inc. (Formerly: The Laclede Group, Inc.)	SR	M	4002506	284847	74-2976504	1-16681	0.85	0.52	3.38	3.30	Yes	Pass	A-	Baa2	R	52.0%	51.0%	44.0%	4.0%
10	UGI	No	No	*UGI Corporation (Propane Focus / VL)	UGI	M	4057537	190756	23-2668356	1-11071	1.10	1.17	5.11	5.00	Fail	Pass	W	W	Fail	60.0%	60.0%	39.0%	1.0%
	TOTAL PEERS	7	6																				

80% Mid Cap

When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, Vl shows "NMF" for 'no meaningful figure'.

*UGI Revenue is >35% from Propane / VL

Test Yr 2023

WGL is NOT shown due to purchase by AltaGas

R 80% or more of assets are regulated
M 50% - 79% of assets are regulated
W Ratings Withdrawn

Water

XXX UW XXX

Screen:	6	VL Water Utilities passing Staff Peer Screen
Sensitivities:	0	VL Water Utilities passing Co. Screen

80% Mid Cap

Sensitivity Modeling

Water Group | Sensitivity

1 #	2 Abbreviated Utility	3 UW 999 Company	4 UW 999 Staff	5 VL Corporate Name Water Utility	6 NYSE Ticker	7 VL Cap Small Mid Large	8 S&P Global Market Intelligence MI Key	9 SPCIQ Key	10 IRS EIN	11 SEC File	12 VL 3/28/2024 Beta <1	13 Yahoo Fin. 3/28/2024 Beta	14 Yahoo Fin. 3/28/2024 Mkt Cap $ Billions	15 VL 3/28/2024 Mkt Cap $ Billions	16 Value Line Water Utility w VL Beta < 1 2/5/2024	17 VL No Div Declines 5 years	18 Either / Or: S&P Local LT 3/28/2024 Rating ≥ BBB-	19 Either / Or: Moody's Local LT 2/23/2024 Rating ≥ Baa3	20 Last 10-K Highly Regulated LDC Revenue	21 VL 2024 LT Debt < 56% of Capital	22 VL 2026-2028 LT Debt % of Capital	23 VL 2024 Common Equity % of Capital	24 VL 2024 Preferred Stock of Capital
1	American Water	No	Yes	American Water	AWK	L	4004387	250885	51-0063696	1-34028	0.95	0.62	23.68	25.60	Yes	Pass	A	Baa1	R	57.5%	57.5%	42.5%	0.0%
2	American	No	No	Amer. States Water	AWR	M	4093614	304353	95-4676679	1-14431	0.70	0.42	2.68	3.00	Yes	Pass	A	W	M	46.5%	50.0%	53.5%	0.0%
3	California Water	No	Yes	California Water Service Group	CWT	M	4721056	257568	77-0448994	1-13883	0.75	0.49	2.70	3.00	Yes	Pass	A+	W	R	40.5%	38.0%	59.5%	0.0%
4	Essential Utility	No	No	Essential Util.	WTRG	L	4092620	296276	23-1702594	1-6659	1.00	0.81	10.07	10.10	No	Pass	A-	Baa2	R	52.5%	56.0%	47.5%	0.0%
5	Middlesex Water	No	Yes	Middlesex Water	MSEX	S	4104374	288070	22-1114430	0-422	0.75	0.74	936.887m	1.20	Yes	Pass	A	W	R	41.5%	40.5%	58.5%	0.0%
6	SJW	No	Yes	SJW Group	SJW	M	5000889	301316	77-0066628	1-8966	0.85	0.58	1.82	2.10	Yes	Pass	A-	NR	R	52.5%	43.0%	47.5%	0.0%
	TOTAL PEERS	0	4																				

80% Mid Cap

When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, Vl shows "NMF" for 'no meaningful figure'.

R 80% or more of assets are regulated
M 50% - 79% of assets are regulated
W Ratings Withdrawn

Natural Gas

NWN UG 490

1	2	3	4	25	26	27	28
		Screen:	6				
		Sensitivities:	8				
#	Abbreviated Utility	Gas Group UG 490 Company	UG 490 Staff	VL Div. Growth Rate > 0%	Major M&A in Last 4 Years	M&A Activity and General Notes re: Last 4 Years	#
1	Atmos	Yes	Yes	Pass	Pass		1
2	Chesapeake	No	No	Pass	Fail	VL indicates this utility is 72.3% regulated energy operations. 11/7/2022 acquires 100% of Planet Found Energy Development LLC for $9.4 million. 9/26/2023 Agree to acquire Florida City Gas from NextEra for $923 million in Q4 2023.	2
3	New Jersey	Yes	No	Pass	Pass		3
4	NiSource	Yes	Yes	Pass	*Pass	Feb. 2020 Eversource Energy announced a **$1.1 billion acquisition of Columbia Gas of Massachusetts from NiSource**. Feb 29, 2020, NiSource buy Columbia Energy group for $6 billion.	4
5	NW Natural	Yes	Yes	Pass	Pass	October 5, 2022, NWN Water completed the acquisition of the water and wastewater utilities of Far West Water & Sewer, Inc. after closing adjustments, was approximately $97.0 million. 10/2/2023 acquires Rose Valley Water Co.	5
6	ONE Gas	Yes	Yes	Pass	Pass		6
7	South Jersey	No	No	Pass	Fail	**$8.1 billion buyout** of **South Jersey Industries** by Infrastructure Investments Fund pending per S&P	7
8	Southwest Gas	Yes	Yes	Pass	Pass	Carl Icahn Proposes a Hostile Takeover, which Staff discounts because of Utility management and regulatory opposition. On 12/15 SWX announced it will sell MountsinWest Pipelines Holdings Co. to Williams for $1.5 billion in total enterprise value. 2/14/2023 Williams	8
9	Spire	Yes	Yes	Pass	Pass		9
10	UGI	No	No	Pass	Pass	Very Heavy Propane Position	10
	TOTAL PEERS	7	6			*20% of Mkt Cap will pass the M&A screen test.	
			80% Mid Cap				

Test Yr 2023

Water

XXX UW XXX

1	2	3	4	25	26	27	28
		Screen:	6				
		Sensitivities:	0				
#	Abbreviated Utility	Water Group UW 999 Company	Sensitivity UW 999 Staff	VL Div. Growth Rate > 0%	Major M&A in Last 4 Years	M&A Activity and General Notes re: Last 4 Years	#
1	American Water	No	Yes	Pass	Pass	5/27/2023 Pennsylvania American Water, a subsidiary completed a deal with the City of York to acquire the City's wastewater system assets $253.3 million. 32 Acq. Under agreement as of 3/31/2022.	1
2	American	No	No	Pass	Pass		2
3	California Water	No	Yes	Pass	Pass		3
4	Essential Utility	No	No	Pass	Fail	3/16/2020 acquired People's natural Gas for $4.275 billion. 1/3/2023 plan to sell to Hope Gas	4
5	Middlesex Water	No	Yes	Pass	Pass		5
6	SJW	No	Yes	Pass	Pass	2/17/21 SJW TX Subsidiary bought Kendall West and Bandera East water utilities for $23M Annual Report.	6
	TOTAL PEERS	0	4			*20% of Mkt Cap will pass the M&A screen test.	
			80% Mid Cap				

NWN - Gas Peer Dividends

Last Updated: April 4, 2024

UG 490 — Value Line Dividends — Value Line

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Yr
1	1	Atmos	Yes	Yes	ATO	0.575	0.575	0.575	0.625	2.35	0.625	0.625	0.625	0.68	2.555	0.68	0.68	0.68	0.74	2.78	0.74	0.74	0.74	0.805	3.03	2.79	3.22
3	3	New Jersey	Yes	No	NJR	0.3125	0.3125	0.3125	0.3325	1.27	0.3325	0.3325	0.3325	0.3625	1.36	0.3625	0.3625	0.3625	0.3625	1.45	0.39	0.39	0.39	0.39	1.56	1.46	1.68
4	4	NiSource	Yes	Yes	NI	0.21	0.21	0.21	0.21	0.84	0.22	0.22	0.22	0.22	0.88	0.235	0.235	0.235	0.235	0.94	0.25	0.25	0.25	0.25	1.00	0.94	1.06
5	5	NW Natural	Yes	Yes	NWN	0.4775	0.4775	0.4775	0.48	1.91	0.48	0.48	0.48	0.483	1.92	0.483	0.483	0.483	0.485	1.93	0.485	0.485	0.485	0.488	1.94	1.93	1.95
6	6	ONE Gas	Yes	Yes	OGS	0.540	0.54	0.54	0.54	2.16	0.58	0.58	0.58	0.58	2.32	0.62	0.62	0.62	0.62	2.48	0.65	0.65	0.65	0.65	2.60	2.47	2.64
8	8	Southwest Gas	Yes	Yes	SWX	0.545	0.57	0.57	0.57	2.26	0.57	0.595	0.595	0.595	2.36	0.595	0.62	0.62	0.62	2.46	0.62	0.62	0.62	0.62	2.48	2.43	2.48
9	9	Spire	Yes	Yes	SR	0.6225	0.6225	0.6225	0.6225	2.49	0.65	0.65	0.65	0.65	2.60	0.685	0.685	0.685	0.685	2.74	0.72	0.72	0.72	0.72	2.88	2.74	3.02
		TOTAL PEERS	7	6																							
				80% Mid Cap																							

NWN - Gas Peer EPS

Last Updated: April 4, 2024

UG 490 — Value Line Earnings per Share (EPS) — Value Line

	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 490 Company	UG 490 Staff	Ticker	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2024 Yr	2025 Q1
1	1	Atmos	Yes	Yes	ATO	1.71	2.30	0.78	0.37	5.16	1.86	2.37	0.92	0.51	5.66	1.91	2.48	0.94	0.80	6.13	5.65	2.08	2.53	1.06	0.88	6.55	2.21
3	3	New Jersey	Yes	No	NJR	0.46	1.77	(0.15)	0.07	2.15	0.69	1.36	(0.04)	0.50	2.51	1.14	1.16	0.10	0.30	2.70	2.45	0.74	1.35	0.05	0.66	2.80	0.75
4	4	NiSource	Yes	Yes	NI	0.77	0.13	0.11	0.39	1.40	0.75	0.12	0.10	0.50	1.47	0.77	0.11	0.19	0.53	1.60	1.49	0.85	0.15	0.13	0.57	1.70	0.90
5	5	NW Natural	Yes	Yes	NWN	1.94	(0.02)	(0.67)	1.31	2.56	1.80	0.05	(0.56)	1.36	2.65	2.01	0.03	(0.65)	1.26	2.65	2.62	2.00	0.05	(0.65)	1.35	2.75	2.10
6	6	ONE Gas	Yes	Yes	OGS	1.79	0.56	0.38	1.12	3.85	1.83	0.59	0.44	1.23	4.09	1.84	0.58	0.45	1.28	4.15	4.03	1.82	0.57	0.43	1.23	4.05	1.87
8	8	Southwest Gas	Yes	Yes	SWX	2.03	0.43	(0.19)	1.15	3.42	1.58	(0.10)	(0.18)	(4.18)	(2.88)	0.67	0.40	0.04	1.74	2.85	1.13	1.45	0.55	0.20	1.10	3.30	1.75
9	9	Spire	Yes	Yes	SR	1.65	3.55	0.03	(0.26)	4.97	1.01	3.27	(0.10)	(0.20)	3.98	1.66	3.33	(0.48)	(0.66)	3.85	4.27	1.52	3.34	(0.30)	(0.46)	4.10	1.50
		TOTAL PEERS	7	6																							
				80% Mid Cap																							

Water Utility Sensitivity Modeling Information is in progress - being updated for Staff R

NWN - Water Peer Dividends

Sensitivity Modeling — Last Updated: April 4, 2024 — Update Still in Progress

UG 490 — Value Line Dividends — Value Line

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020 Yr	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Yr
1	10	American Water	No	Yes	AWK	0.50	0.55	0.55	0.55	2.15	0.55	0.6025	0.6025	0.6025	2.36	0.6025	0.655	0.665	0.655	2.58	0.655	0.7075	0.7075	0.7075	2.78	2.57	3.00
3	11	California Water	No	Yes	CWT	0.2125	0.2125	0.2125	0.2125	0.85	0.230	0.230	0.230	0.230	0.92	0.250	0.250	0.250	0.250	1.00	0.260	0.260	0.260	0.260	1.04	0.99	1.12
5	12	Middlesex Water	No	Yes	MSEX	0.2562	0.2562	0.2562	0.2725	1.04	0.2725	0.2725	0.2725	0.29	1.11	0.29	0.29	0.29	0.3125	1.18	0.3125	0.3125	0.3125	0.325	1.26	1.18	1.32
6	13	SJW	No	Yes	SJW	0.32	0.32	0.32	0.32	1.28	0.34	0.34	0.34	0.34	1.36	0.36	0.36	0.36	0.36	1.44	0.38	0.38	0.38	0.38	1.52	1.44	1.60
		TOTAL PEERS	0	4																							
				80% Mid Cap																							

Water Utility Sensitivity Modeling Information is in progress - being updated for Staff R

NWN - Water Peer EPS

Sensitivity Modeling — Last Updated: April 4, 2024 — Update Still in Progress

UG 490 — Value Line Earnings per Share (EPS) — Value Line

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2021 Q1	2021 Q2	2021 Q3	2021 Q4	2021 Yr	2022 Q1	2022 Q2	2022 Q3	2022 Q4	2022 Yr	2023 Q1	2023 Q2	2023 Q3	2023 Q4	2023 Yr	2021-23 Average	2024 Q1	2024 Q2	2024 Q3	2024 Q4	2024 Yr	2025 Q1
1	10	American Water	No	Yes	AWK	0.73	1.14	1.53	3.55	6.95	0.87	1.20	1.63	0.81	4.51	0.91	1.44	1.66	0.79	4.80	5.42	0.95	1.50	1.85	0.85	5.15	
3	11	California Water	No	Yes	CWT	(0.06)	0.75	1.20	0.07	1.96	0.02	0.36	1.03	0.35	1.76	(0.40)	0.17	0.60	0.43	0.80	1.51	0.15	0.60	1.00	0.50	2.25	
5	12	Middlesex Water	No	Yes	MSEX	0.39	0.62	0.65	0.41	2.07	0.68	0.50	0.80	0.40	2.38	0.33	0.55	0.56	0.61	2.05	2.17	0.50	0.65	0.75	0.65	2.55	
6	13	SJW	No	Yes	SJW	0.09	0.69	0.64	0.60	2.02	0.12	0.38	0.82	1.09	2.41	0.37	0.58	1.13	0.87	2.95	2.46	0.45	0.60	1.20	0.90	3.15	
		TOTAL PEERS	0	4																							
				80% Mid Cap																							

NWN - Gas Peer Dividends

Historical and Near Term VL Dividends, and

UG 490 — e Estimated Near Future Dividends

	1	2	3	4	5	28	29	30	31	32	33	34	35	
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	VL Avg. 2027 - 29 / Yr	Div Growth 2027-29 vs. 2021-23	#	
1	1	Atmos	Yes	Yes	ATO	3.46	3.53	3.87	4.25	4.63	4.25	7.3%	1	1
3	3	New Jersey	Yes	No	NJR	1.76	1.77	1.86	1.95	2.04	1.95	5.0%	3	3
4	4	NiSource	Yes	Yes	NI	1.12	1.10	1.15	1.20	1.25	1.20	4.2%	4	4
5	5	NW Natural	Yes	Yes	NWN	1.96	1.96	1.97	1.98	1.99	1.98	0.4%	5	5
6	6	ONE Gas	Yes	Yes	OGS	2.68	2.71	2.78	2.85	2.92	2.85	2.4%	6	6
8	8	Southwest Gas	Yes	Yes	SWX	2.52	2.52	2.56	2.60	2.64	2.60	1.1%	8	8
9	9	Spire	Yes	Yes	SR	3.16	3.20	3.40	3.60	3.80	3.60	4.7%	9	9
		TOTAL PEERS	7	6							Staff Gas Screen	3.3%	Mean	
				80% Mid Cap							Company Peer Screen	3.6%		

NWN - Gas Peer EPS

UG 490 — Estimated Near Future Earnings per Share in Blue

	1	2	3	4	5	27	28	29	30	31	32	33	34	35	36	37	38
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	2025 Q2	2025 Q3	2025 Q4	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	VL Avg 2027- 29 / Yr	EPS Growth VL Avg 2027-29 vs. 2021-23	#	
1	1	Atmos	Yes	Yes	ATO	2.65	1.17	0.97	7.00	7.42	7.87	8.35	8.83	8.35	6.7%	1	1
3	3	New Jersey	Yes	No	NJR	1.40	0.05	0.70	2.90	3.09	3.29	3.50	3.71	3.50	6.1%	3	3
4	4	NiSource	Yes	Yes	NI	0.20	0.15	0.60	1.85	1.93	2.01	2.10	2.19	2.10	5.9%	4	4
5	5	NW Natural	Yes	Yes	NWN	0.05	(0.60)	1.45	3.00	3.08	3.16	3.25	3.34	3.25	3.7%	5	5
6	6	ONE Gas	Yes	Yes	OGS	0.60	0.48	1.25	4.20	4.45	4.72	5.00	5.28	5.00	3.7%	6	6
8	8	Southwest Gas	Yes	Yes	SWX	0.65	0.15	1.65	4.20	4.22	4.23	4.25	4.27	4.25	24.7%	8	8
9	9	Spire	Yes	Yes	SR	3.35	(0.11)	(0.24)	4.50	4.81	5.14	5.50	5.86	5.50	4.3%	9	9
		TOTAL PEERS	7	6										Staff Gas Screen	8.2%	Mean	
				80% Mid Cap										Company Peer Screen	7.9%		

ebuttal Testimony VL 27-29 Estimates Not Yet Available.

NWN - Water Peer Dividends

UG 490 — e Estimated Near Future Dividends

	1	2	3	4	5	28	29	30	31	32	33	34	35	
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	VL Avg. 2027 - 29 / Yr	Div Growth 2027-29 vs. 2021-23	#	
1	10	American Water	No	Yes	AWK		0.00	0.00	0.00	0.00		-100.0%	10	1
3	11	California Water	No	Yes	CWT		0.00	0.00	0.00	0.00		-100.0%	11	3
5	12	Middlesex Water	No	Yes	MSEX		0.00	0.00	0.00	0.00		-100.0%	12	5
6	13	SJW	No	Yes	SJW		0.00	0.00	0.00	0.00		-100.0%	13	6
		TOTAL PEERS	0	4							Staff Water Screen	-100.0%	Mean	
				80% Mid Cap							Company Peer Screen	#N/A		

ebuttal Testimony VL 27-29 Estimates Not Yet Available.

NWN - Water Peer EPS

UG 490 — Estimated Near Future Earnings per Share in Blue

	1	2	3	4	5	28	29	30	31	32	33	34	35	36	37	38	
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	2025 Q2	2025 Q3	2025 Q4	2025 Yr	2026 Yr	2027 Yr	2028 Yr	2029 Yr	VL Avg 2027- 29 / Yr	EPS Growth VL Avg 2027-29 vs. 2021-23	#	
1	10	American Water	No	Yes	AWK				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	10	1
3	11	California Water	No	Yes	CWT				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	11	3
5	12	Middlesex Water	No	Yes	MSEX				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	12	5
6	13	SJW	No	Yes	SJW				0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!		-100.0%	13	6
		TOTAL PEERS	0	4										Staff Gas Screen	-100.0%	Mean	
				80% Mid Cap										Company Peer Screen	#N/A		

NWN GRC
UG 490 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22	
						Yahoo Finance Q1 2024 $ Stock Closing Price 1st Trading Day of Month							VL 2024 Cap Structure								Hamada Adjustment		
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	Ticker	Feb. 2/1/2023	Mar. 3/1/2024	Apr. 4/1/2024	3-Day Avg $ Stock Price	Div Yield at Recent Price	VL 2024 Return on Common Equity		% Long-Term Debt	% Common Equity	VL Beta	2024 VL Tax Rate	Hamada Unlevered Beta	Relevered Beta Equity at 50.0%		Equity Risk Premium	Equity At 50.0%	#	
1	1	Atmos	Yes	Yes	ATO	112.91	118.87	116.23	116.00	2.6%	8.5%		40.0	60.0	0.85	12.0%	0.54	1.01		4.20%	0.66%	1	1
3	3	New Jersey	Yes	No	NJR	41.61	42.91	42.78	42.43	3.7%	11.5%		57.0	43.0	0.95	22.0%	0.47	0.83		4.20%	-0.50%	3	3
4	4	NiSource	Yes	Yes	NI	26.06	27.66	27.19	26.97	3.7%	9.5%		57.5	37.5	0.90	19.0%	0.40	0.73		4.20%	-0.73%	4	4
5	5	NW Natural	Yes	Yes	NWN	36.74	37.22	26.41	33.46	5.8%	8.0%		52.5	47.5	0.85	25.0%	0.46	0.81		4.20%	-0.15%	5	5
6	6	ONE Gas	Yes	Yes	OGS	59.60	64.53	63.72	62.62	4.2%	8.5%		45.0	55.0	0.85	16.5%	0.50	0.93		4.20%	0.32%	6	6
8	8	Southwest Gas	Yes	Yes	SWX	68.15	76.13	74.54	72.94	3.4%	6.5%		58.0	42.0	0.90	21.0%	0.43	0.77		4.20%	-0.54%	8	8
9	9	Spire	Yes	Yes	SR	59.32	61.37	59.34	60.01	4.8%	8.0%		52.0	44.0	0.85	19.0%	0.43	0.79		4.20%	-0.27%	9	9
		TOTAL PEERS	7	6		Dividend Yield = (Annual Dividends per Share) / Price per Share												Staff Gas Screen			-0.1%	Mean	
				80% Mid Cap		When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, Vl shows "NMF" for 'no meaningful figure'.												Company Peer Screen			-0.2%		

Water Sensitivity Modeling
UG 490 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11	#	13	14	15	16	17	18	#	20	21	22	
						Yahoo Finance Q1 2024 $ Stock Closing Price 1st Trading Day of Month							VL 2024 Cap Structure								Hamada Adjustment		
	#	Abbreviated Utility	UW 999 Company	UW 999 Staff	Ticker	Feb. 2/1/2023	Mar. 3/1/2024	Apr. 4/1/2024	3-Day Avg $ Stock Price	Div Yield at Recent Price	VL 2024 Return on Common Equity		% Long-Term Debt	% Common Equity	VL Beta	2024 VL Tax Rate	Hamada Unlevered Beta	Relevered Beta Equity at 50.0%		Equity Risk Premium	Equity At 50.0%	#	
1	10	American Water	No	Yes	AWK	118.54	122.21	118.52	119.76	2.3%	9.50%		57.5	42.5	0.95	21.0%	0.46	0.82		4.20%	-0.54%	1	1
3	11	California Water	No	Yes	CWT	45.89	46.48	45.76	46.04	2.3%	8.50%		40.5	59.5	0.75	21.0%	0.49	0.87		4.20%	0.52%	3	3
5	12	Middlesex Water	No	Yes	MSEX	50.89	52.50	48.26	50.55	2.5%	11.00%		41.5	58.5	0.75	21.0%	0.48	0.86		4.20%	0.46%	5	5
6	13	SJW	No	Yes	SJW	55.06	56.59	54.45	55.37	2.7%	7.50%		52.5	47.5	0.85	21.0%	0.45	0.81		4.20%	-0.16%	6	6
		TOTAL PEERS	0	4		Dividend Yield = (Annual Dividends per Share) / Price per Share												Staff Gas Screen			0.1%	Mean	
				80% Mid Cap		When Value Line (VL) Beta ratio exceeds 99.9 or earnings are negative, Vl shows "NMF" for 'no meaningful figure'.												Company Peer Screen			#N/A		

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

ROE – Three-Stage DCF:
Models X and Y

April 18, 2024

4.46% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows   Staff   UG 490   Model X

	1	2	3	4	5	6	7	8	9
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*
1	1	Atmos	Yes	Yes	Yes	7.9%	40.5%	0.00	(116.00)
2	3	New Jersey	Yes	No	No	8.4%	34.3%	(0.00)	(42.43)
3	4	NiSource	Yes	Yes	Yes	8.2%	36.0%	0.00	(26.97)
4	5	NW Natural	Yes	Yes	Yes	8.8%	28.3%	0.00	(33.46)
5	6	ONE Gas	Yes	Yes	Yes	8.0%	36.6%	0.00	(62.62)
6	8	Southwest Gas	Yes	Yes	Yes	7.1%	46.6%	0.00	(72.94)
7	9	Spire	Yes	Yes	Yes	9.6%	25.2%	0.00	(60.01)
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)
		TOTAL PEERS	7	6	10	Mean			
				80% Mid Cap		8.27%	35.52%	0.00	Staff Gas Screen
						N/A	35.52%	0.00	Staff Gas and Water Sensitivity Screen
						8.29%	35.35%	(0.00)	Company Peer Screen

#	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Initial Stage					Transition Stage					Final Stage				
1	3.22	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62
3	1.68	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10
4	1.06	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83
5	1.95	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52
6	2.64	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01
8	2.48	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44
9	3.02	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69
10	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	1.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

#	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Perpetuity	#	
	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
1	7.96	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	459.93	14.67	445.26	1	1
3	3.23	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	163.78	5.96	157.82	3	2
4	1.91	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	102.70	3.53	99.17	4	3
5	2.63	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	120.25	4.84	115.41	5	4
6	4.19	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	233.09	7.72	225.37	6	5
8	3.60	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	267.23	6.62	260.61	8	6
9	5.95	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	234.76	10.95	223.81	9	7
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	10	8
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	11	9
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	12	10
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	13	11

Staff will update Water Sensitivity in Staff Rebuttal Testimony

B.O.Y. Cash Flows   Staff   UG 490   Model X

	1	2	3	4	5	6	7	8	9
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*
1	1	Atmos	Yes	Yes	Yes	8.1%	38.5%	(0.00)	(116.00)
2	3	New Jersey	Yes	No	No	8.6%	32.7%	0.00	(42.43)
3	4	NiSource	Yes	Yes	Yes	8.3%	34.6%	(0.00)	(26.97)
4	5	NW Natural	Yes	Yes	Yes	9.0%	27.6%	0.00	(33.46)
5	6	ONE Gas	Yes	Yes	Yes	8.2%	35.4%	0.00	(62.62)
6	8	Southwest Gas	Yes	Yes	Yes	7.2%	45.6%	0.00	(72.94)
7	9	Spire	Yes	Yes	Yes	9.8%	23.7%	0.00	(60.01)
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)
		TOTAL PEERS	7	6	10	Mean			
				80% Mid Cap		8.43%	34.23%	(0.00)	Staff Gas Screen
						N/A	34.23%	(0.00)	Staff Gas and Water Sensitivity Screen
						8.45%	34.01%	(0.00)	Company Peer Screen

#	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	Initial Stage					Transition Stage					Final Stage				
1	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96
3	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23
4	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91
5	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63
6	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19
8	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60
9	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

#	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Perpetuity	#	
	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
1	8.32	8.69	9.08	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	14.67	458.33	15.32	443.01	1	1
3	3.38	3.53	3.69	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	5.96	164.11	6.22	157.89	3	2
4	2.00	2.09	2.18	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	3.53	103.03	3.68	99.34	4	3
5	2.75	2.87	3.00	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	4.84	121.90	5.06	116.85	5	4
6	4.38	4.57	4.78	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	7.72	234.64	8.07	226.58	6	5
8	3.76	3.92	4.10	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	6.62	269.14	6.92	262.22	8	6
9	6.21	6.49	6.78	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	10.95	235.14	11.44	223.70	9	7
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	10	8
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	11	9
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	12	10
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#VALUE!	0.00	#VALUE!	13	11

Staff will update Water Sensitivity in Staff Rebuttal Testimony

Average B.O.Y. & E.O.Y. Cash Flows   Model X

	1	2	3	4	5	6	7	8	9			
							Terminal Value as	Average 2023 - 2027 Dividend Growth Rates				
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	Average IRR	% of NPV_{DIV}	EOY	BOY	Average	#	
1	1	Atmos	Yes	Yes	Yes	8.0%	39.5%	7.2%	7.5%	7.4%	1	1
2	3	New Jersey	Yes	No	No	8.5%	33.5%	3.8%	3.8%	3.8%	3	2
3	4	NiSource	Yes	Yes	Yes	8.3%	35.3%	3.1%	2.8%	3.0%	4	3
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.9%	0.4%	0.4%	0.4%	5	4
5	6	ONE Gas	Yes	Yes	Yes	8.1%	36.0%	1.9%	2.2%	2.1%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	7.2%	46.1%	1.2%	1.2%	1.2%	8	6
7	9	Spire	Yes	Yes	Yes	9.7%	24.4%	4.5%	4.8%	4.6%	9	7
8	10	American Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	10	8
9	11	California Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	11	9
10	12	Middlesex Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	12	10
11	13	SJW	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	13	11
		TOTAL PEERS	7	6	10	Mean						
				80% Mid Cap		8.35%	34.88%	3.09%	Staff Gas Screen			
						N/A	34.88%	#DIV/0!	Staff Gas and Water Sensitivity Screen			
						8.37%	34.68%	3.19%	Company Peer Screen			

Staff will update Water Sensitivity in Staff Rebuttal Testimony

4.58% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal **EPS Growth**

E.O.Y. Cash Flows

Staff UG 490 Model Y

	1	2	3	4	5	6	7	8	9
	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*
1	1	Atmos	Yes	Yes	Yes	8.2%	42.9%	0.00	(116.00)
				e					
2	3	New Jersey	Yes	No	No	8.7%	36.8%	0.00	(42.43)
				e					
3	4	NiSource	Yes	Yes	Yes	8.4%	37.4%	-	(26.97)
				e					
4	5	NW Natural	Yes	Yes	Yes	8.8%	28.2%	0.00	(33.46)
				e					
5	6	ONE Gas	Yes	Yes	Yes	8.2%	37.7%	0.00	(62.62)
				e					
6	8	Southwest Gas	Yes	Yes	Yes	8.9%	56.3%	0.00	(72.94)
				e					
7	9	Spire	Yes	Yes	Yes	9.7%	26.5%	0.00	(60.01)
				e					
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)
				e					
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)
				e					
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)
				e					
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)
				e					
		TOTAL PEERS	7	6	10	Mean			
			80% Mid Cap			8.71%	38.17%	0.00	Staff Gas Screen
						N/A	38.17%	0.00	Staff Gas and Water Sensitivity Screen
						8.72%	37.97%	0.00	Company Peer Screen

Staff will update Water Sensitivity in Staff Rebuttal Testimony

#	10	11	12	13	14	15	16	17	18	19
	Initial Stage					Transition Stage				
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1	3.22	3.46	3.53	3.87	4.25	4.63	4.97	5.34	5.72	6.13
	7.00	7.42	7.87	8.35	8.83	9.44	10.09	10.77	11.49	12.25
3	1.68	1.76	1.77	1.86	1.95	2.04	2.15	2.26	2.37	2.49
	2.90	3.09	3.29	3.50	3.71	3.95	4.19	4.45	4.72	5.01
4	1.06	1.12	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47
	1.85	1.93	2.01	2.10	2.19	2.32	2.46	2.61	2.76	2.92
5	1.95	1.96	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02
	3.00	3.08	3.16	3.25	3.34	3.46	3.59	3.73	3.87	4.01
6	2.64	2.68	2.71	2.78	2.85	2.92	3.00	3.07	3.15	3.23
	4.20	4.45	4.72	5.00	5.28	5.48	5.69	5.90	6.12	6.35
8	2.48	2.52	2.52	2.56	2.60	2.64	2.67	2.70	2.73	2.77
	4.20	4.22	4.23	4.25	4.27	5.32	6.58	8.07	9.82	11.85
9	3.02	3.16	3.20	3.40	3.60	3.80	3.99	4.18	4.37	4.58
	4.50	4.81	5.14	5.50	5.86	6.12	6.39	6.67	6.96	7.27
10	3.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
11	1.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
13	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

#	20	21	22	23	24	25	26	27	28	29
	Final Stage									
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
1	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08	9.48
	12.81	13.39	14.01	14.65	15.32	16.02	16.75	17.52	18.32	19.16
3	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69	3.85
	5.23	5.47	5.73	5.99	6.26	6.55	6.85	7.16	7.49	7.83
4	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18	2.28
	3.05	3.19	3.34	3.49	3.65	3.82	3.99	4.18	4.37	4.57
5	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00	3.13
	4.19	4.38	4.58	4.79	5.01	5.24	5.48	5.74	6.00	6.27
6	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78	4.99
	6.64	6.94	7.26	7.59	7.94	8.31	8.69	9.08	9.50	9.94
8	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10	4.28
	12.39	12.96	13.55	14.18	14.82	15.50	16.21	16.96	17.73	18.54
9	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78	7.08
	7.60	7.95	8.31	8.69	9.09	9.50	9.94	10.40	10.87	11.37
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

30	31	32	33	34	35	36	37	38	39	40	41	42	
Final Stage									2052 Terminal Value	2053 Div	2053 Sale		
2044	2045	2046	2047	2048	2049	2050	2051	2052				2054	#
9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	534.40	14.68	519.71		1
20.04	20.96	21.92	22.92	23.97	25.07	26.22	27.42	28.67		29.99		31.36	
4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	193.54	5.97	187.58		3
8.19	8.57	8.96	9.37	9.80	10.25	10.72	11.21	11.72		12.26		12.82	
2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	112.53	3.53	109.00		4
4.78	5.00	5.23	5.46	5.72	5.98	6.25	6.54	6.84		7.15		7.48	
3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	119.33	4.85	114.48		5
6.56	6.86	7.17	7.50	7.85	8.21	8.58	8.97	9.39		9.82		10.27	
5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	250.14	7.73	242.41		6
10.39	10.87	11.36	11.88	12.43	13.00	13.59	14.22	14.87		15.55		16.26	
4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	533.71	6.63	527.08		8
19.39	20.28	21.21	22.18	23.20	24.26	25.37	26.53	27.75		29.02		30.35	
7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	259.10	10.97	248.13		9
11.89	12.43	13.00	13.60	14.22	14.87	15.56	16.27	17.01		17.79		18.61	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		10
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		11
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		12
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		13
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	

B.O.Y. Cash Flows Staff Model Y EPS Growth

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2024	2025	2026	2027	2028
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
										Initial Stage				
1	1	Atmos	Yes	Yes	Yes	8.4%	40.9%	0.00	(116.00)	3.46	3.53	3.87	4.25	4.63
				e						7.00	7.42	7.87	8.35	8.83
2	3	New Jersey	Yes	No	No	8.9%	35.2%	0.00	(42.43)	1.76	1.77	1.86	1.95	2.04
				e						2.90	3.09	3.29	3.50	3.71
3	4	NiSource	Yes	Yes	Yes	8.5%	35.9%	0.00	(26.97)	1.12	1.10	1.15	1.20	1.25
				e						1.85	1.93	2.01	2.10	2.19
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.3%	0.00	(33.46)	1.96	1.96	1.97	1.98	1.99
				e						3.00	3.08	3.16	3.25	3.34
5	6	ONE Gas	Yes	Yes	Yes	8.3%	36.4%	0.00	(62.62)	2.68	2.71	2.78	2.85	2.92
				e						4.20	4.45	4.72	5.00	5.28
6	8	Southwest Gas	Yes	Yes	Yes	9.0%	55.4%	0.00	(72.94)	2.52	2.52	2.56	2.60	2.64
				e						4.20	4.22	4.23	4.25	4.27
7	9	Spire	Yes	Yes	Yes	10.0%	25.0%	0.00	(60.01)	3.16	3.20	3.40	3.60	3.80
				e						4.50	4.81	5.14	5.50	5.86
8	10	American Water	No	No	Yes	N/A	N/A	N/A	(119.76)	0.00	0.00	0.00	0.00	0.00
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!
9	11	California Water	No	No	Yes	N/A	N/A	N/A	(46.04)	0.00	0.00	0.00	0.00	0.00
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!
10	12	Middlesex Water	No	No	Yes	N/A	N/A	N/A	(50.55)	0.00	0.00	0.00	0.00	0.00
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!
11	13	SJW	No	No	Yes	N/A	N/A	N/A	(55.37)	0.00	0.00	0.00	0.00	0.00
				e						0.00	#DIV/0!	#DIV/0!	0.00	#DIV/0!
		TOTAL PEERS	7	6	10	Mean								
				80% Mid Cap		8.86%	36.83%	0.00	Staff Gas Screen					
						N/A	36.83%	0.00	Staff Gas and Water Sensitivity Screen					
						8.87%	36.60%	0.00	Company Peer Screen					

#	Abbreviated Utility	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
		15	16	17	18	19	20	21	22	23	24	25	26	27
		Transition Stage					Final Stage							
1	Atmos	4.97	5.34	5.72	6.13	6.40	6.69	6.99	7.30	7.62	7.96	8.32	8.69	9.08
		9.44	10.09	10.77	11.49	12.25	12.81	13.39	14.01	14.65	15.32	16.02	16.75	17.52
3	New Jersey	2.15	2.26	2.37	2.49	2.60	2.72	2.84	2.96	3.10	3.23	3.38	3.53	3.69
		3.95	4.19	4.45	4.72	5.01	5.23	5.47	5.73	5.99	6.26	6.55	6.85	7.16
4	NiSource	1.30	1.36	1.41	1.47	1.54	1.61	1.68	1.75	1.83	1.91	2.00	2.09	2.18
		2.32	2.46	2.61	2.76	2.92	3.05	3.19	3.34	3.49	3.65	3.82	3.99	4.18
5	NW Natural	2.00	2.01	2.01	2.02	2.11	2.21	2.31	2.41	2.52	2.63	2.75	2.87	3.00
		3.46	3.59	3.73	3.87	4.01	4.19	4.38	4.58	4.79	5.01	5.24	5.48	5.74
6	ONE Gas	3.00	3.07	3.15	3.23	3.37	3.52	3.68	3.84	4.01	4.19	4.38	4.57	4.78
		5.48	5.69	5.90	6.12	6.35	6.64	6.94	7.26	7.59	7.94	8.31	8.69	9.08
8	Southwest Gas	2.67	2.70	2.73	2.77	2.89	3.02	3.15	3.29	3.44	3.60	3.76	3.92	4.10
		5.32	6.58	8.07	9.82	11.85	12.39	12.96	13.55	14.18	14.82	15.50	16.21	16.96
9	Spire	3.99	4.18	4.37	4.58	4.78	4.99	5.22	5.45	5.69	5.95	6.21	6.49	6.78
		6.12	6.39	6.67	6.96	7.27	7.60	7.95	8.31	8.69	9.09	9.50	9.94	10.40
10	American Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
11	California Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
12	Middlesex Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
13	SJW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

#	Abbreviated Utility	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2052 Terminal Value	2053 Div	2053 Sale	2054	#
		28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
		Final Stage															
1	Atmos	9.48	9.90	10.35	10.81	11.29	11.79	12.32	12.87	13.44	14.04	14.68	535.07	15.36	519.71		1
		18.32	19.16	20.04	20.96	21.92	22.92	23.97	25.07	26.22	27.42	28.67		29.99		31.36	
3	New Jersey	3.85	4.02	4.20	4.39	4.59	4.79	5.00	5.23	5.46	5.70	5.97	193.82	6.24	187.58		3
		7.49	7.83	8.19	8.57	8.96	9.37	9.80	10.25	10.72	11.21	11.72		12.26		12.82	
4	NiSource	2.28	2.38	2.49	2.60	2.71	2.84	2.96	3.09	3.23	3.38	3.53	112.69	3.69	109.00		4
		4.37	4.57	4.78	5.00	5.23	5.46	5.72	5.98	6.25	6.54	6.84		7.15		7.48	
5	NW Natural	3.13	3.27	3.42	3.57	3.73	3.89	4.07	4.25	4.44	4.64	4.85	119.55	5.07	114.48		5
		6.00	6.27	6.56	6.86	7.17	7.50	7.85	8.21	8.58	8.97	9.39		9.82		10.27	
6	ONE Gas	4.99	5.21	5.45	5.69	5.94	6.21	6.48	6.77	7.08	7.39	7.73	250.49	8.08	242.41		6
		9.50	9.94	10.39	10.87	11.36	11.88	12.43	13.00	13.59	14.22	14.87		15.55		16.26	
8	Southwest Gas	4.28	4.47	4.67	4.88	5.10	5.32	5.56	5.81	6.07	6.34	6.63	534.01	6.93	527.08		8
		17.73	18.54	19.39	20.28	21.21	22.18	23.20	24.26	25.37	26.53	27.75		29.02		30.35	
9	Spire	7.08	7.40	7.73	8.07	8.43	8.81	9.20	9.61	10.04	10.49	10.97	259.60	11.47	248.13		9
		10.87	11.37	11.89	12.43	13.00	13.60	14.22	14.87	15.56	16.27	17.01		17.79		18.61	
10	American Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		10
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
11	California Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		11
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
12	Middlesex Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		12
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	
13	SJW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	0.00	#DIV/0!		13
		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!		#DIV/0!	

Staff will update Water Sensitivity in Staff Rebuttal Testimony

Average B.O.Y. & E.O.Y. Cash Flows Model Y EPS Growth

	#	Abbreviated Utility	UG 490 Company	UG 490 Staff	UG 490 Staff Sensitivity	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2023 - 2027 Dividend Growth Rates EOY	BOY	Average	#	
	1	2	3	4	5	6	7	8	9	10		
1	1	Atmos	Yes	Yes	Yes	8.3%	41.9%	7.2%	7.5%	7.4%	1	1
2	3	New Jersey	Yes	No	No	8.8%	36.0%	3.8%	3.8%	3.8%	3	2
3	4	NiSource	Yes	Yes	Yes	8.4%	36.7%	3.1%	2.8%	3.0%	4	3
4	5	NW Natural	Yes	Yes	Yes	8.9%	27.7%	0.4%	0.4%	0.4%	5	4
5	6	ONE Gas	Yes	Yes	Yes	8.3%	37.0%	1.9%	2.2%	2.1%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	9.0%	55.9%	1.2%	1.2%	1.2%	8	6
7	9	Spire	Yes	Yes	Yes	9.9%	25.8%	4.5%	4.8%	4.6%	9	7
8	10	American Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	10	8
9	11	California Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	11	9
10	12	Middlesex Water	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	12	10
11	13	SJW	No	No	Yes	N/A	N/A	-100.0%	#DIV/0!	#DIV/0!	13	11
		TOTAL PEERS	7	6	10	Mean						
				80% Mid Cap		8.79%	37.50%	3.09%	Staff Gas Screen			
						N/A	37.50%	#DIV/0!	Staff Gas and Water Sensitivity Screen			
						8.79%	37.29%	3.19%	Company Peer Screen			

Staff will update Water Sensitivity in Staff Rebuttal Testimony

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

ROE – Three-Stage DCF:
Summary and Recommendation

April 18, 2024

UG 490 Staff ROE Summary

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates						
Component	Real Rate	TIPS Inflation Forecast	20-Yr Nominal Rate	Weight	Weighted Rate	
Energy Information Administration (EIA)	2.24%	2.39%	4.69%	20.0%	0.94%	
Organization for Economic Co-operation and Development (OECD)ggridlines	1.81%	2.39%	4.24%	20.0%	0.85%	
Social Security Administration (SSA)	1.95%	2.39%	4.39%	20.0%	0.88%	
Congressional Budget Office (CBO)	2.02%	2.39%	4.46%	20.0%	0.89%	
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	20.0%	1.02%	
Composite				100%	4.58%	Composite
Congressional Budget Office Long-Term 20-Year Budget Outlook			3.80%	100.0%	4.46%	CBO
BEA Nominal Historical,1980 Q1–2023 Q4	2.65%	2.39%	5.10%	100.0%	5.10%	Historical

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity

	X	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.35%		8.44%		8.83%	
2	Company Peer Screen	8.37%		8.46%		8.85%	

Hamada to Right

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Adjusted)

X	CBO	4.46%	Composite	4.58%	Historical	5.10%	
Staff Gas Screen	8.23%		8.32%		8.71%		1
Company Peer Screen	8.20%		8.29%		8.68%		2

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale

	Y	CBO	4.46%	Composite	4.58%	Historical	5.10%
1	Staff Gas Screen	8.83%		8.79%		9.12%	
2	Company Peer Screen	8.83%		8.79%		9.13%	

Hamada to Right

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)

Y	CBO	4.46%	Composite	4.58%	Historical	5.10%	
Staff Gas Screen	8.71%		8.67%		9.00%		1
Company Peer Screen	8.66%		8.62%		8.96%		2

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				12.5	bps
Range of Modeled Results	8.84%	to	9.26%	ROE	
Best Fit Range of Reasonable ROEs	8.9%	to	9.3%	ROE	
	Midpoint	9.1%	ROE		

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.
Gordon Growth Model points toward lower end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

ROE:
Capital Asset Pricing Model (CAPM)

April 18, 2024

NWN	4.42%	Rf Rate as shown in Exhibit NWN/400 Coyne-Nelson/13 @31
Opening	13.31%	NWN Mkt Return
Testimony	8.89%	NWN Mkt Risk Premium (MRP) as shown in Exhibit NWN/400 Coyne-Nelson/13 @30
Staff	4.555%	R_f as April 5, 2024 30 Yr UST Yields WSJ: Bonds & Rates (wsj.com)
	9.90%	S&P 500 Market Return 1993 thru 2023
	5.35%	Staff Mkt Risk Premium MRP)

$R_{CNG} = R_f + Beta*MRP$

	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	VL Q1 2024 Beta	ROE w VL Beta CAPM	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	0.85	9.10%	1	1
2	3	New Jersey	Yes	No	No	NJR	0.95	9.63%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	0.90	9.37%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	0.85	9.10%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	0.85	9.10%	6	5
6	8	Southwest Ga	Yes	Yes	Yes	SWX	0.90	9.37%	8	6
7	9	Spire	Yes	Yes	Yes	SR	0.85	9.10%	9	7
8	10	American Wa	No	No	Yes	AWK	0.95	9.63%	10	8
9	11	California Wa	No	No	Yes	CWT	0.75	8.56%	11	9
10	12	Middlesex Wa	No	No	Yes	MSEX	0.75	8.56%	12	10
11	13	SJW	No	No	Yes	SJW	0.85	9.10%	13	11
		No. of Peers:	7	6	10			VL Betas		
					Company Screen		Mean	9.3%	ROE	
					Staff Gas and Water Sensitivity Screen		Mean	9.1%	ROE	
					Staff Screen		Mean	9.2%	ROE	

CAPM points toward middle to upper end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 105

ROE:
Gordon Growth – Single Stage DCF

April 18, 2024

Staff's Representative Single Stage (Gordon Growth) Discounted Cash Flow (DCF) Model

Presumes the Peer Utility will pay its divident as a fixed multiple of growth into the future as it is now.

The results would be true only if the utility stock's dividends were to grow at a constant rate forever.

Value of Stock $(P_0) = D_1 / (k - g)$ — Stock Price Now = Next Year's Dividend / (Required Stock Return - Growth in Dividends)

$k = (D_1 / P_0) + g$ — Required Rate of Return on Utility Equity = (Next Year's VL Dividend / Recent Stock Price) - Perpetual Growth

		1	2	3	4	5	6	7	8	9	11 = 9 + 10	13	14	15
	Screen #	Abbreviated Utility	UG 490 NWN	UG 490 Staff	UG 490 Staff Sensitivity	Ticker	Recent Stock $ Price	Current Dividend Yield	Next VL Annual Dividend	Anticipated Dividend Yield	VL Dividend Growth	Investor Required ROE	Screen #	
1	1	Atmos	Yes	Yes	Yes	ATO	116.00	2.6%	3.22	2.8%	7.3%	10.1%	1	1
2	3	New Jersey	Yes	No	No	NJR	42.43	3.7%	1.68	4.0%	5.0%	8.9%	3	2
3	4	NiSource	Yes	Yes	Yes	NI	26.97	3.7%	1.06	3.9%	4.2%	8.1%	4	3
4	5	NW Natural	Yes	Yes	Yes	NWN	33.46	5.8%	1.95	5.8%	0.4%	6.2%	5	4
5	6	ONE Gas	Yes	Yes	Yes	OGS	62.62	4.2%	2.64	4.2%	2.4%	6.7%	6	5
6	8	Southwest Gas	Yes	Yes	Yes	SWX	72.94	3.4%	2.48	3.4%	1.1%	4.5%	8	6
7	9	Spire	Yes	Yes	Yes	SR	60.01	4.8%	3.02	5.0%	4.7%	9.7%	9	7
8	10	American Water	No	No	Yes	AWK	119.76	2.3%	3.00	2.5%	-100.0%	-97.5%	10	8
9	11	California Water	No	No	Yes	CWT	46.04	2.3%	1.12	2.4%	-100.0%	-97.6%	11	9
10	12	Middlesex Water	No	No	Yes	MSEX	50.55	2.5%	1.32	2.6%	-100.0%	-97.4%	12	10
11	13	SJW	No	No	Yes	SJW	55.37	2.7%	1.60	2.9%	-100.0%	-97.1%	13	11
		No. of Peers:	7	6	10							Mean		

	Mean	
Company Screen	7.7%	ROE
Staff Gas and Water Sensitivity Screen	N/A	ROE
Staff Screen	7.5%	ROE

Gordon Growth Model points toward lower end of Staff's 3 Stage DCF Modeling results.

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

ROE: BEA Historical
GDP Growth

April 18, 2024

Bureau of Economic Analysis (BEA) Staff Accessed February 20, 2024

Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual https://fred.stlouisfed.org/series/GDPA https://fred.stlouisfed.org/series/GDPCA Quarterly https://fred.stlouisfed.org/series/GDP https://fred.stlouisfed.org/series/GDPC1

(Seasonally adjusted annual rates)

Yr	GDP in billions of current dollars	GDP in billions of chained 2017 dollars
1947	249.616	2184.614
1948	274.468	2274.627
1949	272.475	2261.928
1950	299.827	2458.532
1951	346.914	2656.32
1952	367.341	2764.803
1953	389.218	2894.411
1954	390.549	2877.708
1955	425.478	3083.026
1956	449.353	3148.765
1957	474.039	3215.065
1958	481.229	3191.216
1959	521.654	3412.421
1960	542.382	3500.272
1961	562.209	3590.066
1962	603.922	3810.124
1963	637.45	3976.142
1964	684.46	4205.277
1965	742.289	4478.555
1966	813.414	4773.931
1967	859.959	4904.864
1968	940.651	5145.914
1969	1017.615	5306.594
1970	1073.303	5316.391
1971	1164.85	5491.445
1972	1279.11	5780.048
1973	1425.376	6106.371
1974	1545.243	6073.363
1975	1684.904	6060.875
1976	1873.412	6387.437
1977	2081.826	6682.804
1978	2351.599	7052.711
1979	2627.333	7275.999
1980	2857.307	7257.316
1981	3207.041	7441.485
1982	3343.789	7307.314
1983	3634.038	7642.266
1984	4037.613	8195.295
1985	4338.979	8537.004
1986	4579.631	8832.611
1987	4855.215	9137.745
1988	5236.438	9519.427
1989	5641.58	9869.003
1990	5963.144	10055.129
1991	6158.129	10044.238
1992	6520.327	10398.046
1993	6858.559	10684.179
1994	7287.236	11114.647
1995	7639.749	11413.012
1996	8073.122	11843.599
1997	8577.552	12370.299
1998	9062.817	12924.876
1999	9631.172	13543.774
2000	10250.952	14096.033
2001	10581.929	14230.726
2002	10929.108	14472.712
2003	11456.45	14877.312
2004	12217.196	15449.757
2005	13039.197	15987.957
2006	13815.583	16433.148
2007	14474.228	16762.445
2008	14769.862	16781.485
2009	14478.067	16349.11
2010	15048.97	16789.75
2011	15599.731	17052.41
2012	16253.97	17442.759
2013	16880.683	17812.167
2014	17608.138	18261.714
2015	18295.019	18799.622
2016	18804.913	19141.672
2017	19612.102	19612.102
2018	20656.516	20193.896
2019	21521.395	20692.087
2020	21322.95	20234.074
2021	23594.031	21407.692
2022	25744.108	21822.037
2023	27356.393	22375.307

1980 through 2023 Q4

Quarter	GDP in billions of current dollars	GDP in billions of chained 2017 dollars	Qtr#	Average	Ln(Real GDP)	
1947Q1	243.164	2182.681	1	1	8.901	1980
1947Q2	245.968	2176.892	2	2	8.880	
1947Q3	249.585	2172.432	3	3	8.879	
1947Q4	259.745	2206.452	4	4	8.898	
1948Q1	265.742	2239.682	5	5	8.917	1981
1948Q2	272.567	2276.690	6	6	8.910	
1948Q3	279.196	2289.770	7	7	8.922	
1948Q4	280.366	2292.364	8	8	8.911	
1949Q1	275.034	2260.807	9	9	8.895	1982
1949Q2	271.351	2253.128	10	10	8.900	
1949Q3	272.889	2276.424	11	11	8.896	
1949Q4	270.627	2257.352	12	12	8.896	
1950Q1	280.828	2346.104	13	13	8.909	1983
1950Q2	290.383	2417.682	14	14	8.932	
1950Q3	308.153	2511.127	15	15	8.952	
1950Q4	319.945	2559.214	16	16	8.972	
1951Q1	336.000	2593.967	17	17	8.992	1984
1951Q2	344.090	2638.898	18	18	9.009	
1951Q3	351.385	2693.259	19	19	9.018	
1951Q4	356.178	2699.156	20	20	9.026	
1952Q1	359.820	2727.954	21	21	9.036	1985
1952Q2	361.030	2733.800	22	22	9.045	
1952Q3	367.701	2753.517	23	23	9.060	
1952Q4	380.812	2843.941	24	24	9.067	
1953Q1	387.980	2896.811	25	25	9.077	1986
1953Q2	391.749	2919.206	26	26	9.081	
1953Q3	391.171	2902.785	27	27	9.091	
1953Q4	385.970	2858.845	28	28	9.096	
1954Q1	385.345	2845.192	29	29	9.103	1987
1954Q2	386.121	2848.305	30	30	9.114	
1954Q3	390.996	2880.482	31	31	9.123	
1954Q4	399.734	2936.852	32	32	9.140	
1955Q1	413.073	3020.746	33	33	9.145	1988
1955Q2	421.532	3069.910	34	34	9.158	
1955Q3	430.221	3111.379	35	35	9.164	
1955Q4	437.092	3130.068	36	36	9.177	
1956Q1	439.746	3117.922	37	37	9.187	1989
1956Q2	446.010	3143.694	38	38	9.195	
1956Q3	451.191	3140.874	39	39	9.202	
1956Q4	460.463	3192.570	40	40	9.204	
1957Q1	469.779	3213.011	41	41	9.215	1990
1957Q2	472.025	3205.970	42	42	9.219	
1957Q3	479.490	3237.386	43	43	9.219	
1957Q4	474.864	3203.894	44	44	9.210	
1958Q1	467.540	3120.724	45	45	9.206	1991
1958Q2	471.978	3141.224	46	46	9.213	
1958Q3	485.841	3213.884	47	47	9.218	
1958Q4	499.555	3289.032	48	48	9.222	
1959Q1	510.330	3352.129	49	49	9.234	1992
1959Q2	522.653	3427.667	50	50	9.244	
1959Q3	525.034	3430.057	51	51	9.254	
1959Q4	528.600	3439.832	52	52	9.265	
1960Q1	542.648	3517.181	53	53	9.266	1993
1960Q2	541.080	3498.246	54	54	9.272	
1960Q3	545.604	3515.385	55	55	9.277	
1960Q4	540.197	3470.278	56	56	9.290	
1961Q1	545.018	3493.703	57	57	9.300	1994
1961Q2	555.545	3553.021	58	58	9.314	
1961Q3	567.664	3621.252	59	59	9.319	
1961Q4	580.612	3692.289	60	60	9.331	
1962Q1	594.013	3758.147	61	61	9.334	1995
1962Q2	600.366	3792.149	62	62	9.337	
1962Q3	609.027	3838.776	63	63	9.346	
1962Q4	612.280	3851.421	64	64	9.353	
1963Q1	621.672	3893.482	65	65	9.360	1996
1963Q2	629.752	3937.183	66	66	9.377	
1963Q3	644.444	4023.755	67	67	9.385	
1963Q4	653.938	4050.147	68	68	9.396	
1964Q1	669.822	4135.553	69	69	9.402	1997
1964Q2	678.674	4180.592	70	70	9.419	
1964Q3	692.031	4245.918	71	71	9.431	
1964Q4	697.319	4259.046	72	72	9.440	
1965Q1	717.790	4362.111	73	73	9.450	1998
1965Q2	730.191	4417.225	74	74	9.459	
1965Q3	749.323	4515.427	75	75	9.471	
1965Q4	771.857	4619.458	76	76	9.487	
1966Q1	795.734	4731.888	77	77	9.497	1999
1966Q2	804.981	4748.046	78	78	9.505	
1966Q3	819.638	4788.254	79	79	9.518	
1966Q4	833.302	4827.537	80	80	9.534	
1967Q1	844.170	4870.299	81	81	9.538	2000
1967Q2	848.983	4873.287	82	82	9.556	
1967Q3	865.233	4919.392	83	83	9.557	
1967Q4	881.439	4956.477	84	84	9.563	
1968Q1	909.387	5057.553	85	85	9.560	2001
1968Q2	934.344	5142.033	86	86	9.566	
1968Q3	950.825	5181.859	87	87	9.562	
1968Q4	968.030	5202.212	88	88	9.565	
1969Q1	993.337	5283.597	89	89	9.573	2002
1969Q2	1009.020	5299.625	90	90	9.579	
1969Q3	1029.956	5334.600	91	91	9.583	
1969Q4	1038.147	5308.556	92	92	9.584	
1970Q1	1051.200	5300.652	93	93	9.590	2003
1970Q2	1067.375	5308.164	94	94	9.599	
1970Q3	1086.059	5357.077	95	95	9.615	
1970Q4	1088.608	5299.672	96	96	9.627	
1971Q1	1135.156	5443.619	97	97	9.632	2004
1971Q2	1156.271	5473.059	98	98	9.640	
1971Q3	1177.675	5518.072	99	99	9.649	
1971Q4	1190.297	5531.032	100	100	9.660	
1972Q1	1230.609	5632.649	101	101	9.671	2005
1972Q2	1266.369	5760.470	102	102	9.676	
1972Q3	1290.566	5814.854	103	103	9.683	
1972Q4	1328.904	5912.220	104	104	9.689	
1973Q1	1377.490	6058.544	105	105	9.702	2006
1973Q2	1413.887	6124.506	106	106	9.705	
1973Q3	1433.838	6092.301	107	107	9.706	
1973Q4	1476.289	6150.131	108	108	9.715	
1974Q1	1491.209	6097.258	109	109	9.718	2007
1974Q2	1530.056	6111.751	110	110	9.724	
1974Q3	1560.026	6053.978	111	111	9.730	
1974Q4	1599.679	6030.464	112	112	9.736	
1975Q1	1616.116	5957.035	113	113	9.732	2008
1975Q2	1651.853	5999.610	114	114	9.738	
1975Q3	1709.820	6102.326	115	115	9.732	
1975Q4	1761.831	6184.530	116	116	9.710	
1976Q1	1820.487	6323.649	117	117	9.699	2009
1976Q2	1852.332	6370.025	118	118	9.697	
1976Q3	1886.558	6404.895	119	119	9.701	
1976Q4	1934.273	6451.177	120	120	9.711	
1977Q1	1988.648	6527.703	121	121	9.716	2010
1977Q2	2055.909	6654.466	122	122	9.726	
1977Q3	2118.473	6774.457	123	123	9.733	
1977Q4	2164.270	6774.592	124	124	9.739	
1978Q1	2202.760	6796.260	125	125	9.736	2011
1978Q2	2331.633	7058.920	126	126	9.743	
1978Q3	2395.053	7129.915	127	127	9.743	
1978Q4	2476.949	7225.750	128	128	9.754	
1979Q1	2526.610	7238.727	129	129	9.762	2012
1979Q2	2591.247	7246.454	130	130	9.767	
1979Q3	2667.565	7300.281	131	131	9.768	
1979Q4	2723.883	7318.535	132	132	9.769	
1980Q1	2789.842	7341.557	133	133	9.779	2013
1980Q2	2797.352	7190.289	134	134	9.782	
1980Q3	2856.483	7181.743	135	135	9.790	
1980Q4	2985.557	7315.677	136	136	9.799	
1981Q1	3124.206	7459.022	137	137	9.796	2014
1981Q2	3162.532	7403.745	138	138	9.808	
1981Q3	3260.609	7492.405	139	139	9.820	
1981Q4	3280.818	7410.768	140	140	9.826	
1982Q1	3274.302	7295.631	141	141	9.834	2015
1982Q2	3331.972	7328.912	142	142	9.841	
1982Q3	3366.322	7300.896	143	143	9.845	
1982Q4	3402.561	7303.817	144	144	9.847	
1983Q1	3473.413	7400.066	145	145	9.852	2016
1983Q2	3578.848	7568.456	146	146	9.855	
1983Q3	3689.179	7719.746	147	147	9.863	
1983Q4	3794.706	7880.794	148	148	9.868	

Long Run Historical GDP Growth Rate

Annualized Real LN GPD Q

2.65%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989672527
R Square	0.979451711
Adjusted R Square	0.979333617
Standard Error	0.048579271
Observations	176

ANOVA

	df	SS	MS	F	Significance F
Regression	1	19.57305439	19.57305439	8293.858359	9.9307E-149
Residual	174	0.410630531	0.002359946		
Total	175	19.98368493			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	8.926549282	0.007354921	1213.683982	0	8.912032939	8.941065626	8.912032939	8.941065626
Average	0.006563839	7.20742E-05	91.07062292	9.9307E-149	0.006421587	0.006706091	0.006421587	0.006706091

Note

July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

1984Q1	3908.054	8034.847	149
1984Q2	4009.601	8173.670	150
1984Q3	4084.250	8252.465	151
1984Q4	4148.551	8320.199	152
1985Q1	4230.168	8400.820	153
1985Q2	4294.887	8474.787	154
1985Q3	4386.773	8604.220	155
1985Q4	4444.094	8668.188	156
1986Q1	4507.894	8749.127	157
1986Q2	4545.340	8788.524	158
1986Q3	4607.669	8872.601	159
1986Q4	4657.627	8920.193	160
1987Q1	4722.156	8986.367	161
1987Q2	4806.160	9083.256	162
1987Q3	4884.555	9162.024	163
1987Q4	5007.994	9319.332	164
1988Q1	5073.372	9367.502	165
1988Q2	5190.036	9490.594	166
1988Q3	5282.835	9546.206	167
1988Q4	5399.509	9673.405	168
1989Q1	5511.253	9771.725	169
1989Q2	5612.463	9846.293	170
1989Q3	5695.365	9919.228	171
1989Q4	5747.237	9938.767	172
1990Q1	5872.701	10047.386	173
1990Q2	5960.028	10083.855	174
1990Q3	6015.116	10090.569	175
1990Q4	6004.733	9998.704	176
1991Q1	6035.178	9951.916	177
1991Q2	6126.862	10029.510	178
1991Q3	6205.937	10080.195	179
1991Q4	6264.540	10115.329	180
1992Q1	6363.102	10236.435	181
1992Q2	6470.763	10347.429	182
1992Q3	6566.641	10449.673	183
1992Q4	6680.803	10558.648	184
1993Q1	6729.459	10576.275	185
1993Q2	6808.939	10637.847	186
1993Q3	6882.098	10688.606	187
1993Q4	7013.738	10833.987	188
1994Q1	7115.652	10939.116	189
1994Q2	7246.931	11087.361	190
1994Q3	7331.075	11152.176	191
1994Q4	7455.288	11279.932	192
1995Q1	7522.289	11319.951	193
1995Q2	7580.997	11353.721	194
1995Q3	7683.125	11450.310	195
1995Q4	7772.586	11528.067	196
1996Q1	7868.468	11614.418	197
1996Q2	8032.840	11808.140	198
1996Q3	8131.408	11914.063	199
1996Q4	8259.771	12037.775	200
1997Q1	8362.655	12115.472	201
1997Q2	8518.825	12317.221	202
1997Q3	8662.823	12471.010	203
1997Q4	8765.907	12577.495	204
1998Q1	8866.480	12703.742	205
1998Q2	8969.699	12821.339	206
1998Q3	9121.097	12982.752	207
1998Q4	9293.991	13191.670	208
1999Q1	9411.682	13315.597	209
1999Q2	9526.210	13426.748	210
1999Q3	9686.626	13604.771	211
1999Q4	9900.169	13827.980	212
2000Q1	10002.179	13878.147	213
2000Q2	10247.720	14130.908	214
2000Q3	10318.165	14145.312	215
2000Q4	10435.744	14229.765	216
2001Q1	10470.231	14183.120	217
2001Q2	10599.000	14271.694	218
2001Q3	10598.020	14214.516	219
2001Q4	10660.465	14253.574	220
2002Q1	10783.500	14372.785	221
2002Q2	10887.460	14460.848	222
2002Q3	10984.040	14519.633	223
2002Q4	11061.433	14537.580	224
2003Q1	11174.129	14614.141	225
2003Q2	11312.766	14743.567	226
2003Q3	11566.669	14988.782	227
2003Q4	11772.234	15162.760	228
2004Q1	11923.447	15248.680	229
2004Q2	12112.815	15366.850	230
2004Q3	12305.307	15512.619	231
2004Q4	12527.214	15670.880	232
2005Q1	12767.286	15844.727	233
2005Q2	12922.656	15922.782	234
2005Q3	13142.642	16047.587	235
2005Q4	13324.204	16136.734	236
2006Q1	13599.160	16353.835	237
2006Q2	13753.424	16396.151	238
2006Q3	13870.188	16420.738	239
2006Q4	14039.560	16561.866	240
2007Q1	14215.651	16611.690	241
2007Q2	14402.082	16713.314	242
2007Q3	14564.117	16809.587	243
2007Q4	14715.058	16915.191	244
2008Q1	14706.538	16843.003	245
2008Q2	14865.701	16943.291	246
2008Q3	14898.999	16854.295	247
2008Q4	14608.208	16485.350	248
2009Q1	14430.901	16298.262	249
2009Q2	14381.236	16269.145	250
2009Q3	14448.882	16326.281	251
2009Q4	14651.249	16502.754	252
2010Q1	14764.610	16582.710	253
2010Q2	14980.193	16743.162	254
2010Q3	15141.607	16872.266	255
2010Q4	15309.474	16960.864	256
2011Q1	15351.448	16920.632	257
2011Q2	15557.539	17035.114	258
2011Q3	15647.680	17031.313	259
2011Q4	15842.259	17222.583	260
2012Q1	16068.805	17367.010	261
2012Q2	16207.115	17444.525	262
2012Q3	16319.541	17469.650	263
2012Q4	16420.419	17489.852	264
2013Q1	16648.189	17662.400	265
2013Q2	16728.687	17709.671	266
2013Q3	16953.838	17860.450	267
2013Q4	17192.019	18016.147	268
2014Q1	17197.738	17953.974	269
2014Q2	17518.508	18185.911	270
2014Q3	17804.228	18406.941	271
2014Q4	17912.079	18500.031	272
2015Q1	18063.529	18666.621	273
2015Q2	18279.784	18782.243	274
2015Q3	18401.626	18857.418	275
2015Q4	18435.137	18892.206	276
2016Q1	18525.933	19001.690	277
2016Q2	18711.702	19062.709	278
2016Q3	18892.639	19197.938	279
2016Q4	19089.379	19304.352	280
2017Q1	19280.084	19398.343	281
2017Q2	19438.643	19506.949	282
2017Q3	19692.595	19660.766	283
2017Q4	20037.088	19882.352	284
2018Q1	20328.553	20044.077	285
2018Q2	20580.912	20150.476	286
2018Q3	20798.730	20276.154	287
2018Q4	20917.867	20304.874	288
2019Q1	21104.133	20415.150	289
2019Q2	21384.775	20584.528	290
2019Q3	21694.282	20817.581	291
2019Q4	21902.390	20951.088	292
2020Q1	21706.513	20665.553	293
2020Q2	19913.143	19034.830	294
2020Q3	21647.64	20511.785	295
2020Q4	22024.502	20724.128	296
2021Q1	22600.185	20990.541	297
2021Q2	23292.362	21309.544	298
2021Q3	23828.973	21483.083	299
2021Q4	24654.603	21847.602	300

149	**9.873**	**2017**
150	**9.879**	
151	**9.886**	
152	**9.898**	
153	**9.906**	**2018**
154	**9.911**	
155	**9.917**	
156	**9.919**	
157	**9.924**	**2019**
158	**9.932**	
159	**9.944**	
160	**9.950**	
161	**9.936**	**2020**
162	**9.854**	
163	**9.929**	
164	**9.939**	
165	**9.952**	**2021**
166	**9.967**	
167	**9.975**	
168	**9.992**	
169	**9.987**	**2022**
170	**9.985**	
171	**9.992**	
172	**9.998**	
173	**10.004**	**2023**
174	**10.009**	
175	**10.021**	
176	**10.029**	

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

ROE: TIPS Implied Inflation

April 18, 2024

2023 through 2053 TIPs-Implied Average Annual Inflation Rate: **2.39%**

Implied Market-based Inflationary Expectations						
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	
2023-Q4	2.2%	2.3%	2.3%	2.6%	2.4%	IPC UE 426

Source: Federal Reserve Statistical Release H.15

See H15 Qtrly Avg for data feed

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels 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-23	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-24	1	102.23	102.30	102.29	102.57	102.35	102.23					102.23	
Dec-25	2	104.50	104.65	104.63	105.21	104.76	104.50					104.50	
Dec-26	3	106.83	107.05	107.03	107.91	107.23	106.83					106.83	
Dec-27	4	109.21	109.51	109.48	110.68	109.75	109.21					109.21	
Dec-28	5	111.64	112.02	111.99	113.53	112.33	111.64					111.64	
Dec-29	6		114.60	114.55	116.45	114.98		114.40				114.40	
Dec-30	7		117.23	117.17	119.44	117.68		117.23				117.23	
Dec-31	8			119.86	122.51	120.45			119.89			119.89	
Dec-32	9			122.60	125.66	123.29			122.62			122.62	
Dec-33	10			125.41	128.89	126.19			125.41			125.41	
Dec-34	11				132.20	129.16				128.99		128.99	128.40
Dec-35	12				135.60	132.20				132.66		132.66	131.46
Dec-36	13				139.08	135.31				136.44		136.44	134.60
Dec-37	14				142.65	138.49				140.33		140.33	137.81
Dec-38	15				146.32	141.75				144.33		144.33	141.10
Dec-39	16				150.08	145.09				148.45		148.45	144.46
Dec-40	17				153.94	148.50				152.68		152.68	147.91
Dec-41	18				157.89	152.00				157.03		157.03	151.43
Dec-42	19				161.95	155.57				161.51		161.51	155.05
Dec-43	20				166.11	159.24				166.11		166.11	158.74
Dec-44	21					162.98					169.31	169.31	162.53
Dec-45	22					166.82					172.56	172.56	166.41
Dec-46	23					170.74					175.87	175.87	170.37
Dec-47	24					174.76					179.25	179.25	174.44
Dec-48	25					178.88					182.70	182.70	178.60
Dec-49	26					183.08					186.21	186.21	182.86
Dec-50	27					187.39					189.79	189.79	187.22
Dec-51	28					191.80					193.43	193.43	191.68
Dec-52	29					196.32					197.15	197.15	196.26
Dec-53	30					200.94					200.94	200.94	200.94

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.14**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**
2015-Q1	0.11	0.23	0.27	0.52	0.71
2015-Q2	**-0.10**	**0.22**	**0.30**	**0.67**	**0.91**
2015-Q3	0.26	0.48	0.57	0.92	1.14
2015-Q4	**0.36**	**0.51**	**0.66**	**1.02**	**1.24**
2016-Q1	0.15	0.32	0.49	0.88	1.11
2016-Q2	**-0.24**	**-0.05**	**0.19**	**0.62**	**0.85**
2016-Q3	-0.22	-0.09	0.08	0.44	0.62
2016-Q4	**-0.06**	**0.12**	**0.33**	**0.69**	**0.86**
2017-Q1	0.07	0.33	0.44	0.75	0.95
2017-Q2	**0.10**	**0.30**	**0.44**	**0.76**	**0.94**
2017-Q3	0.17	0.36	0.45	0.75	0.94
2017-Q4	**0.32**	**0.44**	**0.50**	**0.72**	**0.87**
2018-Q1	0.56	0.65	0.68	0.82	0.93
2018-Q2	**0.69**	**0.77**	**0.79**	**0.88**	**0.95**
2018-Q3	0.81	0.81	0.81	0.88	0.93
2018-Q4	**1.06**	**1.06**	**1.06**	**1.15**	**1.23**
2019-Q1	0.73	0.76	0.79	0.96	1.10
2019-Q2	**0.42**	**0.46**	**0.51**	**0.71**	**0.89**
2019-Q3	0.18	0.16	0.15	0.37	0.59
2019-Q4	**0.09**	**0.11**	**0.15**	**0.36**	**0.54**
2020-Q1	-0.14	-0.12	-0.06	0.14	0.29
2020-Q2	**-0.49**	**-0.50**	**-0.48**	**-0.27**	**-0.09**
2020-Q3	-1.19	-1.09	-0.94	-0.58	-0.33
2020-Q4	**-1.32**	**-1.13**	**-0.91**	**-0.50**	**-0.29**
2021-Q1	-1.70	-1.27	-0.86	-0.34	-0.09
2021-Q2	**-1.71**	**-1.18**	**-0.79**	**-0.27**	**-0.03**
2021-Q3	-1.69	-1.31	-1.02	-0.53	-0.30
2021-Q4	**-1.65**	**-1.30**	**-1.00**	**-0.58**	**-0.38**

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**2.81**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**
2015-Q1	1.45	1.77	1.97	2.32	2.55
2015-Q2	**1.52**	**1.91**	**2.17**	**2.62**	**2.89**
2015-Q3	1.55	1.94	2.22	2.65	2.96
2015-Q4	**1.59**	**1.94**	**2.19**	**2.60**	**2.96**
2016-Q1	1.37	1.69	1.92	2.32	2.72
2016-Q2	**1.24**	**1.54**	**1.75**	**2.15**	**2.57**
2016-Q3	1.13	1.40	1.56	1.91	2.28
2016-Q4	**1.61**	**1.93**	**2.13**	**2.52**	**2.82**
2017-Q1	1.94	2.25	2.44	2.78	3.04
2017-Q2	**1.81**	**2.07**	**2.26**	**2.64**	**2.90**
2017-Q3	1.82	2.06	2.24	2.58	2.82
2017-Q4	**2.07**	**2.25**	**2.37**	**2.62**	**2.82**
2018-Q1	2.54	2.69	2.76	2.91	3.03
2018-Q2	**2.77**	**2.87**	**2.92**	**3.00**	**3.08**
2018-Q3	2.81	2.88	2.93	3.00	3.07
2018-Q4	**2.88**	**2.96**	**3.03**	**3.17**	**3.27**
2019-Q1	2.47	2.55	2.65	2.85	3.01
2019-Q2	**2.12**	**2.22**	**2.33**	**2.58**	**2.78**
2019-Q3	1.63	1.71	1.80	2.08	2.28
2019-Q4	**1.62**	**1.72**	**1.79**	**2.10**	**2.26**
2020-Q1	1.16	1.29	1.38	1.71	1.88
2020-Q2	**0.36**	**0.54**	**0.69**	**1.15**	**1.38**
2020-Q3	0.27	0.46	0.65	1.15	1.36
2020-Q4	**0.37**	**0.61**	**0.86**	**1.40**	**1.62**
2021-Q1	0.60	0.98	1.32	1.92	2.07
2021-Q2	**0.84**	**1.27**	**1.59**	**2.17**	**2.26**
2021-Q3	0.80	1.10	1.32	1.86	1.93
2021-Q4	**1.18**	**1.42**	**1.54**	**1.97**	**1.95**

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.67**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**
2015-Q1	1.35	1.54	1.70	1.79	1.85
2015-Q2	**1.63**	**1.69**	**1.86**	**1.95**	**1.97**
2015-Q3	1.29	1.47	1.65	1.73	1.82
2015-Q4	**1.23**	**1.43**	**1.53**	**1.58**	**1.72**
2016-Q1	1.23	1.37	1.43	1.45	1.61
2016-Q2	**1.48**	**1.58**	**1.56**	**1.53**	**1.72**
2016-Q3	1.35	1.49	1.48	1.47	1.66
2016-Q4	**1.67**	**1.80**	**1.80**	**1.83**	**1.96**
2017-Q1	1.87	1.92	2.01	2.03	2.10
2017-Q2	**1.71**	**1.78**	**1.82**	**1.88**	**1.96**
2017-Q3	1.65	1.70	1.79	1.83	1.88
2017-Q4	**1.75**	**1.81**	**1.87**	**1.89**	**1.95**
2018-Q1	1.97	2.04	2.08	2.08	2.11
2018-Q2	**2.07**	**2.11**	**2.13**	**2.12**	**2.14**
2018-Q3	2.01	2.07	2.11	2.11	2.13
2018-Q4	**1.81**	**1.90**	**1.98**	**2.02**	**2.03**
2019-Q1	1.73	1.79	1.86	1.89	1.91
2019-Q2	**1.70**	**1.76**	**1.82**	**1.87**	**1.88**
2019-Q3	1.45	1.55	1.64	1.71	1.69
2019-Q4	**1.53**	**1.61**	**1.64**	**1.74**	**1.72**
2020-Q1	1.30	1.41	1.44	1.58	1.59
2020-Q2	**0.85**	**1.05**	**1.16**	**1.42**	**1.47**
2020-Q3	1.46	1.55	1.59	1.73	1.69
2020-Q4	**1.69**	**1.75**	**1.78**	**1.90**	**1.91**
2021-Q1	2.30	2.25	2.18	2.26	2.16
2021-Q2	**2.55**	**2.45**	**2.39**	**2.44**	**2.29**
2021-Q3	2.49	2.41	2.34	2.39	2.23
2021-Q4	**2.83**	**2.72**	**2.54**	**2.55**	**2.33**

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , Feb. 15, 2023: http://federalreserve.gov/releases/h15/data.htm

Monthly https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M
TIPS-10m	10				RIFLGFCY10_XII_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-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	**0.46**	**0.59**	**0.73**	**1.06**	**1.26**
2016-01	0.33	0.49	0.67	1.05	1.26
2016-02	0.14	0.30	0.47	0.85	1.09
2016-03	-0.03	0.16	0.34	0.73	0.99
2016-04	**-0.22**	**-0.03**	**0.19**	**0.60**	**0.86**
2016-05	**-0.22**	**-0.04**	**0.21**	**0.64**	**0.86**
2016-06	**-0.27**	**-0.07**	**0.17**	**0.63**	**0.82**
2016-07	-0.32	-0.16	0.04	0.42	0.61
2016-08	-0.17	-0.06	0.09	0.43	0.62
2016-09	-0.17	-0.05	0.12	0.47	0.64
2016-10	**-0.26**	**-0.10**	**0.10**	**0.49**	**0.69**
2016-11	**-0.07**	**0.11**	**0.32**	**0.69**	**0.86**
2016-12	**0.15**	**0.36**	**0.56**	**0.89**	**1.04**
2017-01	0.03	0.27	0.42	0.74	0.92
2017-02	0.01	0.29	0.40	0.73	0.93
2017-03	0.18	0.42	0.49	0.79	0.99
2017-04	**0.08**	**0.28**	**0.39**	**0.72**	**0.91**
2017-05	**0.09**	**0.29**	**0.47**	**0.80**	**0.99**
2017-06	**0.14**	**0.32**	**0.46**	**0.75**	**0.93**
2017-07	0.23	0.42	0.55	0.84	1.01
2017-08	0.16	0.35	0.43	0.74	0.93
2017-09	0.12	0.31	0.37	0.67	0.87
2017-10	**0.25**	**0.42**	**0.50**	**0.77**	**0.94**
2017-11	**0.30**	**0.43**	**0.50**	**0.72**	**0.87**
2017-12	**0.42**	**0.48**	**0.50**	**0.68**	**0.80**

Monthly

UST-05m	5	Year	H.15 ID	RIFLGFCY05_N.M
UST-07m	7			RIFLGFCY07_N.M
UST-10m	10			RIFLGFCY10_N.M
UST-20m	20			RIFLGFCY20_N.M
UST-30m	30			RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**
2015-01	1.37	1.67	1.88	2.20	2.46
2015-02	1.47	1.79	1.98	2.34	2.57
2015-03	1.52	1.84	2.04	2.41	2.63
2015-04	**1.35**	**1.69**	**1.94**	**2.33**	**2.59**
2015-05	**1.54**	**1.93**	**2.20**	**2.69**	**2.96**
2015-06	**1.68**	**2.10**	**2.36**	**2.85**	**3.11**
2015-07	1.63	2.04	2.32	2.77	3.07
2015-08	1.54	1.91	2.17	2.55	2.86
2015-09	1.49	1.88	2.17	2.62	2.95
2015-10	**1.39**	**1.76**	**2.07**	**2.50**	**2.89**
2015-11	**1.67**	**2.02**	**2.26**	**2.69**	**3.03**
2015-12	**1.70**	**2.04**	**2.24**	**2.61**	**2.97**
2016-01	1.52	1.85	2.09	2.49	2.86
2016-02	1.22	1.53	1.78	2.20	2.62
2016-03	1.38	1.68	1.89	2.28	2.68
2016-04	**1.26**	**1.57**	**1.81**	**2.21**	**2.62**
2016-05	**1.30**	**1.60**	**1.81**	**2.22**	**2.63**
2016-06	**1.17**	**1.44**	**1.64**	**2.02**	**2.45**
2016-07	1.07	1.33	1.50	1.82	2.23
2016-08	1.13	1.40	1.56	1.89	2.26
2016-09	1.18	1.46	1.63	2.02	2.35
2016-10	**1.27**	**1.56**	**1.76**	**2.17**	**2.50**
2016-11	**1.60**	**1.93**	**2.14**	**2.54**	**2.86**
2016-12	**1.96**	**2.29**	**2.49**	**2.84**	**3.11**
2017-01	1.92	2.23	2.43	2.75	3.02
2017-02	1.90	2.22	2.42	2.76	3.03
2017-03	2.01	2.30	2.48	2.83	3.08
2017-04	**1.82**	**2.10**	**2.30**	**2.67**	**2.94**
2017-05	**1.84**	**2.11**	**2.30**	**2.70**	**2.96**
2017-06	**1.77**	**2.01**	**2.19**	**2.54**	**2.80**
2017-07	1.87	2.13	2.32	2.65	2.88
2017-08	1.78	2.03	2.21	2.55	2.80
2017-09	1.80	2.03	2.20	2.53	2.78
2017-10	**1.98**	**2.20**	**2.36**	**2.65**	**2.88**
2017-11	**2.05**	**2.23**	**2.35**	**2.60**	**2.80**
2017-12	**2.18**	**2.32**	**2.40**	**2.60**	**2.77**

Staff Accessed, Feb. 15, 2023: http://federalreserve.gov/releases/h15/data.htm
https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Annual

TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A
TIPS-10a	10				RIFLGFCY10_XII_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	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
2018	0.78	0.82	0.83	0.93	1.01
2019	0.35	0.37	0.40	0.60	0.78
2020	-0.79	-0.71	-0.60	-0.31	-0.11
2021	-1.69	-1.26	-0.91	-0.43	-0.2
2022	0.22	0.33	0.43	0.64	0.76
2023	1.80	1.73	1.68	1.73	1.8

Annual

UST-05a	5	Year	H.15 ID	RIFLGFCY05_N.A
UST-07a	7			RIFLGFCY07_N.A
UST-10a	10			RIFLGFCY10_N.A
UST-20a	20			RIFLGFCY20_N.A
UST-30a	30			RIFLGFCY30_N.A

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	1.64	2.14	2.54	3.07	3.34
2015	1.53	1.89	2.14	2.55	2.84
2016	1.33	1.63	1.84	2.22	2.59
2017	1.91	2.16	2.33	2.65	2.89
2018	2.75	2.85	2.91	3.02	3.11
2019	1.95	2.05	2.14	2.40	2.58
2020	0.53	0.72	0.89	1.35	1.56
2021	0.86	1.20	1.45	1.98	2.06
2022	3.00	3.01	2.95	3.30	3.11
2023	4.06	4.03	3.96	4.26	4.09

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 108

Value Line (VL)
Natural Gas and Water Utilities

April 18, 2024

NATURAL GAS UTILITY

Stocks of a number of companies in *Value Line's* Natural Gas Utility Industry have been fairly rangebound since our last report in November. But that should come as no surprise, given that historical price movements of this typically defensive sector have tended to be on the steady side. It's also important to mention that the big draw here is these equities' reliable, healthy amounts of dividend income (which are sufficiently covered by corporate earnings). What's more, at recent quotations, 3- to 5-year capital appreciation potential for some of the stocks in our universe looks decent, resulting in solid total return possibilities.

INDUSTRY TIMELINESS: 66 (of 93)

Natural Gas Prices

Natural gas quotations have weakened significantly over the past few months reflecting, among other factors, heightened production levels and mild winter weather. Although this scenario does not augur well for companies that produce this commodity, regulated utility units generally benefit. That's partially because diminished gas pricing tends to lead to lower prices for customers, which may bring down bad-debt expense. Moreover, there is an increased possibility that homeowners will convert from alternative fuel sources, such as propane or oil, to natural gas. (At present, it's estimated that roughly half of all households in the United States use natural gas.) It should be mentioned, however, that nonregulated operations (discussed below) tend to underperform when gas pricing is at subdued levels.

Nonregulated Businesses

Some of our industry participants have dedicated substantial resources to the nonregulated arena, which includes pipelines and energy marketing & trading services, and we see this trend continuing in the future. Indeed, these units offer opportunities for utilities to diversify their revenue streams. Also, the fact that nonregulated segments can provide potential upside to earnings per share is notable, since the return on equity is limited by the regulatory state commissions (generally in the 9%-11% range) on the regulated divisions.

Interest Rates

In January, the Federal Reserve announced that it would keep interest rates steady while waiting to see if additional actions were necessary to combat inflation, which has eased some during the past year but remains elevated. (The central bank has been engaged in its fastest rate-increase cycle since the 1980s.) So, this raises the question, "How does a rising interest rate environment affect the participants in the Natural Gas Utility Industry?" One way is by increasing borrowing costs, an especially important factor because these companies tend to maintain substantial levels of debt. Furthermore, rising interest rates might make bonds more attractive to conservative, yield-oriented investors, the very ones who are typically drawn to utility stocks.

Attractive Payouts

The main appeal of utility equities is their dividends, which tend to be adequately covered by corporate profits. (It's important to state that the Financial Strength ratings for more than half of the nine companies in our category are at least an A, and the lowest is a respectable B++.) At the time of this industry review, the average yield for the group was approximately 4.3%, nearly double the *Value Line* median of 2.2%. Standouts include *UGI Corp.*, *ONE Gas, Inc.*, *Northwest Natural Holding Co.*, and *Spire Inc.* When the financial markets experience heightened volatility (which seems to be more often the case these days), healthy dividend yields provide a measure of much-needed stability.

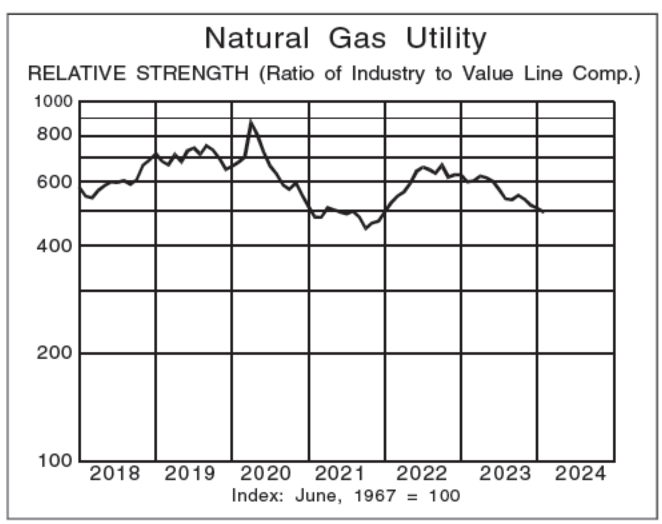
Prospects Out To Late Decade

We are optimistic, overall, about the industry's long-term operating performance. Natural gas should remain an abundant resource in the U.S., brought about partially by new technologies, so a shortage does not appear likely in the years ahead. Too, there are limited alternatives for the services the companies in this sector offer. Furthermore, it's a challenge for new entrants in the market, given such factors as the size of existing competitors and the substantial initial capital outlays that are required. Finally, the country's population, now numbering more than 330 million, should stay on a steady, upward course, which augurs well for future demand for utility services.

Conclusion

None of the equities in our Natural Gas Utility Industry stand out for Timeliness, at this juncture, besides *UGI Corp*. Nevertheless, they ought to be of interest to income-focused investors with a conservative orientation, given that these good-yielding issues boast high marks for Price Stability, and the majority are ranked 1 (Highest) or 2 (Above Average) for Safety. Consider, too, that there are some appealing choices for capital appreciation potential for both the 18-month horizon and over the pull to 2027-2029. As always, our subscribers are advised to carefully examine the following reports before committing funds.

Frederick L. Harris, III



ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 114.00 | P/E RATIO 17.4 (Trailing: 18.6 Median: 20.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 2 Raised 2/9/24
BETA .85 (1.00 = Market)

High:	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	118.9
Low:	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.6

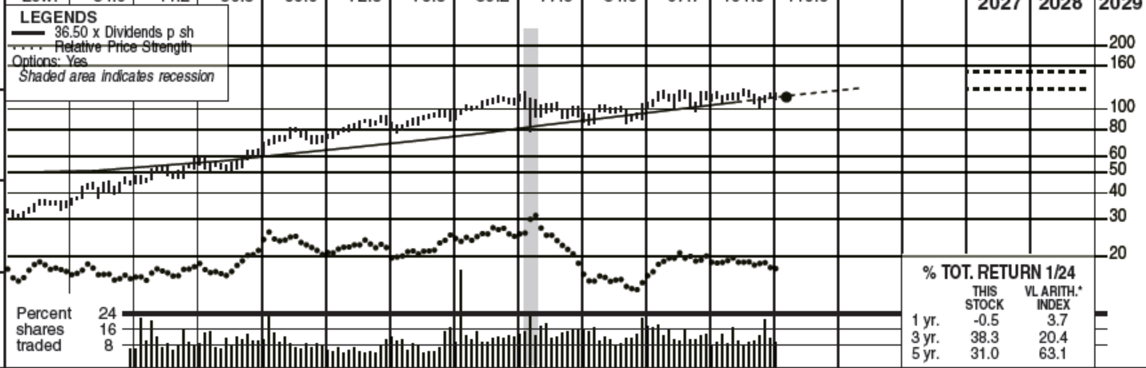
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$98-$153 $126 (10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	10%
Low	125	(+10%)	6%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	337	314	322
to Sell	258	281	280
Hld's(000)	131736	136508	137279



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.5	3.7
3 yr.	38.3	20.4
5 yr.	31.0	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	*26.75*	*27.85*	Revenues per sh A	*37.15*
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	*10.75*	*11.55*	"Cash Flow" per sh	*13.65*
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	*6.55*	*7.00*	Earnings per sh AB	*8.35*
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	*3.22*	*3.46*	Div'ds Decl'd per sh C■	*4.25*
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	*18.70*	*19.00*	Cap'l Spending per sh	*20.00*
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	*74.90*	*78.25*	Book Value per sh	*83.50*
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	*155.00*	*158.00*	Common Shs Outst'g D	*175.00*
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	*Value Line*		Relative P/E Ratio	*.90*
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
						4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	*4145*	*4400*	Revenues ($mill) A	*6500*
						289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	*1000*	*1100*	Net Profit ($mill)	*1475*
						39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	*15.0%*	*16.0%*	Income Tax Rate	*25.0%*
						5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	*24.1%*	*25.0%*	Net Profit Margin	*22.7%*
						44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*40.0%*
						55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	*60.0%*	*60.0%*	Common Equity Ratio	*60.0%*
						5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	*19350*	*20600*	Total Capital ($mill)	*24350*
						6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	*20700*	*21800*	Net Plant ($mill)	*25500*
						6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	*8.5%*	*9.0%*	Return on Com Equity	*10.0%*
						4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
						50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	*50%*	*50%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $7540.8 mill. **Due in 5 Yrs** $915.0 mill.
LT Debt $7529.3 mill. **LT Interest** $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill. **Oblig.** $431.6 mill.

Common Stock 150,839,709 shs. as of 2/2/24

MARKET CAP: $17.2 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	12/31/23
Cash Assets	51.6	15.4	278.3
Other	2996.1	870.4	1401.4
Current Assets	3047.7	885.8	1679.7
Accts Payable	496.0	336.1	416.7
Debt Due	2386.4	253.4	11.5
Other	720.2	763.1	742.3
Current Liab.	3602.6	1352.6	1170.5
Fix. Chg. Cov.	1238%	1059%	1080%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	*5.0%*
"Cash Flow"	6.5%	7.0%	*6.5%*
Earnings	9.5%	9.0%	*7.0%*
Dividends	7.0%	8.5%	*7.5%*
Book Value	9.5%	12.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	*1600*	*786.5*	*600*	*4145*
2025	*1225*	*1700*	*840*	*635*	*4400*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	*2.53*	*1.06*	*.88*	*6.55*
2025	*2.21*	*2.65*	*1.17*	*.97*	*7.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy started fiscal 2024 with healthy bottom-line results. (The year concludes on September 30th.) First-quarter earnings per share of $2.08 were 9% higher than the $1.91 tally posted in fiscal 2023. That was made possible partly by positive rate-case outcomes. Diminished bad-debt expense helped, too. It should also be mentioned that the current-quarter figure was favorably impacted by legislation to reduce property-tax expenses in Texas. But increased depreciation expense and higher interest expense provided somewhat of an offset. Still, at this juncture, it appears that full-year profits will advance roughly 7%, to $6.55 per share, compared to fiscal 2023's $6.10 total. Regarding next year, share net stands to advance at a similar percentage rate, to $7.00, assuming additional widening of operating margins.

There's sufficient liquidity to satisfy various obligations for quite a while. When the December period ended, cash and equivalents sat at $278.3 million. Moreover, long-term debt looked reasonable (40% of total capital) and short-term commitments were minimal. Also, $3.1 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in March, 2026. Finally, the company had four undrawn revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program.

Prospects out to the end of the decade seem decent. Atmos Energy ranks as one of the nation's biggest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Furthermore, we believe the pipeline and storage segment has promising overall expansion opportunities, since it operates in one of the most-active drilling regions in the world. The solid balance sheet is another strength.

What about the stock? Capital appreciation potential over the 18-month span seems worthwhile. However, the dividend yield is lower than the average of *Value Line's* Natural Gas Utility Industry. Meanwhile, ATO shares are unfavorably ranked for Timeliness.

Frederick L. Harris, III February 23, 2024

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 105.22 | P/E RATIO 20.8 (Trailing: 21.3) (Median: 23.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 2/9/24
SAFETY 2 New 6/5/15
TECHNICAL 4 Raised 12/29/23
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$87-$167	$127 (20%)

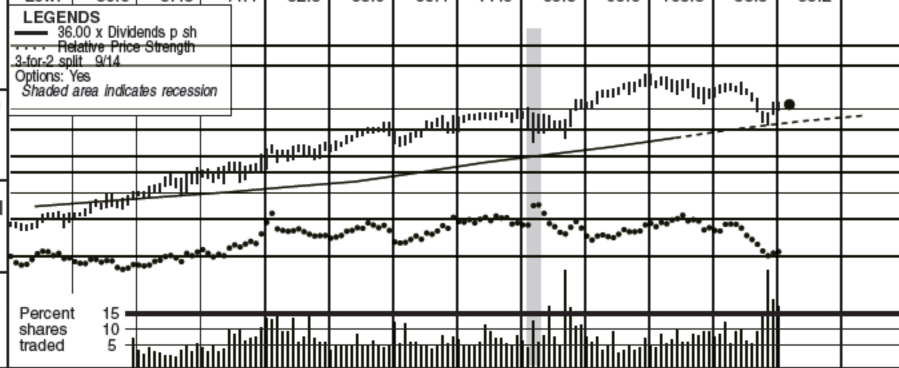
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+45%)	11%
Low	110	(+5%)	4%

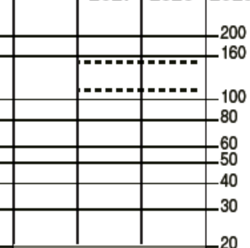
Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	128	107	126
to Sell	97	121	98
Hld's(000)	13346	13342	13495

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	40.8	52.7	61.1	70.0	86.4	93.4	98.6	111.4	146.1	146.3	132.9	107.5
Low:	30.6	37.5	44.4	52.3	63.0	66.4	77.6	69.5	99.6	105.8	83.8	99.2



Target Price Range 2027 | 2028 | 2029



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-18.1	3.7
3 yr.	5.1	20.4
5 yr.	22.1	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	32.28	38.37	**36.20**	**38.95**	**42.05**	Revenues per sh	**70.20**
2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	8.28	8.87	**8.80**	**9.35**	**10.00**	"Cash Flow" per sh	**11.70**
1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	4.73	4.97	**4.85**	**5.10**	**5.35**	Earnings per sh A	**6.50**
.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	2.03	2.25	**2.44**	**2.60**	Div'ds Decl'd per sh B■	**3.20**
3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	10.59	7.23	**10.80**	**11.55**	**11.80**	Cap'l Spending per sh	**12.25**
12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	43.85	46.94	**49.30**	**53.40**	**56.50**	Book Value per sh	**66.40**
10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	16.40	17.46	17.66	17.74	**18.50**	**19.00**	**19.50**	Common Shs Outst'g C	**23.50**
14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	24.7	21.6	25.6	25.8	**23.7**	Bold figures are		Avg Ann'l P/E Ratio	**20.0**
.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	1.38	1.49	**1.32**	Value Line		Relative P/E Ratio	**1.10**
4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%	1.6%	2.0%	estimates		Avg Ann'l Div'd Yield	**2.5%**
						498.8	459.2	498.9	617.6	717.5	479.6	488.2	570.0	680.7	**670**	**740**	**820**	Revenues ($mill)	**1650**
						36.1	40.2	44.7	43.8	56.6	61.1	70.6	83.5	88.4	**90.0**	**97.0**	**105**	Net Profit ($mill)	**155**
						39.9%	39.5%	38.8%	39.5%	27.1%	25.6%	25.0%	25.9%	27.4%	**26.0%**	**26.5%**	**27.0%**	Income Tax Rate	**29.0%**
						7.2%	8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	14.6%	13.0%	**13.4%**	**13.1%**	**12.8%**	Net Profit Margin	**9.4%**
						34.5%	29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	41.5%	41.0%	**43.0%**	**42.0%**	**42.0%**	Long-Term Debt Ratio	**40.0%**
						65.5%	70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	58.5%	59.0%	**57.0%**	**58.0%**	**58.0%**	Common Equity Ratio	**60.0%**
						458.8	507.5	583.0	683.7	834.5	1001.7	1205.6	1324.0	1411.2	**1600**	**1750**	**1900**	Total Capital ($mill)	**2600**
						689.8	855.0	986.7	1126.0	1384.0	1463.8	1601.2	1744.9	1810.5	**1950**	**2175**	**2400**	Net Plant ($mill)	**3000**
						8.5%	8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	7.1%	7.1%	**7.0%**	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
						12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	**10.0%**	**9.5%**	**9.5%**	Return on Shr. Equity	**10.0%**
						12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	10.6%	**10.0%**	**9.5%**	**9.5%**	Return on Com Equity	**10.0%**
						7.4%	6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	6.7%	6.4%	**5.5%**	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
						38%	40%	39%	45%	39%	40%	38%	38%	40%	**46%**	**48%**	**48%**	All Div'ds to Net Prof	**49%**

CAPITAL STRUCTURE as of 9/30/23
Total Debt $782.4 mill. Due in 5 Yrs $334.0 mill.
LT Debt $643.8 mill. LT Interest $40.0 mill.
(LT interest earned: 6.0x; total interest coverage: 6.0x) (43% of Cap'l)
Leases, Uncapitalized Annual rentals $2.9 mill.
Pfd Stock None
Pension Assets-12/22 $46.2 mill. **Oblig.** $51.6 mill.
Common Stock 17,796,741 shs. as of 10/27/23

MARKET CAP: $1.9 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	5.0	6.2	1.8
Other	168.1	187.8	135.7
Current Assets	173.1	194.0	137.5
Accts Payable	52.6	61.5	53.7
Debt Due	239.6	223.6	138.6
Other	84.2	83.9	96.1
Current Liab.	376.4	369.0	288.4
Fix. Chg. Cov.	771%	692%	710%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	2.0%	-1.0%	11.5%
"Cash Flow"	8.0%	8.5%	5.5%
Earnings	9.0%	10.0%	5.0%
Dividends	7.0%	8.5%	8.5%
Book Value	9.5%	9.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	191.2	111.1	107.3	160.4	570.0
2022	222.9	139.5	131.1	187.2	680.7
2023	218.1	135.6	131.5	**184.8**	**670**
2024	**235**	**160**	**150**	**195**	**740**
2025	**255**	**180**	**170**	**215**	**820**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.96	.78	.71	1.28	4.73
2022	2.08	.88	.54	1.47	4.97
2023	2.04	.90	.53	**1.38**	**4.85**
2024	**2.10**	**.98**	**.60**	**1.42**	**5.10**
2025	**2.16**	**1.05**	**.66**	**1.48**	**5.35**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.405	.405	.44	.44	1.69
2021	.44	.44	.48	.48	1.84
2022	.48	.48	.535	.535	2.03
2023	.535	.535	.59	.59	2.25
2024	.59				

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2022: Regulated Energy, 63.1%; Unregulated Energy, 41.2%; Other, d4.3%. Officers and directors own 2.7% of common stock; BlackRock, 13.9% (3/23 Proxy). Chairman and CEO: Jeffry M. Householder. Inc.: DE. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities just concluded an important agreement with NextEra Energy. It paid that firm $923 million for Florida City Gas (FCG), serving 120,000 residential and commercial customers across eight counties in Florida, including Miami-Dade, Broward, Palm Beach, and Indian River. We like that move partly because it more than doubled the natural gas operations in The Sunshine State, which has bright growth prospects. Another plus is enhanced economies of scale. It's also worth mentioning that the deal was funded via a balanced mix of equity and long-term debt, thus maintaining the company's sound finances.

Another business was brought into the fold. Chesapeake purchased, for an undisclosed amount, the propane operating assets of J.T. Lee and Son's. As a consequence, its geographic footprint extended further into the promising North Carolina market, via the addition of 3,000 customers. Synergistic benefits are probable, as well. So, we would not be surprised to see similar transactions going forward.

It appears that the energy firm posted uninspiring 2023 results. Recall that for the first nine months, profits of $3.47 per share were a few pennies below 2022's $3.50 figure. That can be traced partly to much warmer weather in the northern service territories, especially during the first six months, which constrained customer consumption. Moreover, there were increased interest charges, employee-related expenses, and facilities & maintenance costs. However, the company's performance did benefit from factors such as contributions from a Florida natural gas base rate proceeding, increased propane margins and fees, plus pipeline expansion projects. Still, it seems that, for the entire year, earnings per share sat at around $4.85, modestly below 2022's $4.97 tally. But regarding 2024 and 2025, share net stands to reach $5.10 and $5.35, respectively (a 5% advance for both years), if the business climate cooperates.

The equity does not have much to offer other than decent 18-month capital gains potential. Upside possibilities out to 2027-2029 lack appeal. The dividend yield is not enticing, either, versus those of other Natural Gas Utility stocks we cover.

Frederick L. Harris, III February 23, 2024

(A) Diluted shrs. Excludes nonrecurring gains (loss): '08, (7¢); '15, 6¢; '17, 87¢; '22, 8¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Quarters for 2019 don't equal total because of rounding. Next earnings report due early May.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 42.13 | P/E RATIO 15.0 (Trailing: 18.3 Median: 17.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 5 Lowered 1/5/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 4 Lowered 1/5/24
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$31-$51 $41 (-5%)

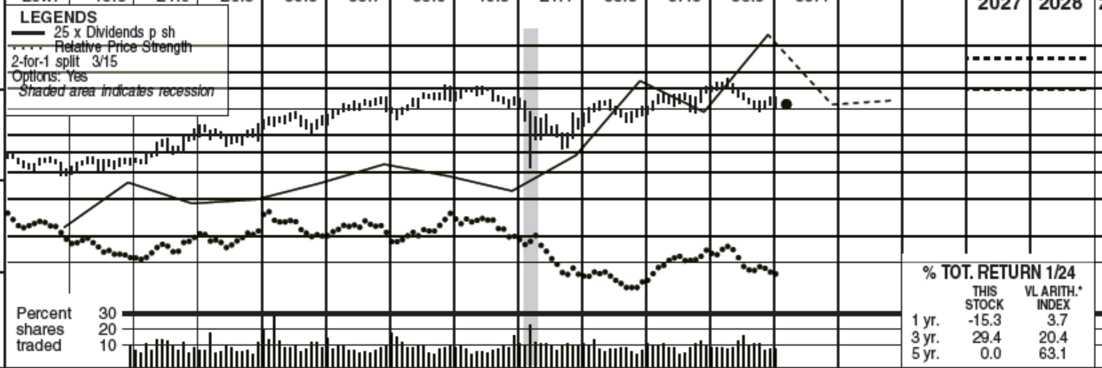
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+65%)	16%
Low	50	(+20%)	8%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	157	157	153
to Sell	133	156	163
Hld's(000)	73728	71570	69494

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	45.8
Low:	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-15.3	3.7
3 yr.	29.4	20.4
5 yr.	0.0	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	**21.50**	**22.00**	Revenues per sh A	**25.00**
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	**4.40**	**4.50**	"Cash Flow" per sh	**5.25**
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	**2.80**	**2.90**	Earnings per sh B	**3.50**
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	**1.68**	**1.76**	Div'ds Decl'd per sh C■	**1.95**
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	**5.15**	**5.50**	Cap'l Spending per sh	**6.25**
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	**22.30**	**23.65**	Book Value per sh D	**27.00**
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	**100.00**	**100.00**	Common Shs Outst'g E	**100.00**
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02	*Value Line*		Relative P/E Ratio	**.95**
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**

CAPITAL STRUCTURE as of 12/31/23
Total Debt $3227.3 mill. **Due in 5 Yrs** $580 mill.
LT Debt $2739.0 mill. **LT Interest** $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 3.3x)
Pension Assets-9/23 $405.0 mill. **Oblig.** $493.7 mill.
Pfd Stock None
Common Stock 98,303,527 shs. as of 2/2/24
MARKET CAP: $4.1 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	**2150**	**2200**	Revenues ($mill) A	**2500**
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	**280**	**290**	Net Profit ($mill)	**350**
30.2%	26.3%	15.5%	17.2%	- -	- -	NMF	10.3%	21.4%	15.8%	**22.0%**	**22.0%**	Income Tax Rate	**22.0%**
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	**13.0%**	**13.2%**	Net Profit Margin	**14.0%**
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	**57.5%**	**57.0%**	Long-Term Debt Ratio	**55.0%**
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	**42.5%**	**43.0%**	Common Equity Ratio	**45.0%**
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	**5250**	**5500**	Total Capital ($mill)	**6000**
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	**5150**	**5250**	Net Plant ($mill)	**5550**
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.0%**
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	**12.5%**	**12.5%**	Return on Shr. Equity	**13.0%**
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	**12.5%**	**12.5%**	Return on Com Equity	**13.0%**
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	**5.0%**	**5.0%**	Retained to Com Eq	**5.5%**
40%	50%	60%	59%	40%	59%	60%	56%	53%	57.8%	**60%**	**60%**	All Div'ds to Net Prof	**56%**

CURRENT POSITION ($MILL.)

	2022	2023	12/31/23
Cash Assets	1.1	1.0	2.7
Other	755.0	531.1	675.3
Current Assets	756.1	532.1	678.0
Accts Payable	156.6	151.8	105.6
Debt Due	499.1	368.3	488.3
Other	448.5	286.5	368.1
Current Liab.	1104.2	806.6	962.0
Fix. Chg. Cov.	545%		

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	2.5%
"Cash Flow"	7.0%	4.5%	5.0%
Earnings	5.0%	2.5%	5.0%
Dividends	6.5%	6.5%	5.0%
Book Value	7.5%	7.0%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	*850*	*450*	*382.8*	*2150*
2025	*680*	*770*	*460*	*290*	*2200*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	*1.35*	*.05*	*.66*	*2.80*
2025	*.75*	*1.40*	*.05*	*.70*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources finished fiscal 2023 in good shape. (Fiscal years end September 30th.) Net financial earnings per share of $0.30 in the fiscal fourth quarter propelled the bottom line to $2.70 over the full year, an 8% advance. These metrics aligned exactly with our earlier forecasts; however, revenues were well below our targets due to falling natural gas prices, which are a cost that is largely passed through to customers directly. Notably, strong customer growth at the utility, expansion of Clean Energy Ventures, and the completion of the Adelphia Gateway Pipeline all contributed to the solid twelve-month performance.

Earnings were down to begin fiscal 2024. Share net landed at $0.74 in the December period, well short of our call for $1.10 and the year-earlier tally. Part of the reason for the particularly poor comparison is due to the effect of winter storm Elliot at the end of 2022, which boosted earnings by as much as $0.20 per share. As a result, the Energy Services segment in particular registered a $45 million decrease in net financial earnings, whereas the other segments combined for a $7 million increase, notably led by a $14 million improvement at Clean Energy Ventures.

The remainder of 2024 looks likely to generate growth. While we have left our profit target in place despite the first-quarter earnings miss, management has recently increased its guidance for fiscal 2024, now forecasting a range from $2.85 to $3.00 per share. Winter weather in January was the stated impetus for the increase, with Energy Services set to generate a boost from its Asset Management Agreements. Our forecast reflects earnings growth expectations of 4% this year, versus the target long-run average of 7% to 9% annual increases.

Our long-term outlook provides the basis for solid capital appreciation potential. New rates expected in fiscal 2025 should help deliver towards our targets. Meantime, the stock is ranked to underperform the broader market (Timeliness: 5, Lowest). Thus, patient investors may well find a more favorable entry point, from which to buy-and-hold, in the year ahead.

Earl B. Humes *February 23, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early May.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE 25.63 | P/E RATIO 15.4 (Trailing: 16.3 Median: 21.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Lowered 12/29/23
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Raised 2/23/24
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$23-$39	$31 (20%)

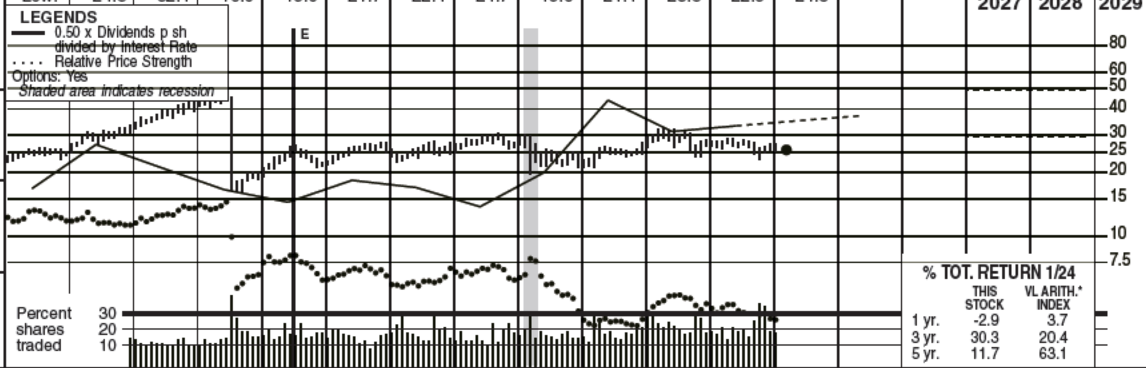
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+75%)	*18%*
Low	35	(+30%)	*10%*

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	301	249	278
to Sell	201	256	234
Hld's(000)	387698	393166	394475

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	27.5
Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	3.7
3 yr.	30.3	20.4
5 yr.	11.7	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	*14.45*	*14.60*	*15.05*	Revenues per sh	*16.10*
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	*3.60*	*3.80*	*4.80*	"Cash Flow" per sh	*4.25*
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	*1.60*	*1.70*	*1.85*	Earnings per sh A	*2.10*
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh B ■	*1.20*
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	*7.95*	*7.00*	*6.50*	Cap'l Spending per sh	*6.75*
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	*19.45*	*20.00*	*20.50*	Book Value per sh C	*18.75*
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	*415.00*	*425.00*	*435.00*	Common Shs Outst'g D	*450.00*
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	*16.8*	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	*.97*	*Value Line*		Relative P/E Ratio	*1.05*
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $13258.0 mill. **Due in 5 Yrs** $2355 mill.
LT Debt $11011.3 mill. **LT Interest** $368 mill.
(Interest cov. earned: 5.8x) (59% of Cap'l)

Leases, Uncapitalized Annual rentals $8.0 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $1547 mill. **Pfd Div'd** $55.1 mill.

Common Stock 413,415,441 shs.
as of 10/24/23
MARKET CAP: $10.6 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	*6000*	*6200*	*6550*	Revenues ($mill)	*7250*
530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	*665*	*725*	*805*	Net Profit ($mill)	*945*
36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	*19.0%*	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	2.0%	2.3%	*2.5%*	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	*57.5%*	*57.5%*	*57.5%*	Long-Term Debt Ratio	*55.0%*
43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	*35.0%*	*35.0%*	*35.0%*	Common Equity Ratio	*37.5%*
14331	9792.0	10129	11832	12856	13843	14972	16131	17099	*19000*	*20000*	*21000*	Total Capital ($mill)	*22500*
16017	12112	13068	14360	15543	16912	16620	17882	19843	*22500*	*24500*	*25750*	Net Plant ($mill)	*28000*
5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	*3.5%*	*3.5%*	*4.0%*	Return on Total Cap'l	*4.0%*
8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	*8.0%*	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	*10.0%*	*10.5%*	*11.0%*	Return on Com Equity	*11.0%*
3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	*3.5%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
61%	NMF	63%	NMF	60%	64%	67%	64%	64%	*63%*	*62%*	*60%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	85.2	40.8	56.0
Other	1835.6	2543.5	1759.4
Current Assets	1920.8	2584.3	1815.4
Accts Payable	697.8	899.5	648.2
Debt Due	618.1	1791.9	2246.7
Other	1430.3	1969.1	1500.5
Current Liab.	2746.2	4660.5	4395.4
Fix. Chg. Cov.	250%	255%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	*1916.6*	*6000*
2024	*2000*	*1125*	*1150*	*1925*	*6200*
2025	*2115*	*1190*	*1215*	*2030*	*6550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	*.53*	*1.60*
2024	*.85*	*.15*	*.13*	*.57*	*1.70*
2025	*.90*	*.20*	*.15*	*.60*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265				

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2022: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.1% electric, 2.3% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource's stock offers good value to risk-averse income investors. The natural gas and electric utility company's shares moved sideways in the three months since our November review, as the broader U.S. equity markets pushed on to record highs. Utilities have underperformed as bond yields and growth sectors have drawn investors' attention. Further, inflationary costs and higher interest rates (both of which we think are likely to decrease), have pressured growth, hurting this stock's performance. Yet, these shares have reached a compelling risk-adjusted valuation in comparison to others in the sector. Considering the ongoing transition to renewable energy and building of sustainable energy infrastructure, we see a lot of potential upside to buy-and-hold strategies.

Blackstone, Inc.'s recent acquisition of a non-controlling stake in NIPSCO, a NiSource subsidiary, points to the value here. Blackstone's infrastructure unit purchased 19.9% of the electric and gas subsidiary for $2.16 billion in January. The cash will aid the company's ambitious clean energy transition and decarbonization programs; NIPSCO is planning to phase out its coal-fired power plants by 2028, whereas this sourced 75% of power production as recently as 2018.

The significant investment required to reach its sustainability goals will be a key driver of growth. Capital investments amounting to $16 billion are planned over the next five years, contributing to an expected rate-base increase of 8% to 10% per year, and a 6% to 8% annual increase in earnings per share. Execution on regulatory approvals has been a key strength.

All told, we expect growth to continue at a moderate pace through the next three to five years. The utility likely ended 2023 in good form, and earnings per share probably grew roughly 9%. Note: The company was scheduled to report its annual results as we went to press with this Issue. We think earnings are likely to increase by about 7% per year on average, while dividends may grow by 5% annually.

This issue's Safety rank has risen a notch, to 2 (above average). Likewise, the risk-adjusted upside is attractive.

Earl B. Humes *February 23, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early May. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '22: $1485.9 million, $3.61/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

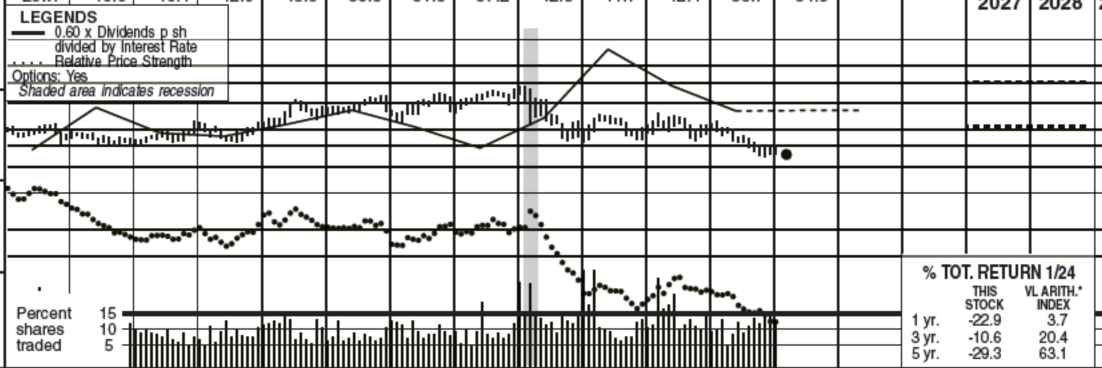
N.W. NATURAL NYSE-NWN

RECENT PRICE 36.62 | P/E RATIO 13.8 (Trailing: 13.3 Median: 24.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 Raised 2/23/24
TECHNICAL 3 Raised 2/23/24
BETA .85 (1.00 = Market)

High:	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	40.3
Low:	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.9

LEGENDS
— 0.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$59	$46 (25%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+120%)	24%
Low	50	(+35%)	12%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	115	122	115
to Sell	102	123	110
Hld's(000)	26729	26926	27474

Percent shares traded 15 10 5

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.9	3.7
3 yr.	-10.6	20.4
5 yr.	-29.3	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	*31.10*	*30.25*	*30.75*	Revenues per sh	*31.25*
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	*5.85*	*6.15*	*6.85*	"Cash Flow" per sh	*7.55*
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	*2.65*	*2.75*	*3.00*	Earnings per sh A	*3.25*
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	*1.95*	*1.96*	Div'ds Decl'd per sh B■	*1.98*
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	*9.00*	*9.25*	*9.50*	Cap'l Spending per sh	*10.00*
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	*31.70*	*39.70*	*40.55*	Book Value per sh D	*38.70*
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	*37.00*	*38.00*	*39.00*	Common Shs Outst'g C	*42.00*
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	*16.3*	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	*.94*	*Value Line*		Relative P/E Ratio	*1.10*
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*
						754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	*1150*	*1150*	*1200*	Revenues ($mill)	*1250*
						58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	*98*	*105*	*115*	Net Profit ($mill)	*135*
						41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	*25.0%*	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
						7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	*8.5%*	*9.1%*	*9.8%*	Net Profit Margin	*10.9%*
						44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	*54.0%*	*52.5%*	*52.5%*	Long-Term Debt Ratio	*50.0%*
						55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	*46.0%*	*47.5%*	*27.5%*	Common Equity Ratio	*50.0%*
						1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	*2550*	*2625*	*2750*	Total Capital ($mill)	*3250*
						2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	*3250*	*3400*	*3550*	Net Plant ($mill)	*3750*
						5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	*4.0%*	*4.0%*	*4.5%*	Return on Total Cap'l	*4.0%*
						7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	*7.5%*	*7.0%*	*7.5%*	Return on Shr. Equity	*8.5%*
						7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	*7.5%*	*7.0%*	*7.5%*	Return on Com Equity	*8.5%*
						1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	*2.0%*	*2.0%*	*3.0%*	Retained to Com Eq	*3.5%*
						85%	92%	87%	NMF	76%	82%	79%	71%	79%	*73%*	*70%*	*65%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1686.3 mill. **Due in 5 Yrs** $713 mill.
LT Debt $1424.6 mill. **LT Interest** $75 mill.

(Total interest coverage: 1.9x)

Pension Assets-12/22 $300.0 mill. **Oblig.** $413.4 mill.

Pfd Stock None

Common Stock 36,778,271 shares as of 10/26/23

MARKET CAP $1.3 billion (Small Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	18.6	29.3	156.6
Other	418.7	714.9	350.8
Current Assets	437.3	744.2	507.4
Accts Payable	133.5	180.7	99.3
Debt Due	389.8	348.9	261.7
Other	201.5	369.1	229.1
Current Liab.	724.8	898.7	590.1
Fix. Chg. Cov.	335%	320%	275%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	*308.2*	*1150*
2024	*445*	*220*	*130*	*355*	*1150*
2025	*465*	*230*	*135*	*370*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	*1.26*	*2.65*
2024	*2.00*	*.05*	*d.65*	*1.35*	*2.75*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488				

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,258. BlackRock Inc. owns 17.3% of shares; Vanguard, 12.2%; Off./Dir., .95% (4/23 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural stock offers good value for income-seeking accounts. The stock's price has fallen from highs of $77 a share in as few as four years, as the appeal of a steady income stream from utility companies has been overshadowed by the growth potential of other sectors and diminished by higher interest rates. Indeed, this sets the stage for what we believe is an attractive combination of stability and value. The stock's 5.3% dividend yield, well above the *Value Line* median, is a strong incentive which provides a solid foundation for future total return potential. While government bonds offer a similar value proposition with less risk, the idea that interest rates may well come down in the near future adds to the appeal of receiving this dividend. Furthermore, the current price-to-earnings ratio of 12.5 is notably low for the stock, and the issue's Safety rank was recently raised a notch, to 2 (Above Average).

The company likely ended 2023 in good shape. Note: The company was scheduled to report its annual results shortly after we went to press with this Issue. Our conservative fourth-quarter outlook is influenced by mild El Nino year regional weather, and some inflationary pressure. Nonetheless, full-year share earnings likely rose a decent 4%, thanks largely to a strong first quarter. We expect earnings per share to advance anothe 4% in 2024, and 9% in 2025.

Resilient economic trends and sustainability initiatives underscore our earnings growth outlook. The company's service area ranks among the middle of the pack in economic and population growth trends, which contributes to our expectations for stability. The company's sustainability strategies are the main impetus for growth. Investments in this domain, including its expanding water business, and continual infrastructure hardening, should lead to rate-case execution and earnings increases ahead.

Risks are worth noting. Two key areas of concern are the possible banning of natural gas in new construction (a growing urban trend), and the increasing threat from wildfires in the region. Also, the stock's Earnings Predictability rank is quite low.

Earl B. Humes *February 23, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2022: $149 million, $4.20/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

ONE GAS, INC. NYSE-OGS

RECENT PRICE **62.45** | P/E RATIO **15.2** (Trailing: 15.2 / Median: NMF) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 4 Lowered 2/9/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
\$52-\$101	\$77 (25%)

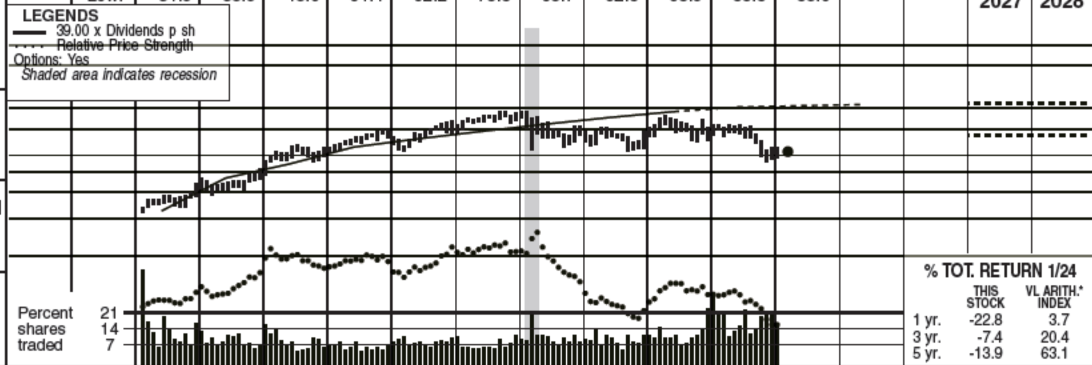
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+70%)	17%
Low	75	(+20%)	9%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	157	158	148
to Sell	133	133	153
Hld's(000)	51917	53044	51074

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	65.8
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	58.0



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-22.8	3.7
3 yr.	-7.4	20.4
5 yr.	-13.9	63.1

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.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	*46.50*	*47.55*	*49.55*	Revenues per sh	*70.15*
4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	*9.10*	*9.85*	*10.90*	"Cash Flow" per sh	*13.95*
2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	*4.15*	*4.05*	*4.20*	Earnings per sh A	*5.00*
.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	*2.64*	*2.68*	Div'ds Decl'd per sh B■	*2.85*
5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	*11.75*	*11.95*	*12.15*	Cap'l Spending per sh	*12.60*
34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	*47.05*	*49.55*	*54.50*	Book Value per sh	*60.20*
52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	*55.50*	*55.50*	*55.50*	Common Shs Outst'g C	*57.00*
17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	*17.9*	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	*1.00*	*Value Line*		Relative P/E Ratio	*1.00*
2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*
1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	*2580*	*2640*	*2750*	Revenues (\$mill)	*4000*
109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	*230*	*225*	*235*	Net Profit (\$mill)	*285*
38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	*15.5%*	*15.5%*	*16.0%*	Income Tax Rate	*20.0%*
6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	*8.9%*	*8.5%*	*8.5%*	Net Profit Margin	*7.1%*
40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	*42.0%*	*45.0%*	*45.0%*	Long-Term Debt Ratio	*51.0%*
59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	*58.0%*	*55.0%*	*55.0%*	Common Equity Ratio	*49.0%*
2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	*4500*	*5000*	*5500*	Total Capital (\$mill)	*7000*
3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	*6050*	*6425*	*6800*	Net Plant (\$mill)	*8000*
4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	*6.5%*	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	*9.0%*	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	*3.5%*	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
40%	53%	52%	55%	56%	56%	58%	60%	60%	*63%*	*65%*	*63%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt \$2990.0 mill. **Due in 5 Yrs** \$1250.0 mill.
LT Debt \$1862.6 mill. **LT Interest** \$115.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals \$6.5 mill.
Pfd Stock None
Pension Assets-12/22 \$950.8 mill.
Oblig. \$953.0 mill.
Common Stock 55,454,050 shs.
as of 10/23/23
MARKET CAP: \$3.5 billion (Mid Cap)

CURRENT POSITION (\$MILL.)	2021	2022	9/30/23
Cash Assets	8.9	9.7	9.2
Other	2215.7	1207.9	555.2
Current Assets	2224.6	1217.6	564.4
Accts Payable	258.6	360.5	168.6
Debt Due	494.0	572.7	1127.4
Other	227.9	256.2	275.7
Current Liab.	980.5	1189.4	1571.7
Fix. Chg. Cov.	625%	540%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	- -	6.5%	*10.0%*
"Cash Flow"	- -	6.0%	*9.0%*
Earnings	- -	6.0%	*4.0%*
Dividends	- -	8.0%	*3.0%*
Book Value	- -	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES (\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	*814*	*2580*
2024	*1040*	*415*	*360*	*825*	*2640*
2025	*1060*	*430*	*410*	*850*	*2750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	*1.28*	*4.15*
2024	*1.82*	*.57*	*.43*	*1.23*	*4.05*
2025	*1.87*	*.60*	*.48*	*1.25*	*4.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66				

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 165 Bcf of natural gas supply in 2022, compared to 164 Bcf in 2021. Total volumes delivered by customer (fiscal 2022): transportation, 57.3%; residential, 31.2%; commercial & industrial, 10.8%; other, .7%. ONE Gas has around 3,600 employees. BlackRock owns 12.6% of common stock; The Vanguard Group, 11.5%; State Street Corporation, 11.5%; officers and directors, 1.5% (4/23 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. probably had a lackluster performance in 2023. (Fourth-quarter numbers were not available when this report went to press.) Recall that during the first nine months, profits of \$2.87 per share were only one cent higher than the previous year's \$2.86 tally. This stemmed, to a certain degree, from a 12.5% increase in total operating expenses, which particularly reflected greater depreciation & amortization and operations & maintenance costs. Also, interest expense rose sharply. The number of diluted shares outstanding was somewhat higher, too. But the company's results were helped partly by new rates. Moreover, the effective income tax rate dropped. Nevertheless, it seems that full-year earnings per share were around \$4.15. That would be quite close to 2022's \$4.08 figure.

We anticipate another underwhelming showing in 2024. Although ONE Gas stands to enjoy the benefits of new rates and customer growth, they ought to be offset by heightened expenses (including employee-related and contractor costs, depreciation expense, and interest costs). So, the bottom line may only finish in the vicinity of \$4.05 per share, modestly below our target for last year. But looking at 2025, a nearly 4% advance, to \$4.20 a share, appears possible based to some extent on our assumption that the business climate is generally favorable.

The quarterly dividend was recently raised by a penny, to \$0.66 a share. The company says that it plans to keep the average annual dividend growth rate between 1% and 2% through fiscal 2028. We believe that substantially slower increase, versus prior years, is partly because operating expenses should continue to climb as ONE Gas expands. In any event, the payout ratio out to the end of the decade ought to be manageable, in the 55% to 60% range.

There are some things to like about these shares. Capital gains potential over the 18-month span is significant. Upside possibilities during the 2027-2029 period are worthwhile, too. The solid dividend yield is another plus. Consider, also, the 2 (Above Average) Safety rank and high Price Stability mark of 90 out of 100.

Frederick L. Harris, III February 23, 2024

(A) Diluted EPS. Excludes nonrecurring gain: 2017, \$0.06. Next earnings report due early May. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.99 | P/E RATIO 19.4 (Trailing: 20.0 Median: 19.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS – Suspended 3/11/22
SAFETY 3 Lowered 8/28/20
TECHNICAL – Suspended 3/11/22
BETA .90 (1.00 = Market)

High:	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	29.2	35.3
Low:	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8	23.1

18-Month Target Price Range

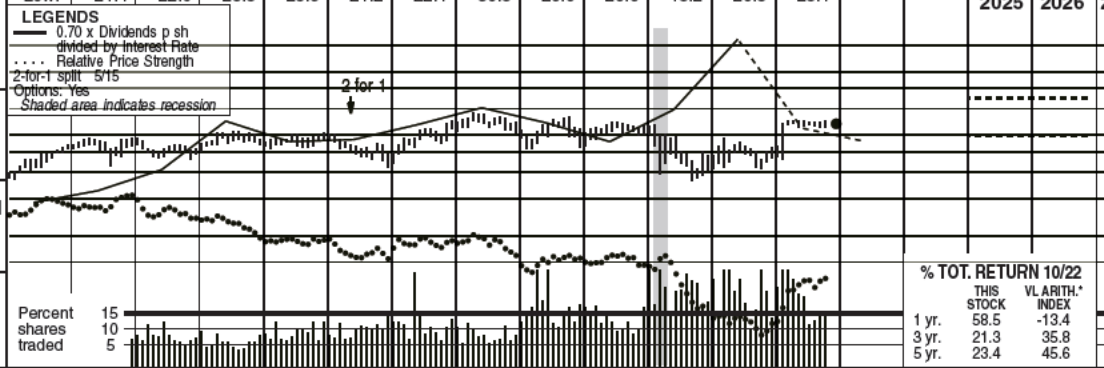
Low-High	Midpoint (% to Mid)
$15-$43	$29 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	10%
Low	30	(-10%)	1%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	135	171	151
to Sell	105	130	143
Hld's(000)	101881	102926	103244



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	58.5	-13.4
3 yr.	21.3	35.8
5 yr.	23.4	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	16.98	21.60	20.00	Revenues per sh	24.00
1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.56	3.32	3.32	2.70	3.00	"Cash Flow" per sh	4.40
1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.12	1.68	1.62	1.70	1.85	Earnings per sh A	2.40
.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	1.22	1.25	1.28	Div'ds Decl'd per sh B ■	1.50
1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	4.53	4.95	5.10	Cap'l Spending per sh	6.75
7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	16.95	18.00	19.00	Book Value per sh C	22.00
58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	117.34	125.00	125.00	Common Shs Outst'g D	125.00
11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	15.1	Bold figures are		Avg Ann'l P/E Ratio	16.0
.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	1.51	.77	.82	Value Line		Relative P/E Ratio	.90
3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	5.0%	estimates		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $3801.1 mill. Due in 5 Yrs $278.5 mill.
LT Debt $3566.8 mill. LT Interest $150 mill.

Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/21 $331 mill. Oblig. $351.6 mill.

Pfd Stock None

Common Stock 124,803,932 shs. as of 11/1/22

MARKET CAP: $4.2 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	1992.0	2700	2500	Revenues ($mill)	3000
93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	178.0	215	230	Net Profit ($mill)	300
10.8%	--	--	5.9%	42.0%	--	--	--	9.9%	22.0%	21.0%	21.0%	Income Tax Rate	21.0%
13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	8.9%	8.0%	9.5%	Net Profit Margin	10.0%
45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	61.6%	62.0%	60.0%	Long-Term Debt Ratio	60.0%
55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	38.4%	38.0%	40.0%	Common Equity Ratio	40.0%
1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	5178.2	5750	6250	Total Capital ($mill)	7000
1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	4912.3	5400	5750	Net Plant ($mill)	6500
7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	4.6%	3.5%	3.5%	Return on Total Cap'l	4.5%
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	9.5%	9.5%	Return on Shr. Equity	10.5%
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	9.5%	9.5%	Return on Com Equity	10.5%
5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	2.2%	2.0%	3.0%	Retained to Com Eq	3.5%
55%	59%	61%	71%	80%	89%	82%	NMF	70%	75%	75%	70%	All Div'ds to Net Prof	65%

CURRENT POSITION ($MILL.)	2020	2021	9/30/22
Cash Assets	34.0	28.8	52.8
Other	472.8	610.2	711.6
Current Assets	506.8	639.0	764.4
Accts Payable	256.6	330.2	483.1
Debt Due	739.2	400.1	234.3
Other	167.8	225.4	369.2
Current Liab.	1163.6	955.7	1086.6
Fix. Chg. Cov.	238%	275%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	1.5%	5.0%	4.5%
"Cash Flow"	4.0%	3.5%	5.5%
Earnings	1.0%	.5%	10.5%
Dividends	6.0%	3.5%	4.0%
Book Value	5.5%	2.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	311.8	365.6	640.3	1992.0
2022	824.6	511.4	608.5	755.5	2700
2023	875	475	525	625	2500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.19	.02	d.17	.58	1.62
2022	1.25	.05	d.18	.58	1.70
2023	1.30	.05	d.10	.60	1.85

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295	.295	.598	1.19
2021	--	.303	.303	.613	1.22
2022	--	.310	.310	.310	

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '21: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,173 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/22 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries is moving ahead with plans to be acquired. On February 24th the company entered into a definitive agreement to be acquired by the private capital Infrastructure Investments Fund (IIF) for $36.00 per share in an all cash bid. Following the announcement, the stock spiked 40% and have since been trading between $32 and $36 per share.

There are a few concerns to note, regarding the proposed transaction. Although unlikely, it is possible for IIF to back out of the deal. This scenario would be disadvantageous at this time, with shares trading at a significant premium to the preannouncement levels. Should this occur, IIF would be penalized up to $255 million, roughly $2 per share, but prices would likely retreat to between $25 and $30. Another consideration is that the deal may take longer than expected to materialize as there are many regulatory hurdles to clear. Currently, we look to the fourth quarter for a resolution in the takeover. The shares are trading fairly close to the buyout price, suggesting the likelihood that the deal should go through as planned. However, conserative accounts may want to sell their shares on the open market on the small chance the transaction is blocked. Relevant regulatory bodies have been known to delay or even prohibit similar acquisitions, and could potentially impede the deal to shareholder's detriment. We deem both scenarios as unlikely, but they are of significant consequence.

South Jersey Industries performed well in the third quarter. The bottom line came in worse than we expected, with a share loss of $0.18 versus our forecast of a $0.12 deficit. Revenue growth was strong, however, at $608 million it was more than 65% higher than in the same quarter last year. Most of this gain came from non-utility revenues, which experienced an equal-sized increase in expenses, contributing to the lowly bottom-line. This should reverse in the winter months, as the groundwork laid by the expensive non-utility infrastructure business will likely bolster earnings in the next two quarters.

These shares are trading with a 5.6% spread on the takeover bid. Pending a close, dividends will continue being paid out at $0.31 per quarter.

Earl B. Humes *November 25, 2022*

(A) Based on economic egs. from 2007. GAAP EPS: '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62; '21, $0.81; '22, $0.93. Excl. nonrecur. gain (loss): '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06); '21, ($0.81); '22 (0.07) Totals may not sum due to rounding. Next egs. due late Februrary (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2021: $672.4 mill., $5.73 per shr. (D) In mill., adj. for split.

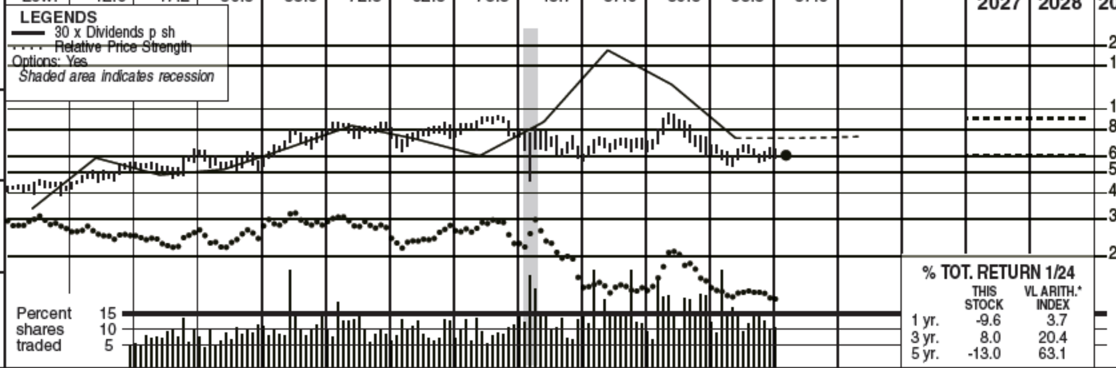
Company's Financial Strength	B++
Stock's Price Stability	55
Price Growth Persistence	15
Earnings Predictability	70

SOUTHWEST GAS NYSE-SWX

RECENT PRICE	P/E RATIO	(Trailing: NMF / Median: 20.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
60.50	15.4	Trailing: NMF; Median: 20.0	0.89	4.1%	

TIMELINESS – Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL – Suspended 11/17/23
BETA .90 (1.00 = Market)

High:	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	65.1
Low:	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$50-$91	$71 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	13%
Low	60	(Nil)	4%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	153	138	103
to Sell	124	136	140
Hld's(000)	65095	65230	64845

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-9.6	3.7
3 yr.	8.0	20.4
5 yr.	-13.0	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	**73.60**	**71.60**	**72.00**	Revenues per sh	**70.95**
5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.91	**9.15**	**9.40**	**10.25**	"Cash Flow" per sh	**11.50**
1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	**2.85**	**3.30**	**4.20**	Earnings per sh A	**4.25**
.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.48	2.48	**2.48**	**2.52**	Div'ds Decl'd per sh B■†	**2.60**
6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	**12.85**	**12.50**	**12.50**	Cap'l Spending per sh	**14.50**
23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	47.95	**50.00**	**52.50**	**52.90**	Book Value per sh	**55.50**
44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	**72.00**	**74.00**	**75.00**	Common Shs Outst'g C	**77.50**
20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	--	**21.7**	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	--	**1.25**	*Value Line*		Relative P/E Ratio	**.90**
3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	**4.0%**	*estimates*		Avg Ann'l Div'd Yield	**3.4%**

CAPITAL STRUCTURE as of 9/30/23
Total Debt $5335.3 mill. **Due in 5 Yrs** $1236 mill.
LT Debt $5235.5 mill. **LT Interest** $300 mill.
(Total interest coverage: 1.25x) (61% of Cap'l)

Leases, Uncapitalized Annual rentals $17.9 mill.
Pension Assets-12/22 $1068.5 mill.
Oblig. $1224.9 mill.
Pfd Stock None

Common Stock 71,519,025 shs.
as of 11/31/23

MARKET CAP: $4.3 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	**5300**	**5300**	**5400**	Revenues ($mill)	**5500**
141.1	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	**205**	**245**	**315**	Net Profit ($mill)	**330**
35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	NMF	**21.0%**	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	**3.9%**	**4.6%**	**5.8%**	Net Profit Margin	**6.0%**
52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	57.8%	**60.0%**	**58.0%**	**58.0%**	Long-Term Debt Ratio	**57.0%**
47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	42.2%	**40.0%**	**42.0%**	**42.0%**	Common Equity Ratio	**43.0%**
3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7621.4	**9000**	**9250**	**9450**	Total Capital ($mill)	**10000**
3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	**7450**	**7550**	**7750**	Net Plant ($mill)	**8000**
5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.5%	NMF	**2.5%**	**2.5%**	**3.5%**	Return on Total Cap'l	**3.5%**
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	**5.5%**	**6.5%**	**8.0%**	Return on Shr. Equity	**7.5%**
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	**5.5%**	**6.5%**	**8.0%**	Return on Com Equity	**7.5%**
5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	**.5%**	**1.5%**	**3.0%**	Retained to Com Eq	**3.0%**
47%	54%	55%	53%	55%	54%	54%	69%	NMF	**87%**	**75%**	**60%**	All Div'ds to Net Prof	**61%**

CURRENT POSITION ($MILL.)

	2021	2022	9/30/23
Cash Assets	222.7	123.1	104.9
Other	1392.1	3584.6	1893.6
Current Assets	1614.8	3707.7	1998.5
Accts Payable	353.4	662.1	255.3
Debt Due	2206.3	1587.4	99.8
Other	552.3	1173.5	697.4
Current Liab.	3112.0	1173.5	1052.5
Fix. Chg. Cov.	310%	265%	145%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '27-'29
Revenues	3.5%	3.0%	*6.0%*
"Cash Flow"	4.0%	1.5%	*8.5%*
Earnings	5.5%	4.5%	*10.0%*
Dividends	8.5%	7.0%	*5.5%*
Book Value	6.5%	7.0%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	885.9	821.4	888.7	1084.5	3680.5
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	*1233.6*	*5300*
2024	*1425*	*1300*	*1220*	*1355*	*5300*
2025	*1445*	*1345*	*1280*	*1330*	*5400*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2.03	.43	d.19	1.15	3.39
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	*1.74*	*2.85*
2024	*1.45*	*.55*	*.20*	*1.10*	*3.30*
2025	*1.75*	*.65*	*.15*	*1.65*	*4.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024					

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. Centuri provides construction services. 2022 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total throughput: 2.2 billion therms. Has 13,614 employees. Off. & dir. own .3% of common; BlackRock, 13.6%; Carl C. Icahn, 12.5%; The Vanguard Group, 9.7%; (3/23 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holdings plans to pivot the spin-off of the Centuri Group. The company announced that it will pursue an initial public offering (IPO) for Centuri Holdings, Inc. versus earlier plans for a tax-free spin-off. Proceeds from the IPO will primarily be used to pay down the subsidiary's debt. Southwest Gas will continue to reduce its ownership interest thereafter. The offering is slated for the spring or summer of 2024, pending the replacement of the current Centuri CEO Paul Daily, after he announced plans for his retirement. The tax-free spin-off option is still available as a second resort. Note: Our forecasts do not account for pending deals until they are completed.

The company likely had a challenging year in 2023. (Southwest was scheduled to report its annual results shortly after we went to press with this Issue.) Although an improvement from a deficit in the year before, earnings in 2023 were likely well below the company's recent averages. A $71 million loss realized on the sale of MountainWest in the first quarter took a toll, along with a significant increase in interest costs. Some rate-base increases and gas purchase cost recoveries likely helped to partially offset these. Overall, net profits probably reached $205 million, which is about $25 million off Southwest's recent high in 2020, but also reflects slimmer margins and stagnant earnings growth. A rapid rate of share dilution made matters worse.

Earnings growth ought to recover over the intermediate term. Expectations for lower debt levels and interest payments, along with more efficient utility operations and tailwinds to the Centuri Group's infrastructure business should lead to a profit-growth recovery over the next two years. Too, we think ongoing changes in executive management and activism in the company's governance roles will likely put a priority on shareholder appeasement and accelerated earnings.

The stock's Timeliness rank remains suspended due to the pending corporate restructuring. While the planned IPO of Centuri Holdings should benefit Southwest Gas, our long-range projections for the company under its current configuration suggest limited upside for SWX.

Earl B. Humes *February 23, 2024*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due early May. (B) Dividends historically paid early March, June, September, and December.
■† Div'd reinvestment and stock purchase plan avail. (C) In millions.
(D) Totals may not sum due to rounding.

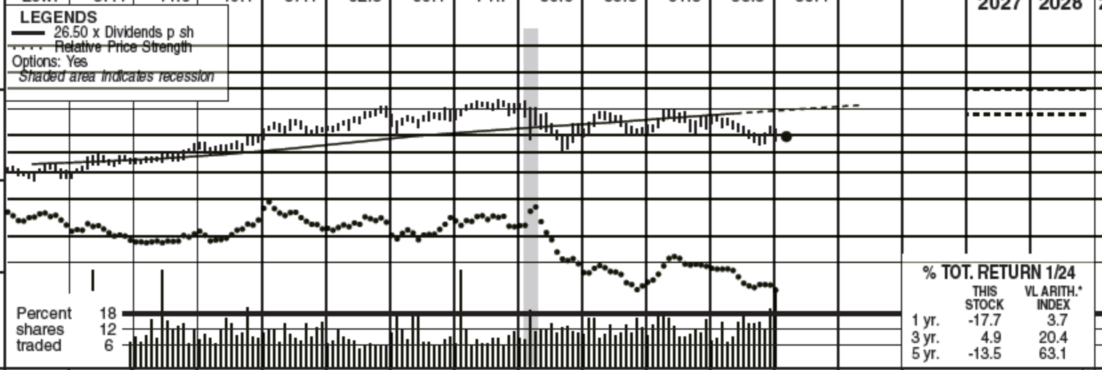
Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	15

SPIRE INC. NYSE-SR

RECENT PRICE 59.34 | P/E RATIO 14.5 (Trailing: 16.0 Median: 19.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 3 Raised 2/16/24
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 9/29/23
BETA .85 (1.00 = Market)

High:	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	64.6
Low:	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4



Target Price Range 2027 | 2028 | 2029

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$50-$88 $69 (15%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+70%)	18%
Low	75	(+25%)	11%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	128	142	131
to Sell	132	138	144
Hld's(000)	45090	46098	48374

% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.7	3.7
3 yr.	4.9	20.4
5 yr.	-13.5	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	**48.90**	**50.25**	Revenues per sh A	**57.25**
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	**9.05**	**9.65**	"Cash Flow" per sh	**11.00**
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	**4.10**	**4.50**	Earnings per sh A B	**5.50**
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	**3.02**	**3.16**	Div'ds Decl'd per sh C ■	**3.60**
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	**13.80**	**14.15**	Cap'l Spending per sh	**14.50**
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	**55.45**	**59.20**	Book Value per sh D	**66.05**
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	**55.50**	**56.50**	Common Shs Outst'g E	**62.00**
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	Bold figures are		Avg Ann'l P/E Ratio	**16.0**
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	Value Line		Relative P/E Ratio	**.90**
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	estimates		Avg Ann'l Div'd Yield	**4.1%**

CAPITAL STRUCTURE as of 12/31/23
Total Debt $4752.3 mill. Due in 5 Yrs $2310.0 mill.
LT Debt $3247.8 mill. LT Interest $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill. Oblig. $832.5 mill.
Pfd Stock $242.0 mill. Pfd Div'd $14.8 mill.
Common Stock 54,983,397 shs. as of 1/29/24

MARKET CAP: $3.3 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	**2715**	**2840**	Revenues ($mill) A	**3550**
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	**230**	**255**	Net Profit ($mill)	**340**
27.6%	31.2%	32.5%	32.4%	- -	15.7%	12.3%	20.1%	21.1%	15.1%	**18.0%**	**19.0%**	Income Tax Rate	**24.0%**
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	**8.5%**	**9.0%**	Net Profit Margin	**9.6%**
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	**52.0%**	**52.0%**	Long-Term Debt Ratio	**51.0%**
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	**44.0%**	**44.0%**	Common Equity Ratio	**45.0%**
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	**7000**	**7600**	Total Capital ($mill)	**9100**
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	**6150**	**6530**	Net Plant ($mill)	**7675**
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.5%**
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	**7.5%**	**7.5%**	Return on Shr. Equity	**8.5%**
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	**7.5%**	**7.5%**	Return on Com Equity	**8.5%**
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	**1.5%**	**2.0%**	Retained to Com Eq	**2.5%**
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	**79%**	**76%**	All Div'ds to Net Prof	**70%**

CURRENT POSITION ($MILL.)

	2022	2023	12/31/23
Cash Assets	6.5	5.6	4.8
Other	1585.5	1071.3	1215.1
Current Assets	1592.0	1076.9	1219.9
Accts Payable	617.4	253.1	293.8
Debt Due	1318.7	1112.1	1504.5
Other	417.5	390.2	412.2
Current Liab.	2353.6	1755.4	2210.5
Fix. Chg. Cov.	393%	294%	310%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	4.0%
"Cash Flow"	8.0%	5.0%	4.0%
Earnings	5.0%	3.0%	4.5%
Dividends	5.0%	5.5%	4.5%
Book Value	5.5%	3.5%	5.5%

QUARTERLY REVENUES ($ mill.) A

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	*1170*	*453.4*	*335*	*2715*
2025	*790*	*1235*	*465*	*350*	*2840*

EARNINGS PER SHARE A B F

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	*3.34*	*d.30*	*d.46*	*4.10*
2025	*1.50*	*3.35*	*d.11*	*d.24*	*4.50*

QUARTERLY DIVIDENDS PAID C ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755				

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire began fiscal 2024 (ends September 30th) on a sour note. First-quarter earnings per share slipped 8.4%, to $1.52, versus last year's $1.66 total. This was due partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions were not repeated. But on the plus side, the Gas Utility unit had a better performance, supported by the benefit of new rates. We do anticipate unspectacular consolidated results for the second quarter. Still, since the company faces easier bottom-line comparisons during the second half, full-year share net stands to grow roughly 6%, to $4.10, relative to the fiscal 2023 figure of $3.85. Regarding next year, profits stand to advance around 10%, to $4.50 a share, as operating margins expand further.

Capital expenditures for this fiscal year are expected to be around $765 million. (That's 15.5% higher than the fiscal 2023 level of $662.5 million.) Funds are being deployed to such areas as infrastructure upgrades at the utilities and new business development initiatives. Management adds that it looks for total spending from fiscal 2024 through fiscal 2033 to be $7.2 billion. Assuming that the balance sheet stays in healthy condition, Spire ought to have little trouble accomplishing these objectives.

Business prospects out to 2027-2029 appear decent. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri. Too, the other operations, particularly pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should help Spire, as well. Finally, acquisitions are plausible, given the adequate finances. To that end, the company just completed the purchase of the MoGas and Omega pipeline systems (both serving customers in Missouri) from CorEnergy Infrastructure Trust, Inc. for $177.6 million.

What about the stock? Its dividend yield compares nicely to those of other equities in *Value Line's* Natural Gas Utility Industry. Moreover, capital gains potential over the 18-month span and out to 2027-2029 looks decent. Meanwhile, the Timeliness rank sits at 3 (Average).

Frederick L. Harris, III February 23, 2024

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

UGI CORP. NYSE-UGI

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
24.00	8.3 (Trailing: 8.3, Median: 17.0)	0.48	6.3%	VALUE LINE

TIMELINESS	1	Raised 12/1/23
SAFETY	3	Lowered 5/26/23
TECHNICAL	3	Raised 2/23/24
BETA 1.10 (1.00 = Market)		

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$20-$50	$35 (45%)

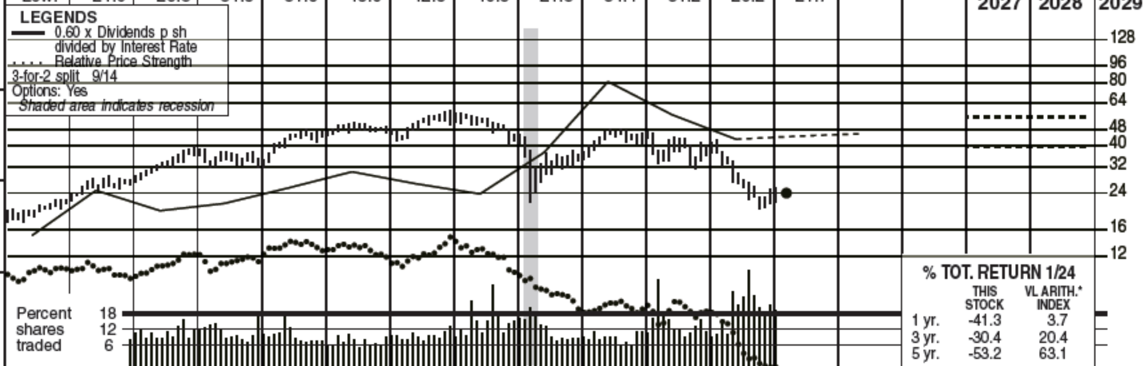
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+130%)	*26%*
Low	40	(+65%)	*18%*

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	242	228	208
to Sell	233	263	246
Hld's(000)	172249	170969	169036

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	28.8	39.7	38.6	48.1	52.0	59.3	57.3	45.3	48.6	47.0	43.2	25.3	
Low:	21.9	26.8	31.5	31.6	45.0	42.5	40.5	21.8	34.4	31.2	20.2	21.7	



% TOT. RETURN 1/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-41.3	3.7
3 yr.	-30.4	20.4
5 yr.	-53.2	63.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	32.84	35.18	43.94	35.03	31.31	35.49	48.00	42.33	*40.75*	*42.65*	Revenues per sh A	*44.80*
2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	4.39	4.73	5.40	4.12	4.99	5.26	5.43	5.43	*5.60*	*5.75*	"Cash Flow" per sh	*6.00*
1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	2.05	2.29	2.74	2.28	2.67	2.96	2.90	2.84	*2.90*	*3.00*	Earnings per sh AB	*3.15*
.50	.52	.60	.68	.71	.74	.79	.89	.93	.96	1.02	1.15	1.31	1.35	1.41	1.47	*1.52*	*1.56*	Div'ds Decl'd per sh C ■	*1.68*
1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	3.26	3.67	3.30	3.37	3.13	3.29	3.82	4.62	*4.50*	*4.65*	Cap'l Spending per sh	*5.00*
8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	16.46	18.18	21.14	18.27	19.70	25.27	27.76	20.00	*21.25*	*22.20*	Book Value per sh D	*23.60*
161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	173.15	173.99	174.14	209.01	209.51	209.84	210.56	210.91	*211.00*	*211.00*	Common Shs Outst'g E	*212.00*
13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	19.3	20.8	17.8	23.4	13.8	13.9	14.1	11.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.80	.69	.69	.94	1.04	.87	.83	.89	1.01	1.05	.96	1.25	.71	.75	.81	.66	*Value Line*		Relative P/E Ratio	*.85*
2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	2.3%	2.0%	2.1%	2.2%	3.6%	3.3%	3.5%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/23
Total Debt $7190 mill. **Due in 5 Yrs** $4176 mill.
LT Debt $6579 mill. **LT Interest** $375 mill.
(Total interest coverage: 4.0x) (60% of Cap'l)

Leases, Uncapitalized Annual rentals $104 mill.
Pension Assets-9/22 $556 mill. **Oblig.** $623 mill.

Pfd. Stock $167.0 mill. **Pfd. Div'd.** $20.25 (1% of Capital)

Common Stock 209,551,431 shares as of 1/26/24

MARKET CAP: $5.0 bill. (Mid-Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
8277.3	6691.1	5685.7	6120.7	7651.2	7320.4	6559.0	7447.0	10106	8928	*8600*	*9000*	Revenues ($mill) A	*9500*
337.2	353.8	360.0	406.5	485.6	412.9	561.0	629.0	626.0	613.0	*630*	*660*	Net Profit ($mill)	*670*
30.6%	30.0%	31.4%	26.5%	- -	16.6%	19.4%	45.4%	24.9%	NMF	*22.5%*	*22.0%*	Income Tax Rate	*22.0%*
4.1%	5.3%	6.3%	6.6%	6.3%	5.6%	8.6%	8.4%	6.2%	6.9%	*7.3%*	*7.3%*	Net Profit Margin	*7.0%*
56.4%	56.1%	56.9%	55.8%	53.0%	60.2%	59.2%	53.4%	51.7%	59.9%	*60.0%*	*60.0%*	Long-Term Debt Ratio	*60.0%*
43.6%	43.9%	43.1%	44.2%	47.0%	39.8%	40.8%	44.7%	46.6%	38.6%	*39.0%*	*39.0%*	Common Equity Ratio	*40.0%*
6092.7	6133.8	6616.9	7157.9	7827.9	9597.4	10109	11861	12549	10937	*11500*	*12000*	Total Capital ($mill)	*12500*
4543.7	4994.1	5238.0	5537.0	5808.2	6687.8	6960.0	7558.0	8040.0	8547.0	*8750*	*9000*	Net Plant ($mill)	*9750*
7.5%	7.7%	7.2%	7.2%	7.7%	5.6%	7.1%	6.6%	6.3%	5.6%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	11.4%	10.3%	14.0%	*13.5%*	*13.5%*	Return on Shr. Equity	*12.5%*
12.7%	13.1%	12.6%	12.9%	13.2%	10.8%	13.6%	11.4%	10.7%	14.5%	*14.0%*	*14.0%*	Return on Com Equity	*13.5%*
7.6%	7.4%	7.0%	7.5%	8.4%	5.6%	7.0%	6.0%	5.6%	6.8%	*6.5%*	*6.5%*	Retained to Com Eq	*6.0%*
40%	43%	45%	42%	36%	48%	49%	45%	47%	52%	*52%*	*52%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)	2022	2023	12/31/23
Cash Assets	405	340	302
Other	3397	1705	1983
Current Assets	3802	2045	2285
Accts Payable	891	613	741
Debt Due	517	706	611
Other	1036	955	989
Current Liab.	2444	2274	2341
Fix. Chg. Cov.	450%	465%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	-1.0%	*6.0%*
"Cash Flow"	5.0%	1.5%	*5.0%*
Earnings	8.0%	4.5%	*6.5%*
Dividends	6.5%	7.0%	*3.5%*
Book Value	6.5%	6.5%	*9.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1932	2581	1496	1438	7447
2022	2673	3466	2033	1934	10106
2023	2759	3106	1659	1404	8928
2024	2121	*3000*	*1700*	*1779*	*8600*
2025	*2750*	*3000*	*1550*	*1700*	*9000*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.18	1.99	.13	d.33	2.96
2022	.93	1.91	.06	- -	2.90
2023	1.14	1.68	- -	.02	2.84
2024	1.20	*1.65*	*.05*	*Nil*	*2.90*
2025	*1.25*	*1.75*	*.05*	*d.05*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.325	.325	.33	.33	1.31
2021	.33	.33	.345	.345	1.35
2022	.345	.345	.36	.36	1.41
2023	.36	.36	.375	.375	1.47
2024	.375				

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 11.6% of net income in 2023), UGI International (28.1%), Gas Utility (35.7%), Midstream & Marketing (31.5%), and Corp. & Other (NMF). UGI Utilities distributes natural gas and electricity to over 672,000 customers mainly in Pennsylvania; wholly-owned AmeriGas Ptrs. is the largest U.S. propane marketer, serving about 1.5 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Vanguard Group owns 12.5% of stock; BlackRock, 12.8%; Officers/directors, 1.2% (12/23 proxy). Has 10,000 empls. President & CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.

Despite the stock slumping, earnings at UGI Corp. held up in fiscal 2023, through a challenging environment for utilities. (Fiscal years end September 30th.) The diversified natural gas company's stock fared much worse than its peers throughout 2023, losing 33% of its value over the twelve-month stretch. However, operating performance held up relatively well in a difficult environment characterized by cost inflation, higher interest rates, turbulent global energy markets, and unusually warm weather. Revenues declined roughly 12%, with all segments other than the regulated utility showing attrition. The adjusted net income of $613 million was fairly resilient, declining only 2% in comparison. The company recorded a few notable one-time charges - a $660 million goodwill impairment to AmeriGas and a $181 million cost related to the exit of the UGI International energy marketing business - which are not included in our adjusted earnings metric.

Our near-term expectations are for uneven sales and steady earnings growth. Indeed, earnings in the fiscal 2024 first quarter were spot on with our target, albeit the top line has slipped since the figure fell far short of our estimate. We are now expecting a dip in revenues over the next two years. Lower liquid propane gas volume trends persist, and the exit of the energy marketing business continues to offset top-line gains in other segments. However, recent investments and acquisitions in the natural gas businesses, and success in rate cases from the utility, are likely enough to start driving an earnings-growth recovery.

Over a multi-year outlook, current strategic initiatives are likely to contribute to financial improvements. Initially, management aims to further align its natural gas businesses to leverage efficiencies and drive cost savings. This should then support liquidity while attempting to delever, with a hefty $1.7 billion of long-term debt coming due in 2025.

Wide recovery potential makes this a compelling choice for risk-tolerant investors seeking a sizable dividend yield (6.3%). The stock offers well-above-average total return potential on a long-term basis, along with some risk.

Earl B. Humes *February 23, 2024*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. gains/(losses): '15, (41¢); '16, 3¢; '17, 17¢; '18, $1.32; '21, $3.96. Next egs. report due eary May. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/23: $3,470 mill., $16.45/sh. (E) In mill., adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	70
Price Growth Persistence	25
Earnings Predictability	90

The Water Utility Industry consists of six investor-owned companies that provide water services to residential, commercial, and industrial customers. It is a niche sector because most of the water utilities in the United States are run by states and local governments that do not issue stock.

In our last Industry report three months ago, we discussed how long-term interest rates had spiked higher. In retrospect, it was close to the peak yield on longer-duration Treasury bonds, which have declined sharply since the latter part of October.

The water infrastructure in the United States remains in subpar condition despite increased investment in this sector over the past decade or so.

Every water company we cover is in the midst of a large construction program. Many pipelines are corroding or leaking, and they need to be replaced.

Since the Industry is spending heavily on capital expenditures, the typical balance sheet in the this space is overleveraged.

The Water Utility Industry is very small. There are only six companies with a combined market capitalization of about $45 billion.

Shares of these stocks have performed very poorly in the recent past. Indeed, the Water Utility Industry is ranked among the lowest of the 93 industries followed by *Value Line*.

A Reversal In Long-Term Interest Rates

All types of utilities are often viewed as income equities due to their combination of high dividend yields and better-than-average distribution growth prospects. The yields on most water stocks are currently very close to the *Value Line* median, however. Indeed, *Essential Utilities's* 3.4% yield is the one exception in the group. In any case, as heavy borrowers of debt, lower interest rates ought to be beneficial to the Industry. On October 18th, the yield on the benchmark 10-year Treasury bond eclipsed 5% in intraday trading. Following some positive news on the inflation front and indications that the Federal Reserve may cut rates this year, long-duration bond prices have rallied strongly. Over the past 10 weeks, the yield on the 10-year Treasury has declined by about 110 basis points to approximately 3.90%.

Antiquated Infrastructure

For decades, annual capital expenditures on modernizing and upgrading assets such as pipelines and wastewater treatment facilities, were underfunded. For the sake of keeping customers bills low, major maintenance projects were deferred. About 10 to 15 years ago, both the operators of the water facilities and state regulators realized that the situation had to change. Depending upon the source of the information, the general condition of domestic pipelines is substandard, with the average age of pipes being anywhere from 50 to 75 years. As mentioned previously, water utilities have been working to upgrade their systems. Fortunately for them, this is a sort of pay-as-you go type of construction. Electric utilities, for example, have to make huge upfront payments to add a new base load unit. Hence, regulators have had a more-constructive relationship with water companies. However, in the years between the housing crisis of

INDUSTRY TIMELINESS: 91 (of 93)

2007-09 and the pandemic, inflation was very low. This made it easier to pass along high-single-digit rate increases without much pushback from customers. The spike in inflation that was caused by the monetary and fiscal policies aimed at combating COVID-19's impact on the economy has declined, but remains above the Federal Reserve's 2.0% target. Should double-digit rate hikes now be required to finance the construction programs, there could be greater displeasure shown by ratepayers (i.e. voters). This may cause regulators to become more restrictive in their rulings.

Growing Via Acquisitions

The water industry in the U.S. is mostly run by local, municipal water districts. (There are some major exceptions, such as in New York City.) As a result, there are tens of thousands of these entities operating separately. There is no need for such an immense number, as it leads to inefficiency. Small districts also do not have the financial wherewithal required to fund the needed upgrades. *American Water Works* and *Essential Utilities* are two companies that use bolt-on acquisitions as part of their overall strategy to expand their rate base. These big utilities can easily absorb smaller ones and achieve substantial cost savings by eliminating redundancies.

Conclusion

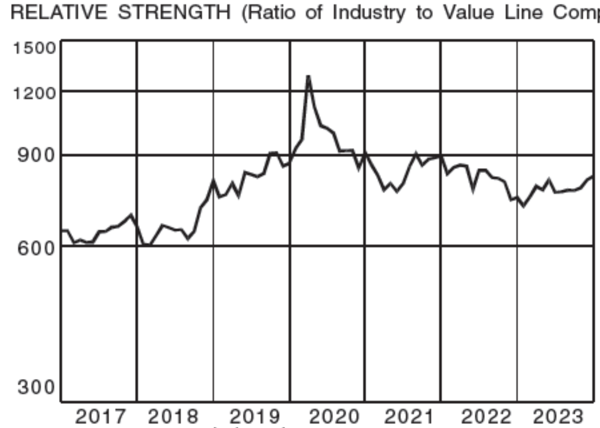
There are no stocks in this industry that stand out for having favorable short-term total appreciation potential. Despite the bad performance by these equities over the past few years, most continue to have high price-to-earnings ratios and are already trading in their 2026-2028 Target Price Ranges. One of the reasons these equities trade at such a premium is because of scarcity. Investors who want to be in this sector ought to be aware that they will have to pay for the privilege. The only equity followed here that has good long-term total-return potential is *Essential Utilities* and that's probably due to its presence in the gas utility sector.

As always, we strongly recommend that subscribers read each individual comment before investing to better understand the underlying risks associated with each stock.

James A. Flood

Water Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

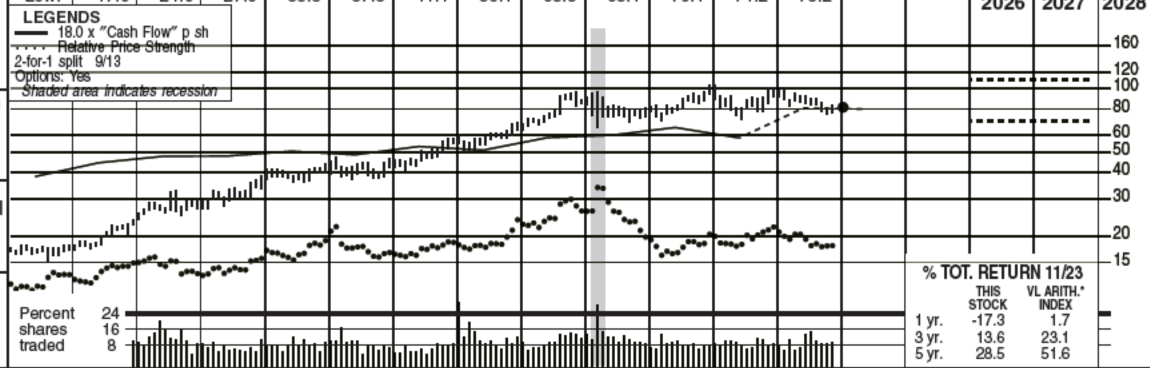
AMER. STATES WATER NYSE-AWR

RECENT PRICE 81.67 | P/E RATIO 29.4 (Trailing: 24.6 Median: 30.0) | RELATIVE P/E RATIO 1.66 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 3 Lowered 12/1/23
SAFETY 2 Raised 7/20/12
TECHNICAL 3 Raised 12/15/23
BETA .70 (1.00 = Market)

High:	24.1	33.1	38.7	44.1	47.2	58.4	69.6	96.0	96.6	103.8	103.4	99.2
Low:	17.0	24.0	27.0	35.8	37.3	41.1	50.1	63.3	65.1	70.1	71.2	75.2

LEGENDS
18.0 x "Cash Flow" p sh
.... Relative Price Strength
2-for-1 split 9/13
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$66-$134	$100 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+35%)	10%
Low	70	(-15%)	-1%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	124	141	158
to Sell	158	138	133
Hld's(000)	27587	27816	28119

Percent shares traded 24 16 8

% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-17.3	1.7
3 yr.	13.6	23.1
5 yr.	28.5	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
8.75	9.21	9.74	10.71	11.12	12.12	12.19	12.17	12.56	11.92	12.01	11.88	12.86	13.24	13.51	13.30	16.35	15.05	Revenues per sh	19.20
1.65	1.69	1.70	2.11	2.13	2.48	2.65	2.67	2.81	2.70	2.96	2.84	3.26	3.34	3.64	3.25	4.60	4.20	"Cash Flow" per sh	5.05
.81	.78	.81	1.11	1.12	1.41	1.61	1.57	1.61	1.62	1.88	1.72	2.28	2.33	2.55	2.11	3.35	3.00	Earnings per sh A	3.40
.48	.50	.51	.52	.55	.64	.76	.83	.87	.91	.99	1.06	1.16	1.28	1.40	1.53	1.66	1.80	Div'd Decl'd per sh B ■	2.30
1.45	2.23	2.09	2.12	2.13	1.77	2.52	1.89	2.39	3.55	3.08	3.44	4.12	3.54	3.91	4.50	4.95	5.15	Cap'l Spending per sh	4.25
8.77	8.97	9.70	10.13	10.84	11.80	12.72	13.24	12.77	13.52	14.45	15.19	16.33	17.39	18.57	19.20	20.95	22.30	Book Value per sh D	24.55
34.46	34.60	37.06	37.26	37.70	38.53	38.72	38.29	36.50	36.57	36.68	36.76	36.85	36.89	36.94	36.96	37.00	37.25	Common Shs Outst'g C	37.50
24.0	22.6	21.2	15.7	15.4	14.3	17.2	20.1	24.6	25.6	25.7	34.0	34.4	34.3	33.2	41.0	25.8		Avg Ann'l P/E Ratio	25.0
1.27	1.36	1.41	1.00	.97	.91	.97	1.06	1.24	1.34	1.29	1.84	1.83	1.76	1.79	2.38	1.49		Relative P/E Ratio	1.40
2.5%	2.9%	2.9%	3.0%	3.2%	3.1%	2.7%	2.6%	2.2%	2.2%	2.0%	1.8%	1.5%	1.6%	1.7%	1.8%	1.9%		Avg Ann'l Div'd Yield	2.6%
						472.1	465.8	458.6	436.1	440.6	436.8	473.9	488.2	498.9	491.5	605	560	Revenues ($mill)	720
						62.7	61.1	60.5	59.7	69.4	63.9	84.3	86.4	94.3	78.4	125	110	Net Profit ($mill)	130
						36.3%	38.4%	38.4%	36.8%	36.0%	22.0%	22.6%	24.6%	24.4%	23.2%	24.5%	24.0%	Income Tax Rate	24.0%
						--	--	--	--	--	--	--	--	2.5%	--	1.5%	2.0%	AFUDC % to Net Profit	1.5%
						39.8%	39.1%	41.1%	39.4%	38.0%	40.5%	44.4%	47.2%	46.1%	39.9%	43.5%	46.5%	Long-Term Debt Ratio	50.0%
						60.2%	60.9%	58.9%	60.6%	62.0%	59.5%	55.6%	52.8%	53.9%	60.1%	56.5%	53.5%	Common Equity Ratio	50.0%
						818.4	832.6	791.5	815.3	854.9	938.4	1082.5	1216.2	1272.6	1181.5	1375	1550	Total Capital ($mill)	1840
						981.5	1003.5	1060.8	1150.9	1205.0	1296.3	1415.7	1512.0	1626.0	1753.8	1875	1985	Net Plant ($mill)	2225
						8.9%	8.6%	9.0%	8.6%	9.3%	7.9%	8.9%	8.0%	8.3%	7.6%	10.5%	9.0%	Return on Total Cap'l	8.0%
						12.7%	12.0%	13.0%	12.1%	13.1%	11.4%	14.0%	13.5%	13.8%	11.0%	16.0%	13.5%	Return on Shr. Equity	14.0%
						12.7%	12.0%	13.0%	12.1%	13.1%	11.4%	14.0%	13.5%	13.8%	11.0%	16.0%	13.5%	Return on Com Equity	14.0%
						6.8%	5.7%	6.0%	5.3%	6.2%	4.5%	6.9%	6.1%	6.2%	3.1%	10.5%	5.5%	Retained to Com Eq	4.5%
						47%	53%	54%	56%	52%	61%	51%	55%	55%	72%	50%	60%	All Div'ds to Net Prof	68%

CAPITAL STRUCTURE as of 9/30/23
Total Debt $612.9 mill. Due in 5 Yrs $178.1 mill.
LT Debt $575.5 mill. LT Interest $44.0 mill.
(43% of Cap'l)

Leases, Uncapitalized: Annual rentals $2.3 mill.
Pension Assets-12/22 $190.7 mill.
Oblig. $186.9 mill.
Pfd Stock None

Common Stock 36,980,592 shs.
as of 11/3/23

MARKET CAP: $3.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	5.0	6.0	8.6
Accts Receivable	34.4	26.2	32.6
Other	98.7	119.1	150.5
Current Assets	138.1	151.3	191.7
Accts Payable	65.9	84.9	71.8
Debt Due	31.4	255.9	37.4
Other	58.3	55.7	85.9
Current Liab.	155.6	396.5	195.1

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	1.5%	2.0%	6.5%
"Cash Flow"	4.5%	4.0%	7.0%
Earnings	6.5%	6.5%	6.5%
Dividends	9.5%	8.5%	8.5%
Book Value	5.5%	6.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	109.1	121.3	133.6	124.2	488.2
2021	117.1	128.4	136.8	116.6	498.9
2022	108.6	122.5	135.0	125.4	491.5
2023	161.4	157.4	151.7	134.5	605
2024	125	132	160	143	560

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.38	.69	.72	.54	2.33
2021	.52	.72	.76	.55	2.55
2022	.38	.54	.69	.50	2.11
2023	.93	1.04	.85	.53	3.35
2024	.60	.80	.85	.75	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.275	.275	.305	.305	1.16
2020	.305	.305	.335	.335	1.28
2021	.335	.335	.365	.365	1.40
2022	.365	.365	.3975	.3975	1.53
2023	.3975	.3975	.43	.43	

BUSINESS: American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Co., it supplies water to 263,265 customers in 10 California counties. Service areas include the metropolitan areas of Los Angeles and Orange Counties. The company also provides electricity to 24,705 customers in Big Bear Lake and San Bernardino Cnty. Provides water & wastewater services to U.S. military bases through its ASUS subsidiary. Sold Chaparral City Wtr. of AZ. (6/11). Employs 811. BlackRock, Inc. owns 18.6% of out. shares; State St., 16.6%; off. & dir., 0.8% (4/23 Proxy). Chair.: Anne M. Holloway. Pres. & CEO: Robert Sprowls. Inc: CA. Address: 630 East Foothill Blvd., San Dimas, CA 91773. Tel.: 909-394-3600. Int.: www.aswater.com.

Rate relief probably enabled American States Water to complete a successful year. The water utility likely posted record profits last year due to a delay in a ruling by California authorities. According to the law, utilities seeking to raise customer bills to recoup expenses and capital investments must submit an official request to raise rates triennially. The California Public Utility Commission (CPUC) then rules on the petition. American States' Golden Water subsidiary followed the correct methods, but the CPUC issued its ruling very late. The utility was forced to absorb higher costs in 2022. Thus, when the rates were granted last year, they were retroactive to the beginning of 2022. The end result was that American States did poorly in 2022 and exceptionally well in 2023.

The bottom line will likely return to normal in 2024. We think that the company's share earnings can reach $3.00. Though it represents a decline, it will be a decent year. The question is whether the CPUC will permit new rates in 2025 or will make the company wait an additional year, like it did the last time.

Nonutility operations could well provide a lift to earnings growth. State regulators place a limit on the level that a utility can earn. There is less risk and less reward in this model. Through its ASUS subsidiary, the company is involved in managing water services at bases owned by the United States Army. There aren't many entities in this field, so ASUS has been successful in winning its share of bids on new 50-year contracts to service these facilities. Since rates of return aren't regulated in this sector, this business can generate higher returns than Golden States' regulated operations. Through the first three quarters, ASUS has been responsible for 14% of the American States share profits. We look for this percentage to rise as more military installations privatize their water operations.

These shares are ranked to perform in line with the market in the year ahead. Out to 2026-2028, the situation appears to be more unfavorable. Despite solid dividend growth prospects, the equity's total return potential to that time is well below the *Value Line* median.

James A. Flood *January 5, 2024*

(A) Primary earnings. Excludes nonrecurring gains/(losses):; '08, (14¢); '10, (23¢); '11, 10¢. Next earnings report due mid-February.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.
(D) Includes intangibles. As of 12/31/22; $1.1 million/$0.03 a share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

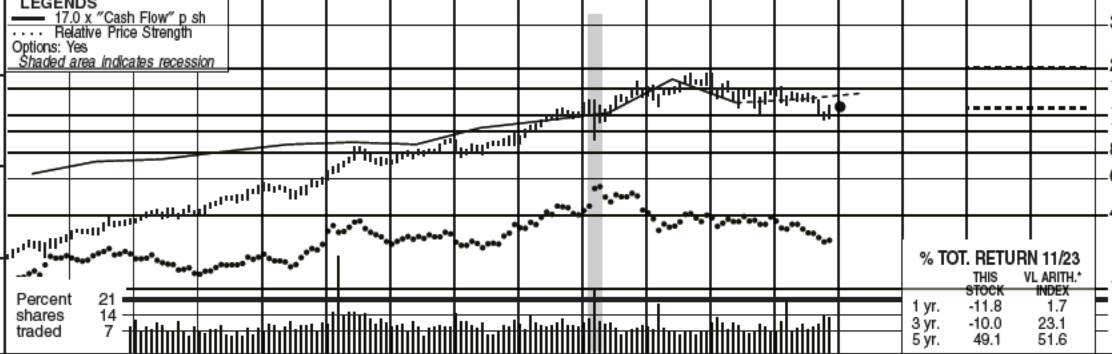
AMERICAN WATER NYSE-AWK

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
131.56	26.8 (Trailing: 27.3 / Median: 28.0)	1.51	2.3%	VALUE LINE

TIMELINESS 4 Lowered 11/17/23
SAFETY 3 New 7/25/08
TECHNICAL 3 Raised 9/29/23
BETA .95 (1.00 = Market)

High:	39.4	45.1	56.2	61.2	85.2	92.4	98.2	129.9	172.6	189.6	189.3	162.6
Low:	31.3	37.0	41.1	48.4	58.9	70.0	76.0	88.0	92.0	131.0	122.8	114.3

LEGENDS
— 17.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$106-$214	$160 (20%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	200	(+50%)	13%
Low	130	(Nil)	2%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	460	436	441
to Sell	404	418	460
Hld's(000)	165074	166259	177196

Percent shares traded: 21, 14, 7

% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-11.8	1.7
3 yr.	-10.0	23.1
5 yr.	49.1	51.6

2007[E]	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
13.84	14.61	13.98	15.49	15.18	16.25	16.28	16.78	17.72	18.54	18.81	19.04	19.97	20.83	21.58	20.85	*21.45*	*22.55*	Revenues per sh	*26.75*
d.47	2.87	2.89	3.56	3.73	4.27	4.36	4.75	5.13	5.26	5.14	6.15	6.65	7.24	10.46	8.08	*8.40*	*9.00*	"Cash Flow" per sh	*10.20*
d2.14	1.10	1.25	1.53	1.72	2.11	2.06	2.39	2.64	2.62	2.38	3.15	3.43	3.91	6.95	4.51	*4.80*	*5.15*	Earnings per sh [A]	*6.10*
--	.40	.82	.86	.90	1.21	.84	1.21	1.33	1.47	1.62	1.78	1.96	2.15	2.36	2.57	*2.78*	*3.00*	Div'd Decl'd per sh [B]■	*3.80*
4.74	6.31	4.50	4.38	5.27	5.25	5.50	5.33	6.51	7.36	8.04	8.78	9.15	10.05	9.71	12.63	*13.00*	*13.25*	Cap'l Spending per sh	*15.75*
28.39	25.64	22.91	23.59	24.11	25.11	26.52	27.39	28.25	29.24	30.13	32.42	33.83	35.58	40.18	42.30	*50.95*	*53.25*	Book Value per sh [D]	*57.25*
160.00	160.00	174.63	175.00	175.66	176.99	178.25	179.46	178.28	178.10	178.44	180.68	180.81	181.30	181.61	181.86	*195.00*	*195.25*	Common Shs Outst'g [C]	*200.00*
--	18.9	15.6	14.6	16.8	16.7	19.9	20.0	20.5	27.7	33.8	27.3	32.9	35.3	23.6	33.6	*29.3*		Avg Ann'l P/E Ratio	*27.0*
--	1.14	1.04	.93	1.05	1.06	1.12	1.05	1.03	1.45	1.70	1.47	1.75	1.81	1.28	1.95	*1.70*		Relative P/E Ratio	*1.50*
--	1.9%	4.2%	3.8%	3.1%	3.4%	2.0%	2.5%	2.5%	2.0%	2.0%	2.1%	1.7%	1.6%	1.4%	1.7%	*2.0%*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $12190 mil. **Due in 5 Yrs** $2486 mil.
LT Debt $11698 mil. **LT Interest** $449 mil.
(54% of Cap'l)

Leases, Uncapitalized: Annual rentals $9.0 mill.
Pension Assets 12/22 $1578.0 mill
Oblig. $1413.0 mill.
Pfd Stock $2.0 mill. **Pfd Div'd** $.1 mill

Common Stock 194,704,997 shares
as of 10/23/23

MARKET CAP: $25.6 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
2901.9	3011.3	3159.0	3302.0	3357.0	3440.0	3610.0	3777.0	3920.0	3792.0	*4180*	*4400*	Revenues ($mill)	*5350*
369.3	429.8	476.0	468.0	426.0	567.0	621.0	709.0	1263.0	820.0	*935*	*1005*	Net Profit ($mill)	*1220*
39.1%	39.4%	39.1%	39.2%	53.3%	28.2%	25.5%	23.3%	23.0%	18.7%	*21.0%*	*21.0%*	Income Tax Rate	*24.0%*
5.1%	--	--	--	--	--	--	--	5.1%	2.9%	*3.5%*	*4.5%*	AFUDC % to Net Profit	*5.0%*
52.4%	52.4%	53.7%	52.4%	54.7%	56.3%	58.5%	59.1%	58.6%	58.7%	*55.0%*	*57.5%*	Long-Term Debt Ratio	*57.5%*
47.6%	47.4%	46.2%	47.5%	45.3%	43.6%	41.4%	40.9%	41.4%	41.3%	*45.0%*	*42.5%*	Common Equity Ratio	*42.5%*
9940.7	10364	10911	10967	11875	13433	14760	15787	17639	18619	*22000*	*24400*	Total Capital ($mill)	*27000*
12391	12900	13933	14992	16246	17409	18232	19710	21084	23223	*25200*	*27250*	Net Plant ($mill)	*30000*
5.1%	5.5%	5.7%	5.6%	4.9%	5.4%	5.4%	5.7%	8.2%	5.5%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
7.8%	8.7%	9.4%	9.0%	7.9%	9.7%	10.1%	11.0%	17.3%	10.7%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
7.8%	8.7%	9.4%	9.0%	7.9%	9.7%	10.1%	11.0%	17.3%	10.7%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
4.7%	4.3%	4.7%	4.0%	2.5%	4.2%	4.4%	5.0%	11.4%	4.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
40%	50%	50%	56%	68%	56%	57%	55%	34%	57%	*58%*	*58%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	136	117	661
Accts Receivable	271	334	382
Other	1147	799	761
Current Assets	1554	1250	1804
Accts Payable	235	254	228
Debt Due	641	1456	492
Other	1265	1101	1023
Current Liab.	2141	2811	1743

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	3.0%	3.0%	*4.0%*
"Cash Flow"	8.5%	10.5%	*3.0%*
Earnings	11.0%	15.0%	*3.0%*
Dividends	9.0%	10.0%	*8.5%*
Book Value	5.0%	6.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	844	931	1079	923	3777
2021	888	999	1082	951	3920
2022	842	937	1082	931	3792
2023	938	1097	1167	*978*	*4180*
2024	*990*	*1150*	*1235*	*1025*	*4400*

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.68	.97	1.46	.80	3.91
2021	.73	1.14	1.53	3.55	6.95
2022	.87	1.20	1.63	.81	4.51
2023	.91	1.44	1.66	*.79*	*4.80*
2024	*.95*	*1.50*	*1.85*	*.85*	*5.15*

Cal-endar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.455	.50	.50	.50	1.96
2020	.50	.55	.55	.55	2.15
2021	.55	.6025	.6025	.6025	2.36
2022	.6025	.655	.655	.655	2.57
2023	.655	.7075	.7075	.7075	

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to approximately 14 million people in 24 states. Nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 86% of 2022 revenues. New Jersey is its largest market accounting for 25.9% of regulated revenues; Pennsylvania, 23.4%; Missouri, 10.9%. Has 6,500 employees. Vanguard owns 11.7% of outstanding shares; BlackRock, 8.6%; State St., 5.4%; officers & directors, less than 1.0% (3/23 Proxy). President & Chief Executive Officer: Susan Hardwick. . Address: 1 Water Street, Camden, NJ 08102. Telephone: 856-346-8200. Internet: www.amwater.com.

American Water Works intends to continue to expand both its rate base and operating margins via bolt-on acquisitions. The water industry in the U.S. is made up mostly of thousands of small, independent, water districts. Not only are these entities inefficient, but they lack sufficient funds to modernize their antiquated infrastructure. American Water expects to spend $4 billion to $5 billion on these types of purchases through 2033. The company has proven that it can take assets from other utilities and realize substantial cost savings. This increases its revenues and operating margins.

The already massive projected capital expenditure budget has been raised again. Previously, leadership forecast that the 10-year construction program would be in the range of $27 billion to $30 billion. In the most recent presentation made in December of 2023, this budget was hiked 10%-11%, to $30 billion to $33 billion.

The balance sheet ought to be healthy enough to handle these outlays. In the year just ended, we think the water utility spent $2.6 billion on capital expenses. A large equity offering that raised $1.7 billion increased shares outstanding 7%-8%. This was unusual, as management has historically been disinclined to raise money in this fashion. Indeed, the number of shares rose only 2.7% in the previous decade. More debt and some new equity issues will be required going forward. American Water's financial condition should remain at least average, however.

Earnings and dividend growth rates here ought to outpace other members of the industry. Assuming reasonable treatment by regulators on the utility's requests for rate relief (more below), we think annual increases in the payout and bottom line can average 7%-9%.

The wild card is here is the regulatory climate. The company has enjoyed constructive relationships with the authorities who determine its allowed returns. This was before the pandemic, though, when low inflation made it easier to pass along big rate hikes to customers.

These shares are untimely. Moreover, despite the stock's underperformance over the last three years, we think that it still doesn't offer much value to 2026-2028.

James A. Flood *January 5, 2024*

(A) Diluted earnings. Excludes nonrecur. losses: '08, $4.62; '09, $2.63; '11, $0.07. Disc. oper.: '06, ($0.04); '11, $0.03; '12, ($0.10); '13,($0.01). GAAP used as of 2014. Includes $2.70 sh. gain from sale of HOS sub.in Q4,'21. Next earnings report due late mid-February.
(B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available.
(C) In millions. (D) Includes intangibles. On 12/31/22: $1.225 billion, $6.75/share.
(E) Pro forma numbers for '07.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	75
Earnings Predictability	60

CALIFORNIA WATER NYSE-CWT

RECENT PRICE 52.29 | P/E RATIO 28.6 (Trailing: NMF; Median: 28.0) | RELATIVE P/E RATIO 1.62 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 4 Raised 12/22/23
SAFETY 3 Lowered 7/27/07
TECHNICAL 3 Raised 12/15/23
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$39-$83	$61 (15%)

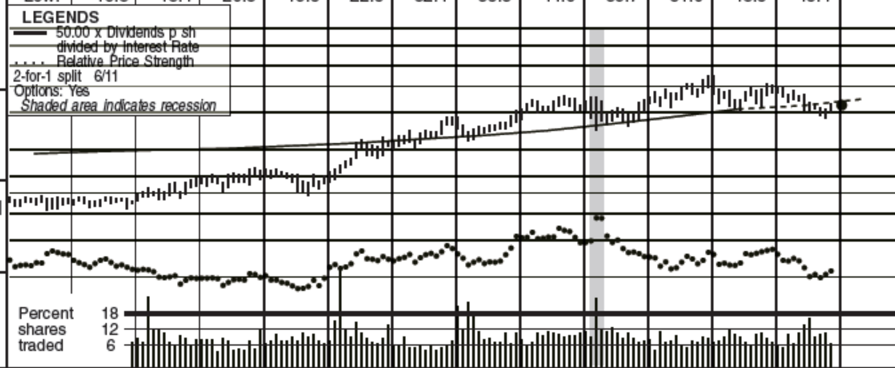
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+55%)	13%
Low	55	(+5%)	4%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	125	139	125
to Sell	124	129	127
Hld's(000)	44814	46985	48886

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	19.3	23.4	26.4	26.0	36.8	46.2	49.1	57.5	57.4	72.1	72.0	63.9	
Low:	16.8	18.4	20.3	19.5	22.5	32.4	35.3	44.6	39.7	51.0	48.5	45.4	



Target Price Range 2026 | 2027 | 2028

% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-20.6	1.7
3 yr.	7.6	23.1
5 yr.	19.8	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.29	12.70	13.89	14.53	14.72	15.78	14.72	15.22	13.95	16.10	Revenues per sh	19.30
1.56	1.86	1.93	1.93	2.07	2.32	2.21	2.47	2.22	2.34	3.00	3.11	3.14	3.88	3.91	3.79	2.20	3.70	"Cash Flow" per sh	4.35
.75	.95	.98	.91	.86	1.02	1.02	1.19	.94	1.01	1.40	1.36	1.31	1.97	1.96	1.77	.80	2.25	Earnings per sh A	2.75
.58	.59	.59	.60	.62	.63	.64	.65	.67	.69	.72	.75	.79	.85	.92	1.00	1.04	1.12	Div'd Decl'd per sh B ■	1.35
1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.76	3.69	4.77	5.40	5.65	5.64	5.93	5.46	5.90	6.00	6.15	Cap'l Spending per sh	6.45
9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.11	13.41	13.75	14.44	15.19	16.07	18.30	21.92	23.70	24.90	26.20	Book Value per sh C	29.50
41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	47.88	47.97	48.01	48.07	48.53	50.33	53.72	55.60	57.00	55.00	Common Shs Outst'g D	50.00
26.1	19.8	19.7	20.3	21.3	17.9	20.1	19.7	24.8	29.6	26.9	30.3	39.3	24.9	30.5	33.0	NMF		Avg Ann'l P/E Ratio	24.0
1.39	1.19	1.31	1.29	1.34	1.14	1.13	1.04	1.25	1.55	1.35	1.64	2.09	1.28	1.65	1.92	NMF		Relative P/E Ratio	1.30
3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%	2.9%	2.3%	1.9%	1.8%	1.5%	1.7%	1.5%	1.7%	1.9%		Avg Ann'l Div'd Yield	2.0%

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1069.6 mill. **Due in 5 Yrs** $357.0 mill.
LT Debt $1052.8 mill. **LT Interest** $40.0 mill.
(Total interest coverage: 2.5x) (44% of Cap'l)

Pension Assets-12/22 $637.3 mill. **Oblig.** $685.3 mill.

Pfd Stock None

Common Stock 57,711,000 shs.

MARKET CAP: $3.0 billion (Mid Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
584.1	597.5	588.4	609.4	666.9	698.2	714.6	794.3	790.9	846.4	795	885	Revenues ($mill) E	965
47.3	56.7	45.0	48.7	67.2	65.6	63.1	96.8	101.1	96.0	46.0	124	Net Profit ($mill)	138
30.3%	33.0%	36.0%	35.5%	30.1%	24.5%	19.1%	11.1%	20.1%	3.3%	21.0%	21.0%	Income Tax Rate	21.0%
4.3%	2.7%	4.3%	6.1%	3.5%	3.1%	5.8%	3.3%	1.7%	1.7%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
41.6%	40.1%	44.4%	44.6%	42.7%	49.3%	50.2%	45.9%	47.3%	44.4%	41.5%	40.5%	Long-Term Debt Ratio	38.0%
58.4%	59.9%	55.6%	55.4%	57.3%	50.7%	49.8%	54.1%	52.7%	55.6%	58.5%	59.5%	Common Equity Ratio	62.0%
1024.9	1045.9	1154.4	1191.2	1209.3	1440.2	1566.7	1702.4	2233.4	2370.1	2420	2415	Total Capital ($mill)	2375
1515.8	1590.4	1701.8	1859.3	2048.0	2232.7	2406.4	2650.6	2846.9	3058.9	3175	3225	Net Plant ($mill)	3450
6.0%	6.3%	5.2%	5.5%	7.1%	5.9%	5.5%	7.0%	5.5%	5.0%	2.5%	5.5%	Return on Total Cap'l	6.5%
7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	8.6%	7.3%	3.0%	8.5%	Return on Shr. Equity	9.5%
7.9%	9.1%	7.0%	7.4%	9.7%	9.0%	8.1%	10.5%	8.6%	7.3%	3.0%	8.5%	Return on Com Equity	9.5%
3.4%	4.1%	2.0%	2.4%	4.7%	4.0%	3.2%	6.0%	4.6%	3.2%	NMF	4.5%	Retained to Com Eq	4.5%
56%	55%	71%	68%	51%	55%	60%	43%	47%	56%	NMF	50%	All Div'ds to Net Prof	49%

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	78.4	62.1	34.7
Other	222.1	233.4	267.6
Current Assets	300.5	295.5	302.3
Accts Payable	144.4	141.0	152.9
Debt Due	40.2	73.3	116.8
Other	72.0	80.4	111.4
Current Liab.	256.6	294.7	381.1

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.5%	3.5%	4.0%
"Cash Flow"	6.0%	9.0%	2.0%
Earnings	7.5%	11.0%	6.5%
Dividends	4.0%	6.0%	6.5%
Book Value	7.0%	9.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	125.6	175.5	304.1	189.1	794.3
2021	147.7	213.1	256.7	173.4	790.9
2022	173.0	206.2	266.3	200.9	846.4
2023	131.1	194.0	255.0	214.9	795
2024	180	210	275	220	885

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	d.42	.11	1.94	.31	1.97
2021	d.06	.75	1.20	.07	1.96
2022	.02	.36	1.03	.35	1.77
2023	d.40	.17	.60	.43	.80
2024	.15	.60	1.00	.50	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.1975	.1975	.1975	.1975	.79
2020	.2125	.2125	.2125	.2125	.85
2021	.230	.230	.230	.230	.92
2022	.250	.250	.250	.250	1.00
2023	.260	.260	.260	.260	

BUSINESS: California Water Service Group provides regulated and nonregulated water service to 496,400 customers in 100 communities in the state of California. Accounts for about 90% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '22: residential, 67%; business, 20%; industrial, 3%; public authorities, 5%; other 5%. Off. and dir. own 1% of common stock (4/23 proxy). Has 1,184 employees. Pres. and CEO: Martin A. Kropelnicki. Inc.: DE. Addr.: 1720 North First St., San Jose, CA 95112-4598. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group's third-quarter financial results were unfavorably impacted by the state's continued indecision on the pending rate case approval. The company reported revenues of $255 million and earnings of $0.60 per share in the September period, with both figures contracting on an annual basis. Management estimated that a favorable decision would have added approximately $20 million to the top line in the third quarter. Meanwhile, a second judge was assigned to the rate case in late July of last year and, according to regulators, the time line for a decision was extended to the end of 2023. Thus, we expect a ruling on the approval to be imminent.

Our 2023 top- and bottom-line estimates are being reduced at this time. We now look for revenues of $795 million (down from our previous call of $805 million) and earnings of $0.80 per share (down from $0.95). Indeed, the slow-moving rate case gives us pause. Elsewhere, consumer water consumption likely remained soft for the remainder of the year. Moreover, higher operating costs, namely water production, purchased water, and labor expenses, probably persisted.

The long-term picture is notably brighter, however. Assuming the abovementioned rate case is approved by regulators, new customer pricing will be retroactive starting from January 1, 2023. These recouped funds, on top of higher rates going forward, augur well. Meanwhile, management is aggressively investing in upgrading its water system infrastructure ($274 million was spent in the recent period), which suggests that additional rate hike approvals may be pursued down the road. Lastly, a healthier economic backdrop ought to support an uptick in broader residential and business water consumption further out.

From an investment standpoint, California Water shares leave something to be desired at the moment. The stock is ranked to trail the broader market averages over the coming six to 12 months. What's more, at the recent quotation, total return potential three to five years hence is below the *Value Line* median.

Nicholas Patrikis *January 5, 2024*

(A) Basic EPS. Excl. nonrecurring gain (loss): '11, 4¢. Next earnings report due late Feb.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '22 : $64.6 mill., $1.16/sh.
(D) In millions, adjusted for split.
(E) Excludes non-regulated revenues.

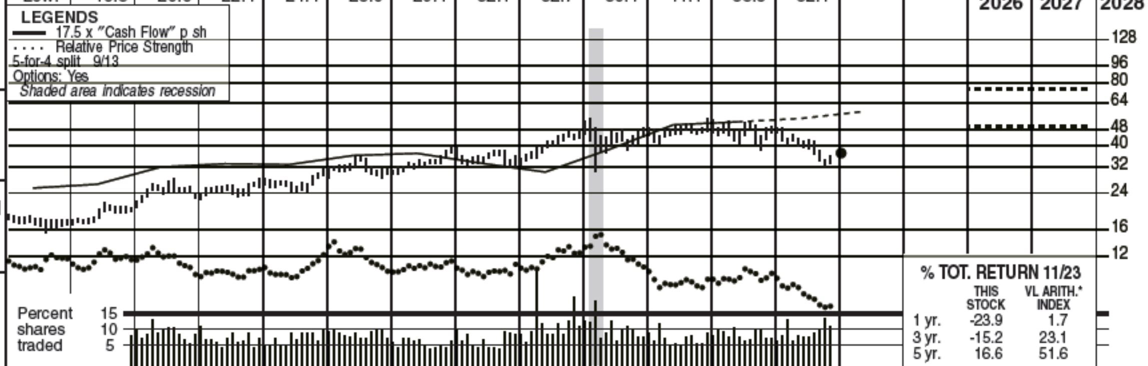
Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	55

ESSENTIAL UTIL. NYSE-WTRG

RECENT PRICE 37.14 | P/E RATIO 19.1 (Trailing: 20.6 Median: 26.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Lowered 12/22/23
SAFETY 3 Lowered 1/8/21
TECHNICAL 3 Raised 11/24/23
BETA 1.00 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	21.5	28.1	28.2	31.1	35.8	39.6	39.4	47.3	54.5	53.9	53.7	49.3
Low:	16.8	20.6	22.4	24.4	28.0	29.4	32.1	32.7	30.4	41.1	38.5	32.1



Target Price Range
2026 | 2027 | 2028

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$29-$62	$46 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+100%)	22%
Low	50	(+35%)	11%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	268	246	254
to Sell	271	295	275
Hld's(000)	189507	195095	204460

% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-23.9	1.7
3 yr.	-15.2	23.1
5 yr.	16.6	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
3.61	3.71	3.93	4.21	4.10	4.32	4.32	4.37	4.61	4.62	4.56	4.71	4.03	5.96	7.43	8.68	8.30	8.80	Revenues per sh	9.10
1.10	1.14	1.29	1.42	1.45	1.51	1.82	1.89	1.87	2.07	2.12	1.90	1.73	2.21	2.89	2.98	3.55	3.65	"Cash Flow" per sh	3.85
.57	.58	.62	.72	.83	.87	1.16	1.20	1.14	1.32	1.35	1.08	1.04	1.12	1.67	1.77	1.85	2.00	Earnings per sh	2.35
.38	.41	.44	.47	.50	.54	.58	.63	.69	.74	.79	.85	.91	.97	1.04	1.11	1.19	1.27	Div'd Decl'd per sh	1.65
1.43	1.58	1.66	1.89	1.90	1.98	1.73	1.84	2.07	2.16	2.69	2.78	2.49	3.41	4.04	4.03	4.05	4.25	Cap'l Spending per sh	3.85
5.85	6.26	6.50	6.81	7.21	7.90	8.63	9.27	9.78	10.43	11.02	11.28	17.58	19.09	20.50	20.39	21.85	23.10	Book Value per sh	25.95
166.75	169.21	170.61	172.46	173.60	175.43	177.93	178.59	176.54	177.39	177.71	178.09	220.76	245.39	252.87	263.74	273.30	277.00	Common Shs Outst'g	285.00
32.0	24.9	23.1	21.1	21.3	21.9	21.2	20.8	23.5	23.9	24.7	32.6	39.1	39.6	28.3	26.6	21.8		Avg Ann'l P/E Ratio	26.0
1.70	1.50	1.54	1.34	1.34	1.39	1.19	1.09	1.18	1.25	1.24	1.76	2.08	2.03	1.53	1.54	1.26		Relative P/E Ratio	1.45
2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	2.4%	2.5%	2.6%	2.3%	2.4%	2.4%	2.2%	2.2%	2.2%	2.4%	3.0%		Avg Ann'l Div'd Yield	2.6%

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
768.6	779.9	814.2	819.9	809.5	838.1	889.7	1462.7	1878.1	2288.0	2275	2435	Revenues ($mill)	2600
205.0	213.9	201.8	234.2	239.7	192.0	224.5	284.8	431.6	465.2	505	555	Net Profit ($mill)	670
10.0%	10.5%	6.9%	8.2%	6.6%	--	--	--	--	--	11.0%	14.0%	Income Tax Rate	16.0%
1.1%	2.4%	3.1%	3.8%	6.3%	6.8%	7.2%	4.5%	4.8%	1.3%	2.5%	3.0%	AFUDC % to Net Profit	5.0%
48.9%	48.5%	50.3%	48.4%	50.6%	54.4%	43.1%	54.0%	52.7%	54.2%	52.0%	52.5%	Long-Term Debt Ratio	56.0%
51.1%	51.5%	49.7%	51.6%	49.4%	45.6%	56.9%	46.0%	47.3%	45.8%	48.0%	47.5%	Common Equity Ratio	44.0%
3003.6	3216.0	3469.5	3587.7	3965.4	4407.8	6824.2	10192	10964	11748	12500	13535	Total Capital ($mill)	16800
4167.3	4402.0	4688.9	5001.6	5399.9	5930.3	6345.8	9512.9	10252	11131	12000	13000	Net Plant ($mill)	14600
8.0%	7.8%	6.9%	7.6%	7.1%	5.5%	4.2%	3.7%	4.8%	5.0%	5.0%	5.0%	Return on Total Cap'l	5.0%
13.4%	12.9%	11.7%	12.7%	12.2%	9.6%	5.8%	6.1%	8.3%	8.7%	8.5%	8.5%	Return on Shr. Equity	9.0%
13.4%	12.9%	11.7%	12.7%	12.2%	9.6%	5.8%	6.1%	8.3%	8.7%	8.5%	8.5%	Return on Com Equity	9.0%
6.7%	6.1%	4.7%	5.6%	5.1%	2.1%	.9%	1.1%	3.3%	3.3%	3.0%	2.5%	Retained to Com Eq	2.5%
50%	52%	60%	56%	59%	79%	84%	82%	60%	62%	64%	64%	All Div'ds to Net Prof	70%

CAPITAL STRUCTURE as of 9/30/23
Total Debt $6806.4 mill. Due in 5 Yrs $1400 mill.
LT Debt $6456.0 mill. LT Interest $254.0 mill.
(52% of Cap'l)

Pension Assets-12/22 $333.2 mill.
Oblig. $324.7 mill.

Pfd Stock None
Common Stock 273,165,817 shares
as of 10/23/23

MARKET CAP: $10.1 billion (Large Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	10.6	11.4	8.5
Receivables	141.0	206.3	133.7
Inventory (AvgCst)	109.6	46.6	48.8
Other	176.6	393.9	218.3
Current Assets	437.8	658.2	409.3
Accts Payable	192.9	238.8	191.9
Debt Due	197.1	427.9	350.4
Other	285.1	355.2	354.3
Current Liab.	675.1	1021.9	896.6

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	5.5%	10.0%	3.5%
"Cash Flow"	6.5%	6.0%	6.0%
Earnings	6.5%	3.5%	7.5%
Dividends	7.5%	7.0%	8.0%
Book Value	10.5%	14.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	255.6	384.5	348.6	474.0	1462.7
2021	583.5	397.0	361.9	535.7	1878.1
2022	699.3	448.7	434.6	705.4	2288.0
2023	726.5	436.7	411.1	700.7	2275
2024	755	475	475	730	2435

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.29	.22	.40	1.12
2021	.72	.32	.19	.44	1.67
2022	.76	.31	.26	.44	1.77
2023	.72	.34	.30	.49	1.85
2024	.80	.35	.30	.55	2.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.219	.219	.2343	.2343	.91
2020	.2343	.2343	.2507	.2507	.97
2021	.2507	.2507	.2682	.2682	1.04
2022	.2682	.2682	.287	.287	1.11
2023	.287	.287	.3071	.3071	

BUSINESS: Essential Utilities, Inc. became the new name for Aqua America on Feb. 3, 2020, to reflect the acquisition of Peoples, a natural gas utility, which occurred in 3/20. In 2022, Aqua Amer. provided water and wastewater services in the states of PA, OH, TX, IL, NC, NJ, IN, VA NS WS. Acquired AquaSource, 7/13; N. Maine Util., 7/15; and others. Water respn. for 47% of revenues in 2022; residential, 27%; commercial, 7%; industrial, wastewater & other, 13%. Gas 50%; other, 3.0%. Employs 3,178. Off. & dir. own less than 1% of the common stock; BlackRock, 11.2%; Vanguard, 10.1%; Can. Pen. Plan 8.2% (3/23 proxy). Pres. & CEO: Christopher Franklin. Inc.: PA Addr.: 762 W Lancaster Ave., Bryn Mawr, PA 19010. Tel.: 610-525-1400. Int.: www.essential.co.

Essential Utilities posted strong third-quarter results. The water and gas utility company's share earnings of $0.30 were $0.01 above our expectations and a 15% increase over the year-ago period. Regulators allowed the implementation of higher rates on water customers' bills in eight different states. This brought in an additional $42.2 million. On the gas side, higher rates permitted by Pennsylvania and Kentucky state authorities brought in $21.3 million in revenues. Also providing a boost to the bottom line was an almost 3% decrease in operating and maintenance expenses. It should be noted that not all revenue is the same in the utility sector. Essential's top line actually declined 5.4% in the September period on a year-over-year basis. When gas is cheaper on the open market, a utility buys it and sells the gas to clients at the same price. So, it is just a pass-through revenue that doesn't impact net income.

The company likely ended 2023 on a positive note. Ongoing cost controls probably also helped profitability. Along with the rate relief, earnings per share probably increased by double digits. Since first-half earnings fell marginally, full-year earnings per share should have rose 5%.

We expect 2024 to be another decent year. Expenses ought to trend higher, but may be offset by rate relief granted in New Jersey, Ohio, and Virginia in the water segment. Overall, share earnings could rise another 5%-10%.

Essential is another member of the water sector that is increasing its size and income through acquisitions. In the U.S., the water industry is made up of thousands of independent, mostly municipally run entities that are often underfunded and inefficient. Like American Water Works, Essential is absorbing these water districts so that it can substantially widen margins on the purchases through economies of scale. Management thinks that these bolt-on purchases can expand its rate base by 2%-3% annually.

This good-yielding stock is ranked to underperform the market averages in the upcoming year. Looking further out to 2026-2028, shares of Essential have better total return potential than any other member of the Water Utility Industry.

James A. Flood *January 5, 2024*

(A) Diluted egs. Excl. nonrec. gains: '12, 18¢. Excl. gain from disc. operations: '12, 7¢; '13, 9¢; '14, 11¢. Quarterly EPS do not add in '19 due to a large change in the number of shares outstanding in the Dec. period. Next earnings report mid-February.
(B) Dividends historically paid in early March, June, Sept., & Dec. ■ Div'd. reinvestment plan available (5% discount).
(C) In millions, adjusted for stock split.
(D) Includes intangibles: 12/31/22, $2345.4 bill./$8.89 a share.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	65

MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 67.58 | P/E RATIO 29.1 (Trailing: 36.7 / Median: 26.0) | RELATIVE P/E RATIO 1.64 | DIV'D YLD 1.9% | VALUE LINE

TIMELINESS 5 Lowered 11/24/23
SAFETY 2 New 10/21/11
TECHNICAL 3 Raised 12/15/23
BETA .75 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$57-$125	$91 (35%)

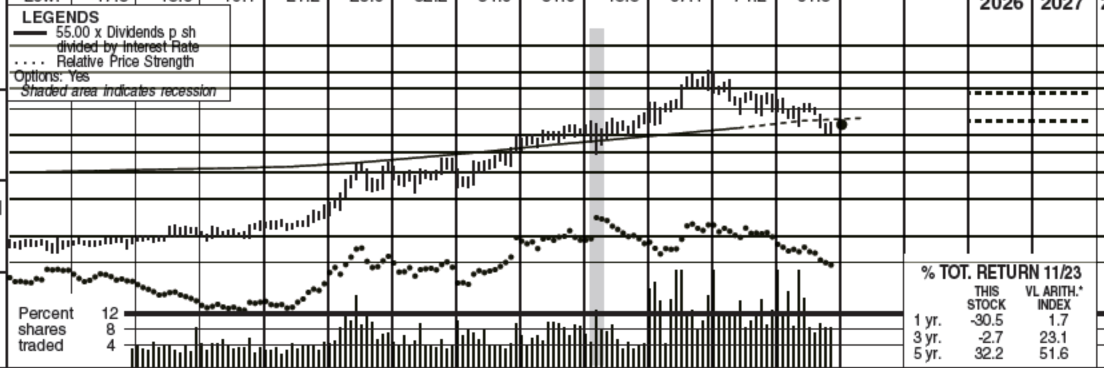
2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+40%)	10%
Low	70	(+5%)	3%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	83	75	79
to Sell	96	99	86
Hld's(000)	11875	12584	13355

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	19.6	22.5	23.7	28.0	44.5	46.7	60.3	67.7	76.1	121.4	121.1	90.6
Low:	17.5	18.6	19.1	21.2	25.0	32.2	34.0	51.0	48.8	67.1	74.2	61.3



% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-30.5	1.7
3 yr.	-2.7	23.1
5 yr.	32.2	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
6.50	6.79	6.75	6.60	6.50	6.98	7.19	7.26	7.77	8.16	8.00	8.42	7.72	8.10	8.17	9.21	*9.50*	*10.05*	Revenues per sh	*11.10*
1.49	1.53	1.40	1.55	1.46	1.56	1.72	1.84	1.97	2.17	2.24	2.89	2.90	3.25	3.28	3.70	*3.05*	*3.60*	"Cash Flow" per sh	*4.10*
.87	.89	.72	.96	.84	.90	1.03	1.13	1.22	1.38	1.38	1.96	2.01	2.18	2.07	2.39	*2.05*	*2.55*	Earnings per sh A	*3.00*
.69	.70	.71	.72	.73	.74	.75	.76	.78	.81	.86	.91	.98	1.04	1.11	1.18	*1.28*	*1.32*	Div'd Decl'd per sh B■	*1.60*
1.66	2.12	1.49	1.90	1.50	1.36	1.26	1.40	1.59	2.91	3.08	4.40	5.11	6.04	4.53	5.18	*5.25*	*5.45*	Cap'l Spending per sh	*6.00*
10.05	10.03	10.33	11.13	11.27	11.48	11.82	12.24	12.74	13.40	14.02	15.17	18.57	19.81	20.99	22.65	*23.55*	*23.60*	Book Value per sh	*23.70*
13.25	13.40	13.52	15.57	15.70	15.82	15.96	16.12	16.23	16.30	16.35	16.40	17.43	17.47	17.52	17.64	*17.85*	*17.90*	Common Shs Outst'g C	*18.00*
21.6	19.8	21.0	17.8	21.7	20.8	19.7	18.5	19.1	25.6	28.4	22.2	29.7	30.1	44.3	38.6	*36.9*		Avg Ann'l P/E Ratio	*28.0*
1.15	1.19	1.40	1.13	1.36	1.32	1.11	.97	.96	1.34	1.43	1.20	1.58	1.55	2.39	2.24	*2.14*		Relative P/E Ratio	*1.30*
3.7%	4.0%	4.7%	4.2%	4.0%	4.0%	3.7%	3.7%	3.3%	2.3%	2.2%	2.1%	1.6%	1.6%	1.2%	1.3%	*1.7%*		Avg Ann'l Div'd Yield	*1.9%*

CAPITAL STRUCTURE as of 9/30/23
Total Debt $361.7 mill. Due in 5 Yrs $43.7 mill.
LT Debt $354.3 mill. LT Interest $7.5 mill.
(Total interest coverage: 9.3x)
(46% of Cap'l)

Pension Assets-12/22 $84.8 mill.
Oblig. $87.8 mill.
Pfd Stock $2.4 mill. Pfd Div'd: $.1 mill.

Common Stock 17,806,000 shs.
as of 11/9/23

MARKET CAP: $1.2 billion (Small Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
114.8	117.1	126.0	132.9	130.8	138.1	134.6	141.6	143.1	162.4	*170*	*180*	Revenues ($mill)	*200*
16.6	18.4	20.0	22.7	22.8	32.5	33.9	38.4	36.5	42.4	*36.5*	*45.5*	Net Profit ($mill)	*54.0*
34.1%	35.0%	34.5%	34.0%	32.7%	2.8%	--	--	2.8%	7.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
1.9%	1.7%	1.9%	2.7%	3.1%	1.4%	3.4%	3.9%	3.9%	3.9%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
40.4%	40.5%	39.4%	37.9%	37.5%	37.8%	41.5%	44.0%	45.3%	41.9%	*44.0%*	*41.5%*	Long-Term Debt Ratio	*40.5%*
58.7%	58.8%	59.8%	61.5%	61.8%	61.6%	58.2%	55.7%	54.4%	57.7%	*56.0%*	*58.5%*	Common Equity Ratio	*59.5%*
321.4	335.8	345.4	355.4	370.7	404.1	556.7	621.5	676.3	692.7	*747*	*724*	Total Capital ($mill)	*720*
446.5	465.4	481.9	517.8	557.2	618.5	705.7	796.6	865.4	920.6	*985*	*995*	Net Plant ($mill)	*1025*
5.9%	6.3%	6.6%	7.1%	6.9%	8.9%	6.7%	6.8%	6.0%	6.8%	*5.5%*	*6.5%*	Return on Total Cap'l	*8.0%*
8.7%	9.2%	9.6%	10.3%	9.8%	12.9%	10.4%	11.0%	9.9%	10.5%	*8.5%*	*10.5%*	Return on Shr. Equity	*12.5%*
8.7%	9.3%	9.6%	10.3%	9.9%	13.0%	10.4%	11.1%	9.9%	10.6%	*8.5%*	*11.0%*	Return on Com Equity	*12.5%*
2.4%	3.1%	3.5%	4.3%	3.8%	7.0%	5.4%	5.8%	4.6%	5.4%	*3.5%*	*5.0%*	Retained to Com Eq	*6.0%*
73%	67%	63%	58%	62%	46%	48%	48%	53%	49%	*62%*	*52%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)

	2021	2022	9/30/23
Cash Assets	3.5	3.8	3.0
Other	30.9	33.5	132.8
Current Assets	34.4	37.3	135.8
Accts Payable	21.1	24.8	28.6
Debt Due	6.7	17.5	7.4
Other	28.8	75.6	85.3
Current Liab.	56.6	117.9	121.3

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	2.5%	1.5%	*4.5%*
"Cash Flow"	8.5%	10.0%	*3.0%*
Earnings	9.5%	11.0%	*5.0%*
Dividends	4.0%	6.5%	*6.5%*
Book Value	6.5%	9.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	31.8	35.3	39.9	34.6	141.6
2021	32.5	36.7	39.9	34.0	143.1
2022	36.2	39.7	47.7	38.8	162.4
2023	38.2	42.8	46.7	*42.3*	*170*
2024	*42.0*	*43.0*	*52.0*	*43.0*	*180*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.44	.55	.72	.47	2.18
2021	.39	.62	.65	.41	2.07
2022	.68	.50	.80	.40	2.39
2023	.33	.55	.56	*.61*	*2.05*
2024	*.50*	*.65*	*.75*	*.65*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.24	.24	.2562	.98
2020	.2562	.2562	.2562	.2725	1.04
2021	.2725	.2725	.2725	.29	1.11
2022	.29	.29	.29	.3125	1.18
2023	.3125	.3125	.3125	.325	

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 61,000 retail customers, primarily in Middlesex County, New Jersey. In 2022, the Middlesex System accounted for 65% of operating revenues. At 12/31/22, the company had 350 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers & directors own 1.9% of the com. stock; BlackRock Inst. Trust Co., 14.6% (4/23 proxy). Add.: 485 C Route 1 South, Suite 400, Iselin, NJ 08830. Tele.: 732-634-1500. Int.: www.middlesexwater.com.

Middlesex Water stock has treaded water since our previous review. Indeed, the equity, which etched an all-time high in late 2021, has contracted more than 40% in value over the past two years or so. After a prolonged period of relatively conservative allocation strategies, the investment community's appetite for riskier assets appears to have shifted somewhat. On balance, based on recent price and earnings momentum, Middlesex shares do not presently stand out for relative year-ahead price performance (Timeliness: 5, Lowest).

We are trimming our 2023 and 2024 bottom-line estimates subsequent to a softer third-quarter showing. The company posted September-period revenues of $47 million, or $3 million shy of our call. Meanwhile, net income of $0.56 per share, which was flat on a sequential basis, came in considerably below consensus expectations. A combination of lower customer demand and higher purchased water costs weighed on results. All told, we are shaving $0.35 and $0.20 per share from our 2023 and 2024 earnings estimates, to $2.05 and $2.55, respectively.

The board of directors recently raised the quarterly dividend payout 4%, to $0.325 per share. The modest annual increase is in line with the company's historical rate of distribution hikes. Moreover, Middlesex's fairly stable secular business model suggests that additional dividend increases are likely in the cards over the long haul.

Better days probably lie ahead. Looking further out, overall water consumption ought to perk up as economic conditions slowly improve. The company should also benefit from additional rate hike approvals. Capital spending on water infrastructure and delivery systems is likely to keep management active in filing for regulator-approved rate increases.

We think patient investors should also hold off, for now. Capital appreciation potential over the pull to late decade, even on a risk-adjusted basis, is nothing to write home about at recent levels. What's more, the current dividend yield is below the *Value Line* median, thus rendering Middlesex shares unenticing as a stand alone, income-generating option.

Nicholas Patrikis *January 5, 2024*

(A) Diluted earnings. Quarterly figures may not sum due to rounding. Next earnings report due early February.
(B) Dividends historically paid in mid-Feb., May, Aug., and November.■ Div'd reinvestment plan available.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	90

SJW GROUP NYSE-SJW

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
66.51	21.8	(Trailing: 21.0; Median: 25.0)	1.23	2.3%	VALUE LINE

TIMELINESS 3 Raised 11/10/23
SAFETY 3 New 4/22/11
TECHNICAL 3 Raised 12/22/23
BETA .85 (1.00 = Market)

High:	26.9	30.1	33.7	35.7	56.9	69.3	68.4	74.5	75.0	73.7	83.9	83.7
Low:	22.6	24.5	25.5	27.5	28.6	45.4	51.3	53.9	45.6	58.0	55.7	57.0

18-Month Target Price Range

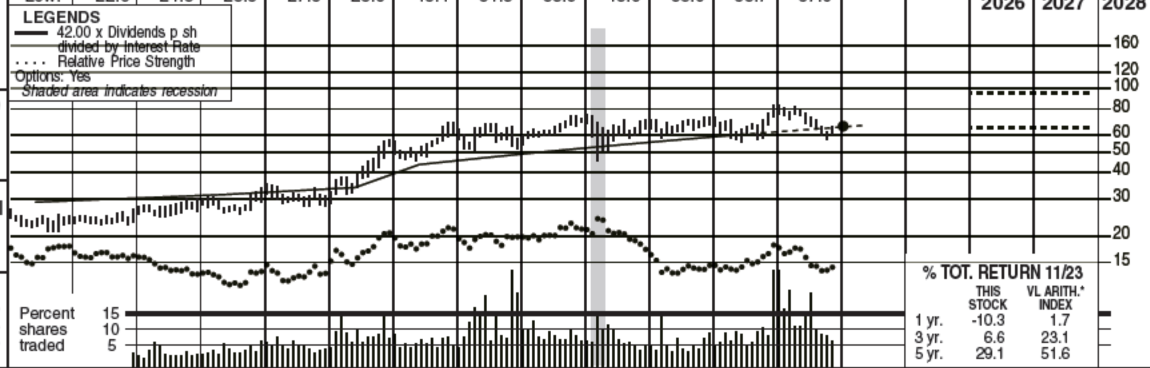
Low-High	Midpoint (% to Mid)
$54-$110	$82 (25%)

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+45%)	11%
Low	65	(Nil)	2%

Institutional Decisions

	1Q2023	2Q2023	3Q2023
to Buy	94	120	128
to Sell	113	91	85
Hld's(000)	27281	26624	24180



% TOT. RETURN 11/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.3	1.7
3 yr.	6.6	23.1
5 yr.	29.1	51.6

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
11.25	12.12	11.68	11.62	12.85	14.01	13.73	15.76	14.97	16.61	18.97	14.00	14.78	19.77	19.01	20.15	20.65	22.10	Revenues per sh	24.15
2.30	2.44	2.21	2.38	2.80	2.97	2.90	4.42	3.86	4.76	5.24	3.29	3.13	5.28	5.13	5.79	4.50	4.75	"Cash Flow" per sh	5.10
1.04	1.08	.81	.84	1.11	1.18	1.12	2.54	1.85	2.57	2.86	1.82	.82	2.14	2.03	2.43	2.95	3.15	Earnings per sh A	3.45
.61	.65	.66	.68	.69	.71	.73	.75	.78	.81	1.04	1.12	1.20	1.28	1.36	1.44	1.52	1.60	Div'd Decl'd per sh B■	1.80
6.62	3.79	3.17	5.65	3.75	5.67	4.68	5.02	5.24	6.95	7.26	5.08	6.25	7.44	8.32	7.85	8.00	8.25	Cap'l Spending per sh	8.75
12.90	13.99	13.66	13.75	14.20	14.71	15.92	17.75	18.83	20.61	22.57	31.31	31.27	32.12	34.28	36.06	38.30	41.15	Book Value per sh	44.15
18.36	18.18	18.50	18.55	18.59	18.67	20.17	20.29	20.38	20.46	20.52	28.40	28.46	28.56	30.18	30.80	32.00	31.00	Common Shs Outst'g C	30.00
33.4	26.2	28.7	29.1	21.2	20.4	24.3	11.2	16.6	15.7	18.8	32.7	78.8	30.0	32.9	27.3	24.1		Avg Ann'l P/E Ratio	23.0
1.77	1.58	1.91	1.85	1.33	1.30	1.37	.59	.84	.82	.95	1.77	4.20	1.54	1.78	1.58	1.40		Relative P/E Ratio	1.30
1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	2.7%	2.6%	2.5%	2.0%	1.9%	1.9%	1.9%	2.0%	2.0%	2.2%	2.1%		Avg Ann'l Div'd Yield	2.3%

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		26-28
276.9	319.7	305.1	339.7	389.2	397.7	420.5	564.5	573.7	620.7	660	685	Revenues ($mill)	725
23.5	51.8	37.9	52.8	59.2	38.8	23.4	61.5	60.5	73.8	95.0	98.0	Net Profit ($mill)	105
38.7%	32.5%	38.1%	38.8%	36.7%	20.6%	26.4%	12.0%	12.2%	10.3%	21.0%	21.0%	Income Tax Rate	21.0%
--	--	--	--	2.0%	1.0%	2.0%	1.5%	2.0%	6.4%	1.5%	1.5%	AFUDC % to Net Profit	1.5%
51.1%	51.6%	49.8%	50.7%	48.2%	32.7%	59.1%	58.4%	59.1%	57.3%	55.5%	52.5%	Long-Term Debt Ratio	43.0%
48.9%	48.4%	50.2%	49.3%	51.8%	67.3%	40.9%	41.6%	40.9%	42.7%	44.5%	47.5%	Common Equity Ratio	57.0%
656.2	744.5	764.6	855.0	894.3	1320.7	2173.6	2204.7	2527.5	2602.8	2750	2675	Total Capital ($mill)	2325
898.7	963.0	1036.8	1146.4	1239.3	1328.8	2206.5	2334.9	2497.5	2630.3	2775	2800	Net Plant ($mill)	2925
5.0%	8.3%	6.3%	7.4%	7.9%	3.9%	1.8%	4.0%	3.5%	4.0%	4.0%	4.0%	Return on Total Cap'l	5.0%
7.3%	14.4%	9.9%	12.5%	12.8%	4.4%	2.6%	6.7%	5.8%	6.6%	7.5%	7.5%	Return on Shr. Equity	8.0%
7.3%	14.4%	9.9%	12.5%	12.8%	4.4%	2.6%	6.7%	5.8%	6.6%	7.5%	7.5%	Return on Com Equity	8.0%
2.8%	10.2%	5.7%	8.6%	8.2%	1.8%	NMF	2.7%	2.0%	2.7%	3.5%	4.0%	Retained to Com Eq	3.5%
62%	29%	42%	31%	36%	60%	NMF	59%	66%	59%	51%	51%	All Div'ds to Net Prof	52%

CAPITAL STRUCTURE as of 9/30/23
Total Debt $1577.3 mill. **Due in 5 Yrs** $44.3 mill.
LT Debt $1533.8 mill. **LT Interest** $50.0 mill.
(LT Interest Coverage: 10.2x)
(57% of Cap'l)

Pension Assets-12/22 $252.0 mill.
Oblig. $289.1 mill.
Pfd Stock None.
Common Stock 31,933,000 shs.

MARKET CAP: $2.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2021	2022	9/30/23
Cash Assets	10.9	12.3	21.1
Accts Receivable	53.7	58.2	70.4
Other	69.5	84.2	137.3
Current Assets	134.1	154.7	228.8
Accts Payable	30.4	29.6	35.9
Debt Due	39.1	4.4	43.5
Other	133.8	230.7	228.7
Current Liab.	203.3	264.7	308.1

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	4.5%	3.0%	3.5%
"Cash Flow"	7.0%	3.0%	-1.0%
Earnings	7.5%	-2.0%	8.0%
Dividends	7.0%	9.0%	5.0%
Book Value	9.0%	10.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	115.8	147.2	165.9	135.6	564.5
2021	114.8	152.2	166.9	139.8	573.7
2022	124.3	149.0	176.0	171.4	620.7
2023	137.3	156.9	204.8	161.0	660
2024	140	165	215	165	685

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2020	.08	.69	.91	.46	2.14
2021	.09	.69	.64	.60	2.03
2022	.12	.38	.82	1.09	2.43
2023	.37	.58	1.13	.87	2.95
2024	.45	.60	1.20	.90	3.15

Cal-endar	QUARTERLY DIVIDENDS PAID BD■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.30	.30	.30	.30	1.20
2020	.32	.32	.32	.32	1.28
2021	.34	.34	.34	.34	1.36
2022	.36	.36	.36	.36	1.44
2023	.38	.38	.38	.38	

BUSINESS: SJW Group engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 231,000 connections with a total population of roughly one million people in the San Jose area and 16,000 connections that reach about 49,000 residents in the region between San Antonio and Austin, Texas. The company merged with Connecticut Water (10/19) which provides service to approx. 138,000 connections with a total population of 450,000 people. Has 757 employees. Officers and directors own less than 1.0% of outstanding shares (3/23 proxy). Chairman & CEO: Eric Thornburg. Incorporated: California. Address: 110 West Taylor Street, San Jose, CA 95110. Telephone: (408) 279-7800. Internet: www.sjwater.com.

SJW Group closed two acquisitions in Texas during the September period. Subsidiary Texas Water Company finalized the purchase of KT Water Development and KT Water Resources for undisclosed amounts. The former provides diverse water services to residential water connections, while the latter is a water wholesaler that will greatly increase Texas Water Company's available water supply over the next several years.

Third-quarter financial results were solid. SJW Group recorded revenues of $205 million, or a 16% annual advance. The gain was underpinned by recent rate increases and higher customer water usages, particularly amidst the end of the state's conservation requirements. On the earnings front, net income jumped 38%, to $1.13 per share, driven largely by strong top-line gains that more than offset a slight uptick in operating expenses, such as water production costs. As a result, we are raising our 2023 revenue and earnings calls from $640 million and $2.75 per share, to $660 million and $2.95 per share, respectively. We think moderate growth is also in the cards for 2024.

Rate case filings ought to continue in the coming years. Most recently, higher customer rates went into effect in Maine and California. Elsewhere, in October, SJW's subsidiary Connecticut Water Company filed an application with state regulators to amend rates. Filings have also been proposed in Texas. In the meantime, management is not likely to take its foot off the gas, in terms of infrastructure investment spending. In fact, the company plans to invest more than $1.5 billion over the next five years, of which a decent portion is expected to be recouped via additional rate hike approvals.

We are not presently recommending this stock. SJW shares are ranked to move in line with the broader market averages over the coming six to 12 months. Moreover, the current dividend yield is roughly on par with that of the *Value Line* median. On balance, total return potential over the 2026-2028 horizon does not stand out at recent levels. All told, we suggest that subscribers looking for exposure to regulated water utilities have a look elsewhere, for now.

Nicholas Patrikis *January 5, 2024*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $1.22; '10, $0.46. GAAP accounting as of 2013. Next earnings report due early February. Quarterly egs. may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions.
(D) Paid special dividend of $0.17 per share on 11/17.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	50

CASE: UG 490
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 109

ROE: Financial News that Investors in Electric Utilities Are Seeing

April 18, 2024

Major energy rate case decisions in the US

January-December 2023

Quarterly update on decided rate cases

Lisa Fontanella, **Research Director**

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Wyatt Scott

For detailed data

Access the RRA's electric and gas rate case decisions as of Dec. 31, 2023, data tables.

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

Table of Contents

Executive Summary

Introduction

Energy authorized returns on equity rose in 2023 as the pace of rate case activity reached record-high levels.

As per calculations from Regulatory Research Associates, the average authorized return on equity (ROE) for electric utilities in cases decided during 2023 was 9.60%, compared to the 9.54% average for cases decided in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in 2022.

Despite the rise in 2023, the average authorized ROE for electric utilities in 2023 remains near historic lows and was the sixth-lowest annual average over the more than 40 years RRA has tracked rate case activity.

The average ROE authorized for gas utilities was 9.64% for cases decided during 2023 versus the 9.53% average observed in 2022. RRA's calculations relied on 43 gas rate case decisions that included an ROE determination during 2023 versus 33 in 2022. For gas utilities, the average authorized ROE in 2023 was the seventh-lowest annual average on record.

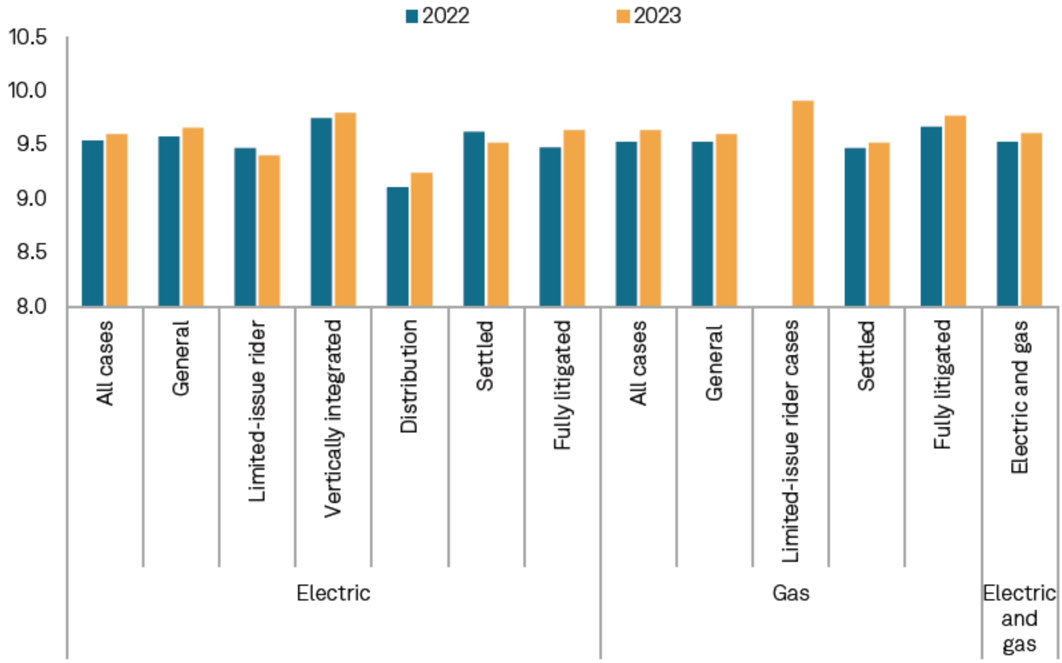
Rate case activity reached record-high levels in 2023, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems, build new natural gas, solar and wind generation, and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sector-wide forces on operations, the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition, recovery of storm and severe-weather related costs, and regulatory approval for alternative regulatory mechanisms.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during 2023 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, which is available on the S&P Capital IQ Pro platform. RRA endeavors to follow all "major" rate cases for investor-owned utilities nationwide, with "major" defined as a case in which the utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA's coverage.

Average authorized ROE (%)



	2022	2023
Electric averages		
All cases	9.54	9.60
General rate cases	9.58	9.66
Limited-issue rider cases	9.47	9.40
Vertically integrated cases	9.75	9.80
Distribution cases	9.11	9.24
Settled cases	9.62	9.52
Fully litigated cases	9.48	9.64
Gas averages		
All cases	9.53	9.64
General rate cases	9.53	9.60
Limited-issue rider cases		9.91
Settled cases	9.47	9.52
Fully litigated cases	9.67	9.77
Composite electric and gas averages		
Electric and gas	9.53	9.61
US Treasury		
30-year bond yield	3.11	4.09

Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

The Take

The average authorized returns in 2023 edged modestly higher than the annual levels observed in 2022 as higher interest rates began to impact authorized ROEs. The effect of interest rate increases on authorized returns will likely be limited, however, given that regulators are slower to adjust ROEs upward than downward, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing almost 165 decisions in 2023. With higher interest rates, higher inflation and accelerating capital spending to address public policy goals, particularly the energy transition, RRA anticipates rate case filings will remain robust.

Overview of electric and gas authorizations

The average electric and gas authorized returns on equity inched gently higher per averages calculated for 2023.

The average ROE authorized for electric utilities rose to 9.60% for rate cases decided in 2023 from the 9.54% average observed in 2022. There were 63 electric ROE determinations reflected in the calculations for 2023 versus 53 in full year 2022.

The average ROE authorized for gas utilities was 9.64% for cases decided in 2023, above the 9.53% average observed in 2022. There were 43 gas rate case decisions decided in 2023 versus 33 in full year 2022.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired. Excluding rider cases, the average authorized ROE for electric cases was 9.66% in 2023 versus 9.58% in full year 2022.

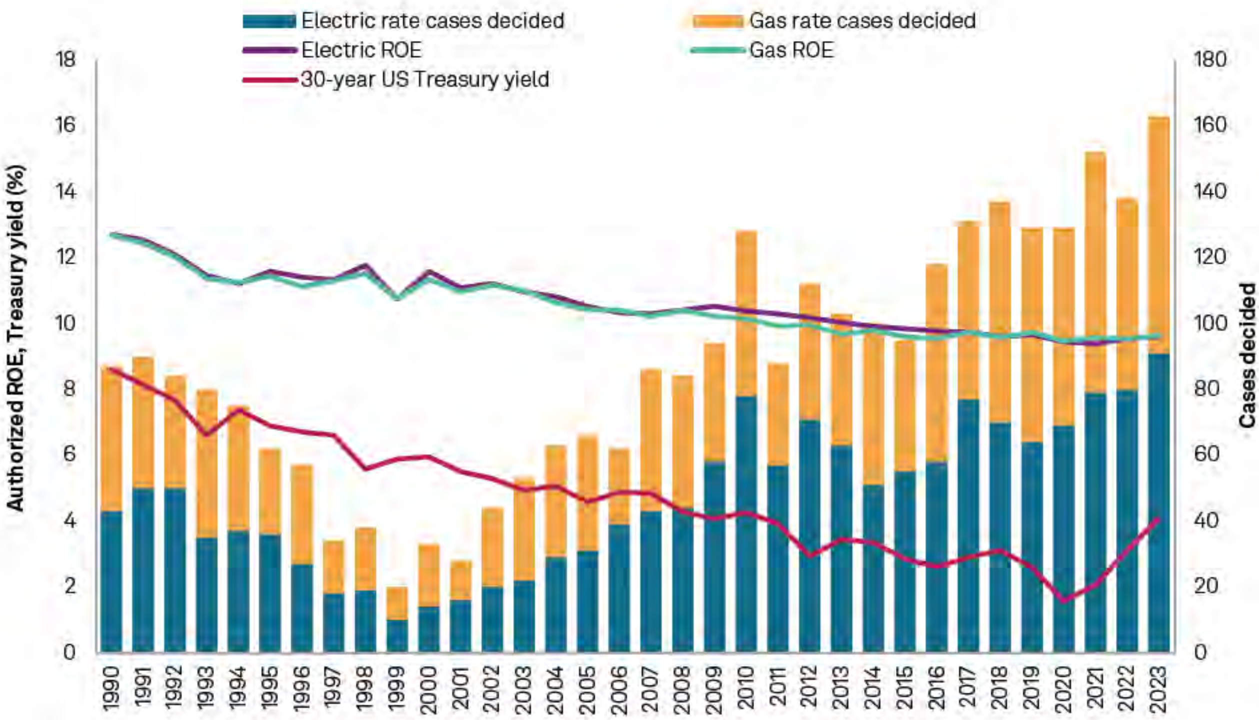
Excluding the six rider cases, the average authorized ROE for gas cases was 9.60% in 2023. There were no rider cases with a gas-authorized ROE in 2022. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

In 2023, the median ROE authorized in all electric utility rate cases was 9.50%, equal to that observed in 2022; for gas utilities, the metric was 9.64% in 2023 and 9.53% in full year 2022.

Historically, authorized returns have generally tracked the overall direction of interest rates, albeit with two important caveats to keep in mind — the magnitude of the change in authorized ROEs may not be as dramatic as that observed in interest rates, and changes in authorized ROEs may lag changes in interest rates, especially in the upward direction.

Interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 12 of the last 15 calendar years. This count includes electric and gas cases where no ROEs were specified, but it does not include withdrawn cases. At almost 165 cases decided, rate case activity in 2023 was the most robust observed in any year during the 1990–2023 period, with authorized increases totaling about $12 billion.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasuries somewhat widened over this period — from a little over 400 basis points in 1990 to peaking at just under 800 basis points in 2020.

This occurrence is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the Fed intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023.

With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.

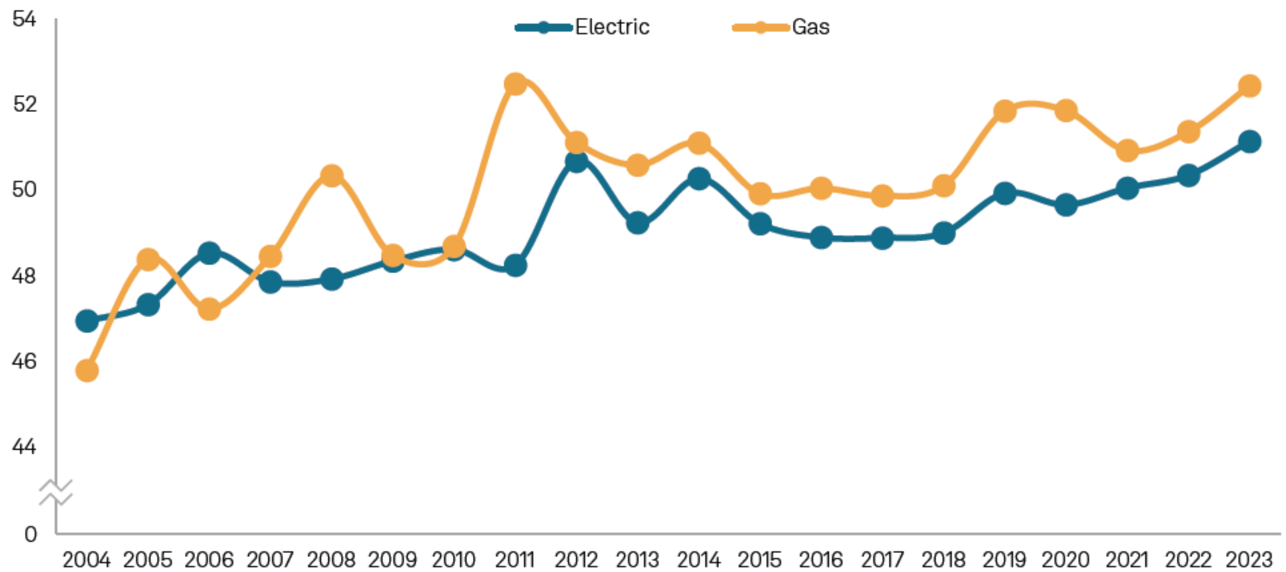
Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2023, 2022, 2021, 2020, and 2019, the average equity ratios authorized in electric utility cases were 51.15%, 50.36%, 50.06%, 49.67% and 49.94%, respectively. The average equity ratios authorized gas utilities for these years were 52.45%, 51.38%, 50.94%, 51.87% and 51.86%, respectively.

From a longer-term perspective, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electric utilities.

Average authorized equity ratio (%)



Data compiled Jan. 26, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

A more granular look at ROE trends

Thus far, the discussion has looked broadly at trends in authorized ROEs; the following sections provide a more granular view.

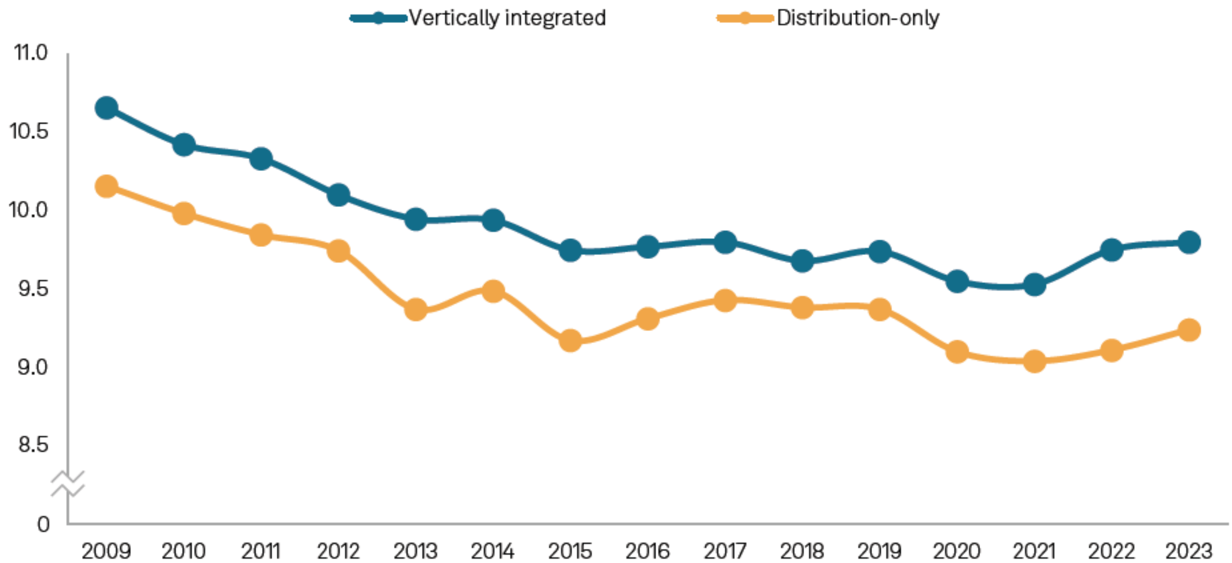
RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of the electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation have been about 30–65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.80% in 2023 versus the 9.75% average in 2022. For electric distribution-only cases, the industry average ROE was 9.24% in 2023 versus the 9.11% average in 2022.

Average authorized electric ROEs (%)

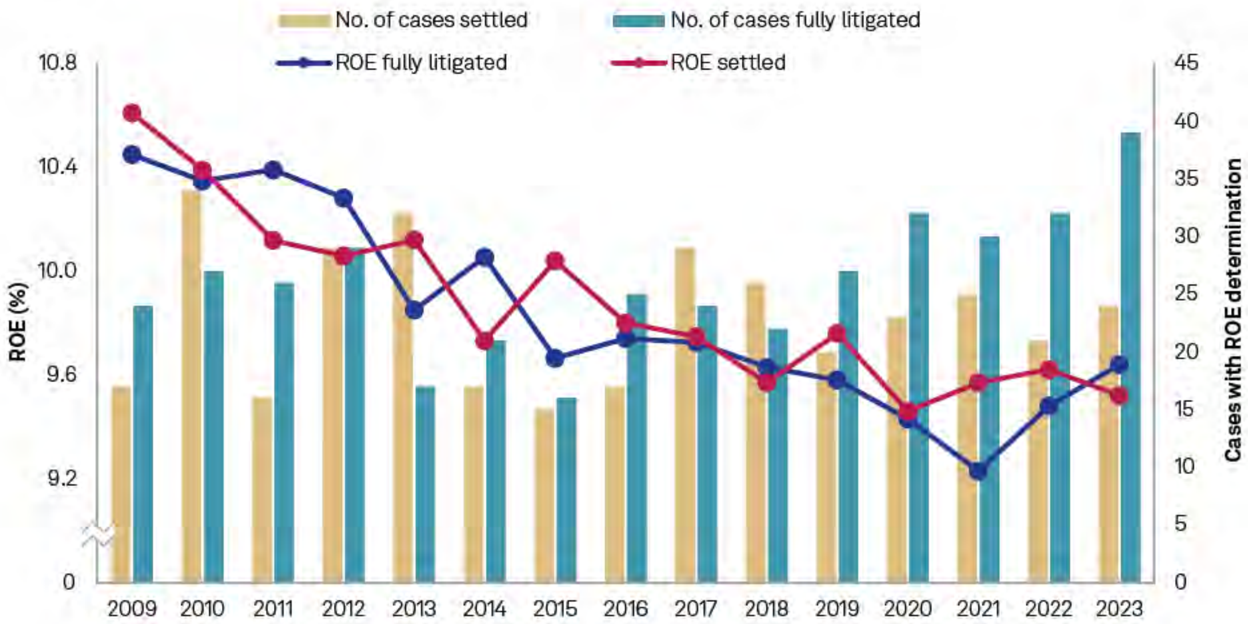


Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

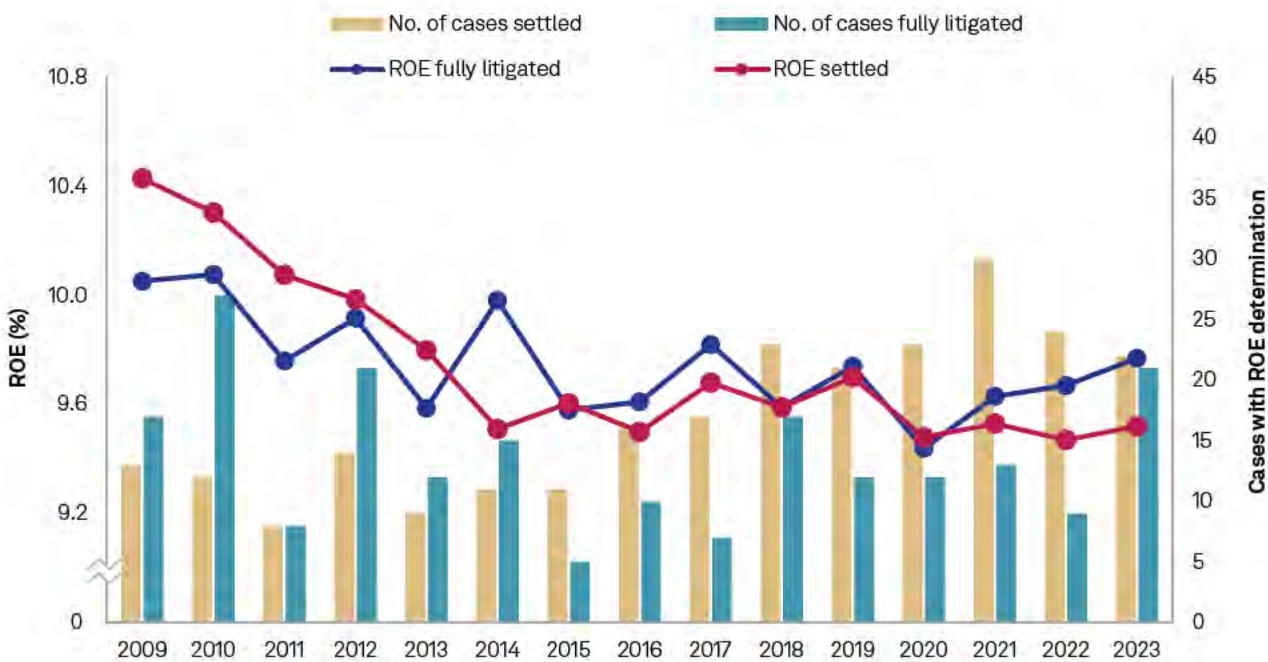
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2019, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

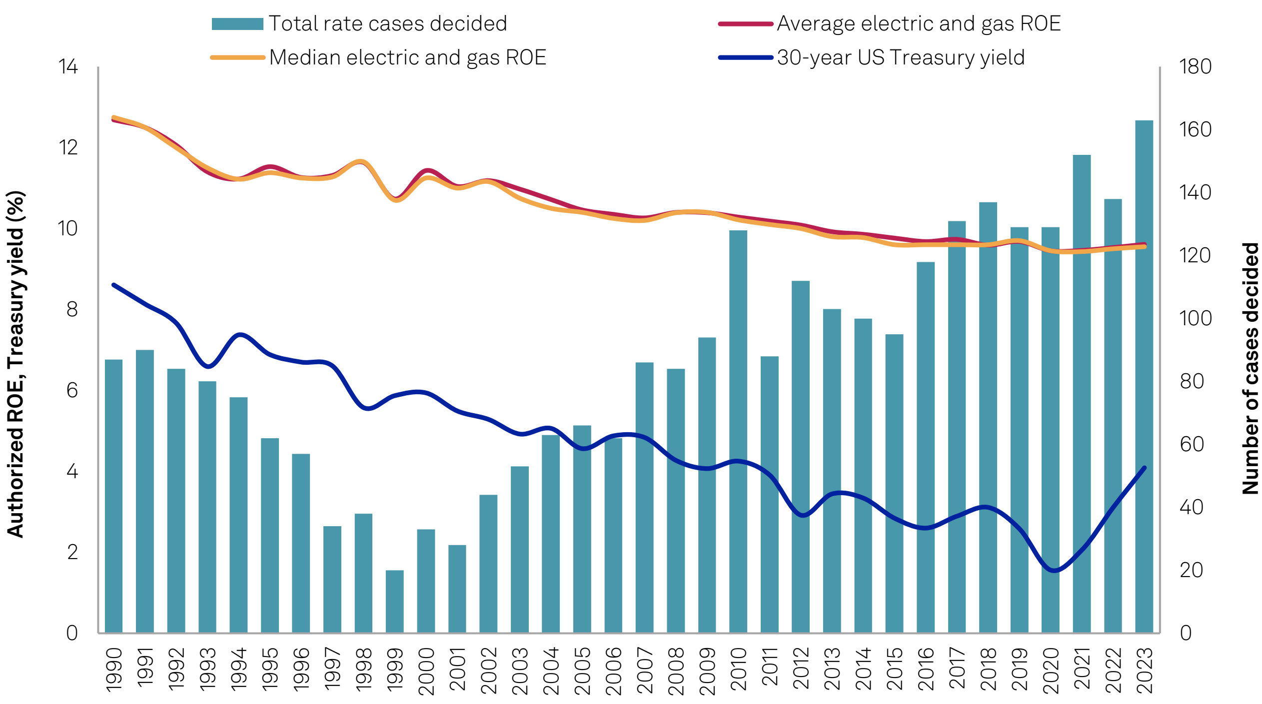
Tables 3 and 4 provide comparisons since 2009 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2023 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs over this time frame.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled Jan. 26, 2024.
ROE = return on equity.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

Further Reading

[The Commissions]

[The rate case process: a conduit to enlightenment]

[Rate base: It's more complicated than it sounds]

[Frequently Asked Questions]

[Intro to Water Utilities — Current Trends and Growth Drivers]

[An Overview of FERC Regulation]

[FERC Regulatory Review]

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For over 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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The Citizens' Utility Board Asked the Oregon Public Utility Commission to Dismiss Portland General Electric's Rate Request for 2025

by Pete Danko – Portland Business Journal – Mar. 15, 2024

In what it called an "unprecedented appeal" to regulators, **Oregon's residential ratepayer advocate** on Thursday formally **asked** the **P**ublic **U**tility **C**ommission to **dismiss** **P**ortland **G**eneral **E**lectric's **latest proposed rate increase**.

PGE late last month requested a 7.4% overall average rate increase in 2025, 7.2% for the residential customers that the Citizens' Utility Board represents. It would come on the heels of an 18% overall increase that hit PGE residential customers in January, with a smaller but not yet set rate boost for wildfire mitigation costs still due to kick in this April.

Rates also rose in 2023, and the new PGE request would push PGE prices some 40% above where they stood in 2022, according to CUB.

Something 'never done before'.

"We're asking the Commission to do something they have never done before," **Bob Jenks**, **CUB**'s executive director, **said** in a news release. "We are seeing historically high bills for many PGE customers, and we **need regulators** to **do something bold and unprecedented**. Now is the time to flip the script and show our utilities that consumer protections come before profits."

A PGE representative, responding to a request for comment, emailed that "PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission."

If not a dismissal, **CUB asked the PUC** to "**segregate**" **several issues from PGE's request**, **including PGE's ask for** an **increase** in its **return on equity** — its profit margin, in essence — **from 9.5% to 9.75%**. **CUB said many of those issues** were **fought** over **in last year's PGE general rate case**.

"The **Company seeks** to re**-litigate many** of the **contentious issues** that were collaboratively resolved and determined to result in just and **reasonable** rates mere weeks earlier," it said in the PUC filing.

CUB said it was **supported in** its **motion by Lewis & Clark Law School's Green Energy Institute and** the Alliance of **W**estern **E**nergy **C**onsumers, which represents big energy users.

Rates are ultimately set by the three-person, governor-appointed PUC after a 10-month process that includes regulatory staff analysis and stakeholder and public input.

PGE's Battery Investments

With rates already on the rise, PGE executives earlier last month had told investment analysts that the company would look to file a narrowly focused general rate case, mostly to pay for new battery energy storage systems it expects to bring online next year.

But CUB saw the request that came less than two weeks later as far from narrow. Out of a $202 million revenue requirement boost, just $17.3 million was directly attributable to the battery systems.

PGE says associated substation costs also need to be paid for, along with other transmission and distribution system upgrades that it says will improve reliability and help it meet growing load.

–

Consumer Group asks Oregon Regulators to Dismiss New PGE Rate Hike Request

by Gosia Wozniacka - Oregonian – Mar. 15, 2024

A state nonprofit group that advocates for utility customers is asking Oregon regulators to dismiss Portland General Electric's newest rate increase proposal.

In a motion filed Thursday, the Oregon **C**itizens' **U**tility **B**oard **asked** the **P**ublic **U**tility **C**ommission to **throw out PGE's 7.4% increase request**. If approved by the commission, the increase would take effect in January 2025.

The **C**itzens' **U**tility **B**oard, which was **created via** a **1984 ballot measure**, said in a statement that it has never taken such an action before and is doing so now "in the face of record bills for PGE customers."

The board points out that PGE's residential customers have seen a 30% increase in power bills over the past two years. Their rates went up 12% in January 2023 and by 18% this past January.

Customers are reeling from record-high bills that resulted from this year's rate increase and the ice storm in January and many won't be able to handle yet another increase, said Bob Jenks, the board's executive director.

Jenks said the utility's latest request for 2025 will likely grow to cover other costs such as wildfire mitigation or winter storm recovery.

"We're asking the Commission to do something they have never done before," Jenks said. "We are seeing historically high bills for many PGE customers, and we need regulators to do something bold and unprecedented."

The **P**ublic **U**tility **C**ommission regulates investor-owned electric and other utilities. Commission spokesperson **Kandi Young said** the **Commission's normal practice** would be to seek written replies from its staff and other parties and then issue a written ruling after reviewing responses. **But** Oregon **CUB's petition asks** the **Commission instead** to **decide** the **motion at** a **public meeting**.

"The Commission is considering CUB's request for a change to the standard process, and will advise parties when written responses are due," Young told The Oregonian/OregonLive via email.

PGE declined to comment on the petition and said it would continue to focus on its rate increase proposal.

"PGE is and will continue to be fully engaged in the public Rate Review process administered by the Oregon Public Utility Commission," the utility's spokesperson, Drew Hanson, said in an email.

PGE's 7.4% rate increase request is tied to clean energy needs – specifically, battery storage projects, PGE said previously.

In its petition, the Citizens' Utility Board told regulators that its review of the request found that the new Constable **Battery Storage** project, which is what's included in PGE's rate increase proposal, will cost only $17.3 million, or 8.5% of the total $202 million revenue demand.

The rest, said **Jenks**, will go toward higher profits for shareholders and shifting financial risk to customers, among other things – issues the **commission already ruled** on and rejected in **December for** the **increase that went into effect this year**.

If the **P**ublic **U**tilities **C**ommission **will not dismiss PGE's entire rate increase case**, the **C**itizens' **U**tility **B**oard **asks** that it **limit** the **scope** of what PGE can request, including **removing all** of the **items** that the **commission previously ruled against**.

Is Oregon Utility Regulation Part of the Problem?

by Bob Jenks – Oregon CUB – Jan. 25, 2024

[Is Oregon Utility Regulation Part of the Problem? | Latest News | News | Oregon CUB]

As utility bills in Oregon continue to rise in 2024, CUB is asking tough questions from state regulators. Currently, utility regulators spend a lot of time looking at many requests from utilities to raise rates. This analysis can take up to 10 months in many cases. But overall affordability to customers is not part of the equation for regulators.

We need to look at utility bills holistically – before we see rates skyrocket. Our current system means that customer advocates, decision-makers, and customers do not have a clear picture of what to expect from utility bills. And an even harder time knowing when rates will go up dramatically.

Exposing Flaws in Oregon's System of Utility Regulation

From December 2022 to January 2024, Portland General Electric (PGE) customers have seen bills go up by 30%. This large increase in 13 months shows real and significant flaws in Oregon's system of regulation utilities.

Our current structure leads regulation to focus on each individual line item, but not on the overall affordability of rates. There are several parts to this problem:

- Utilities have an incentive to spend money.
- Utilities can request dozens of rate increases a year.
- **Regulator looks at individual utility projects**, **not total rates**.
- Costs can be updated even after they are approved by regulators.
- Utilities work to keep information confidential from the public.

Electric utilities are typically the ones who see the most frequent requests for rate increases. PGE is not the only utility that has had large bill increases in the past few years. Pacific Power customers saw bills increase by 21% at the start of 2023 and by 11% on January 1, 2024.

Increasingly, gas utilities are also asking for more from customers more often. Alongside the big spikes in the cost of methane, NW Natural gas rates have increased by 32.7% since September 2022.

Utilities have an incentive to spend money

Utilities make a profit from making capital investments. This ability to profit from a new power plant, laying new lines, or other projects is protected by Oregon law. While many investments are necessary to maintain a reliable system, too many investments can cause rates to be unaffordable.

To justify a capital expense, a utility normally has to show that the investment was expected to bring benefits to the system and to customers. But affordability to customers is not part of the equation for regulators.

Example: Wildfire Mitigation

After the 2020 Labor Day fires, it became clear that utilities needed to invest money in wildfire mitigation. Oregon's utilities are now spending hundreds of millions of dollars to mitigate potential wildfires. Since a wildfire caused by a utility line can cause significant harm, it would be hard to argue that this is not a prudent and necessary investment.

For utilities, wildfire mitigation was an opportunity to spend money and increase profits. Did they ask whether this was affordable for customers? Did they look at other investments to see if there were costs that could be avoided or delayed?

Read More: **Protecting Oregon Customers from Wildfire Risk and Cost Increases**

Regulation Looks at Individual Investments, Not Total Rates

Under Oregon law, regulators at the Public Utility Commission are supposed to establish fair and reasonable rates. What regulators do not consider is how these costs affect customers overall.

When a utility asks regulators if it can charge customers more money, it brings a list of investments and expenses. Regulators go down the list, examining each cost to see if it is reasonable and justifiable. They ask questions like: Will this cost provide a benefit to the energy system? Will this investment be able to be used for its expected lifetime?

What **regulators do not ask**: How much will approving this cost increase customer bills? **What other costs is** the **utility asking for that will increase bills**? Can customers afford this large of an overall increase?

Investments.

When a utility makes an investment, it is motivated by profit first and meeting basic standards of providing service second. What is not considered is how an investment will impact the people they are charging.

While adding many new upgrades to the utility's system may help the system, when combined their cost may be beyond the reach of most customers when they are added to the bill. With neither utilities nor regulators considering whether families can afford total energy bills, a lot of pressure falls on advocates like CUB.

Single-Issue Rate-Making Makes Controlling Costs More Difficult

Holistic Utility Regulation: Under traditional regulation, regulators consider utilities' investments, the overall cost of providing service, profits, and more. For a long time, the holistic model was the standard for utility regulation. Over the past couple of decades, utilities have increasingly asked for surcharges outside of this process.

Single Issue Regulation (Surcharges): In the case of single-issue rate-making, regulators typically only look at the utility costs and surcharge requests related to a single issue. One recent example of a single-issue surcharge is the Wildfire Mitigation cases mentioned above. PGE and Pacific Power both asked to add a surcharge to cover costs related to wildfire prevention. Other examples of single-issue requests include surcharges to cover costs associated with the 2021 ice storm and pilot programs for electric vehicle investments.

Right now, electric utilities are the ones most likely to use the surcharge method to raise rates. But gas utilities are also able to use this tactic. Across the country, energy utilities are using single-issue regulation more and more often to get more and more money from customers

Costs are Updated After Regulators Review Them

In some of these mechanisms, PGE will file a proposal but is allowed to update the proposal. In the case of power costs, the final update is after the Commission actually issues its final order in the case. This means the Commission is expected to make a decision without knowing the rate that is established.

Lack of Transparency on Rate Impacts

In order to protect trade secrets, utilities are allowed to designate some information as **confidential**. But utilities abuse this process. When PGE updates its power cost forecasts in power cost cases, it designates the expected price increase as confidential. CUB cannot think of any reason why a forecasted rate increase could ever be considered confidential. But it does make it difficult to inform the public about what their rates will be, and it makes public discussion of future rate hikes more difficult.

Enough is Enough.

PGE's rates have **increased** by **30% in** the **last 13 months**. But no one has reviewed the overall rate level and asked the question: Are rates fair and reasonable?

Using the Tools in Regulators' Toolbelts

Regulators at the Public Utility Commission have tools that they can use to lower the impact to customers.

Directing Utilities to Adjust Expenses

First, the Commission can order a utility to propose and implement other measures to reduce **rate shock**. The regulators could tell the utility to **delay certain expenses**. They could also direct utilities to take other **cost-cutting measures**, reducing the need for a rate increase altogether.

Delaying Increases

Second, when regulators approve a rate increase, they can order the utility to delay some of that increase until sometime in the future. By **delaying increases**, electric customers in particular can avoid a large increase during winter when energy usage is the highest.

In the case of PGE's 2024 increase, regulators asked the utility to delay an additional 2% increase until the spring. In 2023, Pacific Power delayed the rollout of its 21% increase until the spring, lessening the impact of the winter heating season.

By delaying increases, regulators can help protect customers from surprisingly high bills during the winter months. This could be the difference between a household being able to keep the heat on or facing disconnection.

Tying Customer Costs to Allowable Profits

Third, regulators can add incentives to keep costs low by **lowering allowable profit margins** if the cost to customers is not controlled.

CUB is Pushing for Policy Changes

State utility regulators are required to set some costs, such as utility profits, at a reasonable level. However, the **P**ublic **U**tility **C**ommission **can set** the **rate at** the **lowest level** that is **considered reasonable**. For example, the **Commission might determine** that a **reasonable profit margin is anything between 9.0% and 10.0%**. Under normal circumstances, the Commission might set that margin at the midpoint or 9.5%.

But **to mitigate a large rate increase**, the **Commission can set** the **profit margin at** the **lowest point** which is **reasonable or 9.0%.** Lowering profits will lower the rate increase for customers. This is an important tool because it tells utilities that if they cannot control their costs, it will reduce their profit margins.

CUB advocates are hard at work this year to create lasting change to protect customers from more bill increases. In 2024, we are facing multiple requests from utilities to increase rates again. Oregonians from Newport to Ontario could be impacted.

Reduce the Number of Increases

A big policy issue for CUB this year is to **reduce** the **number of rate requests** that **utilities** are **asking for each year**. We have been pushing back against the rising tide of surcharges facing Oregon energy customers.

In the PGE case, CUB continued to fight for a more holistic approach to utility regulation and won on several issues we raised. Now, PGE is consolidating some of their requests and has dropped others. This is good for customers' ability to know what to expect from bills down the line.

Read more: **Are Utility Customers Being Nickled and Dimed? - CUB Blog**

Pushing for New Policy: Avoid Large Bill Spikes in the Winter

Regulators did the right thing in delaying even more increases for PGE customers this winter. Now, CUB is calling on the Public Utility Commission to make spreading high rate increases a standard practice to prevent disastrous winter bills for Oregonians.

While CUB has negotiated delays in winter increases with utilities, this is the first time in recent memory that the Commission has made such a request. Without this delay, customers could have seen a higher bill increase in January, a month that typically brings the highest energy bills of the year.

Stay Up to Date on Oregon Utility Issues

CUB will continue to advocate for people in Oregon on major utility issues. **Sign up for the CUB email list** for the latest updates, action alerts, and news on policies that affect the utilities your home relies on.

Donate to CUB

To keep up with CUB, like us on **Facebook** and follow us on **Twitter!**

It's Been 30 Years Since Food Ate Up This Much of Your Income

by Jesse Newman and Heather Haddon – WSJ – Feb 26, 2024

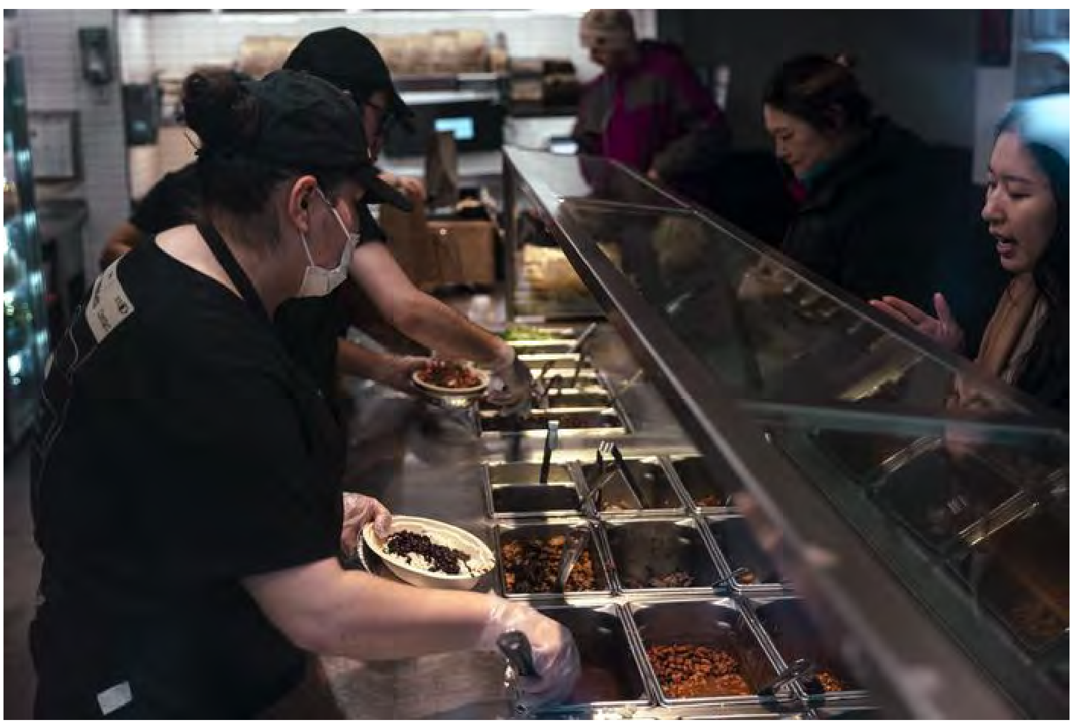
Ongoing high costs lead food manufacturers and restaurants to keep prices elevated.

The last time Americans spent this much of their money on food, George H.W. Bush was in office, "Terminator 2: Judgment Day" was in theaters and C+C Music Factory was rocking the Billboard charts.

Eating continues to cost more, even as overall inflation has eased from the blistering pace consumers endured throughout much of 2022 and 2023. Prices at restaurants and other eateries were up 5.1% last month compared with January 2023, while grocery costs increased 1.2% during the same period, Labor Department data show.

Relief isn't likely to arrive soon. Restaurant and food company executives said they are still grappling with rising labor costs and some ingredients, such as cocoa, that are only getting more expensive. Consumers, they said, will find ways to cope.

"If you look **historically after periods** of **inflation**, there's really **no period** you could point to **where** [**food**] **prices go back down**," said Steve Cahillane, chief executive of snack giant Kellanova , in an interview. "They **tend to be sticky**."



Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers.

In **1991**, **U.S. consumers spent 11.4%** of their **disposable personal income on food**, according to data from the U.S. Agriculture Department. At the time, households were still dealing with steep food-price increases following an inflationary period during the 1970s.

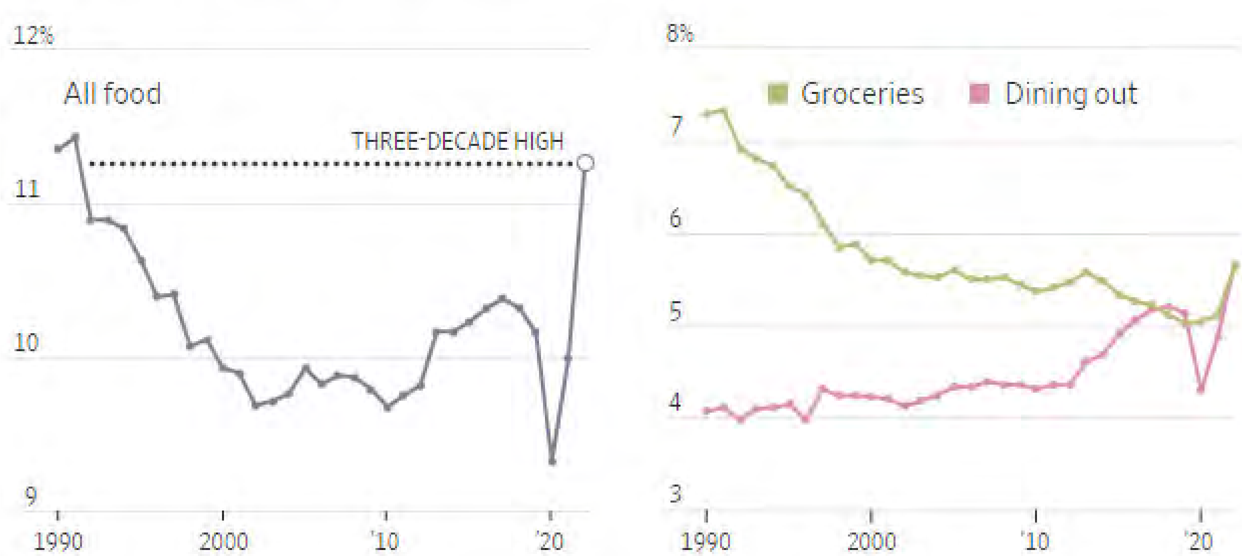
More than three decades later, food spending has reattained that level, USDA data shows. In **2022**, **consumers spent 11.3%** of their **disposable income on food**, according to the most recent USDA data available.

Many diners have said they are going out less frequently or skipping appetizers, while buying cheaper store brands more frequently at supermarkets and seeking out promotions or deals offered via apps. That is starting to chip away at some sales for food makers and restaurant operators.

Food companies said they are feeling pinched themselves. While commodities such as corn, wheat, coffee beans and chicken have gotten cheaper, prices for sugar, beef and french fries are still high or rising. Companies across the U.S. economy have also raised prices beyond covering their own higher expenses, lifting profits for industries including retail, biotech and manufacturing.

Food inflation has raised the ire of President Biden, who took to Instagram during the Super Bowl to blast food makers that he said were providing less bang for consumers' buck – putting fewer chips in each bag or shrinking the size of ice-cream containers.

Food spending's share of disposable income



Source: Agriculture Department

"The American public is tired of being played for suckers," Biden said. "I've had enough of what they call **shrinkflation**. It's a rip-off."

David Chavern, CEO of the Consumer Brands Association, which represents major food manufacturers, said the industry offers many choices at different price points. "We hope to work with the president on real solutions that benefit consumers," he said.

In suburban Chicago, Lisa Wister said her food bills are rising faster than her family's income, leading them to make their own granola from scratch and pack their own snacks for the movies. "Everything is a negotiation, an analysis about our budget," said Wister, an occupational therapist. "It's exhausting."

Denny's, Wendy's and other restaurant chains told investors this month that their guest counts fell last year compared with 2022 levels as consumers, in particular those with lower incomes, feel the financial pinch. Big food makers including Hershey and Kraft Heinz have reported that their sales volumes declined as prices rose for their products, with several reporting a hit to profits in the latest fiscal year – and others an increase.

Oreo maker Mondelez said in January it would continue raising prices on some of its products this year, largely because of cocoa prices, which earlier in February surged past a 46-year record. Hershey said this month it expects more expensive cocoa to cut into the company's profit this year. Kraft Heinz said inflation is moderating but that its costs are still higher, driven in part by pricier tomatoes and sugar.

Companies are set to pay more for staffing, after 22 states in January lifted the minimum wage for hourly workers. Hiring skilled workers like mechanics to replace employees who retired during the pandemic is particularly expensive, said Henk Hartong, CEO of Brynwood Partners, which owns 17 food and beverage plants that make Pillsbury cake mixes and other products.

Many people say they are buying cheaper store brands more frequently at supermarkets.

Restaurant chains said they are trying to operate more efficiently to help defray wage increases, but they also expect to raise prices.

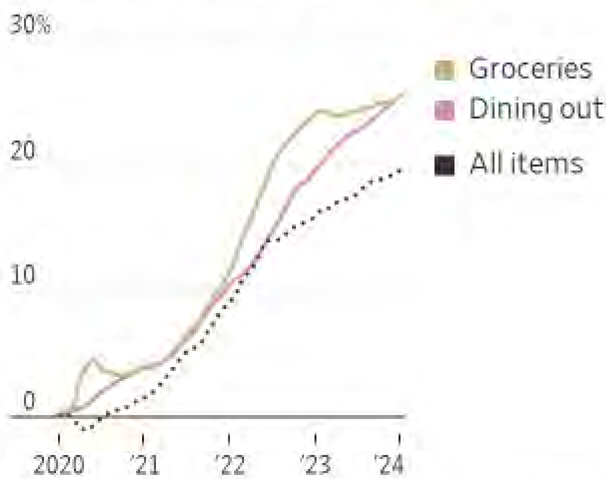
“It’s a really fast move and a high percent increase,” Chipotle Mexican Grill CEO Brian Niccol said in an interview, referring to California’s 25% minimum wage increase for fast-food workers employed by large chains, set to take effect in April. “Pricing is going to be part of the puzzle.”

Some restaurant and food companies, including Kraft Heinz, Mondelez International and Olive Garden owner Darden Restaurants , are projecting higher earnings this year. Signs of a consumer-spending slowdown has led others to temper their outlooks, with same-store sales projection for 2024 and frozen-foods maker Conagra reducing its per-share earnings forecast.

Investors have cooled on food stocks. An S&P 500 subindex of restaurant stocks has risen 10% in the past 12 months through Wednesday’s close, while the broader index gained about 25%. An S&P subindex tracking packaged food and meat companies fell roughly 8% over that period.

When Anna Zabinski and her husband eat out these days, she said, they ask themselves whether a side of macaroni and cheese is worth the extra $1.99, and often go for refills instead of ordering more expensive large-size drinks.

Change in prices since January 2020



Note: Based on seasonally adjusted consumer-price index.
Source: Labor Department

Zabinski, a professor from Normal, Ill., said they'll sometimes split a $20 steak and side dish at Texas Roadhouse or a large sandwich from Jimmy John's. Nonetheless, she said, "our daily and monthly expenditures still seem higher than even two years ago."

Food manufacturers and restaurants have been offering more deals on some items. J.M. Smucker and Conagra have reduced prices on coffee and margarine, passing through lower costs for coffee beans and edible oils. McDonald's and Wendy's said they would offer deals this year aimed at consumers seeking relief from rising prices.

Gary Pilnick, chief executive of WK Kellogg, said the company has been working to market cereals such as Frosted Flakes and Froot Loops to pressured consumers. An ad campaign launched in 2022, for example, encouraged consumers to eat cereal for dinner, pitching it as an easy, inexpensive alternative that, combined with milk and fruit, costs less than $1 per serving. "Give chicken the night off," the campaign's tagline says.

Although it is **rare for food prices to retreat**, it is **also unusual for prices** to **skyrocket as much as** they have in **recent years**, said TD Cowen analyst Robert Moskow. He said he expects grocery prices to decline for a period this year as food makers come under pressure from consumers and retailers.

Kraft Heinz said it is focused on providing affordable options for families, and that while its costs rose 3% in 2023, it raised prices by 1%. WK Kellogg said that before raising prices, the company tries to combat higher costs through greater productivity.

Kellanova said it is working to keep prices as low as possible. Cahillane declined to comment on pricing for his company's products this year but said that the maker of Pringles and Pop-Tarts hasn't raised prices to pad its profit.

Cahillane said that as consumers become accustomed to seeing higher prices on supermarket shelves, they will adjust.

"Just like a gallon of gas, it becomes the new price and people get begrudgingly used to it," he said.

No Surprise from the Fed

by Dante DeAntonio, Director – Moody's Analytics – Mar. 21, 2024

An **upbeat**, if still **cautious**, tone characterized the March meeting of the **Fed**eral Open Market Committee. The **fed funds rate target**, as anticipated, was kept **unchanged**, despite higher-than-expected consumer price inflation reports in recent months. However, reflecting recent communications, the **Fed**eral Reserve **dampened expectations** about the FOMC's urgency to **rush to rate cuts**.

The **committee's latest Summary of Economic Projections suggests** that **2024 will see 75 basis points' worth of cuts to** the **fed funds rate**, **unchanged from** the most recent Summary of Economic **Projections from December**. This reflects policymakers' continued confidence that policy tightening has worked and inflation will eventually return to target. However, the committee reiterated that it will not be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2%

Notably, though, policymakers are now more upbeat about a soft landing than they were in December. The FOMC's GDP forecast for 2024 was revised upward from 1.4% to 2.1%. Subsequently, the Fed predicts 2% growth for 2025 and 2026, up slightly from December without comparable changes to inflation and unemployment projections.

Inflation has receded meaningfully in the U.S. without the corresponding increase in joblessness historically observed when restrictive policy is needed to bring down inflation. However, early inflation readings in January and February came in higher than expected, owing to a large degree to sticky shelter inflation. As Fed Chair Jerome Powell reiterated, the Fed will need to see a few more reports to convince itself that inflation is on a sustainable trend back to target. This renders a May cut unlikely, given a limited number of outstanding inflation reports before then.

The labor market is still threatening to stall progress on inflation. Wage growth is a sizable margin above the level the Fed estimates as compatible with its inflation target. January and February payroll hiring accelerated from late 2023, and at 3.9%, the unemployment rate signals the U.S. labor market is unlikely to have come fully into balance

Our latest baseline forecast puts the first interest rate cut in June. In total, we expect a 75-basis point reduction by the end of 2024. We expect policy is loosened gradually and that the Fed's main policy rate remains restrictive through mid-2026.

CHIPS Act Awards Ramp Up

Federal subsidies to boost semiconductor production in the U.S. are accelerating. In December, U.S. Commerce Secretary Gina Raimondo said she expects to make around a dozen semiconductor chips funding awards within the next year under the CHIPS Act of 2022, some of them multibillion-dollar announcements. This prediction is coming true.

On Tuesday, the White House announced the biggest award yet, approximately $8.5 billion in direct subsidies to Intel along with up to $11 billion in loans. The company had previously announced that it expects to spend upward of $100 billion on U.S. facilities and research programs in Arizona, Ohio, New Mexico and Oregon. Two new facilities just outside Columbus OH will be part of a complex that could ultimately be among the largest chipmaking centers in the world.

Initial CHIPS Act payouts were slow in coming and relatively small. Now the pace is accelerating. On February 19, the Commerce Department announced a large award of $1.5 billion to GlobalFoundries to subsidize three projects. The bulk of the award is for construction of a new plant on the company's Malta NY site, which will make chips for applications in automotive, aerospace, defense and artificial intelligence.

A smaller part of the award is for expansion of the company’s existing Malta facility by adding new technologies already in use in GlobalFoundries’ Singapore and Germany facilities, which supply the auto industry. The third project is to upgrade and expand capacity in the company’s facility in Essex Junction VT, creating the first U.S. facility for high-volume production of gallium nitride semiconductors used in electric vehicles, power grids, data centers, and 5G and 6G smartphones.

The GlobalFoundries award is significant because the company is the only U.S.-based “pure-play” foundry. In other words, it makes chips based on users’ specifications, making it a competitor to Taiwan-based TSMC, albeit much smaller. Although GlobalFoundries is U.S.-based, it also has facilities in Europe and opened one in Singapore in September

The incentives to the company improve the prospects for domestic chip security in two ways: First, the better cost1effectiveness encourages the company to locate its next plant domestically. Second, as a competitor to TSMC, the company can potentially compete to supply some of TSMC’s biggest U.S. customers, notably Apple and Nvidia.

Oregon Loses Jobs for the First Time Since 2021

Mike Rogoway – Oregonian –

Oregon's spectacular rebound from the pandemic recession may be coming to an end.

In January, the state posted a **net loss in jobs compared** to a **year earlier** – the first time that has happened since 2021. And the **unemployment rate climbed above 4%** for the first time in more than a year.

This isn't a recession. Far from it.

Wages continue climbing and Oregon's labor market remains tight, by historical standards. Employers say it's still very hard to find workers.

Still, it's clear that the robust growth that got underway three years ago, in the wake of COVID-19, is at last winding down.

The **state had 1.97 million jobs in January**, according to the latest seasonally adjusted data from the Oregon Employment Department. That's about **5,000 fewer** jobs **than** it had a **year earlier**.

It's a **tiny decline overall, 0.2% on** an **annual basis**. **But** it's a **sharp contrast** to the **prior three years**, when Oregon was adding several thousand jobs each month as the state roared back from the pandemic.

The slowdown isn't a big surprise. **Oregon's workforce had regained** all the **jobs** it **lost to** the **pandemic by** the **start of last year** and, with the **state's population stagnant**, Oregon simply doesn't have more people to fill job openings.

Oregon's slight decline in employment compares to 1.9% job growth nationally over the last 12 months. Employment department economist Gail Krumenauer notes in a new report that Oregon's slowdowns came mostly in the latter part of the year.

Manufacturing was among Oregon's weakest sectors last year, according to Krumenauer, declining by 3.4%. The state's factories began shedding jobs in 2022 and continued their downward trajectory through most of last year.

Blame the semiconductor industry for much of that decline. Chipmakers pulled back last year from three years of outstanding growth. Economists are expecting better results over the next few years as factory upgrades get underway at Intel and other large Oregon chip factories.

In 2023, Oregon also shed jobs in retail – a sector that never fully recovered from the pandemic – and posted declines in categories that include building maintenance and call centers.

Oregon's biggest gains, Krumenauer found, were in health care, local government and hospitality jobs. Construction, which had appeared to be a standout sector last year, actually grew little over the past 18 months, according to newly revised state data.

State economists expect Oregon will resume adding jobs this year, growing by almost 16,000 positions over the next year. Krumenauer notes that works out to about 1% annual growth, anemic by recent standards but suggestive of a state economy that is solid, though no longer spectacular.

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Export Fight Risks Natural-Gas Swings

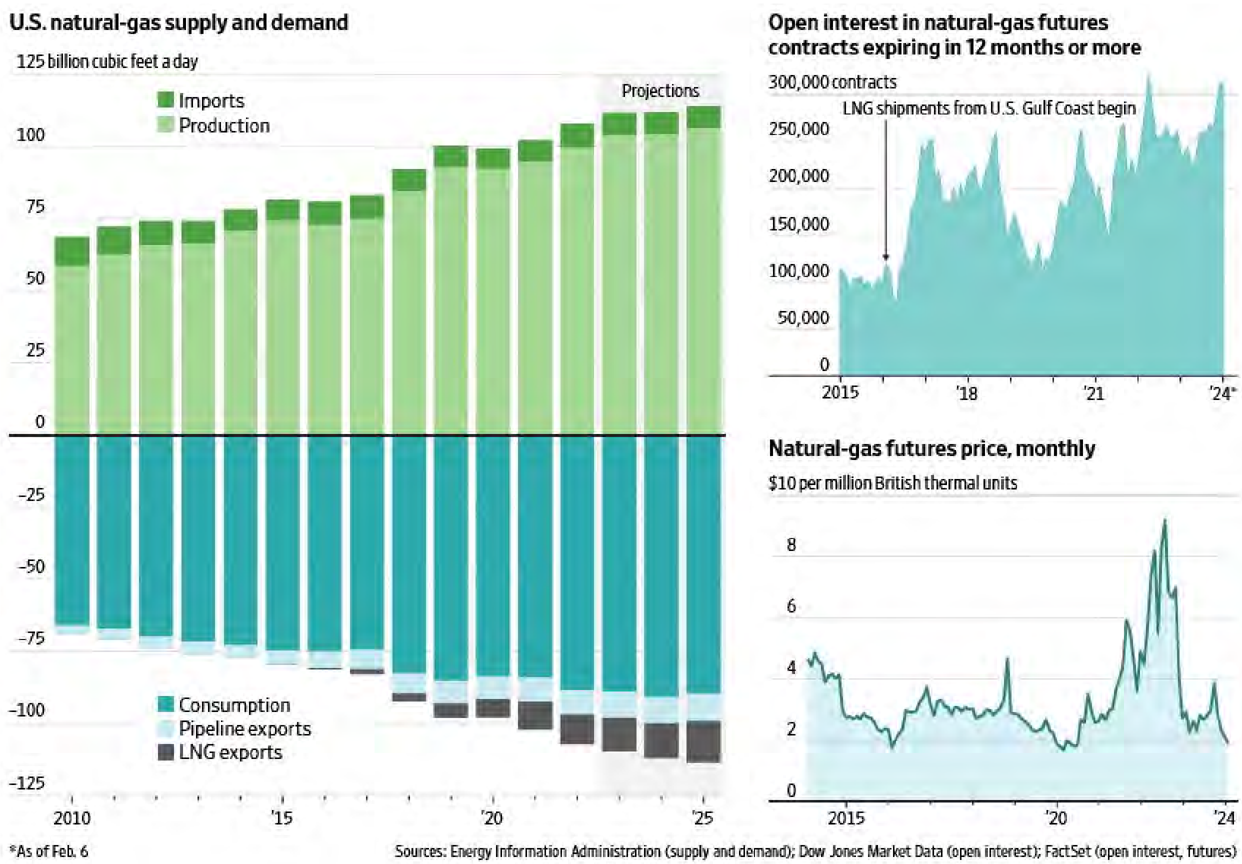
by David Uberti and Ryan Dezember – WSJ – Feb. 2, 2024

Americans' utility bills are getting wrapped up in the fight over President Biden's **pause** on most **new natural-gas exports**.

The White House last month effectively froze new approvals for liquefied natural gas shipments, a booming industry that helped turn the U.S. into an energy-export powerhouse. While environmentalists are urging officials to scrutinize projects' impact on the climate, producers warn the pause could hurt the country's ability to supply allies with fuel in the future.

Now, Americans' power and heating costs are becoming a growing part of the tug of war.

As the Energy Department weighs new criteria for greenlighting future exports, **some manufacturing groups and consumer advocates warn that America's ties to global markets could make price instability more** likely. The **fear** is that additional projects in the next decade **could push up Americans' heat and power bills**, **as well as costs to make everything from drywall to steel**.



At a Senate hearing Thursday, Deputy Energy Secretary David Turk said the administration aims to preserve the country's cheap gas. "That is a huge economic advantage," he said. "Do we want to give that up as a country? Again, we need to analyze that."

The **domestic impact of LNG exports** has been hotly contested since the country began funneling more gas-laden tankers to foreign buyers in 2016. While record production has largely kept U.S. costs low, international shocks in recent years have helped whipsaw prices to shale-era highs and have contributed to some of the most volatile periods in decades.

Thanks to warm weather and roaring production in Texas and Appalachia, benchmark U.S. gas prices this week fell to their lowest levels since the depths of the pandemic, closing Friday at $1.847 per million British thermal units.

But traders are betting on a rally sparked by projects currently under construction, which will allow more gas to flow to businesses across Europe and fast-growing economies in Asia. On Friday, some futures contracts for delivery in 2027 and 2028 traded for more than $4.50.

"Consumers can afford [$4 gas]," said Aubrey Hilliard, president of Texican Natural Gas's Carolinas division. "What they don't want is spikes to $9."

To limit that risk, Hilliard's company is advising customers such as glassmakers and cement producers to lock in supplies further toward 2030. The number of outstanding contracts for deliveries 12 months or more into the future has climbed as additional export terminals in Texas and Louisiana prepare to come online, according to Dow Jones Market Data.

The U.S. is already the world's largest exporter of natural gas. Traders last year sent roughly 11% of the country's production overseas, according to the Energy Information Administration. Analysts project that share could roughly double by the end of the decade and climb higher in the 2030s depending on how many proposals pan out.

Biden's pause on new exports to countries without free-trade agreements keys in on that future wave of projects. Still, industry groups warn the freeze is chilling investment and creating uncertainty for allies that turned stateside for gas after Russia's war on Ukraine set off an economic conflict between the Kremlin and the West.

In defending the climate effects of LNG, companies are highlighting the potential of gas to supplant coal worldwide.

Toby Rice, chief executive of EQT, a top producer, told lawmakers Tuesday that tapping deeper into the global market will push firms to pump more natural gas that can be redirected around the U.S. as needed. Surplus gas is the best defense against foreign shocks, Rice said, adding, "Exports are the only reason for us to create that surplus."

Australia served up a cautionary tale for exporters **during** a **2017 heat wave**, when **foreign shipments totaling** more than **60% of production failed** to **leave enough gas at home** to **prevent prices from surging**. Aluminum smelters cut output. Fishermen watched catches rot during blackouts.

Fears of a similar crunch in the **U.S.** didn't bear out until a string of weather events in 2021 sent prices skyrocketing.

A **deep freeze** in **Texas** in **February 2021** boosted demand and clogged wells with ice. After Americans and Europeans cranked up their air conditioners during a **sweltering summer**, **Hurricane Ida forced** nearly all of the **Gulf** of Mexico's **gas output offline**.

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Water Utility National Equity Return Average Trends Up Slightly in 2023

by Heike Doerr – Regulatory Research Associates (RRA)
an affiliate of Standard and Poor's Global Market Intelligence – Feb 20, 2024

Nationwide, the latest activity with respect to water utility equity returns occurred in July 2023, when cost-of-capital changes were approved for the four largest California investor-owned water utilities under the state's semi-automatic adjustment process. No water utility base rate cases were completed in July or August.

- The return on equity (**ROE**) **approved** for **water utilities nationwide** in **cases decided** during **2023** was **9.64%**. The base rate proceedings spanned nine states, with cost-of-capital parameters provided in seven proceedings, **ranging** from **8.7%** in **Connecticut** to **9.8%** in **North Carolina**. In **2022**, 10 water utility rate cases were completed nationwide, with an average ROE of **9.61%**.
- The **four cost-of-capital proceedings** completed in **California** incorporated the companies' **water cost-of-capital mechanism** (**WCCM**), which resulted in ROEs ranging from 9.31% to 9.8%. A subsequent increase tied to the WCCM, approved in November 2023 and effective Jan. 1, 2024, **increased ROEs by** an additional **70 basis points**.
- **Authorized ROEs for water utilities** are **in line with** the **gas utility average** and **remain above** that of **distribution-only electric utilities**.

Regulatory Research Associates evaluates water utility regulation in more than 20 state jurisdictions and monitors rate proceedings involving rate change requests of at least $1.0 million for the 12 largest investor-owned and privately held water utilities.

For additional details regarding water utility rate cases from Jan. 1, 2010, through Dec. 31, 2023, please refer to this industry document.

2023 rate case highlights

Connecticut – A litigated decision for Eversource Energy subsidiary Aquarion Water Co. of Connecticut Inc. included an 8.7% return on equity, the lowest nonpunitive return authorized for a water utility since 2010, as tracked by RRA. While ROEs authorized in Connecticut have historically been below the prevailing industry average, this return is considerably below the national average. On Eversource Energy's recent earnings call with investors, the company expressed an interest in selling its water business, which is over 90% in Connecticut.

California – ROE determinations for the state's energy and water utilities occur outside of general rate cases in cost-of-capital proceedings, usually conducted every three years. The class A water utilities are divided into two groups by size for cost-of-capital proceedings. At the June 29, 2023, California Public Utilities Commission meeting, the commission approved a proposed decision that laid out recommendations for the state's four largest investor-owned water utilities' ratemaking returns and capital structures through 2024.

The authorized returns for American Water Works Co. Inc. subsidiary California-American Water Co., California Water Service Group subsidiary California Water Service Co., American States Water Co. subsidiary Golden State Water Co., and SJW Group subsidiary San Jose Water Co. ranged from 9.31% to 9.8%, which included 50 basis points or so of benefit from the continued use of the WCCM.

In November 2023, the PUC approved the companies' advice letters based on the movement of the bond index underlying the WCCM. For additional details, refer to "Equity returns of California's largest energy, water utilities to bump up Jan. 1"

North Carolina – In June 2023, the North Carolina Utilities Commission authorized Essential Utilities Inc. subsidiary Aqua North Carolina, Inc. a 9.8% ROE following a decision in Corix Regulated Utilities (Us) Inc. subsidiary Carolina Water Service Inc. of North Carolina's base rate proceeding that utilized the same ROE. Neither decision was unanimous. The dissenting commissioners expressed concern that the ROE was too high, given "the reduced risk to shareholders" that stemmed from using a multiyear, forward-looking approach rather than a historical test year.

As a result of multiyear, performance-based rate plans being implemented, RRA raised its ranking of the North Carolina regulatory environment to Average/2 from Average/3 rating as it pertains to water utility regulation.

2023 Water utility rate case decisions

Order date	Company	State	Case type	ROR (%)	ROE (%)	Common equity as % of capital	Rate base ($M)	Test year end
12/13/23	Aqua Ohio Inc.	Ohio	Base rate case	6.78	9.50	52.10	303	06/30/23
11/15/23	California American Water Co.	California	Cost of capital	7.69	10.20	57.00	NA	NA
11/15/23	California Water Service Co.	California	Cost of capital	7.46	10.27	52.10	NA	NA
11/15/23	Golden State Water Co.	California	Cost of capital	7.73	10.06	54.55	NA	NA
11/15/23	San Jose Water Co.	California	Cost of capital	7.94	10.01	53.40	NA	NA
06/29/23	California American Water Co.	California	Cost of capital	7.29	9.50	57.04	NA	12/31/22
06/29/23	California Water Co.	California	Cost of capital	7.08	9.57	53.40	NA	12/31/22
06/29/23	Golden State Water Co.	California	Cost of capital	7.36	9.36	57.00	NA	12/31/22
06/29/23	San Jose Water Co.	California	Cost of capital	7.47	9.31	54.55	NA	12/31/22
06/29/23	Golden State Water Co.	California	Base rate case	NA	NA	NA	1,161 (Yr1) 1,260 (Yr2) 1,376 (Yr3)	12/31/22
06/05/23	Aqua North Carolina	North Carolina	Base rate case	6.89	9.80	50.00	353 (Yr1) 380 (Yr2) 401 (Yr3)	12/31/23
04/28/23	Veolia Water Idaho Inc.	Idaho	Base rate case	6.91	9.25	55.57	255	12/31/22
04/26/23	Carolina Water Service Inc. of North Carolina	North Carolina	Base rate case	7.22	9.80	50.00	151	03/31/24
04/24/23	Virginia American Water Co.	Virginia	Base rate case	6.29	9.70	40.73	NA	04/30/23
04/12/23	Water Service Corp. of Kentucky	Kentucky	Base rate case	7.07	9.55	50.09	6	12/31/23
03/15/23	Aquarion Water Co. of Connecticut	Connecticut	Base rate case	6.46	8.70	50.35	992	08/31/22
01/12/23	The York Water Co.	Pennsylvania	Base rate case	NA	NA	NA	NA	02/29/24
	Average rate award			**7.17**	**9.64**	**52.53**		

As of Feb. 15, 2024.
NA = not available; Yr = Year.
ROR = Return on rate base; ROE = Return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

ROE trends compared to electric and gas utilities

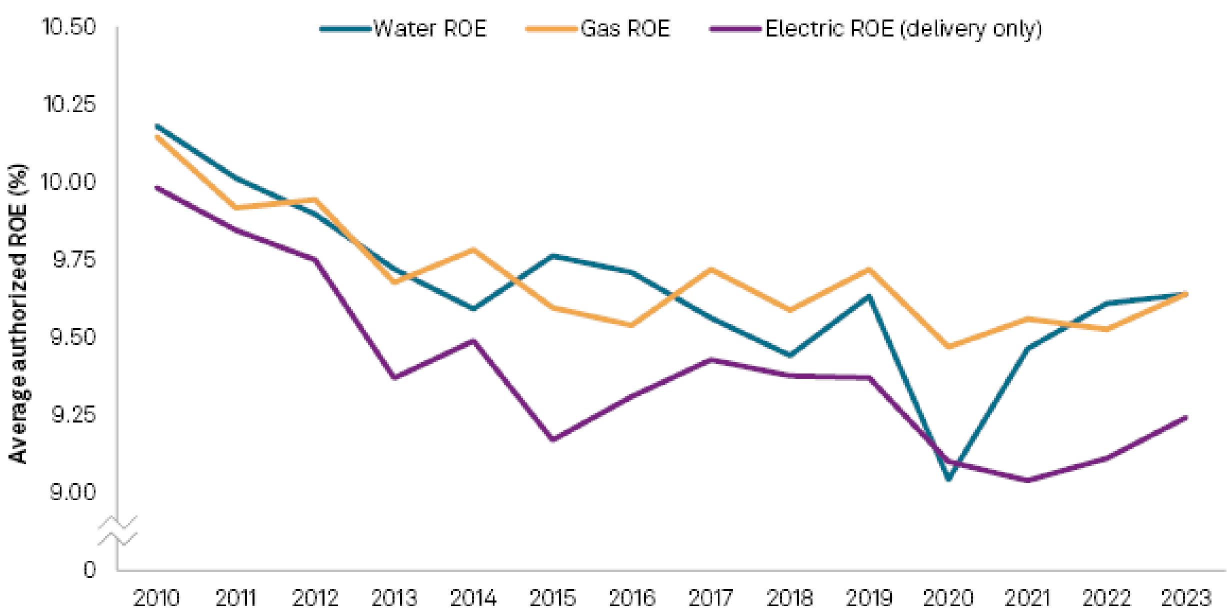
While the pace of rate case activity reached record levels across energy utilities, the number of base rate cases completed across the small water utility sector remained comparable to recent years.

The average ROE authorized for distribution-only electric utilities was 9.24% for cases decided during 2023 versus the 9.11% average observed in 2022. RRA's calculations relied on 12 distribution-only electric rate case decisions that included an ROE determination during 2023 versus nine in 2022.

The **average ROE authorized** for **gas utilities** was **9.64%** for **cases decided** during **2023 versus** the **9.53%** average observed in **2022**. RRA's calculations relied on 43 gas rate case decisions that included an ROE determination during 2023 versus 33 in 2022.

For additional details on electric and gas utility ROE trends, refer to "Energy authorized returns up modestly as rate case activity soared in 2023."

Average electric, gas and water authorized ROEs



As of Feb. 20, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

CenterPoint to Sell Gas Distribution Assets in Louisiana, Mississippi for $1.2B

by Nephele Kirong
Standard and Poor's Global Market Intelligence – Feb. 20, 2024

CenterPoint Energy Inc.has reached a **deal** to **sell** its **natural gas distribution operations** in **Louisiana and Mississippi** for **$1.2 billion to Bernhard Capital Partners Management** LP's **Delta Utilities**.

The assets covered by this transaction include approximately 12,000 miles of main pipeline serving approximately 380,000 customers. The price tag represents approximately 32 multiple of the two local distribution companies' (LDCs) earnings in 2023, CenterPoint said in a Feb. 20 news release announcing the transaction.

The anticipated $1 billion in after-tax proceeds will be recycled into service territory where **CenterPoint has both electric** and **natural gas operations** or where it has a larger presence "at a valuation that is more efficient than issuing common equity," President and CEO Jason Wells said.

"The sale will also enable us to redeploy approximately $1 billion of future capital expenditures intended for Louisiana and Mississippi into jurisdictions with less regulatory lag, thereby enhancing the ongoing earnings power of the company," Wells added. LDCs in the two states represent less than 4% of the company's overall rate base.

In **January 2022**, **CenterPoint closed** the **$2.15 billion sale** of its **Arkansas and Oklahoma gas utilities to Summit Utilities** Inc. **CenterPoint continues** to **hold natural gas utilities** in **Indiana**, **Minnesota**, **Ohio and Texas**. It also **has electric utilities** in **Indiana and Texas**.

For **Bernhard** Capital Partners, this newly announced transaction **builds upon** its previously announced **acquisition of Entergy** Corp.'s **natural gas distribution businesses** in **Louisiana**. "**Once both transactions** are **complete**, **Delta** Utilities will be a **leading natural gas utility** in **Louisiana and Mississippi** and among the top 40 providers in the United States," Jeff Jenkins, founder and partner at Bernhard Capital Partners, said in a separate statement.

The **CenterPoint transaction** is **expected** to **close** toward the end of the **first quarter** of **2025**, **subject to** customary closing conditions, including antitrust clearance and **state regulatory approvals**.

Morgan Stanley & Co. LLC and Wells Fargo Securities LLC were CenterPoint's financial advisers, and Latham and Watkins LLP, Phelps Dunbar LLP and Brunini Grantham Grower & Hewes PLLC were its legal advisers.

Jefferies LLC was lead financial adviser to Bernhard Capital, with Scotiabank also as financial adviser and Kirkland & Ellis LLP as legal adviser. Jefferies LLC and

Scotiabank provided a debt financing commitment to Bernhard Capital in connection with the transaction.

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Southwest Gas Holdings Reorganizes Centuri Ahead of Separation
by Noah Schwartz
Standard and Poor's Global Market Intelligence – Feb. 29, 2024

Southwest Gas Holdings Inc. is **restructuring Centuri** Group Inc. as the utility operator moves ahead with **plans** to **separate** the **utility infrastructure services unit** and operate **as** a **standalone natural gas company**, Southwest Gas executives said on a Feb. 28 earnings call.

The plan to offboard Centuri remains "on track," Southwest Gas CEO and President Karen Haller said. In December 2023, Southwest Gas brought in William Ferhman, the former president and CEO of Berkshire Hathaway Energy, to lead Centuri through the separation process.

Ferhman is prioritizing cost-cutting and reorganization as Centuri works toward independence from the parent company, executives said. The Las Vegas-based gas distributor **did not provide** a **timeline** of when the **Centuri separation** will take place.

"We're focused on reducing costs across all facets of the business, starting with sales, general and administrative expenses," Ferhman said. "I have eliminated two corporate leadership levels, which allows me to get very close to our operating businesses. Each of our business unit presidents now report directly to me."

The restructuring is intended to "streamline our cost structure and implement a disciplined accountability model," Ferhman continued, adding that the company plans to focus its maintenance and growth capital spending on the business lines that are "the most profitable and well run."

The **plan to spin off Centuri** hit a **snag** in **November 2023** when the **US I**nternal **R**evenue **S**ervice **declined** to **rule** on **whether** the **spinoff would qualify for tax-free status**. In an earnings presentation, the company said it will "continue to assess the attractiveness of a tax-free separation of Centuri (either following an IPO or in lieu of an IPO) against other taxable alternatives."

Southwest Gas has submitted a draft registration statement for a potential IPO, according to the investor presentation.

"I have been in this role for about a month so that work is just now beginning and will be more clearly articulated as we go through the IPO process here in a few weeks," Ferhman said on the separation process.

Haller indicated the **strategy for spinning off Centuri remains dependent** on **external factors**. "Following execution of expected IPO, Southwest Gas Holdings may ultimately separate the business through a series of sell-downs, or share exchanges, or depending on market conditions, we could distribute the balance of Centuri shares to Southwest Gas Holdings shareholders through a spin," Haller said during the call.

Investor pressure

Activist investor Carl Icahn, who **became Southwest Gas' top shareholder** in **June 2023**, has **been applying pressure** on the company to cut costs and improve value for shareholders.

In **2021**, **Icahn vigorously opposed Southwest Gas' acquisition** of **Dominion** Energy Inc.**'s Questar Pipeline** Co. The move "will make all past errors pale in comparison," Icahn wrote on the then-rumored deal in a letter to the Southwest Gas board. Icahn then launched an attempted bid to take over Southwest Gas and stop the acquisition.

Despite Icahn's opposition, **Southwest Gas closed** on the nearly **$2 billion deal** in **December 2021**. In **February 2023**, **Southwest Gas completed** the **sale** of **Questar** – which had been **renamed MountainWest Pipeline** LLC – **to Williams** Cos. Inc. **for $1.5 billion**. Icahn supported both the MountainWest divestiture and the spinoff of Centuri.

Southwest Gas reported full-year 2023 adjusted net income of $238.4 million, or $3.36 per share, compared to $196.6 million and $3.00 per share in 2022. For the fourth quarter, the company reported adjusted net income of $81.2 million, or $1.13 per share, compared to $78 million and $1.16 per share in the year-ago quarter.

The company attributed its 2023 growth to a $107 million increase in operating margin from 2022. Executives said the jump in operating margin was fueled by a $53.8 million rate increase in its Arizona service territory that took effect in February 2023.

For 2024, the company issued net income guidance for its gas segment of $228 million to $238 million.

Haller said two pending rate cases will "provide the opportunity to start recovering the significant investments we have made to serve our customers." The company expects a decision on a $70 million rate case in Nevada in the spring and a separate $16 million rate case for its interstate pipeline affiliate, Great Basin Gas Transmission Gas Co., to be completed in the first week of March.

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Utah Governor Names Telecom Vet to State Utility Commission

by Jason Lehmann – Regulatory Research Associates (RRA)
an Affiliate of Standard and Poor's Global Market Intelligence – Mar. 28, 2024

Utah Gov. Spencer Cox has **named Jerry Fenn**, a **Republican**, **to** a position on the three-seat **Public Service Commission** of Utah, to fill the remainder of a term expiring March 1, 2027.

- ➤ Utah Public Service Commission (PSC) members are appointed by the governor and subject to state Senate confirmation, generally for six-year terms. The chairperson may serve an indefinite term in office. No more than two commissioners may serve from the same political party.
- ➤ The **PSC** is **awaiting** a **major electric rate case filing from PacifiCorp** and is also considering a settlement recently filed in **Dominion** Energy Inc.'s **planned sale** of its **Questar Gas** Co.
- ➤ Regulatory Research Associates views the regulatory climate in Utah as somewhat more constructive than average from an investor point of view. The state remains traditionally regulated, and the PSC has been receptive to mergers. There has been little base rate activity in recent years.

Cox submitted Fenn's nomination to the Utah State Senate on March 18 for consideration.

Fenn previously was **president** of **Qwest Communications Utah** and **regional vice president** for **CenturyLink**. Fenn is currently self-employed as an attorney and consultant, and is an **adjunct professor** at **Brigham Young University**. He received a **bachelor's** degree in **economics**, a **master's** degree in **business administration** and his **juris doctorate** from **BYU**.

If confirmed, Fenn would **replace** former PSC Commissioner **Thad Levar**, who appears to have departed the PSC in early January. Levar, a Republican, was appointed to the PSC for a new term in 2021.

The **other members** of the **PSC** are **David Clark**, a **Republican** serving a term extending to March 2025, and **John Harvey**, who joined the PSC in June 2023 for a term expiring in March 2029.

Dominion and Berkshire Hathaway Energy **PacifiCorp** are the **state's major utility** operating **companies**.

The PSC is considering a settlement submitted earlier this month by Dominion, Enbridge Inc. and intervenors in the companies' merger proceeding before the PSC. Under the deal, announced in September 2023, **Dominion** is **selling Questar and other gas utility businesses** in **Ohio** and **North Carolina** and **other assets to Enbridge**.

In the coming weeks, the PSC will also begin adjudicating a planned PacifiCorp electric rate case application (Docket No. 24-035-04). **PacifiCorp proposes** implementing **new electric rates**, subject to commission authorization, on **Jan. 1, 2025.** The company's **last base rate change** took effect in **January 2021** after the commission authorized a $31.4 million electric base rate increase in Docket No. 20-035-04.

PacifiCorp sought a test period determination before filing the general rate case application, proposing a future test period for the 2024 rate case that uses the 12 months ending Dec. 31, 2025, with a 13-month average rate base. The Utah Division of Public Utilities did not oppose the proposal, and on March 11, 2024, the PSC issued an order approving it.

RRA view of Utah regulation

Regulatory Research Associates views the regulatory environment in Utah as somewhat more constructive than average from an investor point of view. The state remains traditionally regulated, and the PSC has been receptive to mergers. There has been little base rate activity in recent years; many prior proceedings had been resolved through settlement agreements, which had sometimes included multiyear rate adjustments.

The PSC's last rate case decision was issued in December 2022 when it authorized Dominion Energy Inc.'s Questar Gas Co. a $47.8 million gas distribution rate increase in Docket No. 22-057-03, effective Jan. 1, 2023. The authorized rate hike was premised upon a 9.6% return on equity (51% of capital) and a 6.856% return on an average rate base. The authorized return on equity (ROE) at the time was above the 9.42% average ROE accorded to gas utilities through the first nine months of 2022. The **average gas ROE authorized** in **2023** was **9.53%.**

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WY Consumer Advocate Seeks Additional Conditions In Enbridge-Dominion Deal

by Monica Hlinka – Standard and Poor's Global Market Intelligence – Apr. 8, 2024

In **Enbridge** Inc.'s pursuit of **acquiring Dominion** Energy Inc.'s **gas utility businesses in Wyoming**, the **Office** of **Consumer Advocate offered** up **additional commitments** that should be **considered before** the **Wyoming P**ublic **S**ervice **C**ommission **issues** a **decision on** the **transaction**. (Docket No. 30010-218-GA-23)

- The Office of Consumer Advocate (**OCA**) filed **testimony** with the commission April 5 in **Enbridge's proposed acquisition** of **Questar Gas** Co. Overall, the OCA supports the deal on the condition that additional commitments are secured.
- The recommended commitments relate to **enhanced ring-fencing measures**, implementing a **cost allocation manual** and a **new low-income assistance** program. The OCA reiterated that the acquisition hinges on its alignment with the public interest and the assurance of the continued provision of safe, reliable natural gas service at reasonable rates.
- Under the deal, announced in September 2023, **Dominion would sell Questar and gas utility businesses in Ohio and North Carolina and other assets to Enbridge**. The sale is **expected** to **close in 2024**, assuming the requisite state and federal approvals are obtained.

➤ In its review, the PSC will examine the proposed deal to ensure that any reorganization resulting from the proposed transaction does not compromise Questar's capacity or ability to serve the public by delivering safe, dependable and reasonably priced natural gas service to its customers.

A prehearing conference is scheduled for May 9, and a two-day public hearing is set to begin May 23.

Questar Gas serves approximately 1.2 million customers **in Idaho**, **Utah and Wyoming**. The **acquisition also requires** approval from the **P**ublic **S**ervice **C**ommission of **Utah** (Docket No. 23-05-16). **While Questar Gas also operates** in **Idaho**, the **I**daho **P**ublic **U**tilities **C**ommission **does not have authority over** the **sale** of **gas utilities at** the **holding company level**.

Regulatory Research Associates views the Wyoming regulatory climate as relatively balanced from an investor point of view, according the jurisdiction an Average/2 ranking.

State law says the Wyoming PSC "shall not approve any proposed reorganization if the commission finds ... that the reorganization will adversely affect the utility's ability to serve the public." The law defines a reorganization as any transaction that results in a change in the majority ownership interest or control of a public utility or the majority ownership interest or control of any entity that owns a majority interest in or controls a public utility.

The commission requires several provisions to be included in an application, such as the utility's financial condition and the proposed transaction's effect on the utility's ability to provide service and on any other utility. There is no statutory time frame within which the PSC is required to render a decision regarding a proposed merger.

OCA recommendations

In its testimony, the OCA said the commitments offered in the initial application "are commendable ... it is imperative to introduce additional conditions and safeguards to ensure that the proposed merger is in alignment with the public interest."

Further, the OCA supports the approval of the acquisition, contingent upon the inclusion of the additional protections.

The **OCA requests** to **cap operating, maintenance, administrative and general expenses per customer for** the **12 months ended December 2023**, which is set at $180.98, **thereby capping** the **amount Questar could seek to recover** in its **next general rate case**. The OCA said this commitment would provide rate stability and facilitate Questar's integration with Enbridge without putting undue financial burden on Wyoming ratepayers.

The OCA also advocated for **further ring-fencing provisions** to **shield Questar from** the **potential adverse effects** of **Enbridge's lower credit rating**. As of March 29, Questar had a higher credit rating than Enbridge from two of the three rating agencies, and therefore, the OCA said it is "important to safeguard Wyoming ratepayers from any adverse effects that may arise from a possible credit downgrade associated with the proposed merger."

The consumer advocate recommended a commitment that would require Questar, in its **next general rate case**, to **demonstrate** that its **requested cost of debt is not higher than** what **would have been incurred had** the **merger not occurred**. "This would entail [Questar] **utilizing** its **current credit rating as** a **benchmark unless** it **can substantiate any downgrade** resulting **from market forces beyond its control**," the OCA said.

In the **company's most recent Wyoming**-jurisdictional **rate case decision** issued Nov. 7, 2023, the **PSC approved** a settlement authorizing a **r**eturn **o**n **e**quity of **9.65%,** a long-term debt cost of 4.07%, and a **capital structure** of **51.56% equity** and 48.44% long-term debt. This results in an **overall rate of return** of **6.95%**.

The OCA said it is "crucial" for the parties to secure a commitment for a **comprehensive cost allocation manual** for services Enbridge provides to Questar. The consumer advocate noted that in Dominion's purchase of Questar in 2016, the approved settlement called for establishing a cost allocation manual outlining the precise methodology for assigning Dominion corporate services costs to Wyoming ratepayers. However, during Questar's most recent gas rate case, the OCA observed "that some progress has been made in presenting a comprehensive, Wyoming-specific cost allocation manual." The OCA said further work is necessary to "ensure accuracy and completeness in cost allocation to Wyoming and other entities within Enbridge."

In its initial application, **Enbridge committed** to "**transparently reporting all costs** and **investments** in its financial reports, including those directly assigned or allocated from another Enbridge subsidiary." The application also said the company agreed to maintain an **audit trail** to specifically identify allocable costs.

The **OCA noted** that on March **22**, **Enbridge reported** having **439 subsidiaries**. With such an extensive corporate structure, the OCA said it is "imperative" to have a complete and comprehensive cost allocation manual, and securing this commitment would "offer a suitable mechanism for tracking and auditing costs assigned to Wyoming ratepayers."

The OCA also requests a formal commitment by the companies to formalize **affiliate transaction reporting requirements**, which can provide information necessary to ensure Wyoming ratepayers receive the least-cost and least-risk service options.

Regarding Wexpro Co. and related entities, hedging policies and gas prices, the OCA is seeking a commitment from Questar to a meeting to review its forecast sources and pricing of natural gas following the issuance of an integrated resource plan and before the subsequent request for proposal process.

According to the OCA, Enbridge and Questar have outlined plans to invest roughly $4.6 million annually in capital expenditures in Wyoming from 2023 through 2027. These investments will support the maintenance and upkeep of Questar's natural gas delivery system in the state.

Regarding the potential implementation of clean energy projects, such as renewable natural gas, hydrogen and compressed natural gas, the OCA seeks a commitment from the companies that these initiatives must be proven to be the least costly and least risky option.

The OCA recommends that the commission direct Questar to engage in discussions with the OCA and commission staff to explore the potential establishment of a **low-income assistance program** for vulnerable ratepayers in **Wyoming**. Additionally, the OCA requests that shareholders commit $50,000 to initiate the program and consider allocating a portion of future charitable donations to Wyoming toward sustaining the program.

Overview of Questar's portion of transaction

On Sept. 5, 2023, **Dominion** announced its **plan** to **sell** its gas **utilities** – The **East Ohio Gas** Co., **Public Service Co**. of **North Carolina** Inc. (**PSNC**) and **Questar Gas** Co. – **to Enbridge for $9.4 billion** in **cash plus** the **assumption** of **$4.6 billion** of **debt**. **Enbridge** will **also acquire Wexpro** Co., **which develops and produces gas reserves**, **from Dominion**.

Enbridge will **pay** roughly **$3 billion** in **cash** and **assume debt** worth **$1.3 billion to acquire Questar** Gas from **Dominion**. The base purchase price is subject to adjustments for cash, indebtedness, working capital and capital expenditures, and any new regulatory assets and liabilities of Questar Gas arising between July 1, 2023, and the transaction's closing.

Following the announcement, **Questar** submitted an application to the Utah and Wyoming utility commissions seeking approval for a proposed corporate reorganization in which the company **would become** a **subsidiary** of **Fall West Holdco** LLC, a new holding company. The **Utah PSC approved** the **application** Nov. 3, **2023**, while the **Wyoming PSC unanimously approved** the proposed **reorganization** during a Nov. 16, **2023**, public meeting.

Additionally, **Dominion notified** the **Idaho PUC** in Case No. QST-G-23-01 of the **pending** acquisition, as required by a 2016 PUC order approving Dominion's acquisition of Questar **Gas**.

Applications were filed with the Utah PSC and Wyoming PSC on Oct. 20, 2023.

Within the proposed Questar Gas acquisition, **Enbridge Quail Holdings**, which was **created explicitly for** the **sale**, will acquire all of the outstanding equity interests in Fall West Holdco, thereby indirectly acquiring all of the equity interests of Questar Gas, the Wexpro companies, Dominion Gas Project Co. LLC and Questar InfoComm Inc.

Enbridge Quail Holdings commits to honoring all Wexpro agreements, stipulations and associated guideline letters.

The applications outlined various financial, managerial and technical commitments offered by the companies to secure approval for the acquisition.

In Utah, on March 21 Dominion, Enbridge and intervenors in the companies' merger proceeding before the Utah PSC reached a settlement outlining a proposed set of enhanced merger commitments that Enbridge intends to implement upon acquiring Dominion's Questar Gas Co. Surrebuttal testimony in the merger proceeding is due April 8, and an evidentiary hearing will be conducted April 11. If necessary, an additional hearing is reserved for April 12.

Additional related transactions

Regarding the sale of PSNC, **Dominion sought N**orth **C**arolina **U**tilities **C**ommission **approval** of a **proposed reorganization** in which **PSNC** would **become** a **direct subsidiary** of a **new holding company**, **Fall North Carolina Holdco** LLC, which would, **in turn**, be a **wholly owned direct subsidiary** of **Dominion**. The **commission approved** the corporate **reorganization** Nov. 20, **2023**.

Enbridge will **purchase** the **utility from Dominion for $2.2 billion** in **cash plus** the **assumption** of **debt worth $1 billion**.

On Oct. 20, 2023, PSNC and Enbridge filed a joint application with the commission seeking approval of the proposed transaction. Intervenor testimony is due by May 13, and rebuttal testimony is due by May 29. A hearing to receive expert witness testimony regarding the application is scheduled for June 11.

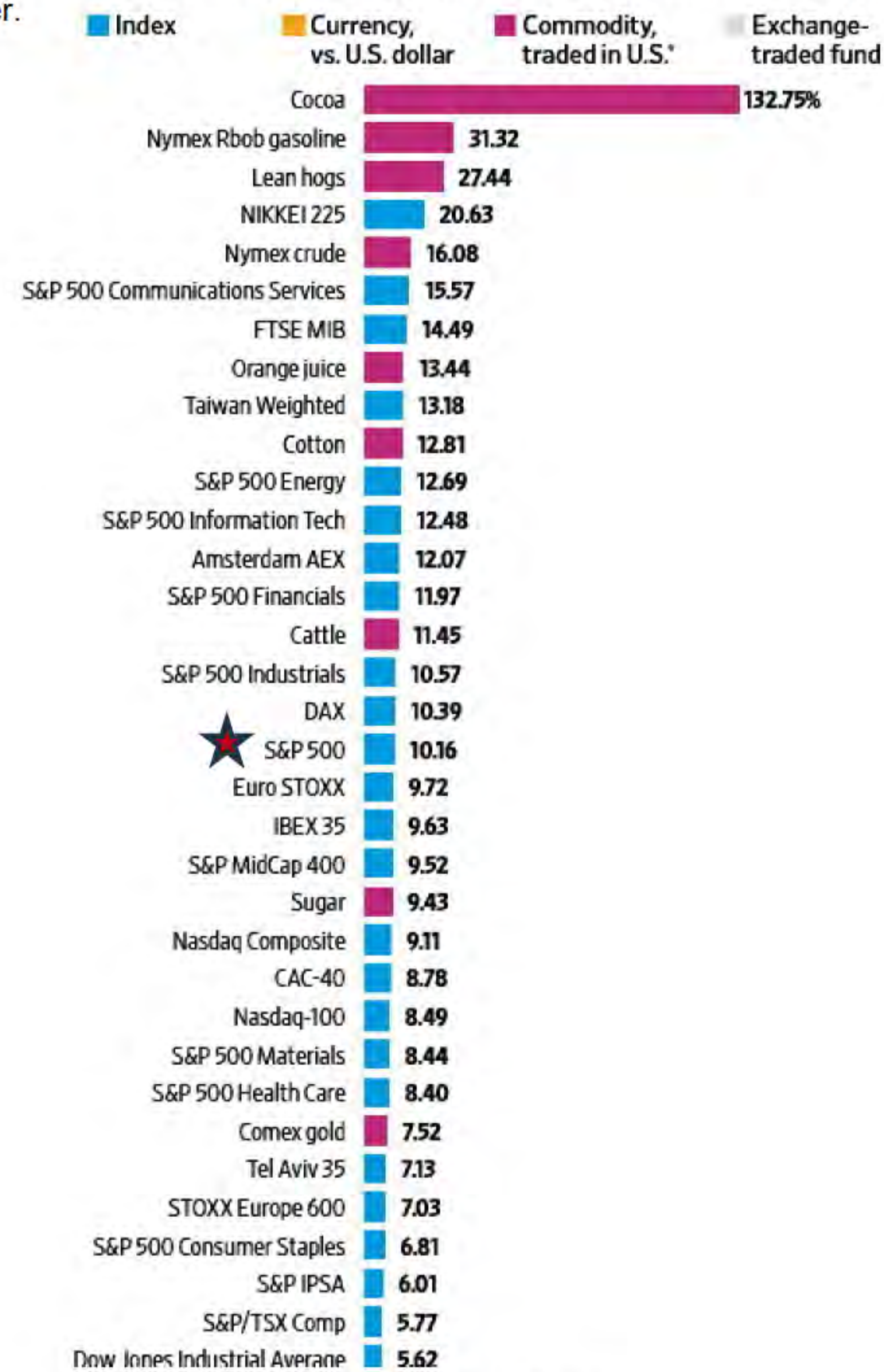
Regarding the **sale** of **East Ohio Gas** Co. **from Dominion**, **Enbridge** will **pay** roughly **$4.3 billion** in **cash** and **assume $2.3 billion** of **debt**. On March 6, the **P**ublic **U**tilities **C**ommission of **Ohio approved** the **transaction** after determining that the deal would not interrupt Dominion Energy Ohio's natural gas service and affirming Enbridge's commitment that it will not recover the transaction costs from customers. The **companies announced** the **completion** of the **sale March 7**.

The **companies** said they **expect** the **deal** to **close** in **2024**, subject to the receipt of several **regulatory approvals**. The expiration or termination of the waiting periods under the **Hart-Scott-Rodino Act** is also required, which occurred Nov. 1, 2023. The companies received final **clearance** from the **Committee** on **Foreign Investment** in the United States on Jan. 11, 2024. The **Federal Communications Commission** must also weigh in regarding the proposed transaction.

Track the Markets: Quarterly Winners and Losers

WSJ – Apr. 1, 2024

A look at how stock indexes, bond ETFs, currencies and commodities performed for the quarter.



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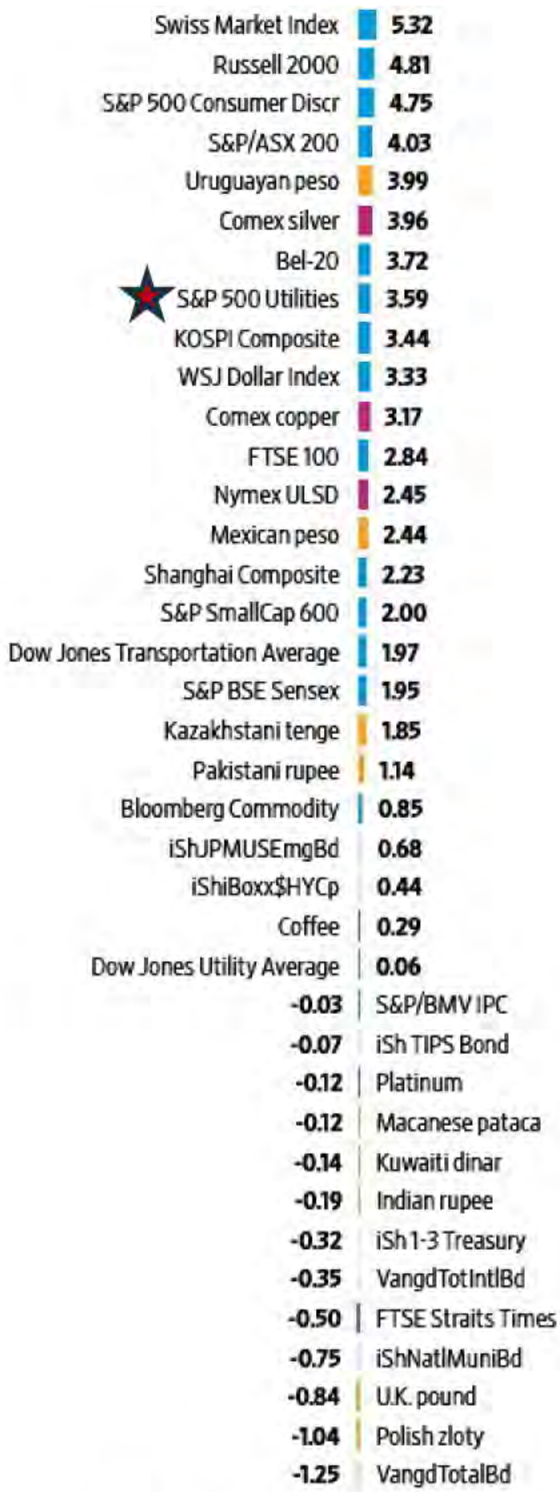

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-0.50	FTSE Straits Times
-0.75	iShNatlMuniBd
-0.84	U.K. pound
-1.04	Polish zloty
-1.25	VangdTotalBd
-1.36	S&P 500 Real Estate
-1.38	Philippine peso
-1.38	DJ Select REIT
-1.50	Chinese yuan
-1.57	iShiBoxx$InvGrdCp
-1.79	iSh 7-10 Treasury
-1.96	Danish krone
-2.13	Romanian new leu
-2.16	Canadian dollar
-2.17	Euro area euro
-2.19	Vietnamese dong
-2.20	Singapore dollar
-2.22	Bulgarian lev
-2.34	Israeli shekel
-2.36	Icelandic krona
-2.74	Malaysian ringgit
-2.80	Ukrainian hryvnia
-2.97	Hang Seng
-3.09	Indonesian rupiah
-3.11	South African rand
-3.24	Brazilian real
-3.85	South Korean won
-3.94	New Taiwan dollar
-4.31	iSh 20+ Treasury
-4.38	Czech koruna
-4.42	Australian dollar
-4.53	Bovespa Index
-4.88	Hungarian forint
-5.25	Swedish krona
-5.33	New Zealand dollar
-5.37	Thai baht
-5.77	Argentine peso
-5.90	Norwegian krone

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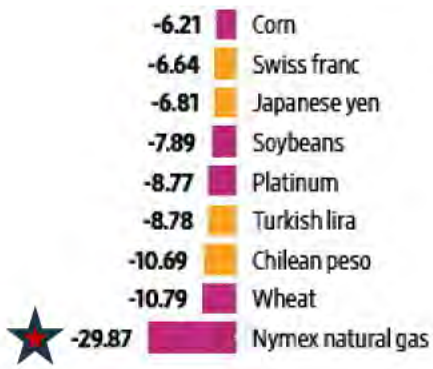

*Continuous front-month contracts
Sources: FactSet (indexes, bond ETFs, commodities), Tullett Prebon (currencies).

CASE: UG 490
WITNESS: Luz Mondragon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

REDACTED
OPENING TESTIMONY
Revenue Requirement Detail, Expense for Customer Service and Customer Accounts, Excess Deferred Income Tax, Interest Synchronization and Budget to Actual analysis.

April 18, 2024

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

A. My name is Luz Mondragon. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Summary of all Test Year adjustments proposed by Staff and the corresponding revenue requirement effect.
- Test Year expenses for Customer Service: Information and Sales Expense (Operations and Maintenance Non-Labor)
- Test Year Excess Deferred Income Tax
- Interest Synchronization analysis.
- Historical Budget to Actuals analysis.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/201 .... Witness Qualifications
Exhibit Staff/202 ……………………......Exhibits in Support of Opening Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

INTRODUCTION

Q. What is the revenue requirement increase proposed by Northwest Natural (NW Natural or NWN) in this docket?

A. Northwest Natural is proposing an overall increase of $154.9 million, or a base increase of 16.62 percent.[1]

Q. What is the adjustment in revenue requirement recommended by Staff?

A. Staff proposes a reduction the Company's requested revenue requirement increase based on a range of ROE. Figure 1 below shows the reduction from the requested $154.913 million to **[BEGIN CONFIDENTIAL]**

- [redacted]
- [redacted] **[END CONFIDENTIAL]**.

Q. What adjustments are you proposing to the Company's revenue requirement?

A. I am proposing adjustments to the Company's Customer Service Test Year expenses and Average Rate Adjustment Method of Excess Deferred Income Taxes (ARAM EDIT).

Q. Are additional adjustments for other issues proposed by other Staff?

A. Yes. The Company's filing is complex, and a thorough review can involve multiple Staff members looking at different issues. Individual Staff are

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1 NW Natural/100, Palfreyman-Kravitz/Page 13.

reviewing additions to different categories of utility plant, test year operating expenses, revenues, and the effects of escalation on individual accounts.

SUMMARY OF REVENUE REQUIREMENT

Q. What factors did Northwest Natural identify in its initial filing as the drivers of the requested rate increase?

A. NW Natural states that it has generated revenue growth, but that growth has been insufficient to offset costs for O&M and investments in rate base.[2] The biggest factor to NW Natural's increase of $375.4 million in rate base is the significant effort to modernize customer meters throughout their system.[3]

Q. When was the Company's last general rate case in Oregon?

A. The Company's last rate case, UG 435, was filed in December of 2021 with approved rates going into effect on November 1, 2022.[4]

Q. According to the Company, how has the Company's Oregon jurisdictional rate base changed since its last filing?

A. The Company's Oregon jurisdictional rate base has increased from $1.7 billion in UG 435 to $2.1 billion in UG 490, an increase of $380.7 million.[5]

Q. According to the Company, how has the Company's Oregon jurisdictional total operating expenses levels changed since its last filing?

A. The Company filed to recover total operating expenses of $675.2 million in UG 435,[6] and it is requesting to recover $886.6 million in the current filing.[7]

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[2] NW Natural/1700, Walker/16.
[3] NW Natural/100, Palfreyman-Kravitz/14.
[4] *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* UG 435, Order No 22-388, Entered 10/24/22, page 2.
[5] UG 490-Exh. 1700-WP1 Revenue Requirements Model.
[6] UG 435-Exh. 1300-WP1 Revenue Requirements Model. The amounts include Gas Purchased.
[7] UG 490-Exh. 1700-WP1 Revenue Requirements Model. The amounts include Gas Purchased.

Q. What is the Company's proposed cost of capital?

A. The Company's filing proposes a rate of return of 7.406 percent with a capital structure of 50 percent equity and 50 percent debt, a 4.712 percent cost of debt, and 10.1 percent return on equity.

Q. Did you review the Company's cost of capital proposal?

A. No. The Company's Cost of Capital (CoC) proposal is reviewed by Staff witness Matt Muldoon in Staff/100 and Rose Pileggi in Staff/1600.

Q. Please provide background on how the Commission reviews a utility's general rate case filing.

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year:

1. The utility's forecasted gross revenues;
2. The utility's operating expenses to provide utility service;
3. The rate base on which a return should be earned; and
4. The rate of return to be applied to the rate base.[8]

Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs each of the different classes of customers impose on the utility's system.

Q. Have the parties agreed to adjust any components of the $154.9 million proposed increase?

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[8] *Pacific Power* and *Light*, UE 116, Order No. 01-787, pp.5-6 (September 7, 2001).

A. Yes, the parties have reached an agreement related to the Company's cost of Long-Term Debt.

Q. Please provide a table summarizing Staff's proposed adjustments.

A. Figure 1 provides a table summary of Staff's proposed adjustments. Table 1 shows Staff's testimony exhibit numbers, the names of the Staff sponsoring the testimony, and a description of the adjustments. The last two columns show adjustments to Test Year revenues, expenses or rate base, and the revenue requirement effect based on Staff's proposed ROE range. Full support and explanations of the proposed adjustments can be found in the respective Staff members' testimony.

Figure 1: Staff Adjustments to Test Year

NWN UG 490
STAFF ISSUES SUMMARY
Test Year Ending October 31, 2025
($000)

Total Incremental Revenue Requirement on the Company's Filed General Rate Case							$154,913	$154,913
							Revenue Requirement Effect	
Testimony	Issue No.	Staff	Proposed Staff Adjustments	Revenue	Expense	Rate Base	@ ROE Floor 8.9%	@ ROE Celing 9.3%
100	S-0	Muldoon	Return on Equity	-	0	0	(18,819)	(12,770)
200	S-1	Mondragon	CS & Infor Dealer Relations	-	(8)	0	(11)	(11)
200	S-2	Mondragon	Sales Exp Dealer Relations	-	(62)	0	(88)	(88)
200	S-3	Mondragon	CS & Infor CPI Adj	-	(0)	0	(0)	(0)
200	S-4	Mondragon	Sales Exp CPI Adj	-	(4)	0	(6)	(6)
200	S-5	Mondragon	ARAM EDIT	-	(100)	0	(140)	(140)
500	S-6	Abraham	Gas Storage Expense	-	(194)	0	(275)	(275)
600	S-7	Anderson	North Coast Feeder (Sec B)	-	11	(6,400)	(601)	(619)
700	S-8	Beitzel	[redacted]					
800	S-9	Chipanera	OPUC Fees	-	137	0	194	194
800	S-10	Chipanera	Cash Working Capital	-	3	(513)	(45)	(46)
900	S-11	Dlouhy	Meter Plant	-	59	(9,316)	(814)	(841)
1000	S-12	Dyck	Intangible Plant/Genesys Contingency Fund	-	23	(3,650)	(319)	(329)
1000	S-13	Dyck	Office Supplies & CPI Adj	-	(688)	0	(975)	(975)
1000	S-14	Dyck	Admin Exp CPI Adj	-	104	0	147	147
1000	S-15	Dyck	Shareholder Meeting & CPI Adj	-	(219)	0	(287)	(287)
1000	S-16	Dyck	Rents CPI Adj	-	(30)	0	(43)	(43)
1200	S-17	Lockwood	Uncollectibles	-	(2,063)	0	(2,926)	(2,926)
1300	S-18	Moore	Distribution O&M	-	(4,491)	0	(6,371)	(6,371)
1300	S-19	Moore	Cust Acct O&M	-	(1,539)	0	(2,184)	(2,184)
1300	S-20	Moore	Materials & Supplies	-	26	(4,027)	(352)	(363)
1500	S-21	Peterson	Pension & Medical	-	(209)	0	(542)	(542)
1700	S-22	Rossow	Office Supplies	-	(8)	0	(12)	(12)
1700	S-23	Rossow	Advertising	-	(119)	0	(169)	(169)
1700	S-24	Rossow	Memberships	-	(352)	0	(499)	(499)
1700	S-25	Rossow	Meals/ Entertain	-	(237)	0	(364)	(364)
2000	S-26	Yamada	Sal&Wages O&M	0	(4,693)	0	(6,657)	(6,657)
2000	S-27	Yamada	Sal&Wages Capital	0	20	(3,187)	(279)	(288)
Total Staff-Proposed Adjustments :			[CONFIDENTIAL]	[redacted]				
Staff-Calculated Revenue Requirements (Base Rates):						[CONFIDENTIAL]	[redacted]	

ISSUE 1. CUSTOMER SERVICE & INFORMATION; SALES EXPENSE O&M (NON-LABOR)

Q. Please describe the activities and expenses associated with Customer Service and Information; Sales Expenses that you reviewed?

A. I reviewed Customer Service and Information; Sales Expense (Customer Service) recorded in FERC Accounts 907–916, excluding 909 Informational and Instructional Advertising Expenses and 913 Advertising Expense, which is analyzed separately. These expenses are for Supervision, Demonstrating and Selling, and Miscellaneous Sales expenses incurred in customer service and informational activities, promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers.[9]

Q. Does the Commission Staff have a standard for how these expenses are treated for ratemaking purposes?

A. Oregon Administrative Rule 860-026-0020—Standards Governing Promotional Activities and Concessions—mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers.

Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries, and safety concerns, resolving

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[9] PART 201—Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. https://www.ecfr.gov/current/title-18/chapter-I/subchapter-F/part-201.

customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. What is the Company proposing regarding Customer Service Information and Sales Expenses?

A. The Company is proposing to increase Oregon allocated expenses by $26 thousand or 5.6 percent to $470 thousand.

Figure 2: Base Year to Test Year

		Test Year 10/31/2025		Base Year 12/31//23	
Account		Company Wide	Oregon Allocated	Company Wide	Oregon Allocated
907	CS and Information Supervision	-	-	-	-
908	Customer assistance Expense	45,169	39,922	43,437	38,392
910	Misc. Customer Service	5,024	4,407	4,753	4,169
911	Sales Supervision	6,493	5,706	6,118	5,377
912	Demonstrating and selling exp	477,137	420,171	449,737	396,043
916	Misc. Sales exp	-	-	-	-
TOTAL O&M Expense (Less Advertising)		533,822	470,207	504,046	443,981

Q. Please describe the Company's Customer Service Information and Sales Expenses in the Base Year and Test Year.

A. NW Natural's Base Year is January through December of 2023 using actual expenses through September 2023 and forecasting the remaining three months of 2023 to develop the total Base Year.[10] NWN adjusted Base Year

[10] NW Natural/1400, Davilla/2.

expense using the most current West Region Urban CPI of 5.6 percent to arrive at the Test Year amounts.

The Company reported a Base Year Oregon allocated non-labor total of $444 thousand for Customer Service expenses. Demonstrating and Selling expenses (FERC 912) make up 89 percent of the Customer Service Base Year. This includes the materials and expenses incurred in promotional, demonstrating and selling activities in the effort to promote and retain present customers and prospective customers. Of this amount, 76 percent of the expenditures in this account are professional services, materials, prices, meals, and sponsorships to support NWN's Corporate identity.

Q. How did Staff perform its analysis of Customer Expenses?

A. Staff reviewed Base Year expenses for appropriate use of FERC account, reviewed transaction-level data to ensure expenses relate to activities such as providing general direction of customer service activities, encouraging safe, efficient, and economical use of the utility's services, as well as costs associated with activities related to the promotion and retention of the use by present and prospective customers. Professional Services, Corporate Identity and Dealer Relations make up the majority of Base Year expenses.

Q. What is Staff's analysis of the programs included in Customer Expenses?

A. Most Professional Services were recorded in FERC Account 908 – Customer Assistance Expense. In this account, 90 percent of Professional services are related to the Weatherization program, while six percent are related to FERC

Account 912 – Demonstrating and Selling Expenses. It is worth noting that services related to the Low-Income Weatherization program are offset by the Company's Oregon Low Income Energy Efficiency (OLIEE) Program. The OLIEE Program is funded through the Public Purposes Funding Surcharge (Schedule 320) and is used to help customers who qualify as low-income, defined as less than 200 percent of the federal poverty line.[11] The Demonstrating and Selling costs were made up of help desks and booths as well as Safety and Innovation outreach and engagement events.[12]

Figure 3: Professional Services

Cost element name	PROFESSIONAL SERVICE		
Row Labels	**Base Year**	**Description of Base Year events**	**Test Year**
908	**2,500,175**		**2,658,619**
10069	984,323	Low Income Weatherization	1,049,332
10099	6,812	Energy Solutions Fee for industrial newsletter	7,262
10102	2,471	No description/justification provided	2,634
10161	-		-
10198	8,332	Tote bags/weatherization kit/printing	8,883
10206	1,419,738	Weatherization	1,507,526
10457	45,568	Gas Heat Pump Consultant and GHPWH committee Fees	48,578
10764	32,932	Co Star data/housing industry news/JD Power data and anlytics services/Johnson Econimics market report	34,406
912	**169,291**		**180,408**
10104	6,000	Professional - KPTV	6,396
10108	2,114	No description/justification provided	2,190
10163	49,774	booths and signage for Street of dreams	53,062
10178	111,402	Natuarl Gas Safety Consumer Engagement events	118,760
Grand Total	2,669,466		2,839,027

Corporate Identity is comprised of event sponsorships, networking events and booths at events. Corporate identity was tracked in FERC Account 912 – Demonstrating and Selling Expenses. Base Year expenses total 62 thousand.

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11 Staff Exhibit 202 and NW Natural/200, Tanaka/24-25.
12 Staff Exhibit 202, NW Natural response to DR 334 and 438.

Figure 4: Corporate Identity

Cost element name	CORPORATE IDENTITY		
FERC_Cost Center	**Base Year**	**Description of Base Year events**	**Test Year**
908	**528**		**555**
10099	528	Pacific NW Steel Fab_Networking golf event	555
912	**61,670**		**64,567**
10177	14,814	Homes and Garden Shows	14,870
10178	-		-
10179	98	St. Jude Reception & Camp fire lunch	105
10180	15,308	Parade of Homes sponsorship, North Plains 60th Bday sponsorship	16,099
10181	25,296	Event booth/Salem Faimily Festival sponsorship/Homeless project/City Nit out Sponsorship	26,932
10185	6,154	Street of Dreams sponsorship fee	6,561
Grand Total	62,198		65,122

Dealer relations consist of registration fees for builder events, treats and refreshments for trade allies, VIP dinners and lunches, block parties, and Get Ready events. In response to a DR issued by Earthjustice regarding promotional concessions, NW Natural identified a total of $41 thousand in Test Year expense that it has inadvertently included in the Company filing and which would be removed in NWN's subsequent reply testimony.[13]

13 Staff Exhibit 202, NW Natural response to Coalition DR 72.

Figure 5: Dealer Relations

Cost element name	DEALER RELATIONS		
FERC_Cost Center	**Base Year**	**Description of Base Year events**	**Test Year**
908	**11,618**		**12,381**
10102	3,454	Cookies & Candy for Trade allys & other that will removed in reply testimony& BIA lunch meeting sponsorship	3,682
10103	44	Water and Soft Drinks for Hosted ASHRAE Meeting @	47
10161	7,620	Registration fee for Professional Women's Builder event/Home builder event/Realtor trade event/Canopy at Trade event/ PMA realtor dues/outdoor oven	8,119
10457	500	ESC Gas Heat Pump Magazine	533
912	**131,258**		**139,013**
10104	54,641	Coop advertising -will be removed in reply testimony/food & equpment rental for HVAC dealer breakfast meeting/training ceertification for dealers	57,355
10163	25,907	Oregon Smart Growth refreshments & sponsorship of Oregon Hme builders Association conference	27,609
10165	2,000	Cookies & Candy for Trade allys	2,132
10178	-		-
10179	1,289	coded incorrectly-should have been materials	1,381
10180	4,152	Tour of homes/Parade of Homes VIP dinner & Lunch/St Jude VIP dinner	4,427
10181	39,792	Get Ready Events/Homeless Connect Project/Veterans Stand Down Event	42,404
10185	3,476	SOD Lunches/Block Party	3,706
Grand Total	142,875		151,394

Q. Did Staff perform any other analysis of the Customer Expenses?

A. Yes. Staff reviewed historical data for trends, variances, averages, and growth. Overall, the expenses in this category have declined since 2021. This result may be due to the Company incorporating the feedback received in the prior rate case and making changes to charge to non-recoverable cost centers. The only account to see an increase is Supervision (FERC 911), growing by 393 percent since 2021 and at 50 percent above the three-year average. Although these percentages seem large, the actual dollar amounts are small. Figure 6 below shows the comparisons.

Figure 6: Customer Expenses Analysis

		Test Year to Base Year		Test Year to Average		Test Year to Base Year Staff CPI Escalated		Growth to Test Year	
Account		$$	%	$$	%	$$	%	$$	%
907	CS and Information Supervision	-	0.0%	-	0.0%	-	0.0%	-	0%
908	Customer assistance Expense	1,531	3.8%	(241,219)	-604.2%	393	1.0%	(406,806)	-91%
910	Misc. Customer Service	238	5.4%	(7,073)	-160.5%	65	1.5%	(3,278)	-43%
911	Sales Supervision	329	5.8%	2,860	50.1%	91	1.6%	4,548	393%
912	Demonstrating and selling exp	24,128	5.7%	(326,538)	-77.7%	6,687	1.6%	(430,828)	-51%
916	Misc. Sales exp	-	0.0%	-	0.0%	-	0.0%	-	0%
TOTAL O&M Expense (Less Advertising)		26,225	5.6%	(571,969)	-121.6%	7,236	1.5%	(836,364)	-64%

Q. Does Staff recommend an adjustment?

A. Staff proposes two adjustments:

- As ratepayers receive little benefit from event sponsorships, fees paid to Home Building Associations, home tours, building industry events and other related activities they do not satisfy the criteria for rate recovery under OAR 860-026-0020(1). Staff recommends adjusting the Test Year expenses by ($108,457) system-wide or ($95,858) Oregon allocated to remove Dealer Relation costs.

Figure 7: Recommended Adjustment listing

FERC_Cost Center	Test Year	Description of Base Year events
908	**11,848**	
10102	3,682	Cookies & Candy for Trade allies & other that will removed in reply testimony& BIA lunch meeting sponsorship
10103	47	Water and Soft Drinks for Hosted ASHRAE Meeting @
10161	8,119	Registration fee for Professional Women's Builder event/Home builder event/Realtor trade event/Canopy at Trade event/ PMA realtor dues/outdoor oven
912	**96,609**	
10104	57,355	Coop advertising -will be removed in reply testimony/food & equpment rental for HVAC dealer breakfast meeting/training ceertification for dealers
10163	27,609	Oregon Smart Growth refreshments & sponsorship of Oregon Hme builders Association conference
10165	2,132	Cookies & Candy for Trade allies
10179	1,381	coded incorrectly-should have been materials
10180	4,427	Tour of homes/Parade of Homes VIP dinner & Lunch/St Jude VIP dinner
10185	3,706	SOD Lunches/Block Party/
	108,457	

- Adjust the Oregon allocated Test Year Customer Service & Information; Sales Expense O&M (NL) by ($5,810) to account for Staff-proposed updated CPI escalations. Staff Exhibit 800 Chipanera further explains Staff's CPI escalation.

ISSUE 2. EXCESS DEFERRED INCOME TAX

Q. Briefly describe excess deferred income taxes and the Commission's resolution in NW Natural's recent rate cases.

A. For purposes of this rate case, Excess Deferred Income Taxes (EDIT) are deferred taxes paid by customers in rates prior to 2018 that became refundable as a result of the 2017 Tax Reform Act that reduced the Federal corporate tax rate from 35 percent to 21 percent. EDIT can be either protected or unprotected. Protected EDIT can be returned to rate payers no faster than the rate allowed under IRS normalization rules (also known as the Average Rate Adjustment Method or ARAM). The 2017 Tax Act created three categories of EDIT for NW Natural:

- Protected EDIT
- Unprotected EDIT
- Gas Reserves EDIT

The ratemaking treatment of each type of EDIT has been addressed in prior Commission orders.[14] In this case, Staff has no issues with NWN's ratemaking treatment of Unprotected and Gas Reserved EDIT but does propose an adjustment to Protected EDIT.

[14] *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 344, Order No. 19-105 (March 25, 2019); *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 388, Order No. 20-364 (October 16, 2020); *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 435, Order No. 22-388 (October 24, 2022).

Q. Please summarize how the protected ARAM EDIT is reflected in this case.

A. ARAM EDIT amortization in the amount of $3.1 million is included in rate base.

NW Natural
UG 490 - Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2025
Base Year Twelve Months Ended December 31, 2023 (Actual and Estimate)
($000)

Line No.	Rate Base	Test Year Oregon (a)	Test Year System (b)	Base Year Oregon (c)	Base Year System (d)
1	Utility Plant in Service	4,120,671	4,665,889	3,608,816	4,077,902
2	Accumulated Depreciation	(1,638,721)	(1,834,526)	(1,464,792)	(1,638,760)
3	Net Utility Plant	2,481,950	2,831,363	2,144,025	2,439,142
4	Aid in Advance of Construction	(6,499)	(10,902)	(6,517)	(10,739)
5	Customer Deposits	(755)	(859)	(677)	(770)
6	Gas Inventory (Working and Cushion)	43,889	49,307	63,623	71,479
7	Leasehold Improvemets	18,596	21,046	21,314	24,121
8	Materials & Supplies	21,810	25,496	19,452	22,740
9	Accumulated Deferred Income Taxes - Depreciation	(441,529)	(484,777)	(429,494)	(471,607)
10	Accumulated Deferred Income Taxes - Other	(6,360)	(7,071)	(8,562)	(9,426)
11	EDIT Rate Base Adjustment	3,100	3,563	3,100	3,563
12	Cash Working Capital	22,159	24,738	19,852	22,163
13	Total Rate Base	2,136,361	2,451,905	1,826,116	2,090,666

In NW Natural's last GRC, UG 435, Staff proposed to increase ARAM EDIT amortization by $100 thousand from $3 million.[15]

Q. What is the ARAM "speed limit"?

A. The "speed limit" is a term coined by NW Natural in its 2020 rate case, UG 388, that simply means the maximum rate that ARAM EDIT benefits can be returned to ratepayers without triggering a normalization violation.[16]

Q. What is a normalization violation?

A. Normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of the Investment Tax Credit (ITC) or accelerated

15 UG 435 Staff/300, Fox/17.

16 See In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision, Docket No. UG 388, NW Natural/2500, Borgerson/22.

depreciation of public utility assets with their regulatory treatment. Under normalization, a utility receives the tax benefit of the ITC or accelerated depreciation in the early years of an asset's regulatory useful life and passes that benefit on to ratepayers ratably over the regulatory useful life in the form of reduced rates.[17]

A violation of the normalization rules would, in particular, eliminate NW Natural's ability to use accelerated depreciation for tax purposes which would have significant negative impacts on the Company's cash flow.

Q. Please elaborate on the Company's response to Staff's data request regarding ARAM EDIT.

A. The Company provided its ARAM EDIT estimates through 2028. The Company estimates that under the current depreciation rates, 50 percent of plant EDIT will be amortized by 2038. Additionally, NWN estimates its actual ARAM amortization will average $2.99 million per year between 2024 and 2026.[18] The slightly higher benefit of $3.1 million in rates reduces the cumulative outstanding balance due to ratepayers that the Company estimates will be $817 thousand at the end of 2028. Increasing the benefit in rates to $3.2 million would bring the balance closer to zero.

Q. Will increasing the amortization by $100,000 cause NWN to violate the normalization speed limit?

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[17] IRS Revenue Procedure 2017-47.
[18] Staff Exhibit 202, NW Natural's response to DR 215.

A. No. The Company provided their ARAM EDIT amortization workpapers where annual amortization and the ARAM Speed limit are calculated.[19] The Speed limit is the cumulative allowable ARAM amortization. Adjusting the amortization amount to $3.2 million annually, increases the actual amortization but stays under the cumulative allowable amount by $316 thousand in 2024 and $317, thousand in 2028, therefore not exceeding the Speed limit.

	Amortization Amount (calendar years)					
	2023	2024	2025	2026	2027	2028
ARAM	2,724,620	2,817,269	2,986,064	3,153,668	3,282,502	3,378,901
Amortization in Rates (Pre Gross-up)	3,100,000	3,200,000	3,200,000	3,200,000	3,200,000	3,200,000
Cumulative Allowable Amortization	13,951,714	16,768,983	19,755,047	22,908,714	26,191,217	29,570,117
Cumulative Actual Amortization	13,252,445	16,452,445	19,652,445	22,852,445	26,052,445	29,252,445
(Over)/Under ARAM Speed Limit	699,269	316,538	102,602	56,270	138,772	317,673

Q. What does Staff recommend?

A. Staff recommends increasing the ARAM EDIT amortization in rates from $3.1 million to $3.2 million, thereby decreasing the amount of federal tax expense by $100 thousand per year. This represents a compromise that will return benefits to customers faster while still leaving a reasonable buffer in the cumulative amount returned.

19 Staff Exhibit 202, NW Natural response to DR 215.

ISSUE 3. INTEREST SYNCHRONIZATION

Q. Please explain what Interest Synchronization is.

A. Interest Synchronization computes the interest component of the revenue requirement. It is computed by multiplying the rate base by weighted cost of debt and comparing it against the interest expense used by the Company in the Test Year. The tax effect of the difference is adjusted and ensures that the revenue requirement reflects the change in interest.[20]

Q. What is the Commission's policy and historical treatment of Interest synchronization?

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes to the regulated utility's cost of capital as initially filed in a general rate case. Interest expense must be coordinated or synchronized to determine the related adjustment for the income tax calculation.

Q. What is the Company proposing in rate base and weighted cost of debt in this rate case?

A. NW Natural is proposing $2.136 million in rate base and requesting a weighted cost of long term (LT) debt of 2.36 percent.

Q. Does Staff object to the Company's proposal?

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[20] NARUC Revenue Requirement Model. https://pubs.naruc.org/pub.cfm?id=5389DCB3-2354-D714-5191-39A4E8DF9C2C.

A. No. during settlement discussions on February 12, 2024, Parties agreed on a cost of LT debt of 4.712 percent which resulted in a Weighted Cost of LT Debt of 2.36 percent.[21]

Regarding Rate Base, members of Staff will independently testify and propose adjustments to Rate Base, if any.

Q. Does Staff have any recommendations on this issue?

A. No. Staff has no recommendations given the result of the settlement of LT debt mentioned above.

[21] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, UG 490, First Partial Multi-Party Stipulation (February 26, 2024).

ISSUE 4. BUDGET TO ACTUALS

Q. Please describe NW Natural's budgeting process?

A. The O&M budget is performed annually, typically beginning in October, and is finalized usually by year end. The budget is performed at the cost center and GL account level, however, not every cost center or GL receives a budget. The O&M FERC accounts are not considered in the budget process. Rather than being in 80 different cost centers, Budgets are accounted for, most often, in a single node and the variances are compared only at the node level.

Q. How does the Company monitor variances between budgeted and actual revenues and expenditures?

A. On a monthly basis, the Finance Committee reviews financial results and explanations or variances. On a quarterly basis, Internal Audit is invited to attend the monthly meetings.

The Income Statement and Balance Sheet are presented and explanation of cost drivers and changes from the prior month are discussed. O&M is reviewed at the Cost Center level with explanations required for areas greater than $25 thousand in variance.[22]

NW Natural states that

> *[T]he Company's goal is to manage operating expenditures to* the *annual budgets. On a monthly basis, the business units are asked to provide variances for the month, YTD and for the remainder of the year. When variances are identified, the business units are asked to*

[22] Staff/Exhibit 202, NW Natural's response to DR 203.

identify if the variance is timing related or permanent. These variances for the business units are then rolled up, and if there are significant permanent overages on an aggregated basis, the Finance team engages the Company on an effort aimed at reducing the overage by reprioritizing expenses.[23]

Q. How did Staff perform its analysis of the Budget to Actuals?

A. Staff requested the budgeted and actuals amounts for each of the approximately 950 cost centers for the calendar years of 2021, 2022, and 2023. Staff then used NW listing of internal accounts and cost centers[24] to create connections between Cost Centers and categorized Cost Centers as either Operations or Administrative & General accounts. Staff analyzed and requested explanations from the Company for

- Variances in budgeted amounts versus actuals.
- Change in actuals over the years.
- Change in budgeting over the years.

Q. What were Staff's findings?

A. Staff's analysis found that overall the Company stayed under their annual budget in both 2022 and 2023 in Operations and A&G.

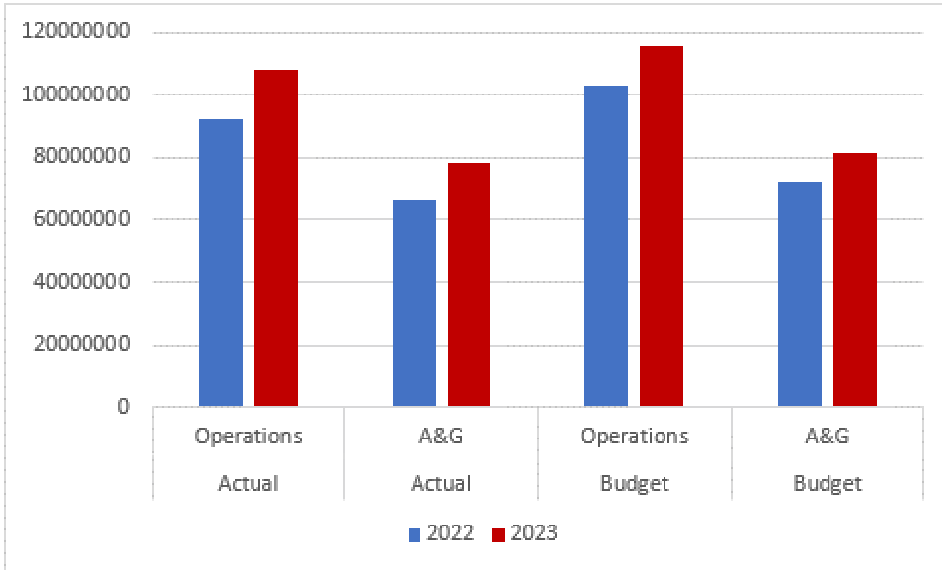
[23] Staff/Exhibit 202, NWN response to DR 204.
[24] Staff/Exhibit 202, NWN response to DR 78.

Figure 8: Budget to Actual Variances

	2023		2022	
Operations	(7,494,832)	-6%	(10,781,599)	-10%
A&G	(3,101,664)	-4%	(5,904,083)	-8%

Although the Company has maintained cost control over expenditures, Staff found that the Company's budget as well as actuals have increased from 2022 to 2023. Staff has issued DRs for more information (due back April 5).

<u>Figure 9: Change over the Years</u>



Q. Does Staff have any concerns with the Company's ability to control costs?

A. Staff does not have concerns regarding the Company's ability to control costs.

Q. Does Staff recommend any adjustments?

A. No.

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Staff proposes to the following adjustments

- Customer Service
  - o Reduce Test Year A&G expense by ($95,858) Oregon allocated, related to Dealer Relation costs.
  - o Adjust the Oregon allocated Test Year by a reduction of $5,810 to $368,859 to account for updated CPI escalations.
- Excess Deferred Income Tax
  - o Increase the ARAM EDIT amortization in rates from $3.1 million to $3.2 million.

My recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Luz Mondragon
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Rates, Safety and Utility Performance Program (RSUP)
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Western Governors University Bachelors of Science in Accounting
EXPERIENCE:	I have been employed with the PUC since March of 2023 as a Senior Finance Analyst tasked primarily with research and analysis of utility company filings, including, affiliated interests and rate case dockets. I have over 15 years of accounting/finance experience, most recently working for Northern Wasco County PUD as a Finance Analyst. My duties included financial reporting, internal and external, as well as budgeting. I also worked very closely with the Engineering team on work orders, inventory, capital budgets and Plant assets.

CASE: UG 490
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 72

Please describe all promotional concessions NW Natural intends to offer during the Test Year.

Response:

NW Natural objects under OAR 860-001-0500 to the request that the Company describe all promotional concessions offered during the Base Year, in that the information requested is not relevant to this proceeding or not reasonably calculated to lead to admissible evidence and is not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates. The Company did not intend to seek cost recovery in this rate case for any promotional concessions.[1]

To that end, and without waiving the Company's objections, there are four expenses included in the filing that the Company inadvertently included in its cost recovery request.

Base Year total for these expenses is $31,992.99. Test Year total is $41,014.70. The Company will update its revenue requirement in its reply testimony.

The four Test Year expenses are explained here:

Date	Paid to	Purpose	Base year / Test Year expense
9/26/2023	NW Natural Appliance Center	Purchase of gas outdoor oven for installation at a home showcase. Demonstration of outdoor gas cooking equipment.	**Base Year:** $1,994.99 **Test Year** $2,185.63

[1] OAR 860-026-0015(1) states, in relevant part, that "promotional concession" means "any consideration offered or granted by an energy … utility or its affiliate to any person with the object, express or implied, of inducing such person to select or use the service or additional service of such utility, or to select or install any appliance or equipment designed to use such utility service." OAR 860-026-0015(2) provides examples of promotional concessions for illustrative purposes, and OAR 860-026-0015(3) lists activities that are not promotional concessions.

5/15/2023	Western Outdoor Wholesale Inc	Purchase of three high-efficiency gas tankless water heaters for installation at a home showcase. The tankless systems included battery backup devices that demonstrated to the public show visitors (with signage) how tankless units could be enabled for operation during a power outage.	**Base Year:** $19,998 **Test Year** $21,908.97
9/7/2023	Willamette Woodstove Inc DBA Home Fire Stove	Advertising coop paid to a hearth dealer. This was previously disclosed in UG 490 OPUC DR 334.	**Base Year:** $5,000 **Test Year** $8,460.05
12/22/2023	Lisac's Fireplace & Stove Inc	Advertising coop paid to a hearth dealer.	**Base Year:** $5,000 **Test Year** $8,460.05

NW Natural

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 78

Please provide a table in the format below (See Table 1) of all internal accounts used by the utility. Organize the list so that the FERC account numbers are listed in numerical order and each internal account assigned to that FERC account is also in numerical order. For each internal account number include the description provided to employees to assist them in allocating the item to the appropriate internal account(s). Please also provide a cross-reference document that lists all internal account numbers in numerical order and indicates to which FERC number they are assigned (See Table 2).

Table 1

FERC Account	Internal Account Number	Description of Internal
908	XXXX1	
908	XXXX2	

Table 2

Internal Account	FERC Account
XXXX01	90X
XXXX02	59X

Response:

Please see Excel file UG 490 SDR 78 Attachment 1. The Excel file lists all cost centers by FERC account used in NW Natural's SAP accounting system.

The Company updated its account coding processes in 2022 eliminating the statistical internal orders. Therefore, the results for SDR 78 and SDR 79 are both for cost centers only.

The spreadsheet contains the following two tabs:

Table 1 – By FERC Account

Table 2 – By Cost Center

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 203

When executing an approved budget, please describe how NW Natural monitors and analyzes variances between budgeted and actual revenues and expenditures.

Response:

Financial results are reviewed monthly and explanations for variances are performed. Results are presented at a monthly Finance Committee which includes members from Accounting, Finance, Tax, Cash Mgmt., and Treasury. On a quarterly basis, also Internal Audit is invited to attend the review meeting.

The Income Statement is presented, and explanations and drivers of the variances are explained. Margin (revenues less cost of gas) and O&M are explained in further detail after the income statement review.

Margin is reviewed in greater detail and this includes not only financial variances but reviews customer counts, volumes and weather variances.

O&M is reviewed in greater detail as well each month and the review is performed at the cost center level with variance explanations required for those areas greater than $25K in variance.

Balance Sheet items are reviewed in the Finance Committee meeting. Changes are reviewed and discussed comparing current month results to the same month in the prior year.

Lastly in the Finance Committee, the Treasury and Cash Management teams walk through the Cash Forecast and explain the drivers of the difference between the cash or borrowing position compared to the budget.

Outside of the Finance Committee, Capital is also reviewed and explanations are gathered from the business unit to explain variances for the month and year to date at the applicant level.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 204

Referencing the data request immediately above, does NW Natural have defined budget variance tolerance levels for specific revenue or expenditure categories?

a. If yes, please include a brief description of how each variance tolerance threshold is developed.
b. If actual expenditures exceed budget variance tolerances without a commensurate increase in revenues, please describe the process for re-aligning expenditures to budgeted levels.

Response:

a. Yes, there are some variance tolerance thresholds that are defined. These are defined by management along with the SOX Compliance Office to determine the appropriate precision to ensure complete and accurate financial statements. NW Natural has defined SOX controls that require investigation into O&M cost center variances of $25k or more and remaining income statement variances of $50k or more.

b. The Company's goal is to manage operating expenditures to the annual budgets. On a monthly basis, the business units are asked to provide variances for the month, YTD and for the remainder of the year. When variances are identified, the business units are asked to identify if the variance is timing related or permanent.

   These variances for the business units are then rolled up, and if there are significant permanent overages on an aggregated basis, the Finance team engages the Company on an effort aimed at reducing the overage by reprioritizing expenses.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 215

Regarding Exhibit 1710 Taxes

a. Please explain why corporate activity tax (CAT) expense is not being treated as deductible expense in the ratemaking state tax calculation.
b. At the current Average rate assumption method (ARAM) amortization rate, how many more years will it take NWN to amortize the $143 million in Plant EDIT that resulted from 2017 Tax Reform Act?
c. Please provide the actual and anticipated ARAM EDIT amortization, by year, from the date of inception through 2028. Provide data in a spreadsheet, including ongoing balances, keeping formulas intact and providing all workpapers with associated calculations.

Response:

a. It is our current position, and was our intention in preparing the revenue requirement, that the Oregon Corporate Activity Tax (CAT) be included as a deductible expense for purposes of calculating state income tax. We have reported the CAT in a similar manner when preparing our Oregon corporate income tax returns. Any deviation from this position is/was inadvertent and will be corrected.

b. As a result of the 2017 Tax Cut and Jobs Act (TCJA), NW Natural and interested parties determined that the Company's excess deferred income tax (EDIT) for plant was $143 million and that $128.4 million of the plant related EDIT was allocable to Oregon. The plant related EDIT balance is being amortized in rates, as a reduction of income tax expense, subject to the limitations imposed under the average rate assumption method (ARAM). The speed of amortization under ARAM is heavily influenced by the depreciation rates used for ratemaking and financial reporting purposes. Any changes in approved rates will result in changes to the ARAM amortization.

   Under currently approved depreciation rates in Oregon, we estimate that 50 percent of the total plant EDIT will be amortized by 2038 and 90 percent will be amortized by 2063. Under the updated cost recovery depreciation study, that is currently before the OPUC, we estimate that 50 percent of the total will be amortized by 2032 and 90 percent will be amortized by 2048.

c. Please see the attachment, "UG 490 OPUC DR 215 NWN Attachment 1.xlsx." Excel columns BP through BZ display the calculated average rate assumption method (ARAM) amortization for the calendar years 2018 through 2028. Excel row 50, of the respective columns, indicates that over the eleven year period approximately 23 percent of the total Oregon allocated excess deferred income tax (EDIT) for plant will have amortized. Recall that, of the total plant related EDIT remeasurement of $143 million, $128.4 million was allocable to Oregon and documented in OPUC Order No. 19-105 (see pdf page number 22 of the Order).

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 334

Using OAR 860-026-0020 as a reference, for each Base Year Cost Element pictured below in accounts 907-916, please provide:

a. Description and total costs of each project or activity contained within the Cost Element.
b. Justification for each project or activity contained within the Cost Element.
c. The net customer benefit for each project or activity contained within the Cost Element.
d. The description and cost of any promotional items distributed to attendees.
e. Using Attachment A, provide
    i. A description of the invoiced services or goods and underlying support and documentation for each line item.
    ii. The business justification for each item and why ratepayers should pay any portion of these costs.

Cost Elements	
Row Labels	**Sum of OR Allocation Amount**
PROFESSIONAL SERVICE	2,189,654
CORPORATE IDENTITY	157,284
DEALER RELATIONS	85,388
OTHER CONTRACT WORK	64,152

Response:

Please see UG 490 OPUC DR 334 Attachment 1.

Responses for items a, b, c, d above are provided in columns N, O, P, Q of UG 490 OPUC DR 334 Attachment 1.

For expenses in cost center 10178 in UG 490 OPUC DR 334 Attachment 1: There are expenses that occurred in the base year but that we are not seeking recovery for in the Test Year. There was no request for recovery of expenses to cost center 10178 in GL account 607500 Corporate Identity, 604600 Dealer Relations and 602100 Other Contract Work. In UG 490 - Exh. 1400 - OM Model Workpaper_High Confidential *or* UG 490 - Exh. 1400 - OM Model Workpaper-Non-Confidential, Dept Non-Payroll Forecast tab, excel line AI532:AI533 & AI541, you will see that the base year expense was adjusted to remove these expenses, and that in BH532:BH533 & BH 541, no Test Year amount is being requested.

Regarding North American Gas Heat Pump Collaborative (NAGHPC) expenses (the next-to-last two rows of UG 490 OPUC DR 334 Attachment 1).

- North American Gas Heat Invoice #307 – Oregon Allocated amount $21,200.24
- North American Gas Heat Invoice #206 – Oregon Allocated amount $19,074.43

Answers to Questions a, b, c, d are shown in the attached spreadsheet. Here is additional supporting information for NAGHPC expense:

NW Natural has recognized the need to reduce demand side gas usage. Adoption of Thermal Heat Pumps (aka Gas Heat Pumps or GHPs) are one means of doing so.

In our efforts to save customers energy and money, NW Natural is a member of the North American Gas Heat Pump Collaborative (the “Collaborative”). Its members are made up of energy efficiency professionals from gas and combination electric/gas utilities as well as the Northwest Energy Efficiency Alliance. The mission of the Collaborative is to accelerate the adoption of space and water heat GHPs for residential and commercial building applications as a means of reducing carbon emissions.

In pursuit of that mission, the Collaborative employs Market Transformation (MT) practices which have been employed by energy efficiency entities and utilities for emerging energy efficiency equipment and devices ranging from LED lighting to electric heat pump water heaters. MT can be defined as *the strategic process of intervening in a market to create lasting change that results in the increased and/or accelerated adoption of energy efficient products, services, and practices*.

MT picks up where technology development ends: with the product. As such, MT practices support emerging products to smooth their entry and adoption by supply chains, installers, and ultimately end-customers. This involves understanding and addressing the hurdles new equipment can face such as the distribution supply chain, establishing installation best practices and understanding among installers, determining how/where the equipment will fit within energy codes, etc.

Rather than bear the expense and efforts on our own, NW Natural has participated in the Collaborative to a) leverage the expertise and knowledge of energy efficiency professionals across utilities, and to b) share in the initial work and costs across members. The Collaborative has engaged Resource Innovations, a well-regarded and known energy efficiency program administrator, to facilitate its work.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 438

For each of the Base Year cost Elements pictured below

a. Provide a listing and description of each project of activity contained within the Cost Element.
b. Provide the total cost of each project or activity listed in part a. The sum of the projects or activities should match the Cost Element amount pictured below.
c. Provide the business justification for each project or activity listed in part a and why ratepayers should pay any portion of these costs.
d. Provide the net benefit to the ratepayer for each project or activity listed in part a.
e. Provide the description and cost of any promotional items distributed to attendees.

Row Labels	Sum of OR Allocation Amount
908	**3,091,531**
DEALER RELATIONS	14,626
OTHER CONTRACT WORK	85,401
PROFESSIONAL SERVICE	2,991,504
Grand Total	**3,091,531**

Cost Center	(Multiple Items)
Row Labels	**Sum of OR Allocation Amount**
912	**443,188**
CORPORATE IDENTITY	181,750
DEALER RELATIONS	80,181
OTHER CONTRACT WORK	31,906
PROFESSIONAL SERVICE	149,351
Grand Total	**443,188**

Response:

a. The detailed listing behind these cost element totals is provided in UG 490 OPUC DR 332 Attachment 1. The detailed listing includes the descriptions of the transaction details.

b. The totals in UG 490 OPUC DR 332 Attachment 1 match the cost element totals included in the request above for FERC 908 exactly. The totals in UG 490 OPUC DR 332 Attachment 1 are slightly higher for FERC 912 than the picture in the request, above; the source of the above-shown picture is unknown and, therefore, the Company is not able to reconcile the immaterial differences quantified below.

Row Labels	**Sum of OR Allocation Amount**	**Sum of OR Allocation Amount**	
912000	**From OPUC DR 332 Attachment 1**	**From DR 438 picture**	**Difference**
CORPORATE IDENTITY	194,830	181,750	13,080
DEALER RELATIONS	83,486	80,181	3,305
OTHER CONTRACT WORK	34,973	31,906	3,067
PROFESSIONAL SERVICE	153,153	149,351	3,802
Total	**466,441**	**443,188**	**23,253**

c. – e. The Company's response to UG 490 OPUC DR 334 and UG 490 OPUC DR 334 Attachment 1 address the January – September transactions of the above pictured totals. Refer to UG 490 OPUC DR 438 Attachment 1 for justification and net customer benefit for the remaining fourth quarter 2023 amounts as reconciled as follows:

		c-e addressed in UG 334	c-e addressed here in UG 438		
	Cost element name	**Sum of OR Allocation Amount**	**Sum of OR Allocation Amount**	**Sum of OR Allocation Amount**	**Amount in DR 438 Picture**
		Jan - Sept 2023	**Oct - Dec 2023**	**TOTAL**	
FERC 908	DEALER RELATIONS	9,942	4,684	14,626	14,626
FERC 908	OTHER CONTRACT WORK	23,643	61,758	85,401	85,401
FERC 908	PROFESSIONAL SERVICE	2,042,436	949,068	2,991,504	2,991,504
			1,015,510		
FERC 912	CORPORATE IDENTIY	158,218	36,612	194,830	181,750
FERC 912	DEALER RELATIONS	75,447	8,039	83,486	80,181
FERC 912	OTHER CONTRACT WORK	40,509	(5,536)	34,973	31,906
FERC 912	PROFESSIONAL SERVICE	147,217	5,936	153,153	149,351
			45,051		
		Total FERC 908 + 912 Jan-Sept	**Totals DR 334**	**Difference**	
	CORPORATE IDENTIY	158,218	157,284	934	
	DEALER RELATIONS	85,388	85,388	0	
	OTHER CONTRACT WORK	64,152	64,152	0	
	PROFESSIONAL SERVICE	2,189,654	2,189,654	(0)	

Note that in the fourth quarter of the base year these exact transactions are not used to forecast the Test Year as the Test Year is based off of the first 9 months of actuals and a forecast only.

CASE: UG 490
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony
Energy Justice

April 18, 2024

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

A. My name is Michelle Scala. I am the Energy Justice Program Manager employed in the Strategy and Integration Division (SID) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of Staff's testimony is to provide and validate energy justice considerations as they intersect with the proposals and potential impacts of NW Natural's general rate case. I further elaborate on specific equity considerations in areas that have been identified as high-impact or high-priority energy justice issues; including, overall bill impacts, rate spread/rate design, and the residential bill discount update and associated cost recovery mechanism.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits:

Exhibit Staff/301. Witness Qualifications Statement

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. ENERGY JUSTICE OVERVIEW

Q. Please briefly describe the primary role of energy justice in utility ratemaking.

A. The primary role of energy justice in utility ratemaking is to advance the equitable distribution of energy system costs and benefits across all customer segments. It aims to address disproportionate impacts of rate structures and energy policies on environmental justice communities.[1] An energy justice informed review applies the concepts of equity, affordability, accessibility, and participation against the utility's general rate case filing and existing operations.

Q. How has the Commission considered energy justice in ratemaking historically?

A. Specific and explicit considerations for energy justice in Oregon regulated utility general rate proceedings have emerged on a more systematic basis in the last four years. This is not to imply that tenets and principles of energy justice such as affordability and distributional equity have not been a part of Commission decision making in the past; only that achieving socially just outcomes in regulatory processes is an ongoing, growing effort that has

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1 Per Oregon Revised Statute (ORS) 756.010(5), "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

recently become a more prominent piece built into Staff's analytical framework for assessing rate proposals and other utility filings.[2]

Q. Please describe to what extent NW Natural's proposal in UG 490 has considered energy justice.

A. In NW Natural's (NWN or Company) opening testimony, the Company dedicates several pages of testimony to communicate its efforts to incorporate energy justice and equity into its operations. In NW Natural/200, Company witness Cecelia Tanaka details the Company's equity actions and proposals relative to the following topics:

- Community Equity and Advisory Group (CEAG)
- Low-Income Needs Assessment (LINA)
- Income-Based Bill Assistance Programs
- Oregon Low-Income Energy Efficiency
- Mitigating Energy Burden in This Case
- NW Natural's Efforts to Address Diversity, Equity and Inclusion.

Additionally, in NW Natural/100, Company witnesses Justin Palfreyman and Zachary Kravitz introduce components of a "responsible growth strategy", including changes to the residential basic charge structure, that are intended to "address intra-class equity concerns between [the Company's] existing and new residential customers."

2 Oregon Public Utility Commission Diversity, Equity, and Inclusion Strategic Plan (https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-PUC-DEI-Plan.pdf).

Q. Has Staff found the Company's existing actions and proposals sufficiently account for energy justice in this filing?

A. Not entirely. To clarify, Staff is very encouraged by the Company's dedicated space for equity testimony and actionable proposals to reflect affordability concerns and distributional equity in this filing. Staff also appreciates the Company's voluntary establishment and use of an equity advisory group in the CEAG. That said, there are some features of the Company's proposal where Staff is still investigating whether additional actions or adjustments are needed to optimize equity outcomes in this proceeding. Staff is particularly concerned with depth of the Company's analysis informing how environmental justice communities may be impacted by its proposals relative to:

- The Residential Bill Discount Program;
- Rate structure changes to the residential basic charge; and
- Overall impacts of the filed case on residential customers.

Staff also has some comments regarding the Company's use of the CEAG and whether there may be opportunities to explore increased visibility, impact, and accountability. Lastly, Staff wishes to elevate certain components of the Company's ongoing low-income energy efficiency program and provide considerations for how this activity may intersect with direct assistance programs such as the Residential Bill Discount, Schedule 33.

Q. Please briefly summarize Staff's energy justice concerns relative to the Company's proposed changes to Schedule 33, the Residential Bill Discount Program.

A. Staff witness Charles Lockwood discusses the Company's Schedule 33 proposal in length in Staff/1200. For the purposes of this testimony, Staff aims to amplify specific parts of Staff's review and position that are of particular import to equitable outcomes in the case. This includes concerns with the Company's methodology used to inform the Program revisions and the impact of the revisions and program growth, generally, on cost recovery through the Company's existing Schedule 335 rate structure.

Q. Please expand on Staff's concerns with the Company's methodology for informing Schedule 33 revisions.

A. Staff is not convinced that the model used by the Company to inform proposed changes in the Residential Bill Discount Program (BPD) adequately considers income distributions and levels of energy burden among participants.[3] In testimony, the Company proposes to revise its approach to setting discount tiers to reduce energy burden below three percent and explains its use of income mid-points in each of the discount tier income ranges as a means to estimate the level of assistance needed to do so.[4] In Staff/1200 Mr. Lockwood describes Staff's concerns that the use of a mid-point within any given income range to rationalize "better coverage

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[3] Staff/1200.

[4] Energy burden in this context is a percentage based on the household's monthly energy bill divided by the household's income.

of reduced energy burden through the tier"[5] must assume a normal income distribution of participants within the tier. However, Staff has not seen evidence that this is in fact the case, nor that the methodology's assumed average residential customer usage value is representative of these groups either. As such, an arguably justified discount level, in reality, not only overlooks critical areas of need for households along the lower end of income ranges and/or higher end of usage patterns but may also limit the program's effectiveness for the majority of participants if the actual income distributions are skewed left and/or usage skewed right.

Q. Does Staff have any other concerns to share regarding this methodology?

A. Yes. Staff would note that the issues identified in the previous section are most pronounced for the highest burdened and lowest income households. To illustrate this point Staff uses the Company's estimates provided in NW Natural/200, Tanaka/24, which indicate that the mid-point methodology reduces estimated energy burden across tiers as depicted in Table 1.

Table 1. NWN Mid-point Methodology Estimated Energy Burden

Tier	Energy Burden – Before Discount	Energy Burden – After Discount	Level of Relief
3	2.00%	1.70%	15%
2	2.80%	2.20%	20%
1	4.70%	2.80%	40%
0	14.00%	2.80%	80%

[5] NW Natural/200, Tanaka/23.

Looking at Tier 0, one can see much higher before discount energy burden that at or between any of the other tiers. Given that this is at the mid-point income, one can infer that energy burden exponentially increases as incomes approach zero. This is significant because it shows not only how extreme energy burden is for households qualifying in Tier 0, but also, that this particular design has rapidly declining benefits for those deeper in need (Table 2).

Table 2. Declining Tier 0 Impacts on Estimated Energy Burden

Tier 0			
% SMI	HH Income	Energy Burden	
		Before Discount	After Discount
0.15	$ 14,061.50	8.0%	1.6%
0.14	$ 13,124.07	8.6%	1.7%
0.13	$ 12,186.63	9.2%	1.8%
0.12	$ 11,249.20	10%	2.0%
0.11	$ 10,311.77	11%	2.2%
0.10	$ 9,374.33	12%	2.4%
0.09	$ 8,436.90	13%	2.7%
0.08	$ 7,499.47	15%	3.0%
0.07	$ 6,562.03	17%	3.4%
0.06	$ 5,624.60	20%	4.0%
0.05	$ 4,687.17	24%	4.8%
0.04	$ 3,749.73	30%	6.0%
0.03	$ 2,812.30	40%	8.0%
0.02	$ 1,874.87	60%	12.0%
0.01	$ 937.43	120%	24.0%

Q. Is Staff recommending that the Company offer deeper discounts for these customers?

A. Not at this time. Staff's discussion here is based on the intersection of two separate elements in the 2022 Key Baseline Evaluation Criteria shared in Docket No. UM 2211, the Energy Affordability Act Implementation Docket. Specifically, regarding the level of relief, Staff recommended utility interim rate programs 1) "prioritize [the] lowest income with the highest energy burden"; and 2) "explain how the interim rate was designed to provide a meaningful reduction of energy burden." [6]

Staff sees and appreciates NW Natural's methodology and proposal as endeavoring to meet the second criterion and looks forward to further exploration of rate designs in the ongoing dialogue on affordability and equity. However, in the interest of Staff's review and transparency in differential rate designs, Staff is compelled to point out the potential gaps in this model, particularly given its conflicts with the first criterion. Put simply, NW Natural's model, while generally benchmarked against a low energy burden target, obscures the level of need amongst the highest energy burdened households by using the mid-point income range absent consideration of actual participant income distributions in the program.

That said, Staff recognizes that this is a step forward from existing designs and would in fact bring more meaningful relief to all current and future participants in Tiers 1 and 0 simply by offering the higher discounts of 40 and 80 percent, respectively. Staff also acknowledges that it can be difficult to truly prioritize the lowest income with the highest energy burden,

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[6] https://edocs.puc.state.or.us/efdocs/HAC/um2211hac17313.pdf

such that these households likely have zero income to weight against energy costs. To this end, Staff's recommendation here is not to discredit the proposal. Instead, Staff has asked the Company to frame this proposal as an incremental step to provide a more significant level of relief rather than a sound design based on the Company's mid-point methodology.[7]

Further, Staff supports the Company's intent to participate in the ongoing UM 2211 process. There, Staff, utilities, and stakeholders can continue to explore sustainable differential rate designs as well as how to leverage State and Federal partnerships in the efforts to reduce energy burden both via direct assistance and targeted demand side management.

Q. Does that mean Staff recommends the Commission adopt NWN's Residential Bill Discount proposal under this alternate framing?

A. Not yet. As explained in Staff/1200, the Company did not perform a cost analysis of the proposed changes on the program or Schedule 335 rates. Absent an understanding of how the Company expects the program to grow, both in terms of costs associated with the higher discount tiers and the participation rate, Staff is unable to assess the impacts of the proposal and cannot recommend approval at this time.

Q. If the Company is able to provide a cost analysis of the proposal on Schedule 335 rates, will Staff then support adoption?

A. No. Not only would Staff need to review the analysis prior to making its recommendation, but Staff also has preexisting concerns regarding the

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7 Staff/1200.

Schedule 335 rate structure that it recommends be addressed in this proceeding.

Q. Please explain.

A. Currently, the Company's cost recovery for the Residential Bill Discount Program is set up as a fixed dollar charge for all general service schedules. This structure effectively caps recovery from each customer type at the level of the fixed dollar charge. Table 3 displays NW Natural's current Schedule 335 rate structure.

<u>Table 3. NW Natural Schedule 335, Bill Discount Program Recovery</u>

Rate Schedule	Charge per Bill
2	$ 0.94
3	$ 3.24
27	$ 0.61
31	$ 25.90
32	$ 62.77

In PGE's 2023 General Rate Case, Docket No. UE 416, Staff argues, in length, about the importance of equitable cost recovery from these programs. While it is true that only income-qualified residential customers can participate and receive the direct benefits of these programs, Staff and other parties have also explained that the legal impetus for these programs omitted any cap on per site or per customer cost recovery and included nonbypassibility language. In this vein, Staff has argued that a more equitable cost recovery structure considers percentage of bill impacts when assessing the reasonableness of the per customer rate. Staff would also note that implementing a more equitable rate structure does not necessarily preclude the existence of a cap if there is a sound argument to include one.

All that said, Staff does want to clarify that the actual average effect of the current structure shows minimal differences between residential and commercial customer percentage of bill impacts for Schedule 335. At this time, only industrial customers appear to have a lower Schedule 335 impact on average. Thus, the cost recovery restructure is not quite as pressing as Staff has observed in other programs. However, given the proposed changes to the discount structure and assumably, forecasted costs, Staff does believe it is necessary to evaluate Schedule 335 in this proceeding. Further, Staff also notes, generally, that it wishes to move towards a more consistent approach with interim bill discount program cost recovery and finds that the Schedule 335 fixed cost recovery model may be a potential deviation from recent recommendations.

Q. Are there any other concerns Staff would like to share relative to the Residential Bill Discount Program proposal at this time?

A. Yes. Staff would like to take this opportunity to reference its summary findings in its accompanying review of the Company's low-income energy efficiency operations and the 2022 Low-Income Needs Assessment (LINA) or Energy Burden Assessment (EBA). In short, Staff has found there to be significant opportunity for the Company to enhance energy efficiency programs among its environmental justice communities. Table 4 is a reproduction of the Company's Oregon Low Income Energy Efficiency

Program Annual Report to the Public Utility Commission of Oregon Program Year: October 2022 - September 2023, CAP Project Completions 2022-2023.

Table 4. CAP Project Completions 2022-2023

CAP Agency	Counties Served	Completions	Projections
Clackamas County CA	Clackamas	1	0
Community Action Organization	Washington	70	70
Community Action Team, Inc.	Columbia and Clatsop	0	8
Community Services Consortium	Benton, Linn and Lincoln	20	40
Homes for Good	Lane	2	20
Mid-Columbia Community Action Council	Hood River and Wasco	0	0
Mid-Willamette Valley CA	Polk and Marion	11	45
Multnomah County Weatherization & Energy Services	Multnomah	66	85
Yamhill Co CA Partnership	Yamhill	5	8
Oregon Coast Comm Action	Coos	0	0
All Agencies		**175**	**276**

As can be seen, there are notable gaps between the Company's OLIEE projections and completions. The Company's 2022 EBA, spoke in length about reducing barriers to energy-efficiency programs and increasing participation rates in the Company's offerings. It noted, this is particularly salient for highly energy burdened households that tend to require more targeted designs and outreach/marketing strategies. To this end, Staff notes that the Energy Affordability Act is a multiprong policy push to tackle energy burden and while the Residential Bill Discount Program represents a significant component of that strategy, it is best delivered with commensurately targeted energy efficiency.

Q. Is the Company doing anything about these issues at this time?

A. Yes. At the March 20, 2024 public meeting, the Commission adopted Staff's recommendation to approve, with modifications, NW Natural's proposals to adjust Schedule 320, Oregon Low-Income Energy Efficiency Programs.[8] This proposal was submitted following engagement with Staff, stakeholders, and CAP agencies in an effort to revise Schedule 320 such that more funds could be allocated to qualifying customers for energy efficiency measure, including expanding eligibility to qualify households earning up to 80 percent SMI and removing project caps for qualified measure to be eligible for up to 100 percent reimbursement of the installed cost.

Staff's modifications included limiting the amount of funding that could be spent on the newly eligible cohort of 61-80 percent SMI in order to "maintain that the majority of low-income weatherization funds be spent on those with the lowest incomes."[9] Staff would also note that in Docket No. ADV 1562, the Commission approved a pause on OLIEE program collections, via Schedule 301, the Public Purpose Funding Surcharge in

[8] Docket No. ADV 1593, Advice No. 24-02 (https://edocs.puc.state.or.us/efdocs/HAU/adv1593hau327269054.pdf).

[9] Id.

acknowledgement of the buildup of the balance in the OLIEE account[10]. According to the Company,

> "The build-up is the result of a deliberate increase in funding, which began in early 2020, intended to increase energy efficiency measures for low-income customer dwellings and to enable the OLIEE program to have broader reach to low-income residents that have not previously benefitted from the OLIEE program. This increased funding was developed with the OLIEE Advisory Committee and approved by the Commission in Advice No. 19-19, docketed as ADV 1056. Subsequently the COVID-19 pandemic severely impacted the delivery of OLIEE program benefits that rely on in person and in-home projects and measures. While OLIEE project spending has since bounced back from pre-pandemic levels, the collection of OLIEE funds at the increased rate has resulted in a build-up of the OLIEE account."[11]

Altogether, Staff finds the Company is actively pursuing ways to improve its low-income energy efficiency programs but encourages robust monitoring of the changes for unintended consequences and continued dialogue on how to effectively bundle OLIEE programs with the Residential Bill Discount Program in this and/or the UM 2211 process.

Q. Staff also mentioned the CEAG as a potential intersection with these topics; what is the relevancy here?

A. Staff appreciates the Company's sincere commitment to equity informed decision making through the CEAG. In Staff's review, the Company provided charter documents and general descriptions of how the CEAG provides input to the Company and used the Bill Discount Program design and outreach as an

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10 Docket No. ADV 1562, Advice No. 23-25 (https://edocs.puc.state.or.us/efdocs/HAU/adv1562hau325663054.pdf).

11 Id.

exemplar. Staff's only flags regarding the CEAG at this time is uncertainty regarding:

1. The visibility of these conversations,
2. The level of accountability the Company provides to the CEAG based on their input, and
3. The Company's commitment to expanding the CEAG's influence to system planning and investment.

Q. Please explain.

A. Staff is not making any recommendations at this time but does wish to continue discussions with the Company in the appropriate venue about how to address or resolve the aforementioned concerns. For example, while Staff appreciates these conversations are happening and the input is being collected, there is still some uncertainty with how this is being recorded and to what extent it can be shared ahead of the Company's assertions that proposals were informed or endorsed by the CEAG.

Staff is also sensitive to how community engagement can easily sour if the format is extractive or lacks agreed upon feedback loops and accountability measures. This is not to say those have not been addressed in NWN's model, and Staff recognizes a meaningful compensation structure is in place. However, Staff still feels some additional visibility and potential sharing of space for a bit of diversity in the content brought before the CEAG may be worth exploring.

This is particularly relevant in the face of some big questions and uncertainty around the Company's future business model and evolving role in the Oregon energy system and decarbonization goals. Put plainly, the topic of stranded costs associated with customers leaving the gas system and concepts of a "just transition" amid calls for electrification have come up in multiple dockets over the last several years.

The CEAG has made valuable progress on issues of accessibility and procedural equity, the Company should work to expand its scope to inform major issues facing the users of NW Natural's system. Staff believes it is important to socialize the tradeoffs of different pathways for the future of NW Natural's system and make the priorities and other feedback available for use in planning and ratemaking dockets... Staff is interested in hearing how the Company plans to use CEAG input to tackle more practical issues that inform its Company's long-term business strategy.

Q. Does this cover Staff's energy justice review of the Residential Bill Discount Program, low-income energy efficiency programs, and CEAG?

A. Yes. However, as noted earlier, perspectives and positions may expand following additional review, process, and dialogue in this proceeding.

Q. Staff had also flagged the residential rate structure change to the basic charge as relevant to energy justice concerns, what can be said about that?

A. Staff wishes to use this testimony to highlight a particular concern regarding what Staff has found to be a significant and premature adjustment to the residential rate structure via the Company's basic charge proposal.

Q. Please explain.

A. The Company has proposed a revision to the basic charge that includes the following three changes:

- Increase the basic charge for residential single-family customer from $8 to $10.
- Implement a bifurcated basic charge that keeps the multi-family basic charge at $8.
- Create a new monthly charge of $16.25 for all new customers to the Company's system that would be added onto the Company's basic charge proposal.

This proposal was reviewed and discussed in length in Staff/1800. There, Staff notes that for the time being, it is supportive of the first two of the three changes. However, Staff opposes the new premise premium of $16.25 for several reasons also discussed in Staff/1800, the last of which how this proposal overlooks significant equity concerns that should be explored in further analysis. Specifically, the Company did not provide any visibility into the distribution of environmental justice communities comprising new premise customers versus existing customers.

While absent a more thorough exploration, one might assume that new premise customers are largely new homeowners, Staff's understanding is that this cohort could just as easily include renters moving into newly constructed multi-family dwellings, some of which might be affordable housing units. To this end, it is very possible that this structural change exacerbates the disproportionate burdens faced by environmental justice communities. Specifically, Staff is referring to the interplay of environmental justice community households already having a reduced capacity to pay for a notably higher charge (i.e., more than three times the existing customer basic charge), with the possibility that these groups are overrepresented among new premise customers, leading to a cost shift at the expense of these groups.

Q. What was Staff referring to regarding the change being premature?

A. Staff notes that the Company referenced this change as one of the components to its "responsible growth strategy." Staff sees this effort to be ill-suited for a rate case proceeding that lacks the more diverse engagement framework and comprehensive planning approach of an IRP.

While Staff appreciates the Company's efforts to be a nimble and adaptive business amidst a changing energy landscape, Staff finds the "least regrets" approach in something as technical and granular to an overall business model as the residential basic charge structure to be to leave it as is. If the Company is able to clearly evidence that there are sufficient protections against exacerbating disproportionate burdens for environmental justice communities with this change, there may be merit to it at a future point in time. However, until then, and in consideration of the significant dollar increase on its face, Staff does not support this change.

The last thing Staff would note regarding this particular topic is a concern that is broached in both Staff/1800 and Staff/900 regarding the Company's Line Extension Allowance (LEA) proposal. As Staff witnesses Mr. Shierman and Dr. Dlouhy explain, there is a level of ambiguity in the LEA changes that is not without consequences for customers. Specifically, the generous LEA, particularly when compared to relatively low volumetric gas prices, may not give customers full visibility into the uncertainty surrounding the future costs and risks of joining the gas system.[12] In this regard, the intersections of the LEA with the new premise premium adds a layer of complexity at best and deception at worst for new NW Natural customers.

While deferring to Dr. Dlouhy on the review and recommendations specific to the LEA, Staff believes that in the interest of socially just outcomes the Commission might look for least regrets actions to address the current state of uncertainty when considering the proposed residential rate design, given that:

1. Disparate impacts have not sufficiently been explored and mitigated; and
2. The proposed basic charge structure appears to offset the purported customer benefits of the LEA.

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[12] Staff/900.

Q. Does Staff have additional comments regarding the residential rate design change?

A. Not at this time.

Q. Are there any other issues Staff wishes to raise on behalf of energy justice considerations?

A. Yes. The final issue Staff is prepared to raise at this time is a brief discussion on the overall impacts of this case on residential customer bills. Specifically, it is a known fact that environmental justice communities are disproportionately burdened by the energy system in general. This includes health disparities associated with pollution, proximity, and access to heating and cooling; as well as higher rates of energy burden, energy insecurity, energy poverty, and energy democracy.[13] What this means is that as certain components of the system change, such as costs recovered in rates, disproportionate burdens are worsened as the impacts of the changes are augmented for these communities.

Recall the discussion around energy burden and Table 2, displayed earlier in this testimony: as incomes draw nearer to zero, energy burden increases exponentially. Similarly, holding incomes constant, as rates increase, for households in the lowest rungs of the income distribution, energy burden increases exponentially. Noting that the magnitude of impact to residential customers in the Company's filing has already been assessed

[13] https://iejusa.org/section-1-defining-energy-justice/

by Staff as constituting rate shock for even the *average* non-energy burdened residential customer.

To this end, Staff is justifiably concerned about how the magnitude scales for environmental justice communities.[14] While the Residential Bill Discount Program is one tool available to address these higher burdens and impacts, Staff clarifies that this is not a comprehensive long-term affordability strategy, and the effects of Schedule 33 are limited to a customer's participation in the program.

In a review of the Company's most recently filed Bill Discount Quarterly Report[15] it appears that roughly six percent of NW Natural residential customers have enrolled in Schedule 33. Census estimates and poverty statistics generally show Oregon poverty levels between 12 to 20 percent with higher concentrations of persistent poverty in the Portland area.[16] Thus it is reasonable to infer that anywhere between 37,000 and 88,500 NW Natural customers are eligible for the Bill Discount Program but not enrolled, and thus expected to face even higher disproportionate energy burdens under the Company's proposal as filed.

Q. Has Staff proposed any changes to address this issue?

A. Staff witness, Eric Shierman has made recommendations to adjust the rate shock mitigation cap and ceiling tools in Staff/1800 (Rate Spread testimony)

14 Staff/1800.
15 RG 102.
16 https://data.census.gov/profile/Oregon?g=040XX00US41; https://www.governing.com/community/oregon-has-44-census-tracts-in-persistent-poverty.

as one means of tempering the effects of the Company’s proposal on certain customer classes. That said, these are adjustments on behalf of customer classes as a whole or on average and do not necessarily fully mitigate the disparate effects faced by environmental justice communities.

As such, for the purposes of this testimony, Staff encourages the Company to explore additional ways to increase the Schedule 33 saturation rate, OLIEE offerings, and future evolutions to differential rate designs in UM 2211. Further, this testimony supports accompanying Staff positions that thoughtfully adjust revenue requirement items downward both on the merits of the analysis and in this instance, in recognition of broad affordability concerns impacting all customers.

Q. Does Staff have other energy justice concerns that relate to the overall impacts of this case?

A. Yes. Staff has heard stakeholders raise concerns regarding the disproportionate health and safety impacts that the natural gas system has on environmental justice communities. Staff seeks to highlight these concerns and encourages the Company to fully examine these issues as it explores the future of the gas system in planning and rate making conversations.

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your adjustments.

A. Staff has not made any specific recommendations that alter the Company's proposal which have not been discussed and summarized in other exhibits of Staff's Opening Testimony. That said, Staff has encouraged activities relative to promoting energy justice in this case and Company operations including:

- Continued and enhanced engagement of residential differential rate designs and programs, including discounts and energy efficiency/weatherization in UM 2211.
- Revisit the Schedule 335, Residential Bill Discount Program cost recovery for potential equity concerns.
- A discussion around the CEAG and the value of increased visibility and accountability.
- Continued consideration of how proposals disproportionately burden environmental justice communities, including the use of more granular customer segment analysis to inform strategies.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: Michelle Scala

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Michelle Scala

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Justice Program Manager
Strategy and Integration Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: University of Hawaii, Manoa
Bachelor of Arts Economics

Bachelor of Arts Political Science
Concentration in Public Policy

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since July 2020 as a Senior Utility Analyst. I initially began work at the Commission in the then "Energy Rates, Finance and Audit Division" and transitioned to the Strategy and Integration Division upon its inception. In May of 2022, I was made Energy Justice Program Manager to the Utility Division where I lead energy equity work across utility rate, planning, and policy dockets. I have provided expert testimony as Commission Staff in general rate cases UE 394, UE 416, UE 426, UG 433, and UG 435, UG 461 and have consulted on others. I have over ten years of experience in policy analysis and program evaluation for state and local governments and received a graduate certificate in Public Administration in 2024. My work prior to the Commission included serving as a Senior Fiscal Analyst at the Oregon Department of Human Services and Economist at the Oregon Employment Department. Before coming to Oregon, I was employed at the Hawaii State Legislature as the Senior Budget and Policy Analyst to the Senate Committee on Ways and Means.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony
Public Comments

April 18, 2024

Please state your name, occupation, and business address.

A. My name is Melissa Nottingham. I am the Consumer Services and RSPF Manager. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Staff Exhibit 401

Q. What is the purpose of your testimony?

A. To provide the public comments submitted by consumers pertaining to UG 490 with a brief summary of issues and/or concerns identified, and if applicable, refer to the Staff testimony addressing the public comment.

Q. Please explain the reasoning behind the inclusion of public comments in Staff's testimonies.

A. Consistent with the Commission's Internal Operating Guidelines as addressed in Order 20-065 in Docket No. UM 2055, to provide more transparency about the public comments in contested cases, public comments received are now made part of the Staff's Opening Testimony.

Please see Staff Exhibit 402 for comments received to date in this general rate case. Staff will also publish supplemental opening testimony on May 7, 2024, with incremental comments received including those received at Commission Public Comment Hearings on April 16, 2024 (virtual).

Written comments received after preparation of Staff's Opening Testimony will be included in subsequent Staff testimony. However, Staff will not be able to testify regarding comments received after Staff prepares its final round of UG 490 testimony.

Presenting comments at a Commission Informational Hearing or through the Commission's website does not make the commenter a "party" to the proceeding or subject the commenting person to cross examination. Any party that has intervened in the proceeding may respond to Staff's summary of the public comments or the comments themselves in evidentiary testimony.

1. Summary of Comments

Q. How are public comments received by Staff?

A. Comments may be submitted via an online form, an email, a letter, or a telephone call. All comments submitted and published to the Commission's webpage and are available for review. Please see: UG 490 NW NATURAL REQUEST FOR A GENERAL RATE REVISION .

Q. Please summarize the public comments received to date in this rate case.

A. Northwest Natural's request for general rate increase has received nine comments.[1] Issues raised by consumers included the following:

a. Affordability and impact of higher rates and the impact to communities with limited incomes.

b. Support for continued decarbonization efforts.

c. Concern about operational costs including wholesale gas market.

Q. Are the public concerns addressed in Staff's testimony for UG 490?

A. Yes. Affordability of rates is included in Charles Lockwood's testimony, Exhibit

[1] Staff/402, public comments.

1200, and operational costs including salaries is included in Stephanie Yamada’s testimony, Exhibit 2000.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

April 18, 2024

Witness Qualification Statement

Name: Melissa Nottingham

Employer: Public Utility Commission of Oregon

Title: Consumer Services and Residential Service Protection Fund (RSPF) Manager

Address: 201 High Street SE, Suite 400
Salem, Oregon 97301

Education: Bachelor of Arts in English, Arizona State University

Experience:

My employment at the Public Utility Commission began on May 1, 2022. During my tenure, I manage a team of 14 employees overseeing consumer complaints, the Oregon Lifeline Program, and the Telecommunication Devices Access Program. Part of my role includes sponsoring and participating in dockets related to Oregon Administrative Rules Division 21 and other consumer protection by regulated utilities in Oregon. I have provided testimony for UM 1908 and UM 2203, and provided comments for AR 653, UM 2237, and ADV 1391.

Prior to my employment at the Public Utility Commission, I worked for PacifiCorp for 25 years. PacifiCorp is a multi-jurisdictional regulated electric utility. From 2010 until my departure in 2022, I was a Regulatory Manager. My responsibilities included ensuring regulatory compliance in six states including Oregon. I provided testimony in general rate cases in six states focusing on the company's Schedule 300 fees and any company tariff modifications. Other duties included: representing the company in formal customer complaints and small claims court, overseeing contracts for new service for loads more than 1 megawatt, sponsoring modifications to the company's rules, and participating in each state's administrative rule dockets.

CASE: UG 490
WITNESS: MELISSA NOTTINGHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Opening Testimony
Public Comments

April 18, 2024

Public Comments Received on the Commission's Website

Jerry Crane Tigard	Is Executive Compensation at NWN tied to profitability and increases in the price of its common stock? How much has executive compensation increased in the last four years?
Jose Galindez Beaverton	Dry Natural Gas prices on the NYMEX today closed at $1.689/MMBtu, its lowest settlement value since July 22, 2020; a 19% drop in the contract during the past six days of price declines and down almost 80% from its mid-2022 highs which were in the $8 to $9 per MMbtu. How can the Commission continue to approve and justify ongoing increases for commercial and residential natural gas service when the cost of gas has dropped 80% reduction since its summer 2022 peak? Thanking you in advance Jose
Paul Chantiny North Bend	Fighting climate change requires us all to shoulder a part of the burden. If we increase the cost of a commodity, won't consumption decrease? Therefore, why isn't Oregon PUC sharply increasing the price of natural gas?
David McNeel Oregon City	Hi there, figuring out your form is impossible for the average Oregonian. I am sure that the Commission wants it that way. I have lived in Oregon all of my 70 years. None of the climate mandates by Kate Brown have ever been voted on by the citizens of Oregon. So, go ahead and jack the electric utility rates to infinity and tax natural gas until the average Oregonian can't afford it. Fortunately, the Oregon climate grows trees very well and Oregonians know how to drop trees by the thousands and split them into firewood. Nothing like a hot fire in the dead of Winter. This Commission and the Climate Crazies think you have all of the answers. You will soon find out how wrong you are. This issue is no different than the tolling of Oregon Highways. Tina Kotek punted tolling to the Oregon Legislature like a hot potato! The PUC is next.
Callie Sacarelos Portland	Consumer group asks Oregon regulators to dismiss new PGE rate hike request: https://www.oregonlive.com/environment/2024/03/consumer-group-asks-oregon-regulators-to-dismiss-new-pge-rate-hike-request.html 5 takeaways: Why are Oregon power rates going up so fast? https://www.oregonlive.com/environment/2024/03/5-takeaways-why-are-oregon-power-rates-going-up-so-fast.html Why are Oregon electric, gas rates going up so fast? https://www.oregonlive.com/environment/2024/03/why-are-oregon-electric-gas-rates-going-up-so-fast-beat-check-podcast.html Oregon's second-largest utility seeks big rate hike, again. Here's why.

	https://www.oregonlive.com/environment/2024/02/oregons-second-largest-utility-seeks-big-rate-hike-again-heres-why.html PGE wins approval for largest rate increase in two decades: https://www.oregonlive.com/business/2023/11/pge-customers-will-pay-more-for-electricity-in-2024.html Here’s how much PGE, Pacific Power electric bills will increase starting January: https://www.oregonlive.com/business/2023/12/heres-how-much-pge-pacific-power-electric-bills-will-increase-starting-january.html PacifiCorp wants state to protect it from future wildfire lawsuits. Past victims are disgusted: https://www.oregonlive.com/business/2023/11/pacificorp-wants-state-to-protect-it-from-future-wildfire-lawsuits-past-victims-are-disgusted.html Pacific Power seeking 12.2% rate increase in 2023: https://www.oregonlive.com/business/2022/03/pacific-power-seeking-122-rate-increase-in-2023.html Here’s how much your electric bill is going up in January: https://www.oregonlive.com/business/2023/01/brace-yourself-heres-how-much-your-electric-bill-is-going-up-in-january.html Portland leaders inch up water rates they just cut, citing desire to aid low-income renters: https://www.oregonlive.com/politics/2023/05/portland-leaders-inch-up-water-rates-they-just-cut-citing-desire-to-save-program-to-aid-low-income-renters.html NW Natural’s proposed rate hike unfairly saddles customers with costs of bonuses, profits: https://www.oregonlive.com/opinion/2022/03/opinion-nw-naturals-proposed-rate-hike-unfairly-saddles-customers-with-costs-of-bonuses-profits.html Oregon natural gas utility can’t ask customers to pay for political spending, new pipelines: https://www.oregonlive.com/environment/2023/10/oregon-natural-gas-utility-cant-ask-customers-to-pay-for-political-spending-new-pipelines.html Oregon gas company using ratepayer money to fight state climate program: https://www.oregonlive.com/business/2023/07/oregon-gas-company-using-ratepayer-money-to-fight-state-climate-program.html Get ready, your NW Natural gas bill’s going up: https://www.oregonlive.com/business/2019/11/get-ready-your-nw-natural-gas-bills-going-up.html PacifiCorp may ask utility regulators to let it pass wildfire litigation costs to customers: https://www.oregonlive.com/business/2023/06/pacificorp-may-ask-utility-regulators-to-pass-its-wildfire-litigation-costs-to-customers.html Amid ongoing pandemic, Portlanders will pay more for water and sewage:

	https://www.oregonlive.com/news/2021/02/amid-ongoing-pandemic-portlanders-will-pay-more-for-water-and-sewage.html PGE says ill-conceived trades cost the utility at least $104m; stock slides 8.3%: https://www.oregonlive.com/business/2020/08/pge-says-ill-conceived-trades-cost-the-utility-at-least-104-million-stock-slides-83.html
Jennifer Priest Portland	Thank you a million times to the PUC for standing up to the gas companies! https://www.opb.org/article/2024/03/15/oregon-natural-gas-companies-fail-approval-climate-action-plans/
Patel Neel Portland	Hello! My name is Neel Patel and I live in Portland, OR (97209). I write to express my concern about methane pollution from our utilities and discuss how the Oregon Public Utilities Commission can play a clean role in decarbonizing our grid. I first want to thank you for all the work you have done so far. I read on OPB that you are keeping the pressure on the 3 natural gas companies in Oregon to comply with our greenhouse gas emission reduction goals. I commend you three (Ms. Decker, MS Tawney, and now Mr. Perkins) on this climate focused action. These companies will try everything they can do to keep using methane when a rapid reduction in methane is one of the best things we can do right now to fight the climate crisis. From your actions, it is clear that you understand the issues with methane- the 80x global warming effect compared to carbon dioxide, the abundance of leaks in the supply chain, and the public health and safety risks, including explosions, degraded indoor air quality, and worsening respiratory conditions. As a physician in our community (I am a radiologist at OHSU), I am particularly concerned about how climate change and fossil fuel pollution interact to worsen human health and wellbeing. We are already feeling the climate change related health effects today: increased extreme weather, more heat related illnesses, asthma and respiratory diseases from particular pollution, and tropical diseases expanding from the tropics (like Dengue in Puerto Rico and Florida). Methane gas usage is particularly harmful. A peer reviewed study (PMID: 36612391) found that gas stove use indoors is attributable to 12.7% of childhood asthma. These effects will only get worse unless we can decarbonize quickly and effectively. Natural gas companies and other fossil fuel companies will continue to spread misinformation to downplay the climate and health risks to the detriment of regular Oregonians and to the benefit of their bottom line. However public utilities like Oregon’s should keep the pressure up to force them to make changes to reduce emissions that will benefit all of us, including the people that work at those companies! I urge you to take strong action in regulating methane emissions from utilities, like

	imposing stricter leak detection standards, efficiency requirements for aging gas infrastructure, or rate-setting and rules that help incentivize cleaner sources of electricity. You can also impose regulations that encourage the switch from gas heating and cooking to electrification. Thank you for your hard work so far and keep up the fight to decarbonize our grid. -Neel Patel, MD
Graham Williams	Strongly oppose! How can we live in this state with your tax tax tax and now increase in electric & water & gas!??? We are all fed up! If we leave the state guess what - you get NO revenue
Kate Fuller	No increase! We are in our 70s, on a fixed income and this would raise our bill by $40 each month. NW turned off the gas while my husband was in cancer treatment. Left a card but never bothered to knock on the door. I prefer a 20% DECREASE please.

CASE: UG 490
WITNESS: David Abraham

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 500

Opening Testimony
Gas Storage Operating Expense, Gas Storage in Rate Base, and Major Storage Projects.

April 18, 2024

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

A. My name is David Abraham. I am a Senior Economist employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/501.

Q. What is the purpose of this testimony?

A. My testimony presents Staff's analysis and recommendations regarding the rate treatment of gas storage operating expense, gas storage in rate base, and major storage projects.

Q. Did you prepare any other exhibits for this docket?

A. Yes. NWN's non-confidential responses to select data requests can be found in Exhibit Staff/502.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. GAS STORAGE OPERATING EXPENSE

Q. What is NWN's gas storage operating expense?

A. NWN's gas storage operating expenses are related to the Company's underground and Liquid Natural Gas (LNG) storage facilities. The storage facilities allow NWN to store lower summer-priced natural gas to be used in the winter during high demand or peak day events. Like transportation, unneeded gas storage capacity can be optimized by selling into a future higher priced market. NWN records gas storage operating expenses in Federal Energy Regulatory Commission (FERC) Accounts 816 through 847, as detailed in the Company's filing.[1]

Q. Please summarize NW Natural's proposal related to gas storage operating expense.

A. The Company is proposing a non-labor Test Year gas storage operating expense of $6,210,300, on a total system basis, or $5,529,651 on an Oregon allocated basis.[2] NWN's gas storage forecast was developed using the Base Year spend multiplied by a Consumer Price Index (CPI) factor of 3.6 percent in 2024 and 2.9 percent for the 10 months in 2025. The Company also identified items that were adjusted according to their specific estimated increase or decrease.[3]

Q. Did Staff analyze if the cost of gas is included in base rates?

[1] NW Natural/1401, Davilla/1.
[2] Staff/502, NWN response to Staff DR 193, Attachment 1, Second Amended.
[3] NWN/1400, Davilla/8.

A. The annual Purchased Gas Adjustment (PGA) filing revises rates to include the forecasted cost of gas for the upcoming year through a mechanism outside of base rates. As a result, cost of purchased gas is addressed in the annual PGA rather than in a General Rate Case (GRC).[4]

Q. Did Staff analyze the Company's use of CPI factors to develop the Test Year gas storage expense?

A. Yes. NWN obtained the Western CPI factors used to develop the Test Year from the Oregon Office of Economic Analysis (OEA) as reported in the September 2023 Oregon Economic and Revenue Forecast. Staff recommends using the all-urban CPI. In addition, the OEA has since issued an updated forecast in March of 2024 and the new all-urban CPI factors are 2.7 percent for 2024 and 2.0 percent for 2025.

Q. Has Staff determined what the impact would be to the Company's Test Year gas storage expense if the updated CPI factors were used?

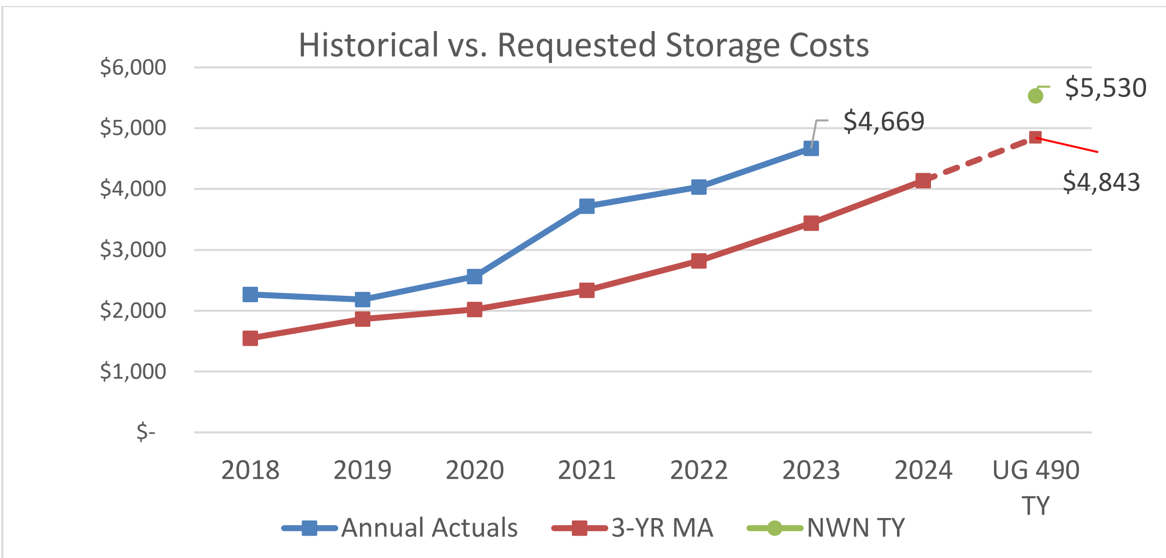
A. Yes. Staff has calculated the Oregon allocated non-labor gas storage expense would be reduced by $79,816 by using the updated all-urban CPI factors released by the OEA in March of 2024.

Q. What else did Staff consider regarding NWN's gas storage operating expense?

[4] NWN/1700, Wyman/21.

A. Staff analyzed historical data provided by the Company in response to Data Request 193 and in the Company's supporting work papers.[5] Staff calculated a three-year moving average of Oregon allocated gas storage costs compared to the Test Year gas storage expense requested by the Company. The proposed Test Year dollar value of non-labor gas storage costs included in the filing and the Company's historic gas storage costs are summarized in Figure 1.

Figure 1 – Value of Historic vs Requested Gas Storage Costs ($000)



Q. Describe Staff's analysis regarding Test Year gas storage costs.

A. Staff's practice is to compare the previous three years' expense and longer-term trends to the requested Test Year amount, relying more heavily on recent trends unless there is a reason not to do so.[6] Staff extended the 2024 three-year moving average trend-line to compare to the Test Year request proposed

[5] NWN/Exhibit/1400/Davilla/Workpaper. See also NWN's response to Staff DR 193, Attachment 1, Second Amended.
[6] See UE 388, Staff/300/3.

by the Company by obtaining the year-over-year moving average growth in gas storage expense from 2023 to 2024 and then adding that increase to the 2024 moving average.

Q. What does Staff's comparison of the Company's Test Year gas storage costs to historical averages show?

A. The extended moving average trend-line, displayed in Figure 1, indicates the Company's Test Year amount would have to be reduced by $686,504 to align with the moving average trend.

Q. Did Staff identify any expenses related to the expansion of gas storage capacity in the Company's Test Year request that would explain why NW Natural's proposed Test Year expense exceeds what would be expected based on historical spend?

A. Staff did not identify any projects at the Mist facility, or any of the Company's LNG storage terminals, that provided for the expansion of gas storage capacity. However, the Company will be initiating rig-based casing inspections in 2024 to satisfy the conditions of 49 CFR 192.12(d)(3).[7] The Well Casing Integrity Inspection Program (FERC 832) is required to address safety issues related to downhole facilities, including wells and casings at underground natural gas storage facilities. The Company estimates the Test Year expense for the casing inspection program to be $625,000, on a total system basis, and $556,000 on an Oregon-allocated basis.

[7] NWN/1400, Davilla/10.

Q. Describe Staff's analysis regarding rig-based casing inspection expenses.

A. NWN's rig based integrity inspection program requires additional operating costs that were not included in the historical moving average but will be incurred during the Test Year. Applying the extended three-year moving average alone would under-estimate the expected Test Year gas storage expense.

Q. Does Staff recommend including the rig-based casing inspection expenses in the Test Year adjustment?

A. Staff proposes that the rig-based casing inspection expense should be included as an off-set to the trend adjustment.

Q. Please summarize Staff's proposed adjustment to NWN's Test Year gas storage operating expense.

A. Staff proposes an Oregon allocated Test Year adjustment that will reduce NWN's requested gas storage operating expense by $210,320. As discussed above, the Company's Test Year expense is higher than what appears reasonable based on a comparison to historical amounts. The Company has explained why the forecasted costs are increasing, but its explanation does not support the full amount of the increase. Table 1 displays a summary of Staff's recommended adjustments to NWN's Oregon-allocated gas storage expense.

TABLE 1. EFFECT OF STAFFS ADJUSTMENTS

Staff's Recommended Adjustments	Oregon Allocation
Staff Reduction due to Updated CPI Factors	$ (79,816)
Staff Reduction - Alignment to Historical Trend	$ (686,504)
Off set to Trend Due to Well Inspection Program	$ 556,000
Staff's Total Adjustment to NWN's Test Year Request	**$ (210,320)**

Staff's recommendation would reduce NWN's Oregon-allocated Test Year gas storage operating expense from $5,529,651 to $5,319,331.

ISSUE 2. GAS STORAGE IN RATE BASE

Q. Please describe the gas storage costs at issue.

A. Storage gas consists of two components, “cushion gas” and “working gas inventory.” “Cushion gas” is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. “Working gas inventory” is the gas that flows in and out of the storage reservoir, or Liquid Natural Gas (LNG) tank, to serve customer loads.

Q. Please summarize NW Natural’s proposed Test Year gas storage costs included in rate base.

A. NW Natural included a total of $43,888,538 for Oregon allocated gas storage in the Test Year rate base, of which $20,217,645 is cushion gas and $23,670,893 is working gas.[8] NW Natural’s Oregon allocated working gas amount for the twelve-month Base Year period ending September 30, 2023, is $63,623,317. NWN’s Test Year gas storage expense represents a 45.5 percent decrease compared to the Base Year.

Q. Please summarize the Commission’s historical treatment of gas storage in rate base.

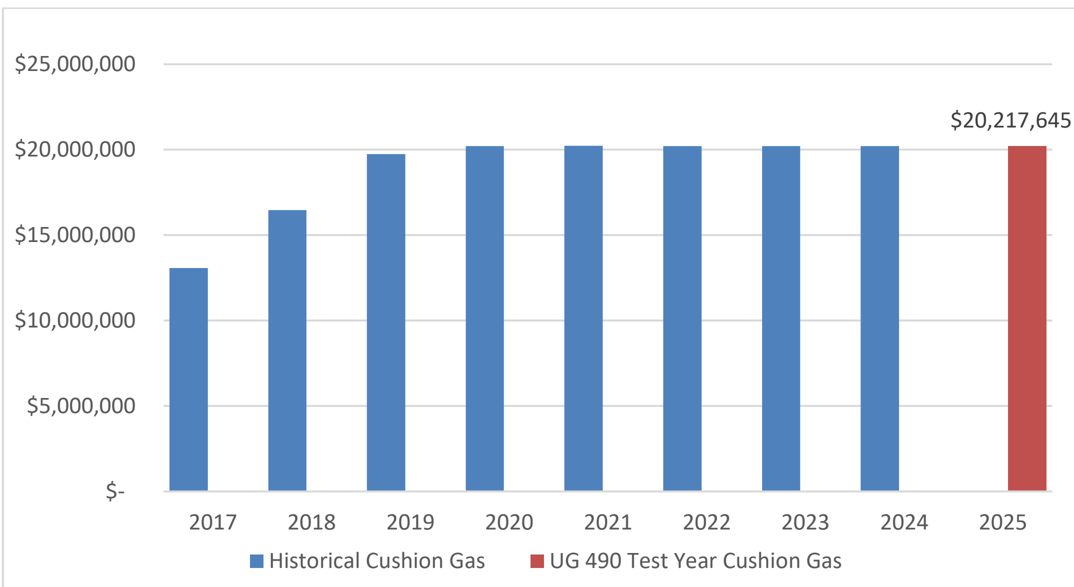
[8] NW Natural workpaper “UG 490 - Exhibit 1713 – WP2 – Other Rate Base Items”, tab “Cushion Gas”, rows 149-156.

A. All three regulated gas utilities serving in Oregon currently include these costs in rate base as a result of stipulations reached by the Parties and adopted by the Commission.[9]

Q. Please explain how Staff analyzed cushion gas costs in rate base.

A. Staff expects cushion gas volumes to remain constant unless there is a major expansion of storage. Typically, the value of cushion gas value is based on its cost when injected into the facility and should change very little in the absence of expansions. The proposed dollar value of cushion gas included in the filing, and the historic value of the Company's cushion gas is summarized in Figure 2.

Figure 1 - $ Value of Historic vs Requested Cushion Gas



Q. Does Staff propose any adjustments to cushion gas inventory included in Rate Base?

[9] See e.g., *In* the *Matter of Northwest Natural,* Order No. 13-349 at 5 (Commission adopting stipulation including NW Natural Gas Company's working gas inventory in rate base).

A. No. Staff does not propose any adjustment to cushion gas inventory in rate base at this time and is satisfied that the amount included in the Test Year filing is appropriate.

Q. Please explain how Staff analyzed working gas costs in rate base.

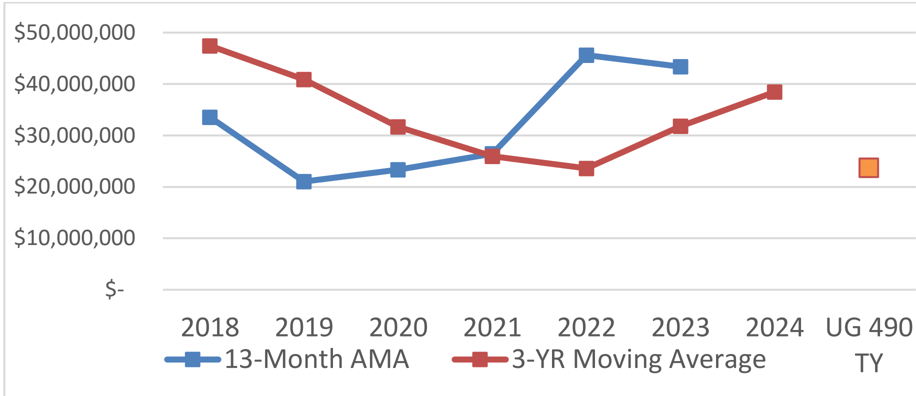
A. Staff analyzed historic data provided by the Company's supporting work papers.[10] The Company used the model "Sendout" to predict its gas prices and storage volumes by month for each storage asset. The requested $23,670,893 in working gas represents Oregon's share of the 13-month average of monthly averages (AMA) of the predicted inventory value in the Test Year.[11] Staff calculated the dollar amount for the working gas inventory in rate base using the 13-month AMA historical balances and a three-year calendar annual moving average. The proposed dollar value of working gas included in the filing, and the historic value of the Company's working gas is summarized in Figure 3.

Q. What are Staff's findings based on its analysis of working gas costs in rate base?

A. Staff found that the Company's requested $23.7 million for Oregon allocated working gas is below the most recent calendar year 13-month AMA and the three-year moving average. NW Natural's working gas request represents a decline of 45.5 percent compared to the 2023 base case.

[10] NW Natural workpaper "UG 490 - Exhibit 1713 – WP2 – Other Rate Base Items", tab "Cushion Gas", rows 146-156.
[11] Ibid.

Figure 2 - $ Value of Historic vs Requested Working Gas[12]



Q. Please summarize Staff's proposed adjustment to Gas Storage in Rate Base.

A. Staff proposes no adjustment to either working gas or cushion gas at this time and recommends allowing the total amount of $43,888,538 for Oregon allocated gas inventory in the Test Year, as requested by NW Natural.

[12] Values presented on an Oregon basis.

ISSUE 3. NEW PLANT – MAJOR STORAGE PROJECTS

Q. Please summarize Staff's analysis of NWN's major gas storage projects.

A. NWN's gas storage facilities include Portland LNG, Newport LNG, and Mist. Although this rate case includes maintenance and inspection projects related to all three storage facilities, Staff did not identify any major gas storage additions to the Company's overall storage capacity.

Q. Please summarize Staff's analysis of the Mist storage facility projects.

A. Staff identified several projects related to the Mist facility, which is an underground storage facility located in Mist, Oregon. In response to a Turbine Compressor Study completed in December 2022, the Company implemented the Mist GC500 Turbine Compressor Cold Spare Project and the Mist GC600 Turbine Compressor Cold Spare Project. The Company expects to complete both projects by October 2024. The cost estimate for both projects is approximately $4.8 million on an Oregon allocated basis.[13] The Mist Electrical Upgrades Project Phase 2 will replace end-of-life equipment and will cost approximately $2.0 million. The Mist Methanol Injection Project at I/W Wells will replace existing methanol tanks and injection systems and will cost approximately $4.1 million. Finally, the Mist Instrument and Controls Project will cost approximately $2.2 million.[14]

[13] NWN/500, Kizer/24.
[14] NWN/500, Kizer/30.

Q. Did Staff identify any other gas storage projects included in the filing?

A. Yes. The Portland LNG Plant will undergo a Valve and Controls Replacement Project, estimated to cost approximately $3.8 million, a Boil-Off Compressor Project estimated to cost approximately $4.2 million, and a Pretreatment Improvement Project estimated to cost approximately $2.3 million.[15] The Newport Plant includes a T-1 Tank Improvement Project, which implements the recommendations made in the Newport LNG Tank Study and includes a cost estimate of approximately $3.2 million, on an Oregon-allocated basis.[16]

Q. Does Staff recommend any adjustments to NWN's new plant additions for gas storage projects?

A. No. Staff did not identify any new plant additions that expanded storage capacity in this filing and has no proposed adjustments for gas storage projects included in this rate case at this time.

Q. Does this conclude your testimony?

A. Yes.

[15] NWN/500, Kizer/34.
[16] NWN/500, Kizer/41.

CASE: UG 490
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATION STATEMENT

NAME: David Abraham

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Costs Section Economist
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Economics
University of Texas,
El Paso, TX

Bachelor of Arts, Business Administration
University of Texas,
El Paso, TX

EXPERIENCE: I have been employed by the Oregon Public Utility Commission as an economist in the Energy Costs Section since November 2023. Prior to working for the Commission, I worked for an Investor-Owned Electric Utility in Texas beginning in 2009. I started with the utility as a real-time energy trader and transitioned into the Regulatory and Resource Planning Department in 2019. Within the planning department, I served as lead-forecaster and was responsible for producing the company's long-term energy forecast. I also prepared weather normalization schedules for regulatory filings and financial reconciliations. In 2019, I attended an electric utility ratemaking course offered through New Mexico State University and the Center for Public Utilities.

CASE: UG 490
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 502

Exhibits in Support Of Opening Testimony

April 18, 2024

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 193
Regarding gas storage expenses:

a. Please indicate whether gas storage expenses are included in the test year. Please provide a separate response for each of the following gas storage expense types:
    i. Underground gas storage,
    ii. LNG gas storage, and
    iii. Other gas storage.
b. If yes to (a), please provide a narrative explanation of how gas storage expenses are forecasted for the Test Year, providing copies of all underlying data used in the forecast in electronic workbook format, and providing references to where the forecast appears in the Company's workpapers. Please provide a separate response for each of the gas storage expense types listed under(a).
c. If yes to (a), please provide, in a single electronic spreadsheet format, for each calendar year from 2011 through 2022, and monthly through 2023, the Company's gas storage expenses. Please provide a separate response for each of the gas storage expense types listed under section (a), as well as a breakdown of the expenses into:
    i. Supervision and engineering,
    ii. Fuel,
    iii. Other equipment, and
    iv. Other expenses.

In response to (c), please separately identify any related labor expense and provide results separately for total company and for Oregon.
Please provide only those categories included in the Company's filing in this response (excluding categories which flow through the PGA).

Amended Response:

Please see "UG 490 OPUC DR 193 Attachment 1 Second Amended" data that only includes non-payroll.

CASE: UG 490
WITNESS: LAUREL ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony
Plant in Service

April 18, 2024

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

A. My name is Laurel Anderson. I am a Senior Telecommunications Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's proposed additions to rate base for new plant.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: UTILITY PLANT IN SERVICE

Q. Please define how NW Natural (NWN or Company) calculated Utility Plant in Service.

A. NWN starts with actual plant account balances as of September 30, 2023. It then forecasts additions, retirements, and transfers for all FERC accounts. As future plant balances are then developed, depreciation expense associated with each asset class can be calculated. Consistent with mass-asset accounting, both the gross plant and accumulated depreciation amounts are lowered to reflect forecasted asset retirements.

Q. Please summarize the amount and timing of the company's utility Plant in Service as proposed in the initial filing.

A. The Company is proposing utility plant in service of $4.121 billion dollars and accumulated depreciation of $1.639 billion, yielding a net utility plant of $2.482 billion[1] as of October 31, 2025, the end of the test year.

Q. Explain Staff's findings regarding how the Company calculated the amount for its Plant in Service.

A. Staff review of the underlying work paper indicates this amount is calculated using plant forecasts of plant in the November 1, 2024 to October 31, 2025, Test Year.[2] Staff notes that the Company's work paper detailing the increase in rate base is confidential in part.

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1 NW Natural/1713, Walker/1.
2 NW Natural/1700, Walker/28.

Q. Please discuss the portion of rate base projections deemed to be confidential.

A. The Company states that "[a]ll data past September 30, 2023, or contained therein" is confidential. As stated in the UG 388 case, "All forward looking monthly data that has not been disclosed to the public has been deemed confidential."[3]

Q. Please discuss Staff's ongoing objection to a portion of rate base projections being designated as confidential.

A. In Staff's view there is a public policy issue here, as the Commission seeks to have as much transparency as possible in its activities.

Q. Please discuss the Company's methodology for developing utility plant estimates.

A. According to the Company's filing, the overall methodology can be summarized as follows:

- **Intangible – Software** (FERC Accts. 303.1 to 303.7) are allocated between Oregon and Washington on the basis of "all customers" allocation factor.[4]
- **Intangible – Other** (FERC Accts. 301 and 302) are specific to Oregon and Washington with no allocation between states.
- **Production** (FERC Accts. 304.1 to 319) are specific to Oregon and directly assigned.

[3] UG 388 Staff/200, Fox/2.
[4] NW Natural/1700, Walker/41.

- **Transmission** (FERC Accts. 365.1 to 367 and Acct. 369) are state situs and therefore are specific to Oregon.
- **Distribution** (FERC Accts. 374.1 to 387.3) are specific to Oregon and Washington with no allocation between states.
- **General** (FERC Accts. 390.1 to 398.5) are allocated using a 3-Factor & Direct method.
- **Storage and Storage Transmission** (FERC Accts. 350.1 to 363.42, and Accts. 367.21 to 367.26) are allocated based on Oregon's share of Firm Delivered Volumes.[5]
- **Land & Structures** (FERC Accts. 389 and 390) are allocated using a more detailed methodology further discussed below.
- **CNG/LNG Refueling Facilities** (FERC Accts. 363.5 and 363.6) are allocated using a 3-Factor method.

Q. Does Staff agree with the Company's calculation and methodology regarding its Plant in Service?

A. Yes. Staff agrees with the Company's methodology, which is consistent with prior rate cases.

Q. Does Staff propose any adjustments?

[5] The allocation methodology also includes a specific adjustment to allocate $33 million of the total South Mist Pipeline Extension to Oregon as agreed in a prior rate case. See the Company's Direct Testimony in UG 152 (UG 152/NWN/400 Stinson at pages 20 – 22) and NWN Advice No. 04-11A.

A. Yes, Staff proposes to remove plant additions that come on-line subsequent to the rate effective date. Staff discusses this in more detail below, along with the proposed amounts to be removed.

ISSUE 2: TEST YEAR RATE BASE
DISCRETE VS. NON-DISCRETE INVESTMENTS

Q. Please define the difference between "discrete" and "non-discrete" expenditures.

A. Discrete investments are investments the Company has proposed and planned to implement to fulfill a specific operational aim, or to address a specific operational issue. Discrete projects tend to fall into subcategories of System Betterments, System Reinforcement Projects, Information Technology, and Land and Structures. Costs of discrete projects can vary widely year over year.

The second category can be thought of as "non-discrete capital expenditures," in which the Company generally does not exercise much discretion. These investments include Public Works, Relocates, Damages, Transportation and Equipment, Tools, Technical Refresh, Leakage, Customer Growth, Transmission Integrity Management Program ("TIMP"), and Distribution Integrity Management Program ("DIMP")

Q. Please discuss the discrete and non-discrete projects the Company plans to add to the rate base, and seek recovery in this case.

A. The Company seeks to add to rate base all capital expenditures completed since the Company's last rate case, UG 435, that will be used and useful as of the rate effective date of this case – November 1, 2024. NW Natural also seeks to add all capital expenditures, both discrete and non-discrete that will be completed during the Test Year.[6]

Q. Please discuss Oregon's "used and useful" standard.

A. ORS 757.355 specifies that before costs of utility plant used to serve customers can be included in utility rates, the plant must be in service. Accordingly, property must be in service prior to the effective date of the rates.[7,8] The law applies to all utility plant including plant placed into service before the rate effective date and prior additions to rate base that are no longer used in providing utility service to customers.

Q. Does the Company's filing include discrete investments that will go into service after the rate effective date?

A. Yes. The Company included the North Coast Feeder Uprate project – Section B, which is expected to go into service in December 2025, after the rate effective date of November 1, 2024. As such the capital costs associated with this project should be removed from the revenue requirement.

Q. Does the Company's filing include non-discrete investments that will go into service after the rate effective date?

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6 NW Natural/1400, Davilla/22.

7 ORS 757.355 prohibits the inclusion of property not presently used for providing utility service to the customer.

8 *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, UE 210, Order No. 10-022, p. 14 (January 26, 2010) ("ORS 757.355 prohibits a public utility from collecting in customer rates the costs of any property not presently used for providing utility service to those customers. . . .Given this evidence, and despite the parties' contentions about specific rate base adjustments, it is clear that the Stipulation will allow Pacific Power to collect in rates only the costs of property presently providing service to customers in conformance with ORS 757.355. We therefore deny ICNU's objection on this point.").

A. Yes. As noted above, the Company includes all capital investment in the Test Year, which is the twelve months following the rate effective date. Staff recommends the Commission include the non-discrete investment in retail rates. An incremental portion of the investment will be on-line each month, so monthly customer rates would not include costs of plant not in service.

ISSUE 4: NEW PLANT MAJOR DISTRIBUTION PROJECTS

Q. Which major distribution projects removed from Docket No. UG 435 have been completed since the Company's 2022 rate case?

A. In its last rate case, the Company agreed to remove the E04 - 6 and 8 inch ILI Conversion Project, the Natural Forces Projects, the Newport Switchgear Replacement Project, the TBD1845 Fire System Upgrade Project (subsequently renamed the Mist Fire System Upgrade Project), and the Mist GC 500 Human-Machine Interface ("HMI") and Controls Project because they were not scheduled to be placed in service by October 31, 2022.[9]

Q. Please provide an update on the status of these projects.

A. The Company completed and placed in service the E04 – 6- and 8-inch ILI Conversion Project in December 2023, the Mist Fire System Upgrade Project in December 2023, the Newport Switchgear Replacement Project in July 2023, and the Mist GC 500 HMI and Controls Upgrade Project in May 2023. These projects are included in plant in the base year ended October 31, 2023.

Q. Please identify the significant distribution system projects included in the current rate case.

A. The Company is requesting recovery for the following significant distribution system projects:

- North Coast Feeder Project;[10]

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[9] NW Natural/500, Kizer/2.
[10] NW Natural/500, Kizer/5-8.

- Tualatin-Sherwood Road Grading Project (the actual costs exceeding those already being recovered in rates);[11]
- P30 Willis Creek HDD Install Project;[12] and
- SE Gate Station Rebuild Project.[13]

Q. Please describe the North Coast Feeder Project

A. In 2018, the Company identified a potential pressure drop in the Northwest area of its service territory in violation of the Company's system reinforcement standards. To address this and other pressure drops the Company presented the North Coast Feeder Uprate Project for acknowledgement in its 2018 Integrated Resource Plan ("IRP") Update 3 filed in docket LC 71 on March 1, 2021. The Company has collected data revealing significant pressure drop violations which pose an unacceptable risk to safety and reliability.

Modeling indicated that, if left unmitigated, pressure drops could potentially reach 0 pounds per square inch gauge ("psig"). To mitigate observed and potential drops in pressure the Company proposed the North Coast Feeder Uprate Project: (1) uprating 6.6 miles of high pressure gas main on one section of its system between the Walluski district regulator and Rodney Acres Road from a maximum allowable operating pressure ("MAOP") of 175 psig to a MAOP of 575 psig ("Section A"); and then uprating another 22.2 miles of high pressure gas main on another section of its system from

11 NW Natural/500, Kizer/8-11.
12 NW Natural/500, Kizer/11-12.
13 NW Natural/500, Kizer/12-13.

Warrenton to Cannon Beach from MAOP of 175 psig to a MAOP of 390 psig ("Section B").

Q. What is the timing and estimated cost to complete the North Coast Feeder Project?

A. The North Coast Feeder Uprate Project Section A is expected to be placed in Service in September 2024 at an expected cost of $8.2 million. Section B is expected to be completed in December 2025 at a cost of $6.4 million.[14]

Q. Please describe the Tualatin-Sherwood Road Grading Project.

A. The Tualatin-Sherwood Road Grading Project relocated approximately 6,400 feet of six-inch high-pressure main, approximately 11,000 feet of 4-inch main, three district regulators and two telemetry facilities on Tualatin-Sherwood Road.

Q. Please describe the additional cost recovery the Company is requesting for the Tualatin-Sherwood Road Grading Project.

A. The Tualatin-Sherwood Road Grading Project was included in the Company's last rate case (UG 435), the Commission-authorized revenue requirement in that case included a forecasted amount of $2.6 million and the actual cost stated in the attestation was $7.0 million. Only $2.6 million was included in the rate base in UG 435. The actual final cost is approximately $9.1 million.[15]

Q. Please explain why final cost for the Tualatin-Sherwood Road Grading Project increased from $7 million to $9.1 million.

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[14] NW Natural/500, Kizer/8.
[15] NW Natural/500, Kizer/10.

A. According to the Company, the final impact to NW Natural facilities and the scope of relocation was not known during the processing of UG 435. Material changes to Washington County's roadway design and schedule beyond the Company's control drove increased construction costs for this project. Due to conflict with other utilities, the County did not permit NW Natural to install mains in the public utility easement. The design change required the new mains to be located within the existing roadway resulting in significantly higher costs.[16]

Q. What is the Company requesting for the Tualatin-Sherwood Road Grading Project in the current rate base?

A. The Company is requesting the recovery of $6.5 million, which is the difference between the initial amount estimated and the total actual costs incurred by the Company to complete the Tualatin-Sherwood Road Grading Project and place it in service.[17]

Q. Please describe the P30 Willis Creek HDD Install Project.

A. The P30 Willis Creek HDD Install Project entails relocating and lowering the P30 transmission pipeline via an HDD installation to mitigate the risk of rupture because of a potential landslide in the Willis Creek area. The Company submitted this project to bid in August 2023. Based on feedback from contractors the proposed solution was not constructable. Based on this

[16] NW Natural/500, Kizer/10.
[17] NW Natural/500, Kizer/11.

feedback, the project is being redesigned with a scheduled construction timeframe of Summer 2024.

Q. What is the Company seeking to recover for the P30 Willis Creek Project?

A. The estimated total cost to complete the P3 Willis Creek HDD Install Project is $3.5 million.[18]

Q. Please describe the SE Gate Station Rebuild Project

A. The SE Gate Station Rebuild Project involves replacing piping, valves, the line heater and station regulation, updating telemetry and controls, and installing a check meter and coalescing filter to improve the gate stations operation, safety, efficiency, and compliance.

Q. What is the timing and estimated cost to complete the SE Gate Station Rebuild Project?

A. The SE Gate Station Rebuild Project is expected to be placed in Service in October 2024 at an estimated cost of $2.3 million.[19]

[18] NW Natural/500, Kizer/12.
[19] NW Natural/500, Kizer/13.

ISSUE 5: NEW PLANT – RESOURCE CENTERS

Q. Please list the Resource Center projects included in this rate case.

A. This case includes the following projects:

- Central Resource Center Phase 2 (Central RC);
- Sunset Resource Center (Sunset RC);
- Miller Station Tenant Improvements (Miller Station);
- Sherwood Data Center; and
- Security upgrades.

Q. Please describe the Central Resource Center Phase 2 project.

A. NW Natural initiated planning for the Central RC in September 2017 and is completing construction in phases. In Phase 1, the Company completed site work and constructed outbuildings. Phase 2 construction began in February 2023 and includes a one-story office building with an attached warehouse. Upon completion of Phase 2, the Company plans to use this property to house workspace for emergency response crews. The Central RC will also contain storage for equipment, parts, and materials and will provide parking for Company vehicles.[20]

Q. Why is the Central RC Phase 2 Project necessary?

A. Phase 2 is necessary to better serve customers, improve facility safety for employees, and meet the Company's increasing emergency response needs. The Central RC will enable the Company to improve response times for

[20] NW Natural/600, Pipes/7.

emergencies in the central business district and in the central east side of Portland.[21]

Q. Has Phase 2 been placed in service and what is the estimated cost?

A. The Company expected Phase 2 in Service in December 2023 at an estimated cost of $9.2 million. The Central RC is allocated 100 percent to Oregon.

Q. Please summarize the upgrades NW Natural is making to the Sunset RC.

A. The Company is making seismic upgrades to the Sunset RC to address resiliency of critical equipment and known seismic vulnerabilities. The Company is also installing a new decanter system and truck scale to enable more efficient operations and ensure compliance with applicable requirements.

Q. When will the upgrades to the Sunset RC begin, and when will they be placed in service and what is the estimated cost?

A. Work on the Sunset RC upgrades is scheduled to begin in April 2024, and expected to be placed in service in October 2024. The Company estimates the cost to $4.1 million for all of the upgrades. The Sunset RC is allocated 100 percent to Oregon. Staff recommends a NWN officer attestation be required that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

Q. Please summarize the Miller Station Tenant Improvements.

[21] NW Natural/600, Pipes/7.

A. Miller Station is located at the Mist Facility in Mist, Oregon. The Company is expanding the existing office space into the warehouse to accommodate more employees and is making structural improvements to address seismic deficiencies.[22]

Q. When will the Miller Station Tenant Improvement Project be placed in service and what is the estimated cost of construction?

A. Construction of the improvements began in May 2023 and finished in mid-November of 2023. The company estimates the cost at $3.2 million or $2.8 million on an Oregon-allocated basis.

Q. Please summarize the upgrades the Company is making to the Sherwood Data Center.

A. To make the Sherwood Data Center more reliable and less vulnerable to failure, the Company is upgrading the electrical system, the HVAC system, and the fire alarm system, and adding a remote monitoring system and seismic upgrades. The Sherwood Data Center hosts 98 percent of the Company's applications, including critical business systems used for all building and asset management. It also houses the servers that receive and compile 90 percent of the data from the Company's Supervisory Control and Data Acquisition ("SCADA") system, which is used to monitor the gas distribution system.

Q. Why does the Sherwood Data Center need to be upgraded?

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[22] NW Natural/600, Pipes/18.

A. An outage at the Sherwood Data Center would cause customer service issues and interrupt many aspects of the Company's business. The biggest risk is the potential for the Gas Control department to lose visibility to the SCADA system.

Q. When does the Company expect the upgrades to the Sherwood Data Center to be placed in service, and what is the estimated cost to complete?

A. The expected in-service date for the electrical, mechanical, and alarm system work was December 2023. The seismic work will be complete in the summer of 2024. The current projected cost for all the upgrades is $3.0 million, or $2.7 million on an Oregon-allocated basis.

Q. Please summarize Staff's recommendation for New Plant – Resource Centers.

A. Staff has not identified any projects it believes to be imprudently incurred. However, Staff does have concerns regarding the reliability of the Company's estimates, especially for projects projected to be placed into service near the rate effective date, and recommends attestations for those projects as further discussed in Issue 6 below. Staff's conclusions regarding prudence are not final and may change based on evidence presented by other parties.

ISSUE 6: ATTESTATIONS AND PROPOSED PROJECT ADJUSTMENTS

Q. Regarding projects specifically discussed in the Company's testimony, what does Staff recommend?

A. Staff recommends officer attestations for the following projects for the reasons stated:

- North Coast Feeder Project

  Section A is expected to be placed in service in September 2024. The estimated cost to complete Section A is $8.2 million. This project is expected to be placed in service just prior to the rate effective date of October 31, 2024.

  Section B is expected to be placed in service at the end of the test year in December 2025. Since this phase of the project will not be "used and Useful" prior to the prior to the rate effective date, Staff recommends this phase be removed from revenue requirements and rate base for this general rate case.

- Tualatin-Sherwood Road Grading Project (the actual costs exceeding those already being recovered in rates)

  The Company completed this project in October 2022. Actual costs to place the project in service should be available to replace estimates.

- P30 Willis Creek HDD Install Project

  This project is in the planning stages and scheduled for construction Summer of 2024. There is a risk that the project will not be in service prior to the rate effective date, and the estimated cost is a rough order of magnitude estimate. Staff recommends a NWN Officer attestation that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

- SE Gate Station Rebuild Project

The project is expected to be placed in service in October of 2024, just prior to the rate effective date. There is a risk that the project will not be in service prior to the rate effective date, and the estimated cost is a rough order of magnitude estimate. Staff recommends a NWN Officer attestation that the plant is in service prior to the rate effective date. Otherwise the plant should be removed from the rate base used to calculate revenue requirements.

Q. What is the net financial impact to Utility Plant in Service from Staff's recommendations?

A. Staff recommends adjusting the Utility Plant by a ($6.4 million) for Section B of the North Coast Feeder Project, which will not be used and useful prior to the rate effective date of October 31, 2024.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: LAUREL ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement
Staff: Anderson

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Laurel Anderson, CPA
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	Utility Analyst, Telecommunications and Water Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION:	Certified Public Accountant Bachelor of Science, Business, Accounting Montana College of Mineral Science and Technology Bachelor of Science, Agriculture, Animal Science Montana State University
EXPERIENCE:	Oregon Public Utility Commission since May 2007 Budget Analyst – May 2007 to July 2013 Utility Analyst – August 2013 to Present Oregon Department of Human Services Budget Analyst-May 2005 to May 2007 Oregon Employment Department Employment Tax Auditor—October 2003 to April 2005 LaCie, Limited Senior Corporate Accountant Oxford Molecular Group Business Segment Accountant Fifteen years of Public Accounting experience including income tax, small business accounting, and municipal auditing

CASE: UG 490
WITNESS: RUSS BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

REDACTED
OPENING TESTIMONY
INSURANCE AND D&O
INSURANCE

April 18, 2024

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

A. My name is Russ Beitzel. I am Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I present Staff's analysis in the general category of Insurance and Directors and Officers Insurance (D&O).

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following supporting exhibits beyond my witness qualifications:

- Exhibit Staff/702 NWN Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. INSURANCE (NON-MEDICAL) AND RISK (NON-MEDICAL)

Q. Does the Commission have a standard means of determining how insurance expenses are treated?

A. Yes. During a rate case, Staff will examine a company's current premiums and remove any costs that are attributed to non-operating and non-regulated operations. Staff reviewed the Company-provided insurance premium documents, noting that these are purchased on the free-market either directly or through a third party tasked with finding the option that meets the Company's requirements.[1]

Q. Please describe how the Company allocates insurance premiums.

A. The Company provided a description of its allocation method in Testimony.

> …these expenses were allocated using the Company's insurance allocation model. This allocation model is designed in compliance with the Company's CAM. Pursuant to the Company's CAM, individual premiums are allocated to entities consistent with the nature of the insurance policy. For example, workers' compensation policies are allocated based on payroll, and property insurance is allocated based on total assets. The Company uses four allocation factors to allocate insurance premiums to non-utility operations and affiliates: revenues, assets, payroll, and number of directors and officers.[2]

Q. Please explain what types of insurance were reviewed.

A. Staff reviewed documents related to insurance for property, liability, terrorism, workers' compensation, and other risk management. Please see Confidential Figure 1 for a list of these various types of insurances and a chart comparing

1 See Staff/702 Company response to Staff SDR 69 and Confidential response to Staff SDR 69 Attachment 1.

2 See NW Natural / 1400, Davilla / 13.

premiums from Base Year to Test Year.

FIGURE 1: OR ALLOCATED TOTALS FOR INSURANCE AND RISK PREMIUMS

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Is expense for insurance increasing?

A. The Company's forecasted Test Year expense for insurance exceeds the Base Year actuals by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This increase is similar to increases noted in other recent energy rate cases.[3]

Q. Please summarize the Company's proposed Test Year expense for FERC 924 (Property Insurance).

[3] See UE 416 Staff/900, Beitzel/6-7 and UE 426 Staff/500, Beitzel/6 Table 1.

A. For the Test Year, the Oregon-allocated total for FERC Account 924 (Property Insurance) is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** increase from the Base Year (Highlighted in Figure 1 below).[4]

Q. Did Staff investigate the reason for the increase?

A. Yes. Staff reviewed the Company's response to Standard Data Request (SDR) Nos. 058 and 067-074 and DRs 224-225, including the confidential responses. In addition, Staff reviewed the Company's testimony on non-medical insurance in NW Natural/1400, Davilla/13.

Q. Is Staff proposing an adjustment involving any of these types of insurances?

A. No. In reviewing the premiums paid for each different type of insurance, Staff concluded the Company's decision to carry these types of insurance coverage is prudent and that the insurance premiums appear reasonable, despite the steady increases in cost. Because of the competitive nature of the insurance industry, it is Staff's position that premiums paid to protect the utility, and ultimately customers, from high dollar casualty losses represents a prudent business decision and that no adjustment is necessary.

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4 Staff/702, NW Natural amended response to Staff DR 224 - Confidential Attachment 1.

ISSUE 2. DIRECTORS AND OFFICERS INSURANCE

Q. What is D&O Insurance?

A. Directors and Officers insurance is liability insurance payable to the Directors and Officers of a company, or to the organization itself, as reimbursement for losses or advancement of defense costs in the event an insured suffers such a loss as a result of a legal action brought for alleged wrongful acts in their capacity as directors and officers. Such coverage can extend to defense costs arising out of criminal and regulatory investigations and trials as well. Intentional illegal acts, however, are typically not covered under D&O policies.

Q. Please explain the standard adjustment to D&O Insurance expense as it relates to NWN's request.

A. Staff has routinely recommend removal of 50 percent of Excess D&O liability insurance as a shareholder cost.[5] This methodology has been followed by Staff in previous dockets in both electric and natural gas utility general rate cases and approved by the Commission.[6] This adjustment is shown in Staff Exhibit 703.

Q. Please explain the rationale for this standard adjustment procedure.

A. D&O insurance protects senior management in the event that they are sued, whether by customers, shareholders, or others in conjunction with the performance of their duties. Customers, who have no say in electing or appointing a Utilities Directors or Officers, should not be held financially

[5] *In re* Portland *General Electric Company*, OPUC Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).

[6] *Ibid*.

responsible for providing 100 percent of the insurance coverage against business decisions or improprieties by management which results in lawsuits. Additionally, a large number of claims are brought by shareholders; customers should not have to pay the full costs of total D&O insurance. The excess insurance should be considered a joint shareholder/customer cost.

Q. Does the Company include the cost of D&O Insurance premiums in its Test Year expense?

A. Yes. As stated in NWN Confidential Response to DR 224, the Oregon Test Year amount for D&O Insurance is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Oregon allocated (Highlighted in Figure 1 above).[7]

Q. What is Staff's proposed adjustment?

A. Staff proposes to adjust D&O Insurance by a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[7] Staff/702, NW Natural amended response to Staff DR 224 - Confidential Attachment 1.

SUMMARY

Q. Please summarize your recommendations, identifying any adjustments you propose.

A. Related to the Insurance accounts, Staff proposes no adjustment at this time. Related to D&O Insurance expense, Staff proposes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

As noted earlier in my testimony, my recommendations may change based on further review and as informed by the testimonies offered by other parties.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: RUSS BEITZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

WITNESS QUALIFICATION STATEMENT

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Russell (Russ) Beitzel
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Program Manager Rates and Telecommunications Section
ADDRESS:	201 High Street SE, Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science in Accounting, Otterbein University

EXPERIENCE:

I have been employed with the Public Utility Commission of Oregon since 2018. I am currently the Program Manager of the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, revenue requirement calculations, deferred tax calculations, rate spread, and rate design. I have also served as case manager on multiple water rate cases, and have provided testimony in UW 185, UW 182, UW 175, UW 177, UE 374, UG 388, UE 416, and UE 426.

Additionally, I worked at Ashland, Inc. for twenty years as a manufacturing and corporate accountant and business analyst for a business unit with approximately one billion dollars in global annual sales. My accountant duties included product cost analysis, general ledger account analysis, SOX compliance, and internal and external audit compliance. My analyst duties included budgeting, forecasting, financial statement analysis, acquisition tracking, and division financial support for a global business unit.

CASE: UG 490
WITNESS: Russ Beitzel

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

NWN RESPONSES STAFF'S DATA REQUESTS

April 18, 2024

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 69

When were property insurance, liability insurance, workers' compensation insurance, and other insurance policies last updated? What is the termination date of these policies? Please provide "term" sheets that cite the premium costs for all current insurance premiums.

Response:

The policies last renewed on [Start Confidential] [redacted] [End] Confidential] for a term of one year expiring on [Start Confidential] [redacted] [End Confidential].

See Confidential UG 490 SDR 69 Attachment 1 for the "term" sheets citing the premium costs for all current insurance policies is attached.

Confidential information is subject to protection under OAR 860-001-0070 or Commission's Protective Order.

[redacted]

CASE: UG 490
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

REDACTED
OPENING TESTIMONY

Escalations, Cash Working Capital, Regulatory Fees, Income Taxes, Leasehold Improvements

April 18, 2024

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

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Escalation of Test Year expenses.
- Test Year cash working capital included in rate base.
- Test Year expenses for Regulatory Fees.
- Test Year expenses for Income Taxes.
- Test Year leasehold improvements included in rate base.

Q. Did you prepare any exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. ESCALATIONS

Q. Please provide a summary of the Commission's historical treatment of expense escalations.

A. It is Staff policy to use the Consumer Price Index – All Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis (OEA) for year over year escalation. The All-Urban CPI measures price changes in a fixed market basket of goods and services in categories, generally including housing, apparel, transportation, medical care, recreation, education, and others to urban consumers.

Q. Why is it necessary to evaluate the escalation factors applied by the Company?

A. The Company's system Test Year (2025) non-payroll operating, and maintenance expenses were filed as $133.4 million compared to $112.4 million in the Base Year (2023), an increase of $21 million.[1] The Company adjusted for some non-payroll O&M items directly without the use of a CPI, therefore the total increase in non-payroll O&M is not completely attributable to CPI escalation. The Company's application of escalation factors, however, is a very important aspect of its Test Year requested non-payroll O&M expenses and it is necessary for Staff to carefully evaluate the source of the escalation factors and how they are applied.

Q. How did the Company apply escalation factors in the filing?

A. According to the Company:

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[1] UG 490 - Exh. 1400 - OM Model Workpaper.

> The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2024, and January 1, 2025. The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease.[2]

Q. What is the Company's rationale for using the Western Region CPI instead of the All-Urban CPI?

A. The Company testifies, "NW Natural specifically selected the Western Region Urban CPI because a regional CPI provides better measure of aggregate changes experienced by the Company than the national CPI."[3] The Company says it sources its services and materials from within Oregon and Washington, therefore the regional CPI is more reflective of the price changes that the Company faces.

Q. Is using the West Region CPI reasonable considering the Company's cost escalation methodology?

A. No. The Company's claim the West Region CPI is more representative index is belied by their substitution of their own escalation rate for various cost categories. Staff does not disagree that it may be impossible to find an index that perfectly matches the inflation experienced by a utility in each cost category. However, Staff has consistently found the All-Urban CPI is a reliable and appropriate source for escalation and believes consistently using this

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2 NWN Natural/1400, Davilla/8, lines 13 to 19.
3 NWN Natural/1400, Davilla/9, lines 3 to 5.

methodology eliminates "forum shopping" for the most favorable inflation escalator on a case-by-case basis.

Q. Have inflation forecasts changed since the September 2023 OEA report relied upon by the Company in its initial filing?

A. Yes. The most recent OEA publication was the March 2024 report, released on February 7, 2024.[4] The March report shows the 2024 and 2025 expected changes in the Western Region CPI index as 2.7 percent and 2.1 percent, respectively, and the change in All-Urban CPI index is expected to be 2.7 percent for 2024 and 2.0 percent for 2025.

Q. What is Staff's recommendation regarding the use of the Western Region CPI?

A. Although the expected changes in the Western Region CPI and All-Urban CPI index in the March publication are identical for 2024 and differ by 0.1 percent for 2025, Staff maintains its long-standing policy of relying on the All-Urban CPI. Staff recommends adjusting the Company's escalation factors to the All-Urban CPI factors as published in the March 2024 OEA report.

Q. Are you recommending any adjustments based on Staff's CPI recommendation?

A. No. Different parts of the Company's filing have been assigned to various Staff and they will apply Staff's recommended escalation factors in their individual reviews.

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[4] Oregon Economic and Revenue Forecast, March 2024, Release Date: February 7th, 2024.

ISSUE 2. CASH WORKING CAPITAL

Q. What is cash working capital?

A. Cash working capital is the amount of investor supplied capital required by a utility to fund its day-to-day operations to provide service to customers prior to receipt of payment from customers. Cash working capital is included as part of the utility's rate base.

Q. Please provide a summary of the Commission's historical treatment of cash working capital.

A. The Commission has generally required a utility's request for cash working capital to be supported by a current lead/lag study.

Q. Did the Company support its cash working capital request with a lead/lag study?

A. Yes.

Q. How is cash working capital calculated?

A. Cash working capital is calculated by multiplying net lag days by the average daily cost of service. Average daily cost of service and net lag days can be broken into other components as shown in the series of equations below.

1. $Cash\ Working\ Capital\ = Daily\ Cost\ of\ Service * Net\ Lag\ Days$

$$Daily\ Cost\ of\ Service = \frac{Annual\ Cost\ of\ Service}{365}$$

$$Net\ Lag\ Days\ = Revenue\ Lag - Expense\ Lag$$

$$Revenue\ Lag = Service\ Lag + Billing\ Lag + Collection\ Lag$$

$$Service\ Lag = Meter\ Read\ Date - Mid\ Point\ of\ Customers\ \ Usage\ Period$$

$$Billing\ Lag = 0$$

$$Collection\ Lag = \frac{Average\ Monthly\ Receivables}{Average\ Daily\ Sales}$$

2. $$Cash\ Working\ Capital = Daily\ Cost\ of\ Service * \{Service\ Lag + Billing\ Lag + Collection\ Lag - \ Expense\ Lag\}$$

Q. How did Staff evaluate the Company's cash working capital calculation for reasonableness?

A. The breakdown of the cash working capital calculation into the series of equations shown above is useful for Staff to analyze the critical drivers of the requested cash working capital amount. Staff separately analyzed each of the components of the cash working capital calculation, particularly the revenue lag and expense lag.

Q. What is the revenue lag and how did the Company calculate its revenue lag?

A. The revenue lag represents the days between the receipt of services by customers and the eventual payment for those services. The revenue lag is the sum of the service lag, the billing lag, and the collection lag.

Q. How did the Company calculate its service lag?

A. The Company calculated its service lag as the "time from the midpoint of a customer's usage period to the meter read date. The Company bills all customers on a monthly basis and, therefore, the average service lag equates to approximately half of a month or about 15.5 days."[5]

Q. What is Staff's view on the service lag calculated by the Company?

A. Staff believes the Company's service lag is overstated. The Company's method of calculating the service lag did not properly account for months that have an odd number of days and over counts the mid-point of months with odd days by half a day. Staff proposes a method that properly accounts for the half days that are part of a month with an odd number of days. Using Staff's proposed approach, Staff calculates a service lag of 15.2 days.

Last Day	Midpoint Date	Company Method	Staff Proposed Method
1/31/2022	1/16/2022	16	15.5
2/28/2022	2/14/2022	14	14.0
3/31/2022	3/16/2022	16	15.5
4/30/2022	4/15/2022	15	15.0
5/31/2022	5/16/2022	16	15.5
6/30/2022	6/15/2022	15	15.0
7/31/2022	7/16/2022	16	15.5
8/31/2022	8/16/2022	16	15.5
9/30/2022	9/15/2022	15	15.0
10/31/2022	10/16/2022	16	15.5
11/30/2022	11/15/2022	15	15.0
12/31/2022	12/16/2022	16	15.5
		15.5	15.2

Q. What is the impact of reducing the Company's service lag from 15.5 days to 15.2 days?

A. Using the Company's filed cash working capital workpaper,[6] Staff reduced the service lag from 15.5 days to 15.2 days and produced an Oregon allocated

[5] NW Natural/1700, Walker/33, line 19.
[6] UG 490 - Exh. 1713 - WP3 - Cash Working Capital – CONFIDENTIAL.

cash working capital amount that is $292.9 thousand lower than the Company's calculation.

Q. Does Staff have any concerns with how the Company estimated the collection lag and the billing lag?

A. No. The collection lag, which is the interval from the invoice date to the date until the customer pays for service, is calculated by dividing average monthly sales by average daily sales. The billing lag is the interval from when the meter is read and when the company processes an invoice in its billing system. The Company says it bills its customers on the same day that it reads meters, therefore the billing lag is zero days.

Q. How did the Company calculate its expense lag?

A. The Company studied expenses for materials received and services rendered separately. The expense lag for materials received was calculated by comparing the invoice date with the payment date. The expense lag for services rendered was calculated by comparing the midpoint of the service period with the payment date. The Company studied the following expense categories:

1. Purchased Gas,
2. Labor,
3. Payroll, Employee Benefits,
4. Prepaid Insurance,
5. Prepaid Information Technology,
6. Regulatory Fees,

7. Municipal Franchise Fees,
8. Other O&M, and
9. Payroll Taxes and Other Taxes (Federal/State, Corporate Activities Tax and Property Taxes).

Q. Does Staff have any concerns with how the Company calculated expense lead/lag days for any of the expense categories?

A. Yes. Staff is concerned that some of the data used to calculate the information technology expense lead days is not representative of the routine contract that requires the company to have a cash cushion provision in the Test Year. The Company said it conducted its analysis using all contracts that were active in calendar year 2022 and it does not forecast prepaid information technology amounts or contracts.[7] Staff identified three information technology contracts the Company has already paid in full even though they extend through the Test Period. Staff proposes to exclude these three contracts from the Test Year cash working capital calculation.

Q. Which three contracts is Staff proposing to exclude from the expense lag calculation?

A. Staff is proposing to remove the three contracts listed in the confidential table below.

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7 NW Natural response to DR 433.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How does the exclusion of the informational technology contracts whose payment dates and prospective renewal dates fall outside the Test Year affect the Company's cash working capital calculation?

A. Excluding these contracts from the cash working capital calculation reduces the Company's information technology expense lead time from 216.04 days to 205.5 days. The change in the information technology lead time results in a reduction to the Company's cash working capital of $220.4 thousand.

Q. What is your total proposed adjustment to the Company's cash working capital?

A. Adjusting the Company's revenue service lag and the information technology expense lead time as proposed reduces the Company's cash working capital by $513.3 thousand.

ISSUE 3. REGULATORY FEES

Q. What is the Oregon regulatory commission fee in this docket?

A. The regulatory commission fee is composed of two fees, the Oregon Public Utility Commission fee (OPUC fee) and the Oregon Department of Energy, Energy Supplier Assessment (ODE ESA). The OPUC fee is a customer-funded fee whose purpose is to cover operating expenses of the Oregon Public Utility Commission. The Commission approves a rate used to collect OPUC fees and the rate is applied to a utility's revenues. The energy supplier assessment is similarly levied on energy suppliers operating in Oregon to fund the Oregon Department of Energy operations. Yearly energy supplier assessments are approved by the Oregon legislature and are capped at 0.375 percent of revenues.[8]

Q. How much is the Company requesting for OPUC fees in the 2024 Test Year and how does it compare to the 2022 Base Year?

A. The Company is requesting $4.024 million in regulatory fees for the Test Year compared to $4.006 million in the Base Year, an increase of 0.5 percent.

Q. What was the OPUC fee rate in effect at the time of the Company's filing?

A. At the time of NW Natural's filing the OPUC fee rate in effect was 0.43 percent.[9]

Q. Did the Company use the OPUC fee rate in effect at the time of its filing to calculate its Test Year OPUC fees?

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8 How We Are Funded, Oregon Department of Energy, published October 2023.

9 *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 23-057.

A. Yes.

Q. Has the OPUC fee rate changed since the Company's filing?

A. Yes. The Commission approved a new rate of 0.45 percent in Order No. 24-054 entered on February 22, 2024.[10]

Q. What is Staff's proposed adjustment to OPUC fees?

A. Staff proposes to adjust the OPUC fees by applying the current effective rate of 0.45 percent. Applying the new rate produces a Test Year OPUC fees amount of $4.2 million, an increase of $187.2 thousand.

Q. How did the Company estimate the Test Year amount for the Department of Energy, Energy Supplier Assessment?

A. The Company used a three-year ODE ESA average rate and applied that rate to Test Year retail sales.

Q. What is Staff's view on how the Company estimated the ODE ESA?

A. Staff agrees with the Company's three-year average rate approach to determine the Test Year ODE ESA amount.

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10 *In the Matter of The Imposition of Annual Regulatory Fees upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 24-054.

ISSUE 4. INCOME TAXES

Q. Please summarize the Company's filing related to income taxes.

A. The Company presents Test Year state income taxes of $16.9 million and federal income taxes of $26.5 million on exhibit NW Natural/1705.[11] The calculated federal income taxes include $3.2 million of federal tax credits.[12]

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269:

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules**.
> (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.
>
> (2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:
>
> (a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
> (b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;
> (c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;
> (d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;

[11] NW Natural/1705, Walker/1.
[12] NW Natural/1710, Walker/1.

(e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and

(f) Reflect other considerations the commission deems relevant to protect the public interest.

(3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

(a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;

(b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or

(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.

(b) The commission shall adopt rules to implement paragraph (a) of this subsection that:

(A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and

(B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.

(5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Staff initially reviewed tax information in the Company's filing and reviewed the Company's responses to standard data requests. Staff's examination and discovery included confirming the federal and state tax rates, apportionment calculations, calculation of current and deferred income tax expense, application of federal and state tax credits, and the amortization of excess deferred income taxes (EDIT) resulting from the 2017 Tax Act.

Q. Please summarize the Company's filing regarding accumulated deferred income taxes.

A. The Company determined Test Year deferred income tax included in rate base by using the December 31, 2022, deferred income taxes and forecasting forward for incremental amounts. The Company said it considered new capital expenditures as well as previous basis amounts in generating book-tax differences and consequent tax.[13] The amount of Oregon allocated deferred income taxes included in Test Year rate base is $447.9 million compared to $438.1 million in the Base Year.

Q. Is Staff proposing adjustments to income tax expense other than those necessary to finalize the Company's revenue requirement?

A. Other than the EDIT adjustment proposed by Staff witness Luz Mondragon in Staff /200, Staff is proposing no further adjustments to the Company's income tax calculation.

13 NW Natural/1700, Walker/31.

ISSUE 5. LEASEHOLD IMPROVEMENTS

Q. What is NW Natural's proposal regarding leasehold improvements in the filing?

A. The Company proposes to include $18.6 million in leasehold improvements in rate base. The filed leasehold improvements balances are primarily from the Company's headquarters building located at 250 Taylor, in downtown Portland.[14]

Q. What is the Commission's historical treatment of leasehold improvements?

A. The Company initially sought cost recovery associated with leasehold improvements at 250 Taylor in its 2020 GRC, UG 388. The Commission approved a Stipulation resolving all issues in that case that allowed the Company to include leasehold improvements balances as part of its rate base except for specific costs related to a fireplace, water feature, wine cooler, and board room table, which were excluded.[15]

Q. Is the Company's treatment of leasehold improvements consistent with UG 388?

A. Yes. The Company treated leasehold improvements in the same manner in UG 490 as it did in UG 388, including removing the costs that were identified to be excluded from rate base.

Q. Is Staff proposing any adjustments to leasehold improvements?

---

[14] NW Natural/1700, Walker/17.
[15] *In the Matter of NW Natural Gas Company, Request for a General Rate Revision,* UG 388, Order No. 20-364 (October 24, 2020).

A. No.

OTHER TOPICS REVIEWED

Q. Please summarize Staff's review of any other topics that were not explicitly discussed in this testimony.

A. Staff reviewed the Company's Test Year amounts for franchise fees and property taxes. In both cases, the Company relied on a historical three-year average rate applied to a suitable base to estimate the Test Year amounts. The suitable tax base for property taxes is assessed property values and the suitable tax base for franchise fees is the utility's revenue. Staff has relied on the three-year average rate approach in prior rate cases as a reasonable way to estimate franchise and property taxes.

Q. Does Staff agree with how the Company handled franchise fees and property taxes in the filing?

A. Yes.

SUMMARY

Q. Please summarize Staff's proposed adjustments in this testimony.

A. Staff is proposing to reduce the Company's Test Year cash working capital by $513.3 thousand and increase the Company's OPUC fees by $187.2 thousand.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ITAYI CHIPANERA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Itayi Chipanera

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Accounting and Finance Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: B.S., Economics
Idaho State University

M.S., Mathematics
University of Nevada – Reno

M.S., Accounting
Indiana University – Bloomington

EXPERIENCE: I have been employed by the OPUC in the Safety, Rates and Utility Performance Program since April of 2023. Prior to my employment with the OPUC I was employed in various finance roles in the insurance and banking industries including Advantis Credit Union where I was employed as a Senior Risk and Financial Analyst; City of Salem, Oregon, where I was a Finance Management Analyst; and SAIF Corporation where I was an Actuarial Research Analyst. I have worked as a revenue requirement summary witness on the following cases PGE UE 416, AVA UG 461, and IPC UE 426.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

REDACTED
Opening Testimony

April 18, 2024

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

A. My name is Curtis Dlouhy. I am a Senior Economic and Policy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's revised decarbonization asks following the invalidation of the Climate Protection Program (CPP), proposed changes to the renewable natural gas automatic adjustment clause, updates to the Company's residential line extension allowance, and meter modernization program.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit 901: Witness Qualifications Statement
- Exhibit 902: Non-Confidential Responses to Data Requests used in Support of Opening Testimony
- Exhibit 903: Other Documents in Support of Opening Testimony
- Exhibit 904: Staff's Line Extension Allowance Model
- Exhibit 905: Excerpt from Staff's Final Comments in LC 79
- Exhibit 906: Past RG 41 Filings

- Exhibit 907: Confidential Responses to Data Requests used in Support of Opening Testimony

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. CLIMATE PROTECTION PROGRAM

Q. What is the purpose of this section of your testimony?

A. I summarize the regulatory environment surrounding the Climate Protection Program (CPP) in Oregon and provide recommendations on the Company's requested five Full-Time Equivalents (FTEs) related to CPP compliance.

Q. What was the CPP and how did it relate to Executive Order 20-04?

A. Executive Order 20-04 (EO 20-04) was issued by former Governor Kate Brown on March 10, 2020. EO 20-04 directs various state agencies to take action to reduce and regulate greenhouse gas (GHG) emissions in response to climate change. In particular, EO 20-04 sets a target of reducing Oregon GHG emissions to at least 45 percent below the 1990 emissions level by 2030 and at least 80 percent below the 1990 emissions levels by 2050.[1] To meet these goals, Oregon Environmental Quality Commission (OEQC) and Oregon Department of Environmental Quality (ODEQ) were directed to cap and reduce emissions from large stationary sources of GHG emissions, transportation fuels, and all other liquid and gaseous fuels.[2] Among other things, the PUC was directed to prioritize activities that advance decarbonization and determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's goals.[3]

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1 EO 20-04, page 5.
2 EO 20-04, pages 6-7.
3 EO 20-04, pages 7-8.

The CPP was a program implemented by OEQC and ODEQ to implement EO 20-04. The program subjected Oregon natural gas utilities to an annual cap on regulated GHG emissions. This cap would have declined annually until it was equal to a 50 percent reduction of the average annual 2017-2019 emissions in 2035 and a 90 percent reduction of the average annual 2017-2019 emissions in 2050. ODEQ planned to freely distribute the compliance instruments up to the amount of the annual cap, and entities could also choose to invest in bankable Community Climate Investments (CCIs) as an alternative way to meet compliance obligations. In effect, the CCIs would have helped fund decarbonization projects.

Q. Why was the CPP declared invalid and how does DEQ plan to respond?

A. As the Company describes in Exhibit 2000, the rules implementing the CPP were declared invalid on procedural grounds.[4] On January 22, 2024, the OEQC and ODEQ stated that they do not intend to appeal the court's decision but will instead begin a new rulemaking process in early 2024. The proposed rulemaking is active with engagement beginning on April 4, 2024, and is expected to conclude in June 2024. The stated goal is to, "[r]eestablish a climate program with comparable scope and emissions reduction ambitions as the previously adopted Climate Protection Program."[5] The Company expects that this process may take around 12 months to complete.[6]

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4 NWN/2000, Kravitz – Therrien/3.
5 See the Climate Protection Plan Advisory Committee Rulemaking Schedule, here.
6 NWN/2000, Kravitz – Therrien/3-4.

Q. What was Northwest Natural's role in the decision by the Oregon Court of Appeals to declare the CPP invalid?

A. Northwest Natural, along with Oregon's two other investor-owned natural gas companies and several other entities, were the petitioners in the case in which the Court of Appeals ruled the rules establishing the CPP were invalid. Petitioners challenged the rules on both procedural and substantive grounds, but the Court of Appeals' opinion only addressed one procedural challenge, finding it was dispositive and there was no need to review the other challenges.[7]

Q. Why do you believe that this is relevant to your testimony?

A. While EO 20-04 is still effective, the future of the CPP is ambiguous in light of the likelihood that the petitioners in the 2023 Court of Appeals challenge will likely re-new the challenges to any EQC rules re-establishing the CPP. NW Natural and other entities have succeeded in delaying implementation of the CPP and it is likely these entities will continue to their challenges to the program if new rules are implemented. Given the uncertainty surrounding the future of the CPP, Staff is concerned that it is premature for NWN to receive rate recovery for costs to implement the CPP.

On the other hand, to properly plan around the regulatory uncertainty while still making progress towards decarbonization, Staff believes that taking "no regrets" actions that have system benefits whether or not the CPP is active

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7 *Northwest Natural Gas Company, et al., vs. Environmental Quality Commission*, 329 Or. App. 648 (2023).

is the most prudent path forward. These actions may include taking actions to limit system growth for the time being, pursuing energy efficiency actions, or investing in non-pipe alternatives.

Q. How does Staff believe these conflicting concerns be addressed?

A. Staff recognizes the need for a fine balance between allowing the Company to meet Oregon's decarbonization goals, advocating for policies in furtherance of said goals, while also taking into account the setbacks that have already occurred in implementing the CPP and the potential for future setbacks.

Q. Did the Company request that any costs related to the CPP be recovered?

A. Yes. In its opening testimony, the Company requests to recover costs associated with five additional FTEs focused on decarbonization and CPP compliance.[8] In its supplemental testimony, the Company reaffirmed its request to recover costs associated with these positions.[9]

Q. What are the job descriptions for these five positions and why does the Company believe that these positions should still be recovered following the invalidation of the CPP?

A. The Company requests that the following positions be recovered in this general rate case:

- Decarbonization Services Analyst: This position will research new and emerging technologies and develop business cases for decarbonization

[8] NW Natural/1500, Kravitz – Chittum/20.
[9] NW Natural/2000, Kravitz – Therrien/6.

services. The Company states that this is a necessary position because even though the CPP has been invalidated, the Company must take steps to decarbonize and DEQ is opening a new rulemaking related to EO 20-04.[10]

- Decarbonization Services Operations Support: This position exists largely to support the Decarbonization Service Analyst. The Company's reasons to continue asking recovery for this position are similar to the Decarbonization Service Analyst.
- Decarbonization Portfolio Manager: This position was intended to manage the Company's decarbonization portfolio prior to the CPP's invalidation.[11] The Company states that they envisioned this role managing CPP compliance workstreams pre-CPP invalidation. Post invalidation, the Company states that they envision this role as engaging in the upcoming rulemaking process.[12]
- Decarbonization Compliance Rates Analyst: This role focuses on providing regulatory analytical support for the Company's decarbonization efforts. The Company states that this role can support its decarbonization efforts, such as RNG acquisition.[13]
- Peak Load Management Analyst: This position performs research, analysis, and other tasks related to Demand Side Management (DSM)

[10] NW Natural/2000, Kravitz – Therrian/6-7.
[11] NW Natural/2000, Kravitz – Therrian/8.
[12] Id.
[13] NW Natural/2000, Kravitz – Therrian/9.

programs. The Company notes that the Commission stated that it expects the Company take seriously the expectation that they mitigate growth where reasonable while trying to maintain reliable service.[14]

Q. Does Staff believe that the Company should be allowed to recover costs related to all these positions?

A. No. Staff believes that only one of these positions' costs should be recovered for the reasons discussed above.

Q. Which role does Staff believe warrants cost recovery even though the CPP has been declared invalid?

A. Staff supports the inclusion of costs related in revenue requirement to the Peak Load Management Analyst. This support is grounded in Staff's experience and belief that exploring methods to reduce load holds intrinsic value for both the Company and its ratepayers, irrespective of the validity of the CPP or any future decarbonization obligation the Company may have. To this note, Staff views pursuing non-pipes alternatives to be a clear "no regrets" path amid the current regulatory uncertainty.

Q. Please explain your conclusion rate recovery for four or the decarbonization FTEs is not warranted at this time.

A. NW Natural's decarbonization efforts are not new. NW Natural has been actively seeking and investing in RNG projects for many years and has had the regulatory team necessary to obtain rate recovery for RNG investments. NW Natural also participated in the original rulemaking proceeding for the CPP.

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[14] NW Natural/2000, Kravitz – Chittum/10.

Absent a new compliance program with which to comply, Staff does not think addition of four incremental FTEs to manage decarbonization portfolios, explore emerging technologies, manage compliance workstreams, and participate in the EQC rulemaking are warranted.

Q. Why does Staff believe rate recovery for a Decarbonization Compliance Rates Analyst is not warranted?

A. According to the Company's testimony, the Decarbonization Compliance Rates Analyst's primary job is to provide analysis and prepare documents for regulatory proceedings related to decarbonization.[15] Absent the CPP or a successor program, the Company states that this role would still have duties related to developing its RNG resources and working on decarbonization projects related to a future Oregon GHG emissions law.[16] Staff does not envision there being significant analysis of the rate impacts of decarbonization absent the CPP or a successor program and would like to reiterate that the SB 98 targets are entirely voluntary.

Q. Why does Staff believe that the Decarbonization Portfolio Manager does not have sufficient duties to warrant an extra FTE?

A. The Company states that if this position were approved, the duties of managing CPP compliance workstreams and recommending compliance actions will not be part of the job's initial duties.[17] Absent this, the only duty the Company lists

[15] NW Natural/2000, Kravitz – Therrien/9.
[16] Id.
[17] NW Natural/2000, Kravitz – Therrien/8.

for this position is to engage in the upcoming rulemaking process and the implementation of new Oregon GHG laws and regulations.[18]

Staff has concerns with funding a position solely dedicated to participating in a GHG emissions rulemaking process. Staff reiterates that the Company states that the *sole* duty for this position is to engage in a single rulemaking process. Staff remains unconvinced that an entire FTE needs to be devoted to engaging in a *single* rulemaking process that may take upwards of a year. While Staff does not disagree with the Company's claim that managing a decarbonization workstream may warrant a full FTE if the CPP or a similar program were in place, Staff finds no reason that funding this position at the moment is in customers' best interest and believes that these duties could be easily managed by existing Company employees.

Q. Why does Staff oppose the inclusion of the FTEs associated with the Decarbonization Services Analyst and the Decarbonization Services Operations Support in rates?

A. According to the Company's testimony, these positions will pursue decarbonization projects. The Company's testimony emphasizes that absent the CPP, these positions can pursue RNG-related projects related to SB 98 RNG acquisitions targets.[19]

Staff first notes that the RNG acquisition targets are voluntary rather than mandatory. Therefore, Staff is skeptical of the customer benefit of giving the

18 Id.
19 NW Natural/2000, Kravitz – Therrien/7.

Company more resources to pursue RNG projects. The Commission has echoed this skepticism in its previous orders related to RNG acquisition.[20]

In other dockets, Staff has expressed its belief that the Company's RNG acquisitions have failed to provide adequate risk modeling or customer protections.[21] Staff finds it to be imprudent to allow additional RNG administrative costs to be recovered by customers given Staff's concerns about RNG project selection and performance.

Staff agrees with the Company that the Company's decarbonization obligations still exist due to EO 20-04 and believes that the continued decarbonization work must be done absent the CPP. However, given the set back to implementation of the CPP, Staff believes it is premature to include in revenue requirement the costs of five incremental employees to implement the CPP.

Q. Please summarize Staff's overall recommendation regarding the five new FTEs related to decarbonization.

A. Staff recommends that the costs associated with four of the new FTEs be removed from revenue requirement for the reasons described above. The rate impact of this adjustment is included in the overall labor cost adjustment in the testimony of Staff Witness Stephanie Yamada in Staff Exhibit 2000.

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[20] Order No. 23-281, page 12.

[21] See UG 462, Staff/200, Drennan/9.

ISSUE 2. RENEWABLE NATURAL GAS AUTOMATIC ADJUSTMENT CLAUSE

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of testimony is to summarize and respond to the Company's proposed changes to its Renewable Natural Gas (RNG) Automatic Adjustment Clause (AAC) mechanism, which is contained in Schedule 198.

Q. Please provide a brief history about how the RNG AAC in Schedule 198 came to be.

A. The RNG AAC was approved in UG 435 in Order No. 22-388. In this docket, NW Natural Proposed an AAC, Schedule 198, to recover its costs for the Lexington RNG project and future RNG projects. This would have an annual rate effective date of November 1. The Company also proposed to allow the inclusion of a deferral to track any startup O&M costs incurred prior to the RNG project being put into service and any revenue requirement between the project's in-service date and the rate effective date.[22]

Unanimous agreement on the Company's proposal was not reached, with some parties outright opposing the addition of Schedule 198 and other parties proposing modifications. Ultimately, the Commission adopted a version of Schedule 198 that incorporates proposed changes from CUB and Staff. The adopted version allows for the RNG AAC to have an annual rate effective date of November 1 and a deferral between forecasted and actual RNG costs subject to an earnings test at 50 basis points below authorized ROE but does

[22] *In the Matter of Northwest Natural Gas Company, dba NW Natural,* UG 435, Order No. 22-388, page 64 (October 24, 2022).

not allow for a deferral between the in-service date and the rate effective date.[23]

In making this decision the Commission noted that it had many concerns with the mechanism that the Company proposed. In Order No. 22-388, the Commission highlights that SB 98 contains *voluntary* RNG targets, whereas the CPP imposes a comprehensive and mandatory GHG cap and reduce mandate, with targets achievable through various channels. The Commission expressed concern that an overly generous AAC may skew the Company's analysis of CPP compliance towards RNG projects that receive full risk-free cost recovery.[24] Staff has previously expressed concern that the Company's current RNG acquisition strategy appears to be skewed to these rate based RNG projects with high customer risk relative to a less risky RNG off-take agreement.[25] The Commission also expressed that it is common practice to not allow for a deferral between the in-service date and rate effective date and did not find reason to change this practice for RNG projects given the Commission's other concerns.[26]

Q. What changes is the Company's proposing to Schedule 198, RNG cost recovery, and its RNG acquisition strategy?

A. In its opening testimony, the Company proposed to make two main changes to its RNG cost recovery:

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[23] Order No. 22-388, page 82.
[24] Order No. 22-388, page 81.
[25] See UG 462, Staff/200, Drennan/9.
[26] Order No. 22-388, page 83.

1. Permit deferrals between the in-service date of the RNG project and the rate effective date,[27] and
2. Set the earnings test for the RNG AAC at the Company's authorized ROE.[28]

In addition to these main changes, the Company proposes to develop RNG investment projects through the utility rather than through an affiliate, which was used for the Lexington and Dakota City projects.[29]

Q. Regarding the Company's first proposed Schedule 198 change, what reasons does the Company give to justify a deferral for RNG projects between the in-service and rate effective dates?

A. The Company states that the CPP is a mandatory program that requires the Company to make investments for compliance purposes. NW Natural makes the comparison to the Renewable Resource Automatic Adjustment Clauses (RAC) that allow electric utilities to recover costs of renewable electric resources through both an AAC and deferral because such investments are necessary for an electric utility to meet its renewable portfolio standard (RPS) obligations.[30] The Company draws a comparison between the CPP and RPS and believes it is consistent to allow them to defer the revenue requirement between the in-service date and rate effective date for RNG resources.

Q. Does Staff agree that the RAC is a fair comparison?

[27] NW Natural/1500, Kravitz – Chittum/15.
[28] NW Natural/1500, Kravitz – Chittum/20.
[29] NW Natural/1500, Kravitz – Chittum/14.
[30] NW Natural/1500, Kravitz – Chittum/15.

A. Not entirely. Staff notes that RPS requires Oregon-regulated electric utilities to meet their obligation solely through generation of renewable energy whereas the CPP was more agnostic about how the Company can meet its emissions reduction targets. In theory, the Company could have met its entire GHG emissions reductions obligations by reducing its natural gas load to a non-zero level that brings its emissions below the CPP cap through strategic electrification, energy efficiency, non-pipes alternatives, or other means. While RNG is one tool that the Company could have used to meet this obligation, it was far from the only tool.

However, when it comes to RPS this was not possible. It is indeed true that an electric utility could offset some of their RPS obligations by pursuing load reducing strategies such as non-wires solutions, energy efficiency, or demand response. However, the RPS was structured as a percent of load program, meaning that an Oregon utility subject to the RPS would have some renewable energy obligations if it has *any* non-zero load. Therefore, an electric utility was forced to use some level of renewable electricity to meet its obligation in Oregon's RPS framework, whereas NW Natural would have had no obligation to use RNG to meet its CPP obligations.

Further, Staff notes that the regulatory environment surrounding renewable electricity when the RAC was approved is much different than the current challenges facing RNG. Whereas renewable electricity projects at the time the RAC was approved were widely commercially available and well known, Staff notes that RNG is still expected to both be costly and risky—a point that the Commission noted in the Company's most recent IRP, LC 79.[31]

Q. Are there other reasons that Staff believes that comparing the Company's RNG AAC to the RAC is not a good reason to approve the Company's requested?

A. Yes. In UE 416 (PGE's 2023 GRC), Staff testified the use of the RAC should be investigated given the drastic change in policy landscape following the passage of HB 2021 to balance concerns of customer protections with resource acquisition.[32] Staff expressed concerns that the RAC—which was authorized as part of the RPS program— was being used to recover costs associated with HB 2021 that were not clearly needed for RPS compliance. While Staff did not necessarily say that this was detrimental to customers, Staff highlighted the need to balance renewable electricity acquisition with customer protection. If the Commission does believe that the RAC and the RNG AAC are suitable comparisons, Staff still believes that this need to balance acquisition with customer protection is extremely important. For reasons previously stated, Staff believes that the Company's current RNG AAC already benefits the Company at the expense of retail customers. Furthermore, Staff believes that the Company's proposed changes would only exacerbate the imbalance.

Q. Would Staff support this deferral if the CPP were in place?

31 *In the Matter of Northwest Natural Gas Company, dba NW Natural 2022 Integrated Resource Plan*, LC 79, Order No. 23-281, page 12 (August 2, 2023).
32 See UE 416, Staff/1100, Dlouhy/20.

A. No. As stated before, Staff does not believe that the comparison between the RAC and the CPP is fair and therefore does not necessarily warrant the same regulatory treatment. Further, Staff continues to hold the Commission's concerns in Order No. 22-388 that an overly generous RNG AAC mechanism would incentivize the Company to unfairly favor RNG investments in a way that may be detrimental to customers and that allowing this deferral would suboptimally shift both upside and downside risks onto customers.

Q. What reasons does the Company give to justify this deferral after the invalidation of the CPP?

A. The Company states that it still has a decarbonization obligation under ORS 468A.205 and will likely be subject to new laws or regulations concerning its customers' use of natural gas.[33] The Company believes that the deferral will allow it to balance interests of its shareholders and customers in pursuit of this goal.

Q. How does Staff's position on this issue change now that the CPP has been declared invalid over procedural concerns?

A. Staff remains unconvinced by the Company's updated arguments in Exhibit 2000 and believes that allowing a deferral between the in-service and rate-effective dates is even less appropriate now that the CPP has been declared invalid and a successor program is only in the rulemaking stage. Until a new set of rules to execute EO 20-04 are created, it is unclear how effective RNG will be as a compliance resource. As Staff has previously described, this

[33] NW Natural/2000, Kravitz – Therrien/11-12.

uncertainty can be attributed to the Company's own lawsuit that invalidated the CPP. While RNG acquisition would likely further the Company's decarbonization efforts in service of its obligations to a future CPP-like compliance program, Staff worries that allowing the proposed deferral would remove essentially all performance risk from the Company without a quantifiable benefit for customers.

Q. Regarding the Company's second proposed Schedule 198 change, what reasons does the Company give to justify setting the earnings test at authorized ROE?

A. The Company recommends that the earnings test be set at the Company's authorized ROE because the current structure provides a disincentive for projects that offtake more RNG than forecasted. The Company testifies that a project that produces more RNG than expected will have a lower per-unit cost but a higher overall revenue requirement due to the biogas contract being tied to the owner's production of biogas.[34] As a result, the Company may be forced to pay higher than forecasted costs for a project that is performing better than expected.

Q. Does Staff believe that this is a problem that can be solved with better forecasting or a one-sided adjustment to the forecast?

A. Not necessarily. While Staff expects that the Company's ability to forecast the productivity of its RNG projects will improve over time, Staff notes that there would still be differences between the forecasted and actual RNG production.

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[34] NW Natural/1500, Kravitz – Chittum/18.

While it would be reasonable to expect that the Company absorbs trivial differences between the forecasted and actual costs, Staff notes that setting the earnings test at 50 basis points below ROE puts the Company in a regulatory bind that should be avoided.

Q. Why do you believe that 50 basis points below ROE earnings test may put the Company in a regulatory bind?

A. Staff believes it to be best practice to incentivize cost effective projects and to include only prudently incurred costs into rates. As the Company describes in its testimony, an RNG project that increases in total costs can also become more cost effective on a per-unit basis if it produces a high amount of RNG. Therefore, the Commission could incentivize high-upside projects by allowing the Company to provide higher RNG production forecasts and recover costs associated with higher RNG production.

This could result in a situation where the Company's over-forecasting allows it to systematically over-recover costs and retain the excess if the earnings test is not triggered. In this case, the Company would have a less effective project that underspends relative to the amounts included in rates, resulting in a situation where over-collected costs should be returned to ratepayers. If the Commission wanted to prevent this problem mainly through forecasting, it would adopt recommendations to forecast lower RNG production. This also presents a problem though, as these lower-production RNG projects are less likely to be considered cost effective in an RFP or prudence review.

Given the awkward push and pull between wanting to reward low per-unit-cost projects and wanting to maintain the lowest overall cost projects, Staff believes that a change to the earnings test for the RNG AAC may be warranted if the Company's characterization of the issue is correct or the magnitude of the costs associated with the volume of RNG is large enough.

Q. Does Staff believe that setting the earnings test for all costs at authorized ROE is the best way to address the issue raised by the Company?

A. No. It is worth reminding the reader that the total costs of the Company's current RNG projects are a mix between fixed costs and variable costs. Staff does not believe that an earnings test is appropriate for the recovery of the fixed costs associated with an RNG plant due to the perverse investment incentives identified by the Commission in Order No. 22-388. Staff believes that retaining the 50-basis point earnings test for these fixed costs is still optimal and could perhaps be optimal for all costs.

Q. How would Staff propose to address this issue while still being mindful of the perverse investment incentives identified by the Commission in Order No. 22-388 if the costs associated with the volumetric portion of each RNG project are substantial enough?

A. If the volumetric portion of the RNG costs subject to the AAC were substantial enough, Staff would recommend that the Commission subdivide the earnings test for the RNG AAC into two parts. The first part would consider the fixed costs recovered through the Company's RNG AAC; this earnings test would remain at the existing 50 basis points below authorized ROE threshold. The second part would consider the volumetric costs recovered through the Company's RNG AAC; this earnings test would be set at the Company's authorized ROE. Staff believes that this would not over-incentivize RNG investment while still rewarding RNG projects that are more productive than expected.

However, Staff has reason to believe that these costs are trivial in the context of the overall revenue requirement of the RNG costs and thus do not rise to a high enough level of concern to warrant a change to the existing RNG AAC.

Q. How did Staff analyze which portions of the Company's forecasted costs related to its RNG project are fixed vs volumetric?

A. Staff issued a data request asking the Company to estimate the total cost of the Company's two RNG projects if the volume of RNG gas delivered was 20 percent above or below the amount forecasted.[35] Staff found that a change in the forecasted amount led to a trivial change in the overall project costs, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[36] According to the Company's response to Staff DR 459, a 20 percent increase in delivered RNG for Dakota City led to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a 20 percent increase in delivered RNG for Lexington led to **[BEGIN**

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[35] Staff/907, Dlouhy/4.
[36] Staff/907, Dlouhy/4.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**to the overall project costs and recommends no changes to the existing RNG AAC.

Q. The Company also stated that it plans to develop RNG investments through the utility rather than the affiliate. Why does the Company propose to do this?

A. The Company proposes to make this change to its RNG acquisition strategy because the process can be administratively burdensome, and the Commission had previously expressed that the affiliate structure may require additional risk sharing in UG 462.[37]

Q. How was the risk sharing between the Company and its customers resolved in UG 462?

A. In UG 462, the Commission adopted the stipulation between all parties that allowed for customers to only pay up to 75 percent of costs above the stipulated benchmark of the average price per Renewable Thermal Credit (RTC) of the next two lowest bids from NW Natural's 2021 RFP.[38] This was due to concerns about risk allocation between the affiliate and NW Natural customers.

Q. What issues of risk allocation exist between the NW Natural's affiliate and its customers?

A. In theory, the affiliate structure provides some level of separation between the utility and the RNG projects. Given that RNG is an emerging field, there is

[37] NW Natural/1500, Kravitz – Chittum/14.
[38] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Renewable Gas Adjustment Mechanism - Dakota City,* UG 462, Order No. 23-367, Appendix A page 3 (October 16, 2023).

some benefit to insulating customers from a project that could become unwieldy if the project costs are borne in full by the affiliate. Conversely, the Company may be able to retain the excess profits in the event that a particular RNG project is overly successful.

That said, Staff has previously brought up concerns that the Company's chosen method of recovering the capital costs of the affiliate's investments rather than creating an off-take agreement essentially eliminates any of the customer risk mitigation benefits.[39]

Q. Does Staff see any benefit to the Company choosing to house these RNG investments under the utility rather than the affiliate?

A. Yes. Staff agrees with the Company that juggling the AI filing with the RNG AAC filing creates an administratively burdensome process that is hard to manage. AI filings have a statutory deadline to be addressed within 90 days of filing, and the prudence review for a new RNG project must be resolved prior to the November 1 rate effective date in the RNG AAC. It is entirely possible for issues in both dockets to be contingent upon decisions made in the other docket, but the timelines may not align to allow for the dockets to be properly consolidated. Further, Staff believes that it may be easier to scrutinize RNG project details and recommend O&M adjustments if the projects were under the utility's umbrella.

However, Staff also believes that the affiliate could be used more productively if the Company chose to structure the interaction between the

[39] UG 462 Staff/200, Drennan/10.

affiliate and the regulated utility differently. In particular as Staff has pointed out in the past, an affiliate-owned investment with an off-take agreement provides greater customer protection against both upside and downside risk.[40]

Q. Staff has previously recommended approving the use of an affiliate to Portland General Electric (PGE). How is this different?

A. Staff notes that the Commission has concerns about the usefulness of PGE's affiliate and only approved its use on a trial basis.[41] Notwithstanding, Staff notes that the affiliate was only approved with conditions to limit the ways in which the affiliate could operate and measures to ensure that customers remain unharmed should the structure not align with the Commission's goals. In that case, Staff notes that there were tangible investment tax credit (ITC) normalization consequences that translate to direct savings for customers. While some questions about risk sharing may apply to both NW Natural's and PGE's affiliates, Staff is unaware of a use case for NW Natural's affiliate that directly leads to savings for customers if the Company continues to recover the capital costs of the projects through rates.

Q. Does Staff believe that the Company should abandon using its affiliate for RNG acquisition?

A. It is unclear whether the Company should fully abandon the affiliate, but Staff believes that the affiliate is not currently being used in a way to shield customers form financial risk or maximize customer benefits. Staff notes that

[40] UG 462, Staff/200, Drennan/10.
[41] Order No. 23-294, page 1.

the ratepayer benefits of an affiliate entail the affiliate absorbing any positive or negative risks associated with a project that would otherwise be part of the Company's regulated operations. The structure approved in UG 462 of passing through 75 percent of added project costs above the benchmark puts risks back onto the Company's customers, thus diminishing the value of the affiliate in the eyes of the customer. Without the benefit of insulating customers from price shocks or output downsides, Staff doesn't see the value of using the affiliate for future RNG projects. However, Staff does believe that the affiliate could be valuable to the utility's customers if the risk sharing is fairly allocated between the Company's regulated and non-regulated entities.

Q. What is Staff's recommendation regarding the use of the affiliate in RNG acquisition?

A. At the moment, Staff recommends that the Company take one of two actions regarding its affiliate:

1. Stop using the affiliate and house all future RNG investments under the utility's regulated arm. If the Company were to do this, Staff notes that this would come with greater scrutiny about the prudency of the investments and the Company's choice to invest in RNG in a least-cost least-risk manner.
2. Continue to use the affiliate but structure any future agreement as an offtake agreement between the affiliate and the regulated utility. This would allow the Company to use the affiliate as intended while insulating customers from both upside and downside risk.

Staff looks forward to reading other parties' testimony on the issue.

ISSUE 3. RESIDENTIAL LINE EXTENSION ALLOWANCE

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of my testimony is to respond to the Company's proposed changes to its residential line extension allowance program.

Q. What is a line extension allowance (LEA)?

A. As the Company describes in its opening testimony, LEAs are a general practice of providing new customers a discount to an existing natural gas or electric network. The traditional thinking is that these discounts, if quantified correctly, can benefit both new customers and existing customers by decreasing the cost of a new customer joining the system, which then leads to another customer on the Company's system who will be able to contribute to the recovery of the system's existing costs over time.

Q. How has the Company and the Commission treated residential LEAs prior to this case?

A. The Company currently uses a Revenue/Margin Multiplier approach for new residential customers, which was authorized in the Company's last general rate case.[42] Under this approach, the amount granted for a line extension equals a multiple of the annual expected non-fuel base distribution margin revenues.[43] In Order No. 22-388 in UG 435, residential LEAs were revised downward from the previous level of $2,875. The Commission directed the Company to calculate residential LEAs using a 5x margin approach with a cap of $2300. It

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[42] NW Natural/1900, Therrien/8.
[43] NW Natural/1900, Therrien/6.

was also ordered that this amount would be lowered to a 4x margin on November 1, 2023, and then to a 3x margin on November 1, 2024.[44]

In making this decision, the Commission felt that the Company failed to integrate costs associated with new customers related to the CPP.[45] The Commission also felt that the Company's current LEA policy leaves unrecovered rate base even after 30 years of continued service.[46]

Q. How have natural gas LEAs been treated in other states with ambitious decarbonization mandates?

A. Staff Exhibit 903 contains recent orders from Washington and California, which both have decarbonization targets or mandates similar to Oregon's.

California's SB 1477 was signed into law in September 2018 and promotes building-related GHG reduction goals. After this was signed into law, the California Public Utilities Commission (CPUC) underwent a rulemaking to achieve "the State's goals of reducing economy-wide GHG emissions by 40 percent below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner."[47] In furtherance of this goal, the CPUC eliminated residential LEAs and permitted non-residential LEAs only under special circumstances.[48]

Washington state passed the Climate Commitment Act (CCA) in 2021, which created a carbon cap-and-invest program to reduce the States' GHG emissions by 95 percent by 2050. In Docket UG 210729, the Washington

44 NW Natural/1900, Therrien/8.
45 Order No. 22-388, page 48.
46 Order No. 22-388, page 49.
47 Page 6 of CPUC Decision 22-09-026 in Staff Exhibit 903.
48 Page 81 of CPUC Decision 22-09-026 in Staff Exhibit 903.

Utilities and Transportation Commission (WUTC) considered whether natural gas LEAs should continue to be calculated assuming that a customer stays on the natural gas system perpetually. This was done by creating a net present value (NPV) LEA calculation with no end date. In this proceeding, the WUTC determined that natural gas companies LEA NPV should be calculated using a seven-year timeline, which in effect lowered the allowable LEA substantially and better aligned LEAs with the legislature's intent with the CCA.[49] In UE-220053 in Washington, settling parties in Avista's joint natural gas and electricity rate case later agreed to fully phase out natural gas LEAs by January 1, 2025.[50]

Q. Does Staff believe that the outcomes and conclusions from California and Washington are relevant to the LEA discussion in Oregon?

A. Yes. Much like both of Oregon's west coast peers, Oregon has an ambitious decarbonization target through EO 20-04. Therefore, it behooves the Commission to take cues from other jurisdictions where natural gas LEAs were considered in the context of a decarbonizing economy. In particular Staff believes it may be in the Commission's best interest to either consider reducing the timeline used in the NPV calculation of the optimal LEA or eliminating residential LEAs entirely if one were to only compare Oregon to its peers.

However, Staff also conducted its own analysis to determine whether residential LEAs still appeared to be in the best interest of Oregon customers.

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[49] Staff/903, Dlouhy/91

[50] Staff/903, Dlouhy/99.

Q. How does this inform the Company's proposed updates to its residential line extension allowance?

A. The Company modeled the cost of CPP compliance in its updated residential LEA, as was directed in Order No. 22-388. To do so, the Company first changed its LEA calculation methodology to a Discounted Cash Flow (DCF) model wherein the Company calculates the LEA amount that would ensure that a new customer is neither subsidized by nor subsidizes existing customers. Underlying this method is the assumption that the new customer pays rates for some time horizon, thereby paying for existing assets that would otherwise only be paid for by existing customers. The use of a DCF model alone does not incorporate CPP compliance costs, but the Company also makes the following changes to incorporate these costs and update the model:

- An assumption that a new customer brings incremental expenses related to the CPP that are not already in base rates.
- An assumption that a new customer will help pay for additional CPP costs, which is incorporated as a credit in the model.
- Incorporate the new customer's contribution to new, non-growth capital and the decline in rates that occurs due to asset depreciation.
- Incorporate a higher fixed charge and new-customer fixed charge that would go into effect on November 1, 2024, if approved.

- An assumption that the DCF has a 25-year term rather than a 30-year term.[51]

Q. With these new assumptions in the model, what is the Company's new proposal for residential LEAs?

A. The Company's new residential LEA proposal is a four-tiered residential LEA based on expected usage. The Company breaks these four groups into customers expecting to use 0-250 therms, 251-450 therms, 451-650 therms, and over 650 therms per year. Following the invalidation of the CPP, the Company still assumes that it will have a future decarbonization obligation and assumes that the dollar value of the decarbonization obligation falls from the CPP CCA price of $123 per metric ton of CO2 to only $63 per metric ton of CO2.[52] This value was based on the price of a compliance instrument for the Washington Climate Commitment Act, which was the most expensive carbon credit that the Company was aware of in the US as of the publication of the Company's supplemental testimony filed on February 23, 2024.

At a high level, the inclusion of the costs associated with decarbonization makes residential customers with lower expected natural gas usage relatively more valuable to the system than customers with higher usage according to the Company's assumptions. The Company's updated proposed residential LEAs are included in its Exhibit 2000 and reproduced in the table below.

[51] NW Natural/1900, Therrien/19.
[52] NW Natural/2000, Kravitz – Therrien/18.

These represent a small increase in the LEAs proposed in the Company's opening testimony.

Table 1: NW Natural's Proposed Residential LEAs[53]

Supplemental Testimony Proposal				
Usage Tiers (therms)	0-250	251-450	451-650	650+
LEA	$3,700	$3,300	$2,950	$2,200

Q. What has Staff done to analyze the Company's proposed residential LEAs?

A. Staff began by first probing the Company's statement about what it believes makes a sound line extension policy and applied it to the current regulatory environment. This provided Staff with high level insights about the validity of LEAs as a general practice and ways in which the Company's model should be updated if one believes they should exist.

Staff then analyzed the Company's modeling choices to determine whether the updates to the LEA DCF model – both related to CPP costs and unrelated to CPP costs – appeared sound and appropriate.

Finally, Staff considered the equity and energy justice implications of LEAs and how it believes that these implications should fit into the Commission's overall direction on LEAs.

Q. Please summarize Staff's analysis of the Company's residential LEA proposal.

53 NW Natural/2000, Kravitz – Therrien/23.

A. Staff believes that the Company's residential LEA analysis fails to take into account the true cost of CPP or decarbonization, best practices that Staff has pushed for in other dockets, or findings from other jurisdictions. Further, Staff does not believe that the Company's overall problem statement on line extensions is valid here, as a "least regrets" action may actually be taking actions to reduce customer count. Finally, Staff worries that line extensions could lead to greater stranded asset costs, which would likely inequitably harm future customers who are financially unable to electrify or otherwise decarbonize.

With this in mind, Staff recommends that the Commission take one of two actions. Staff's primary recommendation is that the Company stop its practice of offering residential LEAs. As an alternative recommendation, Staff recommends that the Commission maintain its previous decision on phasing out residential line extensions. Staff recommends the phase down follow the timing of having the residential LEAs to a level equivalent to the 2x margin beginning on November 1, 2025, and then 1x margin on November 1, 2026, then entirely eliminate residential LEAs by November 1, 2027.

Q. The Company states that one of the goals of a sound line extension allowance policy is to not subsidize new customers.[54] Is this goal accomplished if LEAs are eliminated?

A. Yes. If the Company eliminates line extension allowances, there are no concerns about existing customers subsidizing new customers.

[54] NW Natural/1900, Therrien/5.

Q. The Company also states that LEAs are meant to allow a level of investment from the natural gas utility commensurate with the incremental revenues from the new customer.[55] Do you agree with the Company's perspective that a line extension policy that supports new investments is necessary in the current regulatory climate?

A. No. While the Company makes a skewed attempt at incorporating decarbonization costs in its line extension allowance policy, the Company's analysis tacitly assumes that these new customers will remain on the system and that expanding or maintaining the Company's system is in the public interest. Although the CPP has been declared invalid, the Company still has aggressive decarbonization obligations through its own initiatives, ORS 468A.205, and EO 20-04 and the likely successor program to the CPP through the ongoing rulemaking.

In its last IRP, the Commission questioned the Company's optimistic assumptions around the availability of RNG and its outright refusal to consider electrification as a compliance resource for the CPP— which the Commission believes may potentially harm customers.[56] Staff believes the Commissions concerns remain valid and worries that a line extension allowance policy that continues to tacitly support future Company investments increases the potential for harm to befall the Company's customers through future stranded asset risk.

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[55] Id.
[56] Order no. 23-281, pages 8-9.

Q. Why does Staff believe that the Company's LEA modeling fails to account for best practices or actual CPP costs?

A. Staff believes that there are multiple questionable assumptions in the Company's LEA DCF model that lead to an improperly large LEA. Namely:

1. The Company chose to use a 25-year payback period. Staff has advocated for a 20-year payback period in past dockets and the WUTC has recommended as little as a seven-year payback period. Given past feedback and the evolution of the LEA conversation, Staff finds it reasonable if not overly generous to use a 15-year payback period.
2. The later years in the Company's NPV model assume that the CPP compliance cost is based on RNG acquisition being the marginal resource and costing a fixed $22 per MMBtu. This is similar to the costs projected by the Company in LC 79 that Staff took issue with.
3. The Company's CPP revenue multiplier assumes that a new customer contributes more revenue to the Company's CPP compliance as the Company's CPP emissions cap decreases. This inherently assumes that the GHG emissions compliance obligations will be passed directly back to the new customer without any consideration of rate spread, rate design, or shareholder burden of decarbonization costs.
4. The Company's CPP model assumes the need for an exceptionally high amount of new non-growth capital expenditures that will be paid for by new customers. Despite Staff's concerns about the Company riskily choosing to invest in the system during a period of regulatory uncertainty,

Staff firmly disagrees with the Company's modeling of costs associated with non-growth capital.

5. The Company's model assumes that a residential new line extension is permanently occupied and paying rates. However, in reality there are likely periods where households remain unoccupied, thus not contributing to covering the Company's revenue requirement.

Q. Regarding your first point, why does Staff believe that a 15-year payback period is more appropriate than a 25-year payback period?

A. As Staff pointed out in UG 461, Staff believes that there is considerable payback risk if one assumes that a customer will continue to use the gas system after 20 years.[57] This could lead to a scenario where new customers are subsidized to join the Company's natural gas system, leave the system early due to future policies, energy preferences, or high natural gas prices, and then leave remaining customers to pay for stranded rate base investments that may not have otherwise been pursued. Even though the CPP has been declared invalid and a successor program is not finalized, Staff still agrees a shorter payback period is more appropriate than the Company's proposed 25-year payback period and its previous 30-year payback period. As Staff has expressed in this testimony, the Company still has its own decarbonization obligations through its own decarbonization targets, ORS 468A.205, and the new decarbonization program that is expected to be in place at the end of an ongoing rulemaking.

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[57] UG 461 Staff/500, Bolton/9.

Staff finds that a 15-year payback period better captures Staff's concerns about stranded asset risks given the uncertain regulatory future created in part by the Company, and provides an upper bound for the possible system benefit of an LEA. Given the WUTC's mandate to use a seven-year payback period—before parties agreed to phase out natural gas LEAs entirely for Avista—and the CPUC eliminating LEAs entirely, Staff believes that a 15-year payback period is still perhaps on the longer timeline for the period over which calculating an LEA.

Q. How does changing the payback period affect the optimal LEA?

A. Lowering the payback period from 25 years to 15 years lowers the breakeven LEA in the Company's DCF model for all usage tiers. Due to lower-usage customers contributing less to CPP compliance costs than higher-usage customers in the last five years, the reduction in the breakeven LEA is felt most strongly in the lowest-usage tiers of the Company's proposed LEA.

Q. Regarding your second point, why do you believe that assuming a CPP compliance cost of $22/mmbtu is incorrect?

A. The Company states in its opening testimony that the $22/mmbtu is meant to represent RNG being the marginal CPP compliance resource. Staff notes that this cost is not far off from the Company's assumed cost of RNG acquisition in LC 79. The Commission raised multiple concerns about both the Company's RNG acquisition strategy and its modeling of RNG in LC 79,[58] and Staff

[58] Order No 23-281, Page 12.

expressed concerns in comments throughout the docket that the Company's modeling of RNG costs did not align with other RNG cost forecasts.[59]

Q. What do you believe is an adequate price to use to model RNG acquisition as the marginal CPP compliance resource?

A. Staff believes that assuming a compliance cost of $30/mmbtu is more reasonable. Staff arrived at this number by considering the costs presented in Table 3 of Staff's Final Comments in LC 79, which is reproduced below.[60] In particular, Staff notes that the Historic EPA D3 Cost ranges from a minimum of $22.46/MMBtu to a maximum of $40.95/MMBtu. S&P also provides estimates of RNG that range from $20/MMBtu to $35/MMBtu. Staff believes that assuming a compliance cost of $30/MMBtu is a suitable midpoint estimate of RNG costs outside of the Company's internal projections that Staff has previously been skeptical of.

Table 2: Staff's RNG Cost Projections in LC 79

	Price
Tranche 1 (1/3 of NWN RNG Supply)	Portfolio cost of $14/MMBtu
Tranche 2 (2/3 of NWN RNG Supply)	Portfolio cost of $19/MMBtu
S&P long-term utility purchase of RNG	$20-25/MMBtu
S&P Transportation RNG	$30-35/MMBtu
Historic EPA D3 Cost – minimum (1/4/2021)	$22.46/MMBtu
Historic EPA D3 Cost – maximum (1/3/2022)	$40.95/MMBtu

Q. Regarding your third point, what is the CPP Revenue multiplier in the Company's LEA DCF model and how is it calculated?

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59 Staff/905, Dlouhy/8.
60 Id.

A. The Company's LEA DCF model assumes that as the CPP cap decreases, the costs associated with the cap rise. Additionally, the Company assumes that the revenues collected from the new customer rise in proportion to the ratio of the percent reduction in the cap in a certain year relative to the base year. This ratio is called the "CPP Revenue Multiplier" in the model. The value of the multiplier— which, by definition, varies between 0 percent and 100 percent— is multiplied by the CPP compliance costs added by the new customer to calculate the new CPP Revenues brought in by the new customer in the model. This is meant to represent new customers being responsible both for their additional CPP compliance costs and a share of future CPP compliance costs.[61]

Q. Do you agree with the way the Company chose to model these added CPP revenues?

A. No. The CPP revenues inherently assume that these new costs will be passed directly onto a new customer and the way that Company chooses to spread the recovery of new CPP costs is a foregone conclusion. It is very possible that these costs are not evenly recovered among the residential class, covered by entities outside of the residential class, or even passed on to the Company's shareholders if the costs associated with the continued practice of subsidizing new customers while needing to meet aggressive decarbonization obligations be considered imprudent or there exists another public policy reason to do so.

[61] NW Natural/1900, Therrien/30.

Staff, therefore, believes that the CPP revenues line item is a gross overestimation of revenues brought in by a new residential customer and therefore outputs a higher optimal LEA estimate than the DCF would if the more realistic assumptions were used.

Staff does however note that modeling the revenues generated to comply with the CPP is a tricky modeling exercise. For the purposes of this testimony, Staff leaves this line item unchanged as a bounding exercise. Due to this very generous assumption, Staff's resulting LEA estimates should therefore be interpreted as highest possible LEA to a new residential natural gas customer when incorporating CPP revenues.

Q. Regarding your fourth point, why do you disagree with the quantity of new non-growth capital assumed in the model?

A. As Staff has stated elsewhere, Staff believes that there is a very real possibility that the least-cost least-risk way to meet the Company's expected decarbonization obligations may be to reduce customer count. If this is indeed the least-cost least-risk strategy, then the amount of non-growth capital should reflect a declining system. However, in a period of regulatory uncertainty, Staff believes that there may be reason at the moment to model non-growth capital as if the customer count were static. Much like Staff's modeling choice for CPP revenues, Staff's choice to not adjust new non-growth capital expenditures downward should be treated as a bounding exercise to demonstrate the highest possible LEA.

Despite Staff's choice to keep non-growth capital expenditures modeled as if there were a static customer count, Staff believes that the Company overstates the amount of non-growth capital expenditures.

Q. Why does Staff believe that the amount of non-growth capital expenditures is overstated?

A. Staff inspected the underlying data that the Company used to model its non-growth capital expenditures, which was submitted in response to Earthjustice's Data Request 42. In a workpaper accompanying the response, Staff found that the Company nets out only some of the costs it classifies as being related to new customer acquisitions. While the costs associated with new mains and new services are removed from the capital expenditures, the Company still includes the costs associated with construction permits and meters and the revenues associated with retained contributions. These two items are clearly tied directly to adding a new customer to the Company's system and thus should be included in the Company's estimation of new non-growth capital expenditures. While the Company states that it excludes these costs in response to Earthjustice by reducing capital expenditures by $2 million, Staff found that this does not fully reflect the full effect of removing these costs. When these are included, Staff found that non-growth capital expenditures were overstated by approximately $25 million per year from 2024 through 2032.

Q. How did Staff choose to model the non-growth capital expenditures after including items that Staff believes the Company erroneously omitted?

A. Staff chose to model the omission of these costs as a decrease in new non-growth capital expenditures by $45 million each year through 2026 and $15 million in 2027 onward. Staff made this choice for two reasons. First, the Company's capital expansion workpapers showed a significant decrease in capital expenditures from 2027 onward, indicating a behavioral breakpoint in capital expenditures that should be preserved for modeling accuracy. Second, Staff notes that the Company's LEA DCF model shows a change in capital expenditures from 2027 onward, so Staff believes it best to be consistent with the Company's modeling choices as much as possible.

Q. What is the effect of including these items in the Company's capital expenditures included in the Company's DCF model?

A. Reducing the Company's capital expenditures in the DCF model reduces the amount of plant that a new customer helps pay for, which in effect reduces the size of the calculated LEA.

Q. Regarding your fifth point, why does it matter that a new connection has stretches where it is unoccupied when calculating an optimal LEA?

A. As the Company models them in their DCF workpapers, line extension allowances assume a new customer is continuously paying rates, thereby contributing to the cost recovery of base rates and lowering the revenue requirement burden for existing customers. If a new line extension is paid for but the home is not yet occupied for a stretch of months or a customer moves and leaves a residence unoccupied for a stretch of months, then the value of the new customer to the system is diminished.

Q. Do you have evidence that a new residence granted a line extension has a period where it is unoccupied before the new customer moves in?

A. Yes. In response to Staff DR 135, the Company notes that there is a typical delay of three to six months from the time between a line extension installation and the time that the customer begins to take service, with the expected time being approximately four months.[62] This means that the first year of customer revenues in the Company's NPV calculation likely accounts for approximately four months' worth of revenues that do not actually occur, which would overstate the system value of the line extension allowance.

To account for this in Staff's modifications to the Company's LEA DCF workpapers, Staff reduces the distribution revenues in the first year by two-thirds to reflect that the Company is unlikely to begin receiving customer bills from a new line extension for approximately four months. In effect, this lowers the system value of a new residential LEA.

Q. Do you believe that Staff's adjustment to the first four months of the Company's LEA DCF model fully address the overvaluation problems that arise from a residence being unoccupied?

[62] Staff/902, Dlouhy/3.

A. No. As stated previously, it is likely that a residence is not continuously occupied throughout the entire fifteen-year period that the new customer is assumed to be billed. While there are likely certain types of dwellings such as rental apartments where this is a large problem and owned single-family residences where this is less of a problem, Staff chose not to model this for the sake of feasibility. Given that the resulting model still overstates the months when a dwelling is occupied and a customer is paying natural gas bills, Staff's change only partially reflects the diminished value of a residential LEA relative to the Company's filed model.

Q. Does Staff make any other changes to the Company's LEA DCF model?

A. Yes, Staff makes the following changes to the Company's model to reflect our recommendations on other topic areas.

- Staff lowers the basic charge for a newly connected customer from $26.25 to $10. Staff Witness Eric Shierman discusses Staff's opposition to the new customer basic charge in Staff Exhibit 1800. In effect, this lowers the optimal LEA substantially.
- Staff updates the ROE and long-term cost of debt to reflect Staff's conservative alternative to the midpoint ROE in its opening testimony as well as stipulated agreements. The effect on the optimal LEA from this change is minimal.

Q. Based on all the changes Staff made to the Company's LEA DCF model, what does Staff believe to be the optimal residential LEA under the Company's current tiered LEA framework?

A. Staff's full DCF model can be found in Staff Exhibit 903. Based on these changes, Staff finds that at all tiers, a line extension *disallowance* is justified at every usage tier even with assumptions that Staff views as overly generous. Table 3 contains a summary of the calculated LEAs for each usage tier using Staff's edits to the Company's LEA DCF model.

Table 3: Staff's Residential LEA by Usage Tier

Model Results at Proposed Consumption Levels (Therms)				
UPC (Therms)	250	450	650	1,000
LEA	-$144	-$1,284	-$2,424	-$4,419
Times Margin	-0.4	-2.4	-3.4	-4.3

Q. Are there additional equity or energy justice reasons that it may be in customers' best interest to end the practice of natural gas residential LEAs?

A. Yes. Staff notes that a likely outcome of decarbonization is a decrease in natural gas use. Even if natural gas use falls across the Company's system, assets and other fixed costs will still be in base rates and contribute to revenue requirement. Even if these assets are not technically stranded assets, it is possible that customers who are induced to join the natural gas system now will be on the hook to pay for these assets in the future even if their usage declines. As these costs accumulate and compliance costs with a possible successor program to the CPP rise, one would expect that customers who have the means to switch away from natural gas will choose to do so for economic reasons or other personal preferences. In effect, this may result in only customers with the lowest ability to leave the natural gas system stuck paying for system costs that they may not have had a part in.

A recent paper from Lucas Davis and Catherine Hausmann found that a ten percent decrease in natural gas utility customer count only results in a five percent decrease in utility revenues, with remaining customers left paying for the difference.[63] Staff finds that the potential exacerbation of energy justice concerns is yet another reason to view removing residential LEAs as a "least regrets" outcome at the moment.

Q. What is your recommendation for residential LEAs?

A. Staff recommends that the Commission take one of two actions. Staff's primary recommendation is that the Company stop its practice of offering residential LEAs. Staff believes this to be in the best interest of customers at the time given the regulatory uncertainty surrounding the successor program to the CPP and the results of Staff's model indicating that a line extension disallowance would be in customers' best interest even with the most generous assumptions.

As an alternative and more conservative recommendation, Staff proposes the Commission maintain its current policy that identified a phase down to the residential LEAs. Such a phase down could be to a level equivalent to the 2x margin beginning on November 1, 2025, and then 1x margin on November 1, 2026, and then entirely eliminate residential LEAs by November 1, 2027.

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63 Staff/903, Dlouhy/177.

ISSUE 4. METER MODERNIZATION PROGRAM

Q. What is the purpose of this section of your testimony?

A. This section addresses the Company's proposed meter modernization program contained in the Company's Exhibit 900.

Q. Please summarize the Company's proposed Meter Modernization Program (MMP).

A. The Company's MMP is an initiative undertaken by the Company to replace portions of its aging metering system. The MMP would replace meters that run "fast" – known as Periodic Cause for Change (PCC) meters – and failing Encoder Receiver Transmitter (ERT) devices.[64] In addition to these two main categories, the Company intends to replace its meter reading software and incorporate newer, ultrasonic meters.[65]

As part of the MMP, the Company also requests three new FTEs to run a new software suite, manage workstreams, and manage the meters' expanded AMI capabilities.[66]

The Company proposes to recover an Oregon-allocated $69.2 million in this rate case and the remainder of the capital costs of the four-year project through future rate cases and the Company's proposed multi-year rate plan.[67] The Company also proposes to use a deferral to capture the substantial but

64 NW Natural/900, Karney/3.
65 NW Natural/900, Karney/3-4.
66 NW Natural/900, Karney/34.
67 NW Natural/900, Karney/37-38.

short-lived O&M costs to deploy these meters rather than recover the costs through base rates.[68]

Q. What does it mean for a meter to run "fast" and what is the Company's criteria for a meter that runs too fast?

A. As the Company describes in its opening testimony, a "fast" meter is a meter that reads a higher volume of natural gas consumed than is actually consumed. A meter is determined to be PCC-eligible if it reads at least 102 percent of the actual metered volume of gas.[69] Existing meters that read between 98 and 102 percent of the actual volume of gas and new meters reading between 99 and 101 percent of actual volumes of gas are determined to be accurate.[70]

Q. Does Staff have any issues with these criteria to determine a fast or accurate meter?

A. Not at this time. Staff notes that the Company's forecasted average use per residential customer in the Company's territory is 660 therms in the test year.[71] A two percent increase in billed volume over the course of the year under the existing tariff rate of $1.29519/therm would improperly charge customers with a fast meter an additional $17 per year.

However, Staff was initially concerned that more could be done to verify whether replacing the family was the right decision ex post. Staff issued a data

[68] NW Natural/900, Karney/39.
[69] NW Natural/900, Karney/7.
[70] NW Natural/900, Karney/8.
[71] NW Natural/1800, Wyman/21.

request asking whether the Company does any analysis on the meters after an entire family is replaced. Based on the Company's response to this data request, the Company does do ex post testing that has indeed resulted in keeping meters in service that were previously thought to be PCC meters.[72]

Q. How does the Company determine which meters need to be replaced?

A. The Company designates all its meters pre-2020 into various families and subfamilies based on the manufacturer, meter characteristics, and the date that the meter is placed in service. Post-2020, families are made solely on the meter manufacture date.[73]

Within each family, the Company selects randomly sampled meters that are taken out of service and tested off site. The Company then determines whether more than 80 percent of meters are deemed to be accurate and more than 90 percent are deemed to be fast by taking into account family size and conducting additional testing on 10 year or older meters if needed. A meter family that is either fast or not accurate is a candidate for being changed out by the Company's criteria.[74]

Q. How long does the Company have to replace meters and how many meters has the Company identified for replacement?

A. The Company has four years following its annual Meter Sampling Report filed in RG 41 to remove any non-conforming meters identified in the report. The Company identifies almost 90,000 PCC meters that must be replaced by

[72] Staff/902, Dlouhy/7.
[73] Id.
[74] NW Natural/900, Karney/9-10.

2026.[75] Additionally, the Company identified approximately 500,000 ERTs contained in the Company's meters that are expected to reach the end of their useful life between now and 2027.[76]

Q. Does the Company plan to replace their current meters with a similar design?

A. In part. The Company's Oregon territory is comprised of almost exclusively diaphragm meters, which uses mechanical components to measure the flow of gas. As part of the Company's MMP, the Company proposes utilizing an equal mix of diaphragm meters and ultrasonic meters.[77]

As the Company describes in its opening testimony, these meters are generally more accurate, have more reliable useful lives, and require less maintenance.[78] Overall, the Company plans to deploy approximately 40,000 diaphragm meters and 50,000 ultrasonic meters.[79]

Q. Please summarize the timeline, expected costs, and cost recovery plan for the Company's proposed MMP?

A. The Company expects the MMP to take approximately four years and plans to roll out the MPP in six batches:

- Batches 1-2: Urban areas that don't benefit as much from the ultrasonic cellular meters, such as Eugene and Corvallis.

[75] NW Natural/900, Karney/12.
[76] NW Natural/900, Karney/3.
[77] NW Natural/900, Karney/26.
[78] NW Natural/900, Karney/19.
[79] NW Natural/900, Karney/35.

- Batches 3-4: Rural and coastal areas that will primarily use the ultrasonic cellular meters from Itron. This batch is being deployed later than the first two batches to accommodate Itron's production timelines.
- Batches 5-6: Primarily replacing the PCCs and ERTs in the Portland metro area.[80]

The Company explains that rural and coastal areas are generally harder to reach for the Company's field crew and will likely benefit more from the remote shutoff capabilities of the ultrasonic meters in the event of disasters such as wildfires or tsunamis.[81]

Q. What does Staff think about the Company's prioritization of meter replacements and choice of where to use its various types of meters?

A. While Staff has some concerns about continuing to switch to primarily ultrasonic meters, Staff thinks that the Company's choice of where to deploy ultrasonic meters is sensible in some cases. Staff understands that servicing a meter in a remote location is relatively more costly than doing so in an urban environment and believes that it is prudent to prefer a slightly higher capital cost meter with lower O&M expenses in this circumstance.

However, Staff holds concerns about whether using ultrasonic meters across the Company's entire service territory would be in customers' best interest should the Company choose to move in that direction in the future. As the Company describes in its opening testimony, ultrasonic meters have a

[80] NW Natural/900, Karney/35.
[81] NW Natural/900, Karney/36.

useful life of approximately 20 years.[82] Based on the Company's response to Staff's data requests, these meters would need to be replaced in their entirety at the end of their useful lives.[83]

However, diaphragm meters generally have a suite of replaceable parts that can extend the useful life of the meter beyond the expected service life and in circumstances where a single component fails.[84] Further, diaphragm meters have an expected useful life of 30 years as opposed to the ultrasonic meter's 20-year useful life.[85] While O&M or warranty considerations may not make diaphragm meters the best option in all cases, Staff expects that there will be many cases moving forward where continuing to use diaphragm meters is a more cost effective way to provide service than a full ultrasonic meter conversion.

Q. Does this mean that Staff is supportive of the Company's MMP?

A. Not entirely. In relation to Staff's thoughts regarding the CPP, the RNG AAC, and the residential LEA, Staff is skeptical whether it is in the customers' best interest to undertake an aggressive initiative to replace and upgrade all the Company's meters at this time. As part of the Oregon's and Company's decarbonization goals, Staff expects that some amount of NW Natural customers will voluntarily choose to electrify for either personal or economic reasons. Any customer that receives a meter replacement and opts to fully

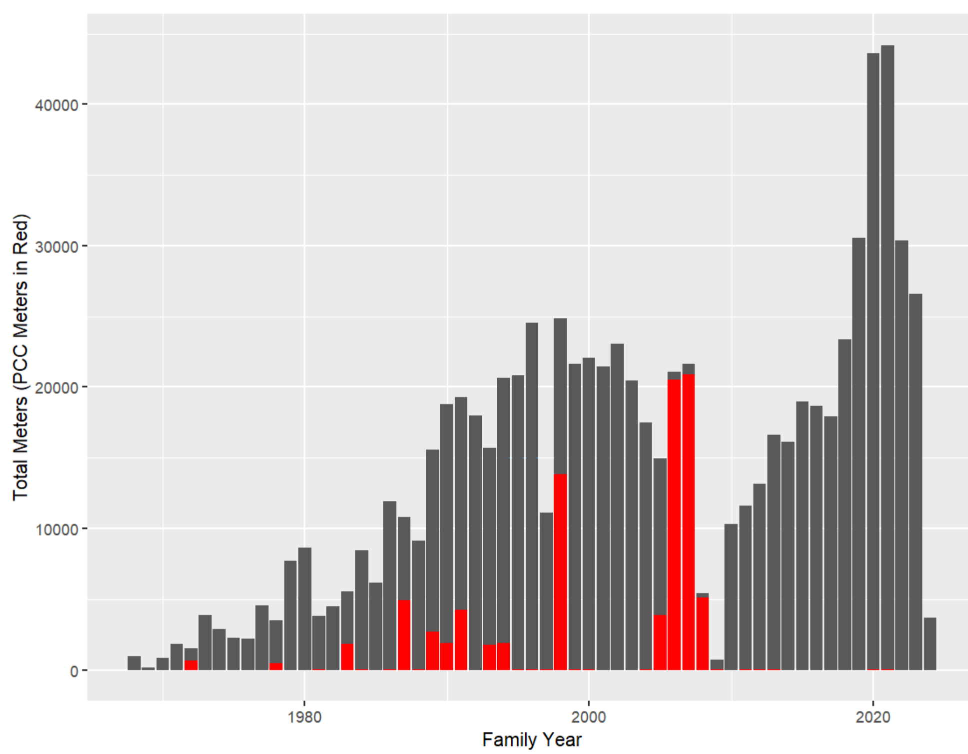
82 NW Natural/900, Karney/19.
83 Staff/902, Dlouhy/5.
84 Staff/902, Dlouhy/4.
85 Staff/902, Dlouhy/10.

electrify before the end of the new meter's service life will necessarily leave stranded asset costs that remaining customers are responsible for paying.

Q. Are there other reasons that Staff has concerns about allowing the Company to fund the replacement of meters through ratepayers?

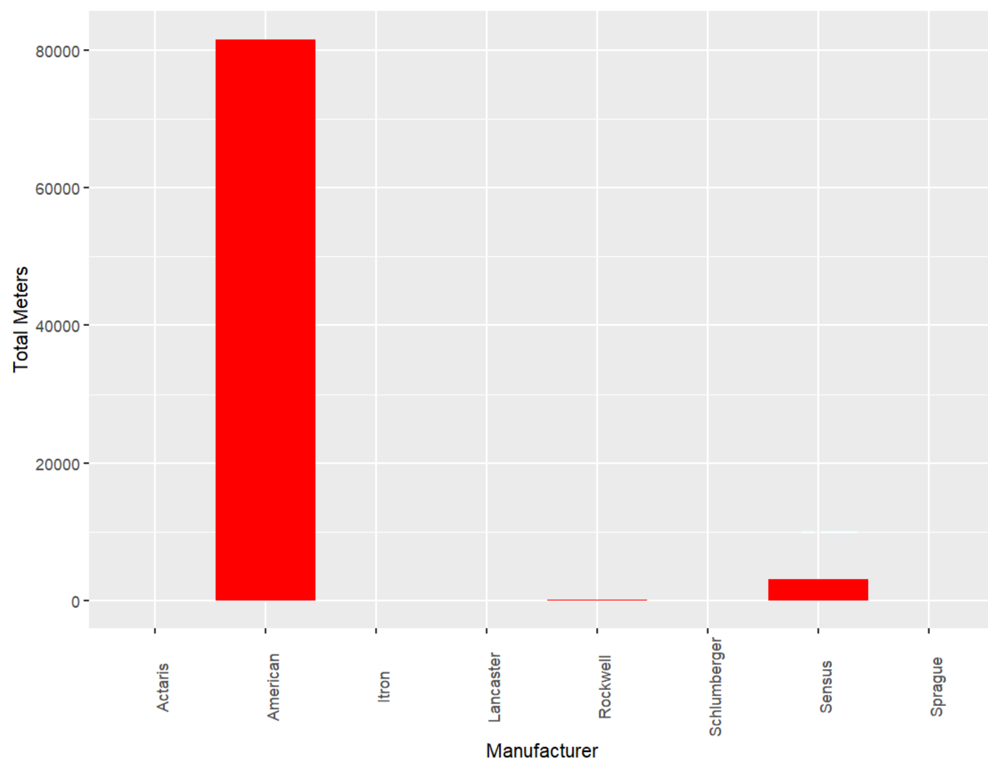
A. Yes. The bulk of the Company's PCC meters appeared to have failed between 2005 and 2008 and seem to come almost exclusively from a single manufacturer. Figure 1 presents a histogram of the Company's meters by their installation year and highlights the quantity of PCC meters within each installation year. The data presented in Figure 1 was compiled from the Company's response to Staff DR 382.

Figure 1 Total Meters and PCC Meters By Family Year



As can be seen in Figure 1, most meters flagged as PCC meters were installed between 2005 and 2008. Figure 2 presents the quantity of PCC meters by manufacturer.

Figure 2: PCC Meters by Manufacturer



Staff notes that the manufacturer American is also known as Honeywell. It can clearly be seen that the bulk of the meters came from American.

Q. Why does the Staff have concerns about the timing of the meter installations?

A. In its response to Staff DR 387, the Company stated that it typically has a 15-year warranty for its meters.[86] Staff notes that many of the PCC meters have been in service for just over 15 years, calling into question whether the

[86] Staff/902, Dlouhy/8.

Company was aware of the problem during the warranty period or should have been aware.

Further, based on the Company's response to DR 387 and discovery from previous dockets, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Does Staff think that the Company could have been aware of these fast meters during the warranty period for the meters?

A. In some cases, yes. Staff Exhibit 906 contains the Company's RG 41 filings from the last four years. Within each year, there are a non-trivial number of meters in each filing that have been in service for less than 15 years.

Q. Has the Company pursued a warranty claim for any of these meters?

A. Yes. According to the Company's response to Staff DR 301 from UG 435, which the Company has provided with its response to Staff DR 387 in this docket, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff issued a follow up data request to determine when these replacement meters were bought or placed in service. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[87] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[88]

Q. Does Staff believe that the Company should have investigated other meters from the manufacturer that is responsible for the defective meters?

A. Yes. Staff notes that not only did the Company identify an entire batch of meters from American that it eventually got refunded through a warranty claim, but the Company also installed a large number of meters from the same manufacturer in each of the prior four years. Staff believes that it would have been a reasonable and prudent step to investigate whether these meters were also systematically running fast given that they came from the same manufacturer and have a similar vintage. Given the large confluence of meters from the same manufacturer that also failed the Company's inspection in such a similar timeframe, Staff is concerned that the Company did not properly

87 Staff/907, Dlouhy/8.
88 Staff/907, Dlouhy/9.

investigate this issue to determine whether it should pursue a warranty claim for these meters prior to the warranty expiring.

Q. What is the net book value of these meters and does the Company intend to remove the net book value of these meters from rate base?

A. It is difficult to exactly determine the net book value of these meters because the Company relies on group depreciation and groups all meters that were put into service in the same calendar year into a single group. Based on the Company's response to Staff DR 461, Staff estimates that the net book value of the PCC meters put into service from 2005 to 2008 to be approximately $9.3 million. Based on the Company's response to Staff DR 462, this amount would continue to be recovered through base rates based on common group depreciation practices.[89]

Q. Why does Staff believe that it is proper to take this amount out of rate base despite common group depreciation practices?

A. As stated previously, Staff believes that the Company could have caught these meters and replaced them under warranty had their quality control been more proactive. Further, Staff questions whether it is in the best interest in customers to replace these meters rather than to merely repair and redeploy them. Therefore, Staff believes that it is improper to fall back on depreciation practices that assume entirely probabilistic asset survival rate.

Q. How does Staff calculate this value?

[89] Staff/902, Dlouhy/12.

A. Staff issued a data request asking for the net book value of meters in each family year. The Company explained to Staff that it uses group depreciation for its meters and could only provide the net book value at the installation year level and provide an average unit cost for the entire year. Using this information, Staff found the average book value of meters in the 2005 to 2008 range and multiplied that by the number of the PCC meters identified by the Company in these years. Staff made this choice after noticing that the in-service year in the Company's Attachment 2 to its response to Staff DR 461 did not perfectly align with the PCC meters by family year in Attachment 1. While Staff believes that this provides a reasonable estimate of the net book value of the meters that should be removed from rate base according to Staff's analysis, Staff welcomes other intervenors or the Company to provide a more accurate methodology to calculate the impact of removing the net book value of these meters from rate base.

Q. The Company states that it chose to replace drifting meters rather than propose a drifting adjustment due to the Commission's opposition to the adjustment in UG 461 and because the ERTs would need to be replaced anyway.[90] Do you think this is sufficient justification to replace PCC eligible meters?

A. Not entirely. Staff highlighted issues with the drift adjustment in UG 461 and the Company notes that it could not impose a drift adjustment if a meter's ERT

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90 NW Natural/900, Karney/32-33.

fails.[91] While Staff understands that there may be instances where it makes sense to replace a PCC meter, that this may be less cost effective than merely replacing the ERT and applying a drift adjustment. Given Staff's concerns about significant stranded asset costs, Staff believes the latter method may be more prudent.

According to the Company's opening testimony, the Company entered into a $28.8 million agreement with Itron to purchase approximately 400,000 ERTs over the coming years.[92] This amounts to a unit cost of approximately $72 per ERT, whereas a new ultrasonic meter with a new ERT costs $200.[93] Further, it is Staff's understanding that a new ultrasonic meter must be entirely replaced at the end of its useful life whereas a diaphragm meter can be refurbished or kept in service. Staff also points out that many of NW Natural's diaphragm meters are still in service well over 30 years. Staff questions whether it is in customers' best interest fully replace a PCC meter and its ERT rather than apply a drift correction and replace the ERT at a third of the cost.

Q. Does Staff have any objections to the three new FTEs related to the MMP?

A. Not at this time.

[91] NW Natural/900, Karney/33.
[92] NW Natural/900, Karney/35.
[93] NW Natural/900, Karney/19.

Q. The Company states that it intends to recover the capital costs of the MMP through a multi-year rate plan and the O&M costs through a deferral.[94] Does Staff agree with this approach?

A. While Staff has raised concerns about the cost effectiveness of the Company's MMP, Staff agrees with the Company that the O&M costs are likely better recovered through a deferral. It is Staff's understanding that the O&M costs are likely to be substantial and short term, meaning that there is risk of the Company over-collecting costs to fund the MMP if the costs remain in base rates and the Company stays out of a rate case for an extended period of time.

Q. Please summarize Staff's take on the Company's Meter Modernization Program.

A. Staff believes that the Company's Meter Modernization Program addresses some of the Company's needs, albeit not necessarily in the most cost-effective manner. Staff takes no issue at this time with the Company's plan to replace ERTs on meters that are nearing the end of their life.

However, Staff is skeptical of the value of transitioning to primarily ultrasonic meters in the long term. As the Company has stated, the more expensive ultrasonic meters have fewer replaceable parts than the existing diaphragm meters and will likely need to be replaced in full at the end of their service life whereas a diaphragm meter is cheaper and may be repaired and redeployed. While Staff believes that there may be appropriate use cases for ultrasonic meters, Staff is wary of investing in the highest-grade technology in

[94] NW Natural/900, Karney/38-39.

an era where the Company is faced with many decarbonization obligations that threaten to drive down the system value of the more expensive and nascent technology.

Staff is also concerned that the Company is replacing many of these meters well before the end of their useful life while keeping the remaining net plant of the meters in rate base. This concern is heightened by Staff's worry that the Company's meter testing practices failed to catch many PCC meters in the 2005-2008 family years while they were still under warranty. Staff recommends that the remaining net book value of the PCC meters in the 2005-2008 family years be removed from rate base to account for Staff's concerns about further building out the gas system in an era of decarbonization and about its concerns that the Company did not do enough to fully investigate the accuracy of these meters while they were still under warranty.

Q. What is Staff's overall adjustment regarding the Company's Meter Modernization Program?

A. Staff's adjustment lowers the Company's Oregon-allocated rate base by $9.316 million to reflect the net book value of PCC meters in the 2005-2008 family years.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 901

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATION STATEMENT

NAME: Curtis Dlouhy

EMPLOYER: Public Utility Commission of Oregon

TITLE: Economist, Strategy and Integration Division

ADDRESS: 201 High St. SE, Ste. 100
Salem, OR 97301-3612

EDUCATION: PhD, Economics
University of Oregon,
Eugene, OR

Master of Science, Economics
University of Oregon,
Eugene, OR

Bachelor of Arts, Economics & Math
Nebraska Wesleyan
University, Lincoln, NE

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399, UE 400, UE 402, UE 416, UE 420, UE 427 (ongoing), and UG 490.

Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes, and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Non-Confidential Responses to Data Requests in Support Of Opening Testimony

April 18, 2024

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 42

Please provide all documents and data provided by NW Natural to Mr. Therrien which he relied upon to prepare NW Natural Exhibits 2000, 2001, 2002, 2003, 2004, 1900, 1901, 1902, 1903, 1904, 1905, 1906, 1907.

Response:

The Company objects to this data request under 860-001-0500 because the request for “all documents and data” is burdensome, overly broad and not commensurate with the needs of this case, the resources available to the parties or the importance of the issues to which the discovery relates. NW Natural also objects on the basis that some of the information requested includes attorney-client privileged information and attorney work product; the attachments to this response are compiled to not contain attorney-client privileged information or attorney work product. Without waiving these objections, the Company responds as follows:

Please refer to UG 490 OPUC DR 378 Attachment 1 and Attachment 2. The tabs, “Input Output - Exh. 1905” and “Input Output - Exh. 1905R (2002)” in Attachment 1 and 2, respectively, indicate data that the Company provided to Concentric Energy Advisors for the exhibits cited above. The data sources are consistent between both attachments. These files can be referenced as follows:

- UG 490 Coalition DR 42 Attachment 1: CPP Proxy Cost for Revised LEA Model.xlsx. Data input: CPP Cost ($/Therm).

- UG 490 Coalition DR 42 Attachment 2: DEQ Compliance schedule - 121621_AttachmentE_Locked.xlsx. Data input: CPP Revenue Multiplier (Annual Cap Percent Change).

- UG 490 Coalition DR 42 Attachment 3: Capex for LEA Analysis.xlsx. Data input: Forecasted System Capex. The “Summary” tab references “Per Jorge email.” The referenced email from Jorge Moncayo, NW Natural’s Business Planning Senior Director – Financial Analysis, described the $2 million/year reduction of the capex numbers to reflect the cost of meters and permits related to new growth, in keeping with the objective of determining future non-growth related capex. It also explained that for years beyond 2032, the capex for 2032 could be used as a proxy.

- UG 490 Coalition DR 42 Attachment 4: 2023 Plant Workpaper.xlsx. Data inputs: Gross Plant and Accumulated Depreciation.
- UG 490 Coalition DR 42 Attachment 5: NWN Depreciation Rates for Concentric.xlsx. Data inputs: Depreciation Accrual Rates.
- UG 490 Coalition DR 42 Attachment 6: NWNG Earnings Review Filing 12-31-2022.pdf. Data inputs: Deferred Taxes, Operations & Maintenance, and Net Utility Plant.
- UG 490 Coalition DR 42 Attachment 7: Workpapers_2022 IRP Scenario Results_v2 (1).xlsx. Data inputs: Customer Count.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 135

Please provide the expected length of time between a residential line extension being fully installed and a residential ratepayer's service with the Company beginning.

Response:

The Company has different expectations for the length of time between a residential line extension installation and when a residential customer is taking service (e.g., when a billing meter is installed and reporting load), depending on market segment. The expected timeline by market segment is as follows:

- Residential conversion services: Three months.
- Residential new construction subdivision services: The billing meter is typically set at the time of service installation, and if not, it is set within three months. The meter is generally set at the time of installation to provide dry-out services to the premise under Rate Schedule 27 Residential Heating Dry-Out Service.
- Residential new construction infill / spot lot services: These projects can occur over longer cycles relative to conversion and new construction subdivision services, but typically billing meters are set within three to six months.

Further, in its estimation of a New Premise Use-per-Customer ("UPC"), the Company found that "in general there is a about a four-month delay between when a [residential] service is initialized and when the bills show therm load.."[1] which is consistent with the Company's expectations described above. For a narrative summary of this analysis, please refer to NW Natural/1800, Wyman/21-24.

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Exhibit NW Natural/1800, Wyman/22, lines 1-3 (December 29, 2023).

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 380

Please discuss whether an entire diaphragm meter must always be replaced at the end of its expected useful life. If it does not, please provide a list of individual components that may be replaced to extend the useful life of the meter, the useful life of these components and the cost of these components.

Response:

No, a diaphragm meter does not need to be replaced when it reaches its expected useful life. For example, if a diaphragm meter is performing normally, it may remain in service fully depreciated for many years after its expected useful life.

A diaphragm meter is considered at the end of its useful life when it must be removed from service. This includes, but is not limited to, when the meter has been declared non-conforming (PCC) by the Meter Sampling Program, if the meter is damaged or otherwise inoperable, the service is being relocated, the meter is sized incorrectly for the load, or if the meter family size is so small that statistical sampling is impractical.

Regardless of the reason for removal, NW Natural replaces these end-of-life diaphragm meters and does not refurbish them. The primary reason for utilizing new meters versus refurbished is that a refurbished meter carries a 1-year warranty, whereas a new meter is given a 15-year warranty from the manufacturer.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 381

Please discuss whether an entire ultrasonic meter must always be replaced at the end of its expected useful life. If it does not, please provide a list of individual components that may be replaced to extend the useful life, the useful life of these components and the cost of these components.

Response:

The ultrasonic meter package has a 20-year life including the meter, RF communications and valve, and we would expect to replace entire meter at that point. Please see NW Natural/900, Karney/Page 19, Lines 9-10.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 382

For each family and subfamily of meters currently in service, please provide:

a. The quantity of meters in the family
b. The In-Service Year for the family
c. The meter manufacturer
d. The cost to purchase each meter
e. The O&M costs associated with installing the meter
f. A description of the geographic area(s) where the meters were installed.
g. An indicator about whether the meter family or subfamily is set to be replaced due to ERT replacement or PCC.

Response:

In response to a follow-up inquiry from the Company, the Staff Initiator of this data request clarified that Staff is requesting aggregated meter information at the family level for all meters. In response to the clarified data request, please see UG 490 OPUC DR 382 Attachment 1 for a comprehensive list of meter families, their in-service year, meter manufacturer, the geographic area where the meter is installed (by Company District) and the number of meters that require ERT replacement or have been declared non-conforming (PCC) and require complete meter replacement. This list is inclusive of the meters in the Company's Meter Sampling Program, which is reflective of approximately 99% of installed meters.

Please note that the list of meters in UG 490 OPUC DR 382 Attachment 1 were developed in response to this data request and will not perfectly tie out to the Company's initial filing in this case because the meter modernization program is already underway and the numbers have changed since that time.

In response to a subsequent follow-up inquiry from the Company, the Staff Initiator of this data request clarified that for subparts (d) and (e), the Company may provide an estimate of expected current costs for the purchase of a new meter (subpart (d)) and with the installation of a meter (subpart (e)). Regarding subpart (d), please see the Direct Testimony of Joe S. Karney, NW Natural/900, Karney/Page 19, Lines 11-15. Regarding subpart (e), please see the Company's response to UG 490 OPUC DR 124.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 386

Please discuss whether the Company performs any ex post testing on a family of PCC meters that were removed.

Response:

NW Natural performs accuracy testing on each meter that is removed from service, including all PCC meters. These test results are recorded for each meter in the Company's Customer Information System. To evaluate the accuracy of the Meter Sampling Program statistical analysis, these test results are periodically evaluated to ensure that the PCC meters being removed from service exhibit the same performance characteristics of the sample meters upon which the PCC determination was based. If the test results from PCC meters removed from service exhibit statistically significant differences from the sample meters, the Company performs additional analysis to determine the reason for the difference.

An example of this analysis was discussed in the Company's RG 41 Annual Meter Sampling Program Report for 2022, included here as UG 490 OPUC DR 386 Attachment 1. A modification to the 2005 Perf #572 Sensus R-275 meter family was made after evaluating meter tests for PCC meters removed from service, where specific delivery lots for these meters were determined to be non-conforming, while others were determined to be conforming, resulting in reducing the number of PCC meters by 6,673. NW Natural continues to evaluate performance of all meters removed from service to ensure accuracy and compliance with the Meter Sampling Program.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 387

Please discuss whether the Company pursues any warranty claims in the event that a family or subfamily of meters does not meet the Company's standards for measurement tolerance. If the Company does receive compensation from a warranty claim, please discuss whether and how the Company returns these monies to ratepayers.

Response:

NW Natural has a 15-year warranty from the three major diaphragm meter manufacturers that provide meters covered under the Company's Meter Sampling Program. These manufacturers are Honeywell (previously known as Elster or American Meter), Itron and Sensus (previously known as Rockwell). If a meter family is determined non-conforming and is within the 15-year warranty period, a warranty claim is pursued for those meters. The claim threshold defined by each warranty specifies that no less than 85% of each shipment shall maintain their original factory setpoint calibration plus or minus 2%, for a period of 15 years.

Warranty claims differ between manufacturers and claims. NW Natural has a pending warranty claim with Honeywell. For more information, please see the Company's response to UG 435 OPUC Confidential DR 301.

If the Company does receive compensation from a warranty claim, the gross plant of the affected meters will be reduced and overall rate base will be reduced. The warranty claims benefit customers by a lower return on meter investments as well as the depreciation expense (return of) those investments in the next rate case and until those meters are retired.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 459

Please provide an estimate of the total 2024 cost for the Lexington RNG project and the Dakota City RNG project under the three following circumstances:

a. Actual RNG offtake is equal to forecasted RNG offtake.
b. Actual RNG offtake is 20 percent higher than forecasted RNG offtake.
c. Actual RNG offtake is 20 percent lower than forecasted RNG offtake.

Response:

Please see Confidential UG 490 OPUC DR 459 Attachment 1. NW Natural can walk through these calculations with Staff at Staff's convenience.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 460

Please provide the expected asset life of the PCC meters that the Company intends to replace as part of the Meter Modernization Program.

Response:

Meters and meter equipment are grouped into categories of like life characteristics as is the standard practice for recovery, therefore individual life per meter asset is not tracked. The current approved and proposed depreciation rate for Meters is based on an average service life of 30 years. Some of the meters being replaced are much older than 30 years and some are not which is consistent with a mortality curve for mass property gas assets.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 461

Please list the dollar value of the gross plant, net plant, and accumulated depreciation of the meters that the Company plans to replace as part of the Meter Modernization Program. When responding to this data request, please break out this request by Family Year.

Response:

NW Natural met with the Staff Initiator on April 1, 2024, to clarify this request. As a result of that meeting, the Company responds as follows. There are two attachments included. UG 490 OPUC DR 461 Attachment 1 is an Excel version of an earlier provided spreadsheet of eligible PCCs by meter family year (UG 490 OPUC DR 382 Attachment 1). UG 490 OPUC DR 461 Attachment 2 is an export from PowerPlan referring to the gross plant, net plant, and accumulated depreciation as of 12/31/2023 of assets inclusive to Meter Modernization.

There are some caveats that should be noted.

For UG 490 OPUC DR 461 Attachment 1:

- Meter modernization will only be changing out residential meter sets from family years 1989 to current. All PCC's from earlier years will be changed out using our internal resources as business as usual.
- A PCC "Family Year" vs. "Purchase Year" may vary somewhat.

For UG 490 OPUC DR 461 Attachment 2:

- NW Natural uses group depreciation, so all vintage years are one asset.
- Average cost provided in column "C".
- For highlighted rows in yellow, we have not updated the quantity within the system yet.
- It reflects the years Meter Modernization will be including, along with the filter of residential meters only.

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Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 462

Please state whether the Company intends to remove from rate base any amounts related to meters that were removed before the end of their useful life as part of the Meter Modernization Program.

Response:

The meters will be retired from plant in service when they are removed and replaced. Based on expected mortality dispersion for all mass property accounts there are many assets that are expected to be replaced before the average and some after the average which is the case for meters. Therefore, rate base is recovered consistent with the mortality life cycle not just a useful life. However, any remaining rate base that may exist will be recovered over the remaining life of the surviving assets which is consistent with group depreciation.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Other Documents in Support
Of Opening Testimony

April 18, 2024

COM/CR6/nd3 **Date of Issuance 9/20/2022**

Decision 22-09-026 September 15, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011

PHASE III DECISION ELIMINATING GAS LINE EXTENSION ALLOWANCES, TEN-YEAR REFUNDABLE PAYMENT OPTION, AND FIFTY PERCENT DISCOUNT PAYMENT OPTION UNDER GAS LINE EXTENSION RULES

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PHASE III DECISION ELIMINATING GAS LINE EXTENSION ALLOWANCES, TEN-YEAR REFUNDABLE PAYMENT OPTION, AND FIFTY PERCENT DISCOUNT PAYMENT OPTION UNDER GAS LINE EXTENSION RULES

Summary

This decision adopts Energy Division's staff proposal to eliminate gas line extension allowances, the 10-year refundable payment option, and the 50 percent discount payment option provided under the current gas line extension rules. The elimination is for all customers in all customer classes effective July 1, 2023. This decision applies to new applications for gas line extensions submitted on or after July 1, 2023. Applications submitted before July 1, 2023 will not be affected by this decision.

These changes move the state closer to meeting its goals of reducing greenhouse gas (GHG)[1] emissions and combating climate change. The result will not only be significant reductions in GHG emissions but also improved quality of life and health for customers, hundreds of millions of dollars in ratepayer savings annually, greater equity for low-income customers, and greater certainty for builders, developers, and individual customers. This decision meets the statutory requirements as set forth in Public Utilities Code Section 783(b)-(d).

This proceeding remains open.

1. Procedural Background

1.1. Senate Bill (SB) 1477

On September 13, 2018, Governor Jerry Brown signed into law SB 1477 (Stern, 2018).[2] SB 1477 promotes California's building-related greenhouse gas (GHG) emission reduction goals, and makes available $50 million annually for

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[1] *See* Appendix A for a list of abbreviations, acronyms, and definitions used in this decision.

[2] SB 1477 was codified as Public Utilities (Pub. Util.) Code Section 748.6, Section 910.4, and Sections 921-922.

four years,[3] for a total of $200 million, dedicated towards two building electrification pilot programs. The funds are derived from the revenue generated from the GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the California Air Resources Board's (CARB) Cap-and-Trade program.[4]

On January 31, 2019, in response to the passage of SB 1477, the California Public Utilities Commission (Commission) initiated this rulemaking to support the decarbonization of buildings in California. The proceeding is:

> designed to be inclusive of any alternatives that could lead to the reduction of greenhouse gas emissions associated with energy use in buildings [related]… to the State's goals of reducing economy-wide GHG emissions 40% below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner.[5]

1.2. Phase I

On May 17, 2019, the assigned Commissioner issued a Scoping Memo and Ruling setting forth the issues to be considered in Phase I of the proceeding (Phase I Scoping Memo). The Phase I Scoping Memo was amended on July 16, 2019 to include additional issues. Phase I was resolved in Decision (D.) 20-03-027, which established the two building decarbonization pilot programs required by SB 1477: the Building Initiative for Low-Emissions

[3] Fiscal Year (FY) 2019-2020 to FY 2022-23.

[4] Four gas corporations currently participate in California's Cap-and-Trade program: Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (SWG).

[5] Order Instituting Rulemaking (OIR) 19-01-011 at 2.

Development (BUILD) Program and the Technology and Equipment for Clean Heating (TECH) Initiative.[6]

1.3. Phase II

On August 25, 2020, the assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase II of this proceeding and included an associated Energy Division Staff Proposal. Phase II was resolved in D.21-11-002, which: (1) adopted guiding principles for the layering of incentives when multiple programs fund the same equipment; (2) established a new Wildfire and Natural Disaster Resiliency Rebuild (WNDRR) program to provide financial incentives to help victims of wildfires and natural disasters rebuild all-electric properties; (3) provided guidance on data sharing; and (4) directed California's three large electric investor-owned utilities (IOUs)[7] to each study energy bill impacts that result from switching from gas water heaters to electric heat pump water heaters, and to propose a rate adjustment in a new Rate Design Window application if their study reflected a net energy bill increase. D.21-11-002 also directed the IOUs to collect data on fuels used to power various appliances, including propane.

1.4. Phase III

On November 16, 2021, the assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase III of this proceeding (Phase III Scoping Memo). Appended to the Phase III Scoping Memo were an Energy Division Staff Proposal (Phase III Staff Proposal or Staff Proposal) and a list of questions to be addressed by respondents and parties. Specifically, Phase III considers eliminating gas line extension allowances

[6] *See* D.20-03-027 at 7.

[7] Southern California Edison Company (SCE), PG&E, and SDG&E.

(allowances), the 10-year refundable payment option (refunds), and the 50 percent discount payment option (discounts) (collectively, gas line subsidies) provided under the current gas line extension rules (gas rules).[8]

The Phase III Scoping Memo set a schedule for the filing and service of comments and reply comments on the Staff Proposal. It also required that comments and reply comments be verified.[9] Verification enables the creation of a robust and reliable record, and allows the Commission to find facts based on those pleadings. It also set a deadline by which parties could file a motion to request evidentiary hearings to cross-examine parties on disputed issues of material fact stated in comments or reply comments, or to seek leave to serve prepared testimony, which in turn might be subject to cross-examination.

Lastly, in compliance with Pub. Util. Code Section 783(c),[10] the Phase III Scoping Memo requested assistance and input from the following state agencies

[8] Gas Rules 15-16 for PG&E (https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_15.pdf, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_16.pdf), SDG&E (https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE15.pdf, https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE16.pdf), and SWG (https://www.swgas.com/1409184638489/rule15.pdf, https://www.swgas.com/1409184638517/RULE_16--GRC_Eff-April-1-2021.pdf), and Gas Rules 20-21 for SoCalGas (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf, https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/21.pdf). Rule 15/20 pertains to gas distribution main extensions and Rule 16/21 pertains to gas service line extensions.

[9] *See* Rule 1.11 and Rule 18.1. Verification requires that the person filing the pleading knows that the statements in the document are true, except for matters which are stated on information or belief, and as to those matters requires that the person believes them to be true. Moreover, it requires that the person declare under penalty of perjury that the foregoing is true and correct. The Phase III Scoping Memo stated that unverified comments and reply comments would only be given the weight of argument.

[10] Pub. Util. Code Section 783(c) states: "The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the

Footnote continued on next page.

and departments: the California State Transportation Agency; the California Department of Food and Agriculture; the California Department of Consumer Affairs (DCA); the California Department of Real Estate (DRE); and the California Department of Housing and Community Development (HCD).[11] On November 17, 2021, the assigned Commissioner sent a follow up e-mail to the Executive Directors (or an equivalent position) of these agencies and departments and invited them to provide input on the Staff Proposal by December 20, 2021.

Verified comments and verified reply comments on the Staff Proposal were filed on December 20, 2021, and January 10, 2022, respectively, by 18 parties: PG&E, SDG&E, and SoCalGas (collectively, the Joint IOUs); SCE; SWG; the Public Advocates Office of the California Public Utilities Commission (Cal Advocates); Clean Energy; Coalition of California Utility Employees (CCUE); California Environmental Justice Alliance (CEJA), Environmental Defense Fund (EDF), Natural Resources Defense Council (NRDC), and Sierra Club (collectively, the Joint Parties); East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Sonoma Clean Power (SCP), and Peninsula Clean Energy (PCE) (collectively, the Joint CCAs); The Utility Reform Network (TURN); and Small Business Utility Advocates (SBUA).[12] No comments or responses from the state agencies and state departments were received.

Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development."

[11] Phase III Scoping Memo at 1 and 12.

[12] The parties filed individual pleadings in several instances and are cited as such in this order. The exception is when they filed jointly and are cited herein as Joint IOUs, Joint Parties, or Joint CCAs.

On January 28, 2022, the assigned Administrative Law Judges (ALJs) issued a ruling seeking clarifications and additional information to assist the Commission in resolving the Phase III issues. On February 21, 2022, comments were filed by Cal Advocates, Clean Energy, SBUA, the Joint Parties, PG&E, SWG, SDG&E and SoCalGas.

On March 22, 2022, the assigned ALJs issued a ruling revising the remaining proceeding schedule and addressing other procedural matters. Specifically, the ruling informed parties of a March 14, 2022, Energy Division data request (ED-DR) sent to PG&E, SoCalGas, SDG&E and SWG; directed the gas utilities to verify and serve their responses to the ED-DR on all parties; provided an opportunity for parties to comment on the gas utilities' responses to the ED-DR; and updated the schedule for the remainder of the proceeding. On April 4, 2022, the gas utilities verified and served their responses to the ED-DR. On April 11, 2022, Clean Energy filed comments on the gas utilities' responses to the ED-DR. On April 18, 2022, the assigned ALJs issued a ruling receiving into the evidentiary record the gas utilities' responses to the ED-DR (April 18, 2022 ALJ Ruling).

No motion was made for evidentiary hearing. No evidentiary hearing was held.

On May 4, 2022, opening briefs were filed and served by PG&E, SoCalGas, SDG&E, Cal Advocates, Clean Energy, the Joint Parties, TURN, and SBUA. On May 18, 2022, reply briefs were filed and served by PG&E, SoCalGas, SDG&E, Clean Energy, the Joint Parties, TURN, and SBUA. The record is the Staff Proposal; comments and reply comments; the gas IOUs' responses to the ED-DR; and parties' briefs. Phase III was submitted for decision on May 18, 2022 (upon receipt of reply briefs).

2. Issues Before the Commission

The Phase III Scoping Memo identified the following issues to be resolved:[13]

A. Whether the Commission should modify or eliminate gas line extension allowances for some or all customer classes (residential and non-residential);

B. Whether the Commission should modify or eliminate gas line extension refunds for some or all customer classes (residential and non-residential); and

C. Whether the Commission should modify or eliminate gas line extension discounts for some or all customer classes (residential and non-residential).

This decision addresses all the issues identified in the Phase III Scoping Memo and concludes Phase III of the proceeding. The proceeding remains open to consider additional building decarbonization issues in future phases.

3. Gas Line Subsidies

3.1. History of Gas Line Subsidies

The history of the gas rules in California dates back more than a century. With Commission decisions beginning in 1915 and continuing to today, California's gas IOUs have an obligation to provide prospective new customers the opportunity to receive utility service via a line extension based on a uniform set of rules. Under current rules, gas IOUs are not obligated to extend gas lines free of cost but must provide the opportunity for customers to be connected to the utility system at reasonable prices, terms, and conditions.

In general, applicants for new service must pay the full cost of the line extension and interconnection but are provided offsets for part of the cost. These offsets, or subsidies, were reasonable when utilities were in a declining cost

[13] Phase III Scoping Memo at 3-5.

industry, in which the addition of more customers led to reductions in the utility's costs and rates, thereby benefiting both old and new customers.

Conditions in the 1970s led the Commission to reconsider these gas line subsidies. These conditions included severe economic and energy challenges such as oil and natural gas embargos, shortages, and significant price increases; increasing cost and environmental concerns from the continued use, and new development of conventional thermal electric generating resources (including oil, gas, coal, and nuclear); inflation; economic stagnation; and repeated gas and electric utility cost and rate increases. In 1974, the Legislature requested that the Commission investigate electric rate structures and consider alternatives that would discourage, rather than encourage, increased energy consumption.

In 1977, the Commission opened an investigation to reconsider line extension rules given these fundamental changes.[14] Among the considerations was whether existing allowances for extensions of gas and electric service should be modified or abolished. Several decisions followed.

In D.91328, the Commission decided to abolish gas and electric line allowances, terminate refunds, and provide incentives for conservation.[15] On rehearing, the Commission decided to phase out line extension allowances over about five years, and established June 1, 1983, for the filing of utility tariffs to begin the phase-out.[16]

The legislature responded to the Commission's decisions ending and phasing out line extension allowances by passing an urgency bill to add

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[14] Case 10260.

[15] D.91328, February 13, 1980.

[16] D.82-04-068, April 1982 and D.82-12-094, December 1982.

Pub. Util. Code Section 783.[17] The new law requires that the Commission continue the line extension rules that were in place on January 1, 1982, and not make any changes (with limited exceptions) unless the Commission made findings on each of seven issues set out in Pub. Util. Code Section 783. Shortly thereafter, the Commission rescinded all prior orders and closed its investigation into line extension rules.[18]

Further consideration of modifying or eliminating gas line subsidies is governed by Pub. Util. Code Section 783(b), which states that whenever the Commission:

> …institutes an investigation into the terms and conditions for the extension of services provided by gas and electrical corporations to new or existing customers, or considers issuing an order or decision amending those terms or conditions, the commission shall make written findings on all of the following [seven] issues.

In summary, the seven issues include an examination of the economic and other effects of line and service extension modifications upon residential and non-residential customers (*e.g.*, agricultural, commercial, industrial), locally funded governmental or district projects, redevelopment projects, existing ratepayers, energy consumption, and energy conservation.

Pub. Util. Code Section 783(c) requires that:

> The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of

[17] SB 48; Stats. 1983, Ch. 1229, Sec. 2, effective September 30, 1983.

[18] D.83-09-066, D.84-04-047.

Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.

Lastly, Pub. Util. Code Section 783(d) requires that:

> Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.[19]

This ensures that the public has at least six months to consider the new order or decision.

3.2. Line Extension Costs and Subsidies

Under current gas rules, the total cost of a gas line extension for an entity (*e.g.*, builder, developer, individual customer) who seeks connection to the utility system (applicant) is paid by the applicant at project commencement. The total project cost is divided into two parts: non-refundable and refundable.[20] Both the non-refundable and refundable parts are paid by the applicant, but the refundable costs are offset or subsidized by all other ratepayers. Refundable costs are first subsidized by "allowances." Refundable costs in excess of allowances, if any, are returned to an applicant via either: (1) refunds over 10 years; or

[19] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[20] Both "refundable" costs and "non-refundable" costs are specified in Section D.6 of Gas Rule 15 for PG&E, SDG&E, and SWG and Gas Rule 20 for SoCalGas. Per Section D.6.a of Gas Rule 15/20, refundable costs include the total estimated installed cost, including taxes, to complete the distribution line extension. Per Section D.6.c of Gas Rule 15/20, non-refundable costs include the estimated value of all substructures and other protective structures. Section E.5 of Gas Rule 16 for PG&E, SDG&E, and SWG, and Gas Rule 21 for SoCalGas specifies that service line extensions are not eligible for refund.

(2) a one-time 50 percent discount at the option of the applicant. These three gas line subsidies are further described below.

3.2.1. Allowances

For residential customers, allowances are fixed amounts awarded by appliance per residential unit. Each gas utility has different allowance levels. The table below has the current allowances.

Table 1. Current Residential Gas Line Extension Allowances (Per Meter or Residential Dwelling Unit, on a per unit basis)

Item	PG&E[21]	SCG[22]	SDG&E[23]	SWG[24]	
				Southern California	Northern California / South Lake Tahoe
Water Heating	$1,391	$1,138	$643	$183	$231
Space Heating	$987	$987	$698	$674	$862
Oven/Range	$84	$201	$114	$69	$28
Dryer Stub	$24	$289	$160	$115	$70
Space Cooling	NA	NA	$1,098	$1,765	NA

For non-residential customers, allowances are provided by a formula that is calculated on a site-specific basis taking into consideration usage, demand, and

[21] PG&E rates effective January 1, 2022 (https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4488-G.pdf).

[22] SCG Rule 20 Gas Rules approved in 2022 (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf).

[23] SDG&E rates approved in 2020 (https://tariff.sdge.com/tm2/pdf/2866-G.pdf).

[24] SWG rates are bifurcated into their two non-contiguous territories (https://www.swgas.com/1409184638489/rule15.pdf).

other factors. The allowance value is equal to "net revenue"[25] divided by "cost of service factor."[26]

In 2021, three of the four California large gas IOUs spent over $104 million on allowances ($81 million on residential allowances and $23 million on non-residential allowances).[27] We note that this amount does not include SDG&E's allowance expenditures.[28] Therefore, if SDG&E's allowance expenditures were to be included, the total amount would be higher.

3.2.2. Refunds

Under the refund option, the gas IOU returns remaining refundable costs (*i.e.*, those that remain after application of allowances) to the applicant over the course of 10 years. Adjustments are made if further development occurs, and new customers are added that utilize the same newly constructed segment of the gas distribution line to fairly allocate common costs.

In 2021, California's four large gas IOUs spent approximately $2.9 million on refunds ($1.5 million in residential refunds and $1.4 million in non-residential refunds).[29] We note that this amount does not include all of SDG&E's refunds

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[25] "Net revenue" is a projection of how much additional revenue a gas IOU is expected to net annually as a result of a new customer using gas.

[26] "Cost of service factor" is a figure that represents the annual cost of servicing one dollar's worth of capital investment for which ratepayers must pay.

[27] The three IOUs are PG&E, SoCalGas, and SWG. The data does not include SDG&E's allowances because SDG&E says that information is not available due to the limitation of SDG&E's project management system. (April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[28] SDG&E did not provide data on allowances to the Commission. In explanation, SDG&E says its project management system does not facilitate data extraction of allowances granted or discounts provided. (*See* April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

[29] April 18, 2022 ALJ Ruling, Attachment 5.

expenditures.[30] Therefore, if all of SDG&E's refund expenditures were to be included, the total amount would likely be higher.

3.2.3. Discounts

The discount payment option is an alternative to the refund option. If the applicant selects the discount option over the refund option, they receive a one-time 50 percent discount on the refundable costs that remain after application of available allowances. The discount is received at the time payments are due and the applicant does not need to wait for refunds over several years.

In 2021, three of four California large gas IOUs spent approximately $23.4 million on discounts ($17.7 million in residential discounts, and $5.7 million in non-residential discounts).[31] We note that this amount does not include SDG&E's discount expenditures.[32] Therefore, if SDG&E's discount expenditures were to be included, the total amount would be higher.

3.2.4. Total Subsidies

Over the last five years (2017 to 2021), California's four gas IOUs (with partial data for SDG&E) spent approximately $622 million (approximately $124 million annually) on gas line subsidies, including allowances, refunds and

[30] SDG&E refund data includes residential and commercial, but not other non-residential (*e.g.*, industrial, agricultural). (April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

[31] The data does not include SDG&E's discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[32] SDG&E did not provide data on discounts to the Commission. In explanation, SDG&E says its project management system does not facilitate data extraction of allowances granted or discounts provided." (*See* April 18, 2022 ALJ Ruling, Attachment 3 at 1.)

discounts.[33] Over the next five years (2022 to 2026) if gas line subsidies continue, the gas IOUs (with partial data for SDG&E) anticipate they will spend approximately $819 million (approximately $164 million annually) on gas line subsidies.[34] The gas IOUs' data shows that this totals more than $1.4 billion over the 10-year period from 2017-2026 (about $144 million annually). The table below provides each of the gas IOUs' historical (2017-2021) and forecasted total gas line subsidies (2022-2026).[35]

Table 2. 2017-2026 Historical and Forecasted Total Gas Line Subsidies ($ million)[36]

IOUs	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total (2017–2026)
PG&E	$44	$57	$75	$88	$69	$101	$106	$105	$101	$97	$843
SoCalGas	$48	$55	$51	$51	$57	$57	$57	$58	$58	$58	$550
SDG&E[37]	$1	$2	$2	$2	$1	$1	$1	$1	$1	$1	$13
SWG	$4	$3	$7	$3	$3	$3	$3	$3	$3	$3	$35
Total	**$97**	**$117**	**$135**	**$143**	**$130**	**$162**	**$168**	**$167**	**$163**	**$160**	**$1,441**

Once the gas line extensions are built, the gas IOUs own and operate the facilities as a part of their systems. The IOUs recover the expended gas line subsidies as capital costs through their ratebase, subject to depreciation and rates of return over the depreciable life (*e.g.*, 30 years) of the line extensions. As a

[33] The total amount includes SDG&E's amounts for refunds but not for allowances and discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[34] April 18, 2022 ALJ Ruling, Attachment 5.

[35] *Id*.

[36] *Id*.

[37] Only partial data for SDG&E.

result, the total amounts paid by ratepayers (revenue requirements) associated with the 2017-2026 total gas line subsidies would be well above the $1.4 billion.

4. Energy Division Staff Proposal

The Staff Proposal recommends eliminating the gas line subsidies for all customer classes. Staff argues that California's gas line subsidies are designed to encourage gas usage, as affirmed in both D.89177 and D.91328, and that by allowing builders to receive a separate allowance for each approved appliance type, builders are incentivized to install more gas appliances in order to defray more costs. Those gas appliances, in turn, perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance, which averages 10 to 20 years for a gas water heater and 18 years for a gas furnace unless the appliance is retired early and replaced with an electric alternative. Additionally, a key strategy to reach carbon neutrality by 2045 is to phase out gas usage in the building sector. Any new gas infrastructure is likely to become a stranded asset. The maintenance and operational costs associated with gas infrastructure will need to be paid for by a shrinking number of future gas customers, which will be reflected in higher rates. These customers are likely to be low-income customers as they face the greatest barriers to electrification, including affordability challenges presented by the upfront costs of electrification. As such, the provision of gas line allowances makes it harder to meet California's GHG reduction goals while increasing the future cost of gas service for customers that are unwilling or unable to switch from gas to electric service.[38] The Staff Proposal provides further details on the following benefits in support of eliminating gas line subsidies for all customer classes.

[38] Staff Proposal. (*See* Phase III Scoping Memo, Appendix A at 24-25.)

4.1. Lowers Gas Consumption and GHG Emissions

The Staff Proposal states that since these subsidies promote the increased and continued use of gas, they perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance unless the appliance is retired early and replaced with an electric alternative. Staff argues that the elimination of these subsidies would result in less gas consumption, more electricity consumption, fewer GHG emissions and less air pollution.[39]

4.2. Results in Ratepayer Savings

According to data submitted by the gas IOUs, and served in response to the March 22, 2022 Assigned ALJs' Ruling, the total amount of subsidies provided across all four gas IOU territories (partial data for SDG&E)[40] in 2021 was approximately $130 million. The IOUs project this to increase in coming years, peaking at $168 million in 2023.[41] Because of data deficiencies from SDG&E, these reported aggregated numbers are undoubtedly lower than the actual subsidies being paid. Additionally, the Staff Proposal states that if a new dual fuel building were to be constructed without gas line subsidies, gas ratepayers would save even more as a result of an additional customer sharing in costs necessary to maintain the common carrier pipeline network, so eliminating the line extension subsidies would save ratepayers hundreds of millions of dollars. Although it is noted that these savings could be used for a multitude of useful purposes, the Staff Proposal does not at this time make any

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[39] Staff Proposal. (*See* Phase III Scoping Memo, Appendix A at 35, 40, and 44.)

[40] The total amount excludes SDG&E's amounts for allowances and discounts because the information is not available due to the limitation of SDG&E's project management system. (*See* April 18, 2022 ALJ Ruling, Attachment 3 and Attachment 5.)

[41] April 18, 2022 ALJ Ruling, Attachment 2 and Attachment 5 at 2.

recommendations on diverting funds for other purposes, but instead highlights that cost savings make other investments possible without causing upward rate pressure.[42] Eliminating gas line subsidies for all new constructions would result in the following estimated minimum savings below.

Table 3. Estimated Annual Savings to Gas Ratepayers from Eliminating Residential Gas Line Subsidies ($ million)

Gas Line Subsidies	2021 Expenditures[43]					Estimated Annual Savings[44] (Average of Forecast 2024-2026)				
	PG&E	**SoCalGas**	**SDG&E**	**SWG**	**Total**	**PG&E**	**SoCalGas**	**SDG&E**	**SWG**	**Total**
Allowances	$39	$40	Did not provide	$2	$81	$47	$41	Did not provide	$2	$90
Refunds	$0.4	$0.1	$1	$.07	$1.57	$.5	$0	$1	$0	$1.5
Discounts	$15	$2	Did not provide	$0.5	$17.5	$18	$2	Did not provide	$0	$20
Total	**$54.4**	**$42**	**$1**	**$2.57**	**$100.07**	**$65.5**	**$42**	**$1**	**$2**	**$110.5**

42 Staff Proposal. *See* Phase III Scoping Memo, Appendix A at 46.

43 April 18, 2022 ALJ Ruling, Attachment 5.

44 April 18, 2022 ALJ Ruling, Attachments 1-5. Estimates are averages provided by the IOUs of projected expenditures from 2024 to 2026. Year 2024 is the first full year that this decision would be in effect.

Table 4. Estimated Annual Savings to Gas Ratepayers from Eliminating Non-Residential Gas Line Subsidies ($ million)

Gas Line Subsidies	2021 Expenditures[45]					Estimated Annual Savings[46] (Average of Forecast 2024-2026)				
	PG&E	**SoCalGas**	**SDG&E**	**SWG**	**Total**	**PG&E**	**SoCalGas**	**SDG&E**	**SWG**	**Total**
Allowances	$8	$14	Did not provide	$1	$23	$13	$14	Did not provide	$1	$28
Refunds	$0.3	$0	$0[47]	$0	$0.3	$1	$0	$0	$0	$1
Discounts	$6	$0	Did not provide	$0	$6	$20	$0	Did not provide	$0	$20
Total	**$14.3**	**$14**	**$0**	**$1**	**$29.3**	**$36**	**$14**	**$0**	**$1**	**$49**

4.3. Places the Financial Responsibility on the Initiating Party

The Staff Proposal argues that eliminating gas line subsidies will force builders, or customers, to shoulder a greater portion of the expenses associated with gas line extensions if they choose to construct a building that uses gas or extends gas service on existing properties. That greater expense, in turn, would be passed on at the point of sale for a new building or directly absorbed by the customer for an existing building. This added up-front cost burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual fuel new construction less desirable and more costly. As such, the builder community would be more likely to gravitate toward all-electric new construction. The Staff Proposal further notes that property price increases for

45 April 18, 2022 ALJ Ruling, Attachment 5.

46 Estimate based on IOU projections reported to CPUC and served as attachment in the April 18, 2022 ALJ Ruling. Figures are 2024 projections as that is the first full year that this decision would be in effect.

47 Commercial only.

dual fuel new construction would become moot if all new homes and offices are built all-electric.[48]

4.4. Incentivizes New All-Electric Construction

The Staff Proposal argues that eliminating the gas line subsidies for all new construction would increase the number of newly constructed all-electric buildings which will likely cost less than newly constructed dual fuel buildings. Dual fuel buildings constructed without gas line extension allowances would be expected to cost more than they do today, but not by more than approximately 0.25 percent on average.[49] The Staff Proposal also notes that specifically eliminating refunds would remove additional incentives for builders to encourage even more dual fuel construction in the future. Because refund payments are contingent on additional dual fuel buildings being added to a newly constructed gas line extension, builders have a strong interest in adding more dual fuel homes in the vicinity of their dual fuel construction projects. Eliminating refunds removes such considerations and motivations for the builder.[50]

4.5. Provides Certainty to Builder Community for Future Projects and Planning

The Staff Proposal states that eliminating refunds has the additional benefit of encouraging a more predictable future for the building industry. California is already on a trajectory toward building decarbonization, which will eventually result in builders receiving less in refund payments as a greater percentage of homes and offices are built all-electric moving forward. Rather

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48 Phase III Scoping Memo, Appendix A at 31.

49 Phase III Scoping Memo, Appendix A at 33-34 and 41.

50 Phase III Scoping Memo, Appendix A at 36.

than have builders speculate as to whether they will ever be refunded their full advance payments for building gas infrastructure, eliminating refunds on a set date lets builders know from what point forward their refund payments will stop, thus enabling the builder community to build that knowledge into their project financing considerations and future revenue assumptions.[51]

4.6. Minimally Impacts Property Prices

The Staff Proposal argues that eliminating the gas line subsidies is not expected to lead to a significant rise in average property prices. To the extent that such a policy change leads to more all-electric new construction, those new homes and offices will be less expensive than if they were built dual fuel due to the elimination of any expense associated with installing gas infrastructure (*e.g.*, trenches, pipes, meters). If a builder opts to still build dual fuel, any resulting property price increase should be minimal.[52] If allowances are eliminated, residential property prices would increase between 0.21-0.25 percent,[53] and non-residential property prices would increase by 0.25 percent.[54] If refunds are eliminated, residential and non-residential property prices are estimated to increase by 0.07 percent.[55] If discounts are eliminated, residential and non-residential property prices are estimated to increase by 0.04 percent.[56] The combined effect of eliminating all subsidies (allowances,

[51] Phase III Scoping Memo, Appendix A at 37.

[52] Phase III Scoping Memo, Appendix A at 31-32.

[53] Phase III Scoping Memo, Appendix A at 32-33.

[54] Phase III Scoping Memo, Appendix A at 33.

[55] Phase III Scoping Memo, Appendix A at 32 and 37-38.

[56] Phase III Scoping Memo, Appendix A at 32 and 41-42.

refunds, and discounts) is 0.32-0.36 percent for residential and non-residential properties.[57]

5. Residential Gas Line Subsidies Revisions

Of the 18 parties commenting on eliminating the gas line subsidies for residential customers, 16 parties endorse the Staff Proposal (or suggest phased elimination) and two oppose.

5.1. Positions of Parties Supporting the Staff Proposal

The 16 parties who endorse the Staff Proposal to eliminate gas line subsidies for the residential sector (or who suggest phased elimination) are: PG&E, SDG&E, SCE, Clean Energy, Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, PCE, and SBUA. SoCalGas did not oppose the recommendation on residential gas line extension allowances, refunds, and discounts as a policy matter. Parties supporting the Staff Proposal make several points.

- Elimination of the gas line subsidies will discourage construction of gas infrastructure while encouraging more all-electric new construction that together will help reduce GHG emissions and improve air quality consistent with California's decarbonization goals;
- Current gas line subsidies provide incentives to install appliances which largely lock-in that use over the 10 to 20-year life of the appliance, which are likely to become

[57] Non-residential property price impacts can be estimated based on the same logic used to estimate residential property price impacts. D.07-07-019 did not make any finding of fact regarding the property price impact associated with the elimination of line extension allowances for non-residential building, but the inputs and assumptions used to determine non-residential allowances (*e.g.*, demand, usage, *etc.*) are largely the same as for residential allowance computations. (Phase III Scoping Memo, Appendix A at 32.)

stranded assets given California's ambitious GHG emissions reduction goals;

- Elimination of gas line subsidies does not prohibit any customer from installing gas appliances in applications that need, or where the customer prefers, to use gas, but it relieves other gas ratepayers from subsidizing the extension for those customers and reduces average gas rates for all gas customers;
- Gas line subsidies originated when interconnecting more customers was thought to lower costs and benefit all; this is no longer the case and the benefits, if any, no longer outweigh the costs of increased GHG emissions and dependence on combustion fuels;
- The elimination of gas line subsidies will save ratepayers hundreds of millions of dollars; support equitable transition from gas to electricity; further California's climate goals; improve air quality and related health outcomes both inside and outside buildings; and provide greater certainty to builders, contractors, and gas distribution workers. Eliminating gas line subsidies is of particular benefit to low-income customers given these financial implications;
- Existing gas line subsidies work against the goals of multiple Commission-authorized building decarbonization programs also funded by ratepayers;
- There will be minimal or no overall negative impacts on workers, with the increased number of jobs in the electric industry being the same or more than the decrease of jobs in the gas industry;
- There will be minimal or no overall negative impacts on low-income customers, as programs such as BUILD, the California Energy Smart Homes Program, and discount rate programs such as the California Alternative Rates for Energy and Family Electric Rate Assistance help mitigate such upfront effects on the affordable housing and low-income sectors. Given their lower rate of new home

purchasing, low-income customers are not typically the ones benefitting from gas line subsidies, yet they contribute towards these subsidies which inequitably increases gas rates for all customers, including low-income customers;

- There will be minimal impacts on property prices, as all-electric new homes are less expensive to build than dual fuel homes. Additionally, programs such as the California Electric Homes Program will provide $75 million in financial incentives and technical support for the construction of new all-electric residential buildings;
- The Commission should consider changes to gas line extension rules in the broader context of California's climate change policy and consult with other state agencies;
- The Joint IOUs recommend a phased elimination to reduce the immediate negative impacts while still accomplishing the overall objectives in support of California's climate goals. In particular, they state that a phased approach would:[58]
    - Avoid near-term gas rate increases if the proposed changes substantially reduce the number of new connections relative to forecasts used in approved ratemaking proceedings;
    - Allow recognition of the varying schedules for future ratemaking proceedings;
    - Allow time for customers to account for increased project costs; and
    - Allow utilities time to study the impact on their electric load profiles and generation needs.

[58] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 9-10.

5.2. Positions of Parties Opposing the Staff Proposal

The two parties who oppose the Staff Proposal in their comments are SWG and CCUE. They make several points in opposition.

- Gas line subsidies allow new customers access to clean, reliable, and affordable fuel (*e.g.*, renewable natural gas, hydrogen) that is poised to contribute significantly to decarbonization efforts;
- Fuel choice should be left to the customer and decisions to reduce GHG emissions should be energy commodity neutral;
- Natural gas systems can decarbonize and play an important role in meeting California's energy objectives;
- Prices for dual fuel homes will increase and prices for all-electric homes will decrease, requiring builders to charge more to offset the loss of the gas line subsidies where natural gas remains in demand (*e.g.*, cold climates);
- Gas rates will increase as fixed costs of the gas system will be spread over a declining customer base, leaving those who cannot afford to electrify or don't have the option to electrify, with higher gas rates;
- Gas industry workers will be negatively impacted, with fewer workers to safely operate and maintain the gas system, safely and properly decommission gas infrastructure, and install new technology, affecting safety and reliability;
- Grid reliability will be negatively impacted as California's supply of gas-fired generation decreases while the need for flexible, fast ramping generation and local reliability remains; and
- A decision in this proceeding should be delayed until Rulemaking (R.) 20-01-007 concludes because both proceedings address similar forward-looking gas infrastructure issues, and delineating the future of natural gas in California is a necessary threshold issue.

5.3. Discussion

5.3.1. Elimination of Gas Line Subsidies for Residential Customers: Approved

This decision adopts the staff's proposal to eliminate the residential gas line subsidies effective July 1, 2023. The elimination of subsidies applies to new applications for gas line extensions submitted on or after July 1, 2023, and will not affect applications submitted to the IOUs before July 1, 2023. Within 30 days of the date of this order, the gas IOUs shall each submit a Tier 2 Advice Letter (AL) to revise their respective gas rules to implement this decision.

We make this revision to the gas rules because it is consistent with state objectives and policy framework. It will move the state closer to meeting its goals of reducing GHG emissions and combating climate change. The cumulative ratepayer savings from avoided gas line subsidies over the life of the gas line extensions will be significant.

As noted above, the total amount in rates paid by all ratepayers (*i.e.*, revenue requirements) associated with the 2017-2026 total gas line subsidies will be at least $1.4 billion. In addition to the significant reductions in GHG emissions and ratepayer savings, these changes will also improve the quality of life and health for customers, provide greater equity for low-income customers, and greater certainty for builders, developers, and individual customers. These benefits are discussed in more detail below.

The Commission also notes the broad support for the Staff Proposal to eliminate the gas line subsidies for the residential sector from a cross-section of parties representing a wide range of interests (*e.g.*, utility, ratepayer, environmental, social justice, community choice aggregators). However, we also address other party concerns in more detail below.

5.3.1.1. Elimination of Residential Gas Line Subsidies Aligns with Overall State Decarbonization Goals

The current gas line subsidies were established during a period when the state's energy needs, and policy goals were very different from today's. They are no longer consistent with today's GHG emission reduction goals, the urgent need to reduce costs and rates, and the long term need to minimize future stranded investment.

The Commission agrees with the Staff Proposal, SCE, Cal Advocates, the Joint Parties, TURN, and the Joint CCAs that the continuation of these subsidies work against today's climate goals and conflicts with SB 32 and SB 1477. As the Staff Proposal correctly points out, current gas line subsidies encourage gas use by providing incentives to builders to install more gas appliances, perpetuating a continued reliance on the gas system both now and over the life of the appliance, and offsetting if not reversing any GHG emission reduction benefits secured through other decarbonization measures.

The Commission also agrees with the Joint Parties that the elimination of the gas line subsidies is essential in complementing the changes made to the 2022 Building Code,[59] which go into effect in 2023.[60] These changes include requiring an electric heat pump space or water heater in standard building design, and electrification readiness (including appropriate electric, space, and plumbing readiness to accommodate a heat pump water heater where not initially installed). The policy would also complement CARB's proposal, laid out in its

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[59] 2022 Building Efficiency Standards (https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2022-building-energy-efficiency).

[60] Opening Brief of Joint Parties at 7-8.

Draft 2022 State Strategy for the State Implementation Plan,[61] to implement a zero-emissions standard for all new space and water heaters by 2030, citing the "opportunity for substantial emissions reductions where zero-emission technology is available."[62]

5.3.1.2. The Elimination of Residential Gas Line Subsidies Improves Overall Quality of Life (GHG Emissions Reductions, Ratepayer Savings, Benefits to Low Income, Greater Certainty)

The Commission also agrees with the numerous supporting parties that the elimination of these subsidies will result in significant societal and ratepayer benefits. These benefits include GHG emission reductions, with improved health conditions for customers via improved indoor and outdoor air quality, with particularly reduced health risks from the reduction of high GHG emitting appliances inside a home. Low-income customers are most likely to face these health risks given they often have less effective stove ventilation systems.[63]

Other impacts include reducing or eliminating a range of other negative environmental effects including land use impacts, wildlife impacts, and impacts on water use and water quality. Building out the natural gas system can cause erosion of minerals and toxins into nearby streams, contamination of drinking water sources, and high levels of water use.[64]

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[61] Although still a draft, this proposal indicates the direction state policy is headed. CARB, Draft 2022 State Strategy for the State Implementation Plan at 86 (https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf).

[62] Opening Brief of Joint Parties at 8.

[63] Opening Brief of Joint Parties at 8-9.

[64] Response of the Joint Parties to the January 28, 2022 Assigned ALJs' Ruling Seeking Clarifications and Additional Information at 5.

The benefits also include hundreds of millions of dollars in utility and ratepayer savings annually and over time. For example, the costs identified by Staff are the costs that the utility must spend each year for construction and installation.[65] Those costs are financed by the utility (*e.g.*, via stocks, bonds, retained earnings) so the funds are available to complete the line extension in the year requested. Those costs are then put into ratebase to be recovered over time (*e.g.*, 30 years) from ratepayers. Thus, the Joint Parties and TURN are correct that the savings identified in the Staff Proposal are understated with respect to the actual cost to ratepayers.[66] The cost is higher since recovery over 30 years costs ratepayers more than would a one-time charge. The elimination of gas line subsidies is one of many steps in furthering the decarbonization of buildings, while easing the burden on residential customers that currently subsidize the new interconnections. This is of particular benefit to low-income customers who face increasing affordability pressures. As the Joint Parties note, the current context perpetuates inequity (*i.e.*, low-income customers are not typically the ones benefitting from gas line subsidies given their lower rate of new home purchasing, yet they contribute towards these subsidies which increase gas rates for all customers).[67]

Additionally, eliminating gas line extension incentives will offer the benefit of greater certainty for the market. This is especially true for the builder community and the contractor community, as noted in the Staff Proposal.

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[65] The customer pays the entire line extension cost upfront, but that total is offset by the subsidies (allowances, refunds, discounts). The utility must fund the subsidies to get back up to the total line extension cost.

[66] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 6.

[67] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 2.

Lastly, eliminating gas line extension allowances is not expected to lead to a significant rise in average property prices per the Staff Proposal. To the extent that such a policy change leads to more all-electric new construction, those new homes and offices will be less expensive than if they were built dual fuel due to the elimination of any expense associated with installing gas infrastructure. On the other hand, construction cost/property prices are likely to increase for those that build dual fuel, necessitating gas line extensions. Data provided in the Staff Proposal, however, shows this increase is limited to about 0.32 percent to 0.36 percent.[68] The Commission agrees that this is a minimal effect on the total cost of a new residential and commercial building. Thus, we find the net benefits from these eliminations to be greater than the additional costs that would be placed on to builders or experienced by owners of new buildings choosing dual-fuel construction.

5.3.1.3. The Elimination of Residential Gas Line Subsidies Benefits Low Income and Vulnerable Communities

Eliminating gas line subsidies will advance equity. This occurs given that low-income customers contribute towards these subsidies through gas rates even though they are typically not the ones applying for, or benefiting from, the gas line subsidies (due to the fact that they are more likely to be renters than homeowners). Equity is advanced by revenue requirements being reduced for

[68] Staff Proposal from ruling of November 16, 2021 at 33 (*see* Phase III Scoping Memo, Appendix A). An increase of 0.036 percent is an increase of $36 for each $100,000.

everyone, including low-income customers, estimated at approximately $164 million annually.[69]

We also note the concern with low-income and vulnerable communities not having the means to electrify, and whether or not they will be "left behind" to carry the burden of higher gas rates as other customers leave the gas system. This is at least in part addressed by current programs, including BUILD and California Energy Smart Homes, which help mitigate these effects by offering subsidies and technical assistance to build homes that are all electric and beyond the current building code. BUILD, in particular, is focused on low-income housing.[70]

Lastly, the Commission agrees with the Joint Parties that:

> …negative implications for affordable housing developers and low-income home purchasers, in terms of upfront purchasing costs, are very small if nonexistent… at least one study has found that electrification in new construction reduces costs over the lifetime of appliances when compared to new homes built with fossil-fuel burning appliances.[71]

5.3.1.4. The Elimination of Residential Gas Line Subsidies Has a Net Positive Impact on Workforce

The Commission acknowledges that as more buildings electrify, there is likely to be a shift in demand for work in both the gas and electric fields. CCUE

[69] Over the next five years (2022 to 2026) if gas line subsidies continue, the gas IOUs (with partial data for SDG&E) anticipate they will spend approximately $819 million (approximately $164 million annually) on gas line subsidies (April 18, 2022 ALJ Ruling, Attachment 5).

[70] Program details about BUILD are available at: https://www.energy.ca.gov/programs-and-topics/programs/building-initiative-low-emissions-development-program. Program details about the California Smart Energy Homes program are available at: https://www.caenergysmarthomes.com.

[71] Opening Comments of CEJA, EDF, NRDC, Sierra Club, and TURN at 7

claims there will be a loss of more than 10,000 gas distribution jobs in California due to decarbonization,[72] while SCE claims a net gain of 7,000 full time jobs (12,400 full time electricity generation and distribution jobs offset by 5,400–6,800 fewer full-time gas distribution jobs).[73] The Commission agrees with SCE that there will likely be a net positive impact as we are likely to see an increase in demand for skilled workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

Additionally, since Track 2 of the Long-Term Gas Planning OIR, R.20-01-007, will be addressing the issue of ensuring an equitable future that minimizes workforce disruption, CCUE's concerns are best addressed in that proceeding. The Scoping Memo in that proceeding lays out a scope that includes how negative impacts on workforce from building decarbonization can be mitigated, what the costs of these mitigation strategies are, and who should be responsible for paying them, among other questions.[74]

5.3.1.5. The Elimination of Residential Gas Line Subsidies Maintains Customer Choice and Advances Equity

The Commission disagrees with SWG that we are removing customer choice by eliminating the gas line subsidies. We reiterate that customers can continue to select their choice of fuel. The only difference is that existing and

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[72] Comments of the CCUE on Phase III Staff Proposal at 5.

[73] Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 4.

[74] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning, Section 2.3.2 at 7 (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M415/K275/415275138.PDF).

future gas customers will no longer have to subsidize investments in the gas infrastructure for new customers. Requiring the new customers to pay their full costs of gas line extensions only places the responsibility back onto builders or customers to shoulder a greater portion of the expense if they choose to construct a building that uses gas or extend gas service on existing properties. Therefore, this change aligns the cost responsibility with the customer who causes the costs, thereby advances equity for all customers.

5.3.1.6. The Elimination of Residential Gas Line Subsidies Will Not Create a Death Spiral

The Commission disagrees with CCUE that this decision will lead to a "death spiral." We acknowledge that the effect of eliminating gas line extension incentives would be that the cost of constructing a building that uses gas, or extends gas service on existing properties, may increase relative to the status quo. This cost would in turn likely be passed down at the point of sale for a new building or directly absorbed by the customer for an existing building. Neither CCUE nor any other party presents any credible data to show that the gas rates increase will cause the cost of a building to escalate so much that demand for buildings will disproportionately decline, leading to higher gas rates and even less building until the gas utility goes out of business, or some other catastrophic outcome for the gas system. Further, there is no support for the argument that there will be a "death spiral" due to the elimination of gas line extension subsidies that leads to an unreliable and unsafe utility system, as discussed more fully below.

Rather, eliminating gas line extension incentives will send a price signal that building new gas infrastructure is more expensive, thus making dual fuel new construction less desirable and financially riskier. As such, there would be a gravitation toward all-electric new construction, leading to all the benefits described above, helping California meet its decarbonization goals. We conclude that these benefits outweigh any concerns about a hypothetical "death spiral" due to the decisions we make here.

5.3.1.7. The Elimination of Residential Gas Line Subsidies Maintains Gas System Reliability and Safety

CCUE argues that the elimination of the gas line subsidies will lead to fewer gas customers and higher rates, putting the utilities at risk of not having enough revenue to cover the costs to pay workers to maintain the system, which leads to a less safe and less reliable gas system. CCUE states that some of the anticipated impacts include fewer leaks detected and repaired (impacting both safety and the climate), reduced customer response levels at call centers, extended response time from reconnections, longer service outages, deferred reliability maintenance projects, deferred gas pipeline replacements, and slower emergency response times.[75]

CCUE's concerns are misplaced. The Commission disagrees with CCUE that eliminating gas line extension subsidies would adversely impact gas system reliability and safety. The Commission's regulatory and ratemaking process consistently ensures that utilities have sufficient resources to operate and maintain a safe and reliable system, and minimize rate impacts. The utilities' revenue requirement covers worker compensation, essential work including leak detections and leak repairs, appropriate customer response levels at call centers, reasonable response times, minimizing service outages, not deferring projects

[75] Comments of CCUE on Phase III Staff Proposal at 3-4.

that are necessary for reliability, not deferring replacements, and maintaining responsible emergency response times. There is no credible evidence that the authorized revenue requirements have been, or will be, inadequate to maintain safe and reliable gas systems. And there is certainly no evidence that utilities will not apply for additional funding as and when necessary. In setting the overall revenue requirement, the Commission does not micromanage how utilities spend their authorized revenue. Utility managements are responsible for allocating the authorized revenue (with limited exceptions) to meet all requirements of the utility system, and apply for additional funding when necessary.

But let there be no misunderstanding, safe and reliable services of the utilities the Commission regulate is our top priority. We disagree that the changes we make in this decision compromises that priority in any manner.

5.3.2. Elimination of Gas Line Subsidies for Residential Customers Through a Phased Approach: Denied

This decision denies the Joint IOUs' proposal to eliminate the gas line subsidies through a phased, or delayed, approach. The Joint IOUs argue that: (1) removing the gas line subsidies too quickly could result in a near-term increase in gas rates if the proposed changes substantially reduce the number of new connections relative to the forecasts within the utilities' approved and ongoing ratemaking proceedings; (2) gas utilities have varying schedules for their ratemaking proceedings so a utility-specific phase-in may be appropriate; (3) customers will have time to account for increased project costs; and (4) utilities will have time to study the impact to its electric load profile and generation needs to ensure the safety and reliability of services.[76] The Joint IOUs recommend a workshop to explore these issues in more detail.

The Commission is not convinced by the Joint IOUs' arguments for a phased approach. Rather, we agree with SCE that we must pursue carbon neutrality with unprecedented urgency and commitment as California is already behind in meeting its 2030 emission reduction targets.[77]

The Joint IOUs do not provide a detailed plan for a phased approach (other than a recommendation to simply delay the elimination of the gas line subsidies). Nonetheless, the Commission considers each of the Joint IOUs' claims with the information we do have but do not find any of them convincing.

The Commission disagrees, for example, that eliminating gas line subsidies now could result in unreasonable near-term rate increases due to a reduction in the number of residential customers. In fact, no credible evidence is presented on what the impact will be on gas rates, let alone that it will be unreasonable. We understand that the change for residential customers due to the policy we adopt today may have an incidental effect on gas rates. We do not, however, foresee that it will be such a significant increase in the near term as to require a phasing in of our policy, particularly given the unprecedented urgency with which we must pursue carbon neutrality. Many variables affect the final determination of the gas rates. The Commission is not convinced that the policy change we adopt today requires special treatment; rather, it can be reasonably addressed when we address all relevant variables in determining gas rates.

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[76] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 9-10.

[77] Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 2.

The Commission disagrees that utilities' varying ratemaking schedules require a utility-specific phase in. No credible evidence is presented that the impact on rates, if any, will be so dramatic that we must account for the timing of various ratemaking proceedings, nor that any effect on rates cannot be addressed within current ratemaking tools.

The Commission also disagrees that customers need more time to adjust. The available evidence is that all electric homes are less costly to construct than dual fuel homes. Customers do not need time to adjust when costs decline. Further, given that the elimination of the gas line subsidies would not take effect until July 1, 2023 (the time required by Pub. Util. Code Section 783(d)), there is already a reasonable amount of time built in for the change, particularly for those customers who still require dual fuel service. Therefore, the Joint IOUs' concerns about sufficient time with regards to the implementation of any changes have already been addressed by statute.

Finally, the Commission disagrees that electric utilities need time to study the impact on load and generation requirements. No credible evidence is presented that the change in the number of residential customers will cause such a dramatic change in the near term as to require delayed implementation in order to study load and generation requirements, particularly with respect to safety and reliability. The changes will be incremental and can be factored into current tools to forecast load and generation requirements to ensure safe and reliable service.

Utilities are obligated to provide safe and reliable service. The Commission adjusts rates so that each utility has the financial resources to do so. Utilities continually consider safety and reliability of their systems and make necessary changes. SCE says, for example, that it continuously evaluates how the grid must evolve to support California's GHG reduction goals. Each year, SCE reports that it conducts transmission, sub-transmission, and distribution system planning assessments for a 10-year planning horizon that identify the grid needs to accommodate new generation resources, customer load and Distributed Energy Resource growth. SCE says it will continue working with the California Energy Commission (CEC) to develop the building electrification forecast and include it in the Integrated Energy Policy Report load forecast to ensure the reliable and affordable integration of building electrification growth into SCE's annual system planning assessments.[78]

The Commission expects that each electric utility, just like SCE, continuously evaluates how the grid needs evolve to support a wide range of goals, including California's GHG reduction goals.

Based on these considerations, the Joint IOUs' request for additional workshops is unnecessary and denied. We conclude that the elimination of the gas line subsidies for the residential sector effective July 1, 2023 complies with the timelines required under Pub. Util. Code Section 783(d) and should not be further delayed.

5.3.3. Continued Coordination/ Consultation with Other State Agencies: Approved

Cal Advocates recommend that the Commission coordinate with the state agencies that are responsible for the state building code (*e.g.*, the CEC) and that the Commission should "approach GHG reductions broadly and work to promote GHG reduction across all sectors."[79] The Commission agrees with

[78] Opening Comments of SCE on Phase III Amended Scoping Memo and Ruling of Assigned Commissioner at 14.

[79] Opening Comments of Cal Advocates at 3.

Cal Advocates that coordination is critical. The Commission has and will continue to consult with the CEC and CARB, and other agencies as appropriate, on these issues.

The publications of both CEC and CARB reflect relevant views on eliminating line extensions and building electrification, which we note here. The 2021 Integrated Energy Policy Report, published by the CEC, recommends that the "CPUC should continue to investigate eliminating line extension allowances for new gas hookups."[80] CARB has released its draft 2022 Scoping Plan for Assembly Bill 32 compliance, and dedicates an appendix chapter to building electrification, strongly advocating for electrification as a means to reduce GHGs from the building sector.[81] CARB notes that scaling back natural gas infrastructure is a potential action to support a successful transition to building electrification.[82] CARB further notes that the Staff Proposal to eliminate gas line subsidies "can encourage all-electric new construction and help alleviate future gas rate escalation."[83]

The Commission will continue to work closely with CEC, CARB, and other state agencies on these issues to ensure consistency in our approaches to GHG reductions broadly.

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[80] CEC, Final 2021 Integrated Energy Policy Report at 182 (https://efiling.energy.ca.gov/GetDocument.aspx?tn=241599).

[81] CARB, Draft 2022 Scoping Plan, Appendix F (https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-f-building-decarbonization.pdf).

[82] CARB, Draft 2022 Scoping Plan, Appendix F (https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-appendix-f-building-decarbonization.pdf).

[83] *Id.* at 22-23.

5.3.4. Delay Decision Until the Conclusion of the Long-Term Gas System Planning Rulemaking (R.20-01-007): Denied

SWG recommends that a decision on gas line subsidies be suspended until R.20-01-007 concludes because the relationship between this proceeding and R.20-01-007 requires further analysis, and that "delineating the future of natural gas in California is a necessary threshold issue." They argue that addressing similar forward-looking gas infrastructure issues in separate, concurrent proceedings could result in inconsistent factual findings and policy determinations, potentially causing future confusion and inefficiencies.[84] The Commission disagrees.

R.20-01-007 includes two tracks. The scope of Track 1A includes reliability standards that reflect the current and prospective operational challenges that face gas system operators. Track 1B addresses market structure and regulation. Track 2A addresses the appropriate gas infrastructure for California given the state's GHG reduction laws, addressing gas transmission and distribution infrastructure. Track 2B addresses equity, rate design, and gas revenues, with a particular lens for low-income customers and those residing in disadvantaged communities. Track 2C addresses forecasting and data.[85]

Both R.20-01-007 and this proceeding address issues relating to gas systems; however, the scope of this decision is narrowly focused on the elimination of the gas line subsidies. Our decision on this limited issue here will not have a material impact on any issues scoped in R.20-01-007. Therefore, we

[84] Opening Comments of SWG at 7.

[85] R.20-01-007 Scoping Ruling dated January 5, 2022 at 2-11.

deny SWG's recommendation to delay a decision in this proceeding until R.20-01-007 concludes.

6. Non-Residential Gas Line Subsidies Revisions

Of the 18 parties commenting on eliminating the gas line subsidies for non-residential customers, 12 parties support the Staff Proposal and six oppose.

6.1. Positions of Parties Supporting the Staff Proposal

The 12 parties who endorse the Staff Proposal to eliminate gas line subsidies for the non-residential sector are: SCE, Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, PCE, and SBUA. In addition to many of the same points made supporting the elimination of the gas line subsidies for the residential sector as discussed above, they make these additional points in support of eliminating the gas line subsidies for non-residential customers:

- Elimination of the gas line subsidies is a reasonable and necessary step in pursuit of reducing GHG emissions given that California is at substantial risk of not achieving its SB 32 requirement to reduce emissions to 40 percent below 1990 levels by 2030, and as such, California must pursue carbon neutrality with urgency;
- Elimination of the gas line subsidies does not equate to a gas ban as builders and customers can continue to build new facilities with gas service capabilities, and there is currently no mandate prohibiting customers from continuing to install gas infrastructure; and
- Large non-residential customers are the most significant contributors to GHG gas emissions with great potential to drive problematic expansion of the main gas line infrastructure further beyond existing use areas.

6.2. Positions of Parties Opposing the Staff Proposal

The six parties who oppose the Staff Proposal to eliminate gas line subsidies for the non-residential sector are: PG&E, SDG&E, SoCalGas, SWG, Clean Energy, and CCUE. In addition to many of the same points made opposing the elimination of the gas line subsidies for the residential sector as discussed above, they make these additional points in opposition to eliminating the gas line subsidies for non-residential customers:

- There is continued need for gas and the natural gas system specifically in the industrial sectors that have yet to see energy options that can help them transition to a decarbonized future. Cleaner gases can replace or contribute to the natural gas service and full electrification, contributing to California's energy objectives;
- Removing gas line subsidies for large non-residential or industrial customers will result in a net increase in GHG emissions because it will disincentivize the use and production of cleaner gases, which can replace higher GHG emitting fuels, or "dirtier fuels";
- Removing gas line subsidies for large non-residential or industrial customers will increase project costs and create additional hardship, which may cause developers to slow down projects, abandon projects or develop projects outside California, negatively impacting California's economy; and
- Minimizing short lived climate pollutants (SLCPs) should be the Commission's top priority, as opposed to eliminating non-residential gas line subsidies, as these are the only reductions that benefit the climate immediately.

6.3. Alternate Proposals

6.3.1. Exemptions for Specific List of Projects that Provide Environmental or Financial Benefits (Joint IOUs)

The Joint IOUs propose to continue the non-residential gas line subsidies for several categories of non-residential projects that provide environmental or financial benefits to California ratepayers. They also propose a mechanism to update these categories periodically. According to the Joint IOUs, the following 10 non-residential projects would provide environmental or financial benefits to California ratepayers:[86]

- Renewable Natural Gas (RNG) or Hydrogen (Piped and Virtual);
- Compressed Natural Gas (CNG), Liquid Natural Gas, and Hydrogen Stations;
- Electric Generation Projects;
- Backup Generation Projects;
- Facility Conversions (facilities switching from dirtier fuels);
- Large Commercial Customers;
- Industrial Customers;
- Transmission Customers;
- Critical Load; and
- Restaurants (proposed by SDG&E and SoCalGas).

The Joint IOUs also propose that the categories of customers receiving gas line subsidies would be reviewed via a Tier 2 AL (to be filed every three years starting in 2026) or that a cadence for re-visiting the subsidies be established in the ongoing long term gas planning proceeding (R.20-01-007). In support, they

[86] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 7.

say the review would ensure that gas ratepayers continue to benefit from providing gas line subsidies. According to the Joint IOUs, "non-residential customers identified as having economic and environmental benefits to gas ratepayers can shift over time and that the removal of residential allowances may have a negative impact on affordable housing developers."[87]

Additionally, PG&E proposes two new methods for calculating the allowance amounts for non-residential projects that provide environmental or financial benefits to California ratepayers: (1) the ability for all current calculations of distribution to be applied to the non-residential projects; and (2) the addition of a graduated discount when additional load reduces GHG emissions. PG&E also proposes that the gas line subsidies be modified such that customers cannot switch from core service to noncore service until the allowance amount is fully recovered through revenue. In support, PG&E states that the current practice of switching from core to non-core service creates an unsustainable loophole where core customers can receive a higher allowance amount which may not be fully repaid should they switch to non-core service before the allowance amount is recovered.[88]

6.3.2. Exemptions for Projects That Enable Hydrogen, RNG and CNG Use (Clean Energy)

Clean Energy recommends that the Commission prioritize the phase-out of diesel in the transportation, electricity, and agricultural sectors. To do this, Clean Energy proposes maintaining incentives for customers seeking to develop hydrogen, agricultural customers seeking to produce biogas and RNG from

[87] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 10.

[88] Opening Comments of the Joint IOUs on Phase III Staff Proposal at 13.

manure, and private companies investing in CNG fueling stations that distribute RNG to facilitate reductions in SLCP.[89]

For the transportation sector, Clean Energy states that the gas line subsidies make construction of new CNG fueling stations financially viable and present opportunities for collocation with hydrogen fueling stations.[90] For the electricity sector, they argue that renewable gas, including biogas and hydrogen from organic waste, can provide the same reliability services with far lower emissions than diesel backup generators.[91] For the agricultural sector, they state that agricultural feedstock RNG (particularly negative carbon RNG feedstock such as animal agriculture) can significantly lower GHG emissions, and help the state achieve its climate goals.[92] Therefore continuing gas line subsidies for these customers will encourage further development of these "carbon beneficial" fuel options.

6.3.3. Application Process for Select Projects that Provide Environmental or Financial Benefits (Joint Parties and TURN)

The Joint Parties and TURN oppose providing any exceptions to offering the gas line subsidies, but state that if the Commission decides to provide limited exemptions, it should require the IOUs to submit a stand-alone application seeking ratepayer support for specific line extension projects. They assert that the

[89] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 2-3.

[90] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 11-13.

[91] Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 6.

[92] Response of Clean Energy to Assigned ALJs' Ruling Seeking Clarification and Additional Information at 10-15.

IOUs should demonstrate that ratepayer funding is just and reasonable in light of reasonably anticipated ratepayer benefits and in furtherance of California's decarbonization policy.[93] Specifically, the Joint Parties propose that the application meet the following minimum criteria: (1) the extension does not emit local criteria or toxic air pollution; (2) the extension is not located in an environmental and social justice community; (3) the extension is consistent with all California climate goals; (4) the project does not claim any environmental credits; and (5) there are no feasible non-pipeline alternatives to the extension.[94] Given the need to verify these facts with discovery, the Joint Parties recommend an expedited application process that should receive at least the same level of scrutiny as a Tier 3 AL, where the applicants must demonstrate the factual basis for its assertions, and parties are allowed to conduct discovery to verify that each of the suggested criteria have been met. TURN also recommends that if exceptions are made to preserve gas line subsidies for some non-residential customers, the Commission should protect residential customers and require the non-residential customer classes to subsidize the costs.[95]

6.3.4. Assistance for Low Income, Rural and Small Businesses (SBUA)

SBUA supports the elimination of gas line subsidies for non-residential customers, but recommends replacing the allowance regime with direct assistance to small businesses not currently connected to gas infrastructure but who upgrade to high-efficiency electric appliances in furtherance of the state's

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[93] Reply Comments of Joint Parties and TURN on Phase III Staff Proposal at 10-14.

[94] Response of CEJA, EDF, NRDC, and Sierra Club to the Assigned ALJs' Ruling Seeking Clarifications and Additional Information at 6-10.

[95] Reply Brief of TURN at 8.

GHG emission goals. More specifically, they propose: (1) opening a further phase of this proceeding to understand the support required to assist small businesses in overcoming barriers to electrification, such as by providing subsidies for appliance or panel upgrades in locations where stranded asset problems are most likely to be acute or where propane reliance is high; (2) establishing a pilot project to investigate the effectiveness of electrification incentive programs, akin to the San Joaquin Valley Pilots (D.18-12-015) referenced in the Staff Proposal; and (3) requiring electric utilities, through the advice letter process, to gather further data on bill savings comparisons between gas and electric usage and propose programs to address financial barriers to adoption of electric appliances.[96]

6.4. Discussion

6.4.1. Elimination of Non-Residential Gas Line Subsidies: Approved

This decision adopts the staff's proposal to eliminate the non-residential gas line subsidies effective July 1, 2023. The elimination of subsidies applies to new applications for gas line extensions submitted on or after July 1, 2023, and will not affect applications submitted before July 1, 2023. Within 30 days of the date of this order, the gas IOUs shall each submit a Tier 2 AL to revise their respective gas rules to implement this decision.

Gas line subsidies are eliminated for the non-residential sector for the same reasons as for the residential sector. These benefits include significant ratepayer savings, reductions in GHG emissions, combating climate change, improved overall quality of life, greater certainty for the builder community, and benefits

[96] Opening Brief of SBUA at 8-9.

to low-income customers. The Commission reiterates that the elimination of these subsidies is one of many necessary and important steps in furthering California's decarbonization goals, while easing the burden on gas ratepayers, ensuring grid safety and reliability, and continuing to promote alternative clean fuels.

We also adopt the proposal of the Joint Parties and TURN, with modifications, to allow individual applications for the provision of gas line subsidies for select unique projects meeting specific application criteria discussed below.

The Commission agrees with SBUA and other parties that large non-residential customers are the most significant contributors to GHG gas emissions,[97] making it especially important to adopt this policy change for this customer segment. Absent this change, non-residential customers create the great potential to drive problematic expansion of gas line infrastructure beyond existing use areas, and create additional stranded investment.

Therefore, we eliminate gas line subsidies to promote the many benefits of this policy. However, gas line subsidies may be extended to a limited number of unique gas line extension projects meeting specific criteria, and will be reviewed through the application process outlined below.

6.4.2. Exemptions for Specific List of Projects that Provide Environmental or Financial Benefits: Denied

This decision denies the Joint IOUs' proposal to continue offering gas line subsidies to their proposed list of 10 non-residential project categories that might

[97] Reply Brief of SBUA at 2 and https://ww2.arb.ca.gov/ghg-inventory-data.

provide environmental and financial benefits to ratepayers. We are not convinced by the Joint IOUs' argument that an exception for a specific group of projects is necessary given the urgent nature of California's decarbonization goals and the likelihood that any new gas investments could become stranded assets in the future. Rather, as explained below, the potential benefits of an exemption for a specific group of customers are outweighed by the environmental and stranded investment costs.

The Joint IOUs propose this exception for a group of large non-residential customers that they argue provide environmental and financial benefits. The categories, however, are very broad and vague, such as "large commercial customers" and "industrial customers." It would not be reasonable to adopt a category as broad as "industrial customers" since not every project serving an industrial customer can be said to provide environmental or financial benefits to California ratepayers. Adopting the Joint IOUs' proposal as is could effectively make the elimination for the gas line subsidies largely meaningless, while adding confusion and administrative inefficiencies to the process as the categories are reviewed and parties argue for adjusting the categories.

Moreover, most parties, even when prompted by the assigned ALJs to be more specific,[98] did not provide a sufficiently unambiguous and clear definition of what constitutes environmental and financial benefits for the Commission to adopt this as a workable basis to establish categories. Instead, the Joint IOUs only provide a list of 10 categories they claim provide financial and/or environmental benefits to California ratepayers.

[98] January 28, 2022 ALJ Ruling Seeking Clarification and Additional Information, Attachment 1 at 3.

PG&E and Clean Energy, on the other hand, propose the following definitions within the limited context of this proceeding. PG&E proposes:[99]

- <u>Direct Environmental Benefit</u>: A project offers a direct environmental benefit where it provides on-site GHG, NOx, or other pollutant reduction compared an existing fuel baseline.
- <u>Indirect Environmental Benefit</u>: A project offers an indirect environmental benefit where it displaces either existing gas system emissions (*e.g.*, through renewable natural gas) or off-site (*e.g.*, through CNG) GHG, NOx, or other pollutant emissions.
- <u>Financial Benefit</u>: Broadly, a new gas connection offers financial benefit to all gas ratepayers where the connecting customer financially contributes, via gas rates, in excess of the costs to extend gas service to that customer. The customer may also offer financial benefit in the form of externalities that are more difficult to quantify (*e.g.*, job creation, increased state and local tax revenue, and local development).

Clean Energy proposes:[100]

- <u>Environmental Benefit</u>: (a) receipt of any tradable environmental attributes; (b) reduction of SLCPs; (c) reduction of GHG emissions; or (d) reduction of regulated air or water pollutants.
- <u>Financial Benefit</u>: (a) addresses the pay-back period for the gas line subsidies; (b) reduces system costs by more than the cost of the subsidy; or (c) contributes significantly to racial or social equity, public health, community resilience, or a robust economy.

[99] PG&E's Response to Assigned ALJ's Ruling Seeking Clarification and Additional Information at 6-7.

[100] Reply Comments of Clean Energy on Amended Scoping Memo and Ruling and Staff Proposal at 4.

We appreciate the proposals of PG&E and Clean Energy but find these definitions overly broad and lacking in adequate benchmarks or specific criteria for how to establish the 10 categories for potentially vast numbers of different projects, all of which would qualify for the exception. Absent an adequate definition or a reasonably accurate baseline for calculating environmental or financial benefits, many categories of projects could broadly make a case for the exception, and many customers might be granted exemptions even if the criteria are imprecise. We share TURN's concern that:

> Any project that adds new customer load to the gas system could, all else being equal, provide a contribution to margin for at least some amount of time. However, any system buildout today could become a stranded asset well before the end of the asset's life because of electrification — whether mandated by state or local building codes or inspired by ratepayer-funded incentive programs and market transformation. This serious risk cuts against any near-term financial benefits from increased sales associated with new customer load.[101]

Thus, along with the lack of adequate definitions and criteria provided by the Joint IOUs, PG&E and Clean Energy, and without sufficient information and analysis on the record, we are not convinced that continuing gas line subsidies for this broad set of non-residential projects would lead to the benefits claimed.

We acknowledge that there may be limited circumstances where gas line extensions for some non-residential projects can be beneficial. Nonetheless, these potentially limited circumstances are not sufficient to warrant blanket subsidies for various broad categories of projects, such as the 10 project types proposed by the Joint IOUs. Not only would this be complicated, but more importantly, this

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[101] Opening Brief of TURN at 8.

would be misaligned with California's overall decarbonization goals. Exceptions for such broad categories of projects would perpetuate, even if on a smaller scale, the continued reliance on gas and locking in gas use for the life of the asset.

Instead, we adopt a limited alternative below that considers applications for specific and unique projects meeting a narrow set of criteria that may warrant gas line subsidies. This will account for the special cases of environmental, financial, or other benefits without creating up to 10 broad project categories.

This decision also denies PG&E's proposal for two new methods for calculating allowance amounts. We find this proposal now moot since we eliminate all gas line subsidies. Moreover, we do not wish to complicate the application process described below with additional factors.

6.4.3. Exemptions for Projects That Enable Hydrogen, RNG and CNG Use: Denied

This decision denies Clean Energy's proposal to continue offering blanket gas line subsidies for non-residential transportation, agricultural, commercial, and industrial projects that enable RNG use in order to prioritize reduction in SLCP emissions. We are not convinced by Clean Energy's argument that gas line subsidies should continue to be offered to the non-residential sector to advance the goal of reducing SLCPs. Rather, we believe that ending gas line subsidies and supporting the hydrogen/RNG/CNG sector to reduce SLCPs can be successfully achieved together.

Clean Energy claims that the lack of gas line subsidies could be the sole reason that a new project will not be built, because the project may no longer be economical.[102] Clean Energy argues that typically, a CNG project will cost

[102] Opening Brief of Clean Energy at 24.

approximately $1.5-$2.0 million plus a gas line extension cost of $400,000-$500,000 — approximately 25 percent of the investment.[103] Clean Energy does not, however, state whether the full gas line extension cost is eligible for gas line subsidies. As noted earlier in this decision, gas line extension costs are made up of a refundable portion and a non-refundable portion, with only the refundable portion being eligible for a subsidy. Clean Energy also does not provide data on average subsidies received for its projects. Recent data provided by the IOUs show the following average non-residential subsidies paid below.

Table 5. Average Subsidies Paid to Non-Residential Projects in 2021

	Average Subsidies Paid Per Project in 2021[104]			
Gas Line Subsidies	**PG&E**	**SoCalGas**	**SDG&E**	**SWG**
Allowances	$12,030	$7,058	Not Provided	$107,228
Refunds	$490	$0	$9,056	Not Provided
Discounts	$8,702	$74	Not Provided	$4,418

Although these average subsidies are not identified by project type, we note that they are far below the CNG gas line extension estimate of $400,000 to $500,00[105] provided by Clean Energy. Given the absence of sufficient information to support Clean Energy's claim, and based on the gas IOUs' 2021 average subsidies as shown above, the Commission is not convinced by the speculative argument that eliminating the gas line subsidies for non-residential project could be the sole reason that a new project will not be built.

[103] *Id. at* 30.

[104] April 18, 2022 ALJ Ruling, Attachment 5.

[105] Assuming the full amount is refundable as defined under the gas rules.

While this analysis suggests that the average subsidies may be small compared to the overall project costs, we acknowledge that there may be some CNG/RNG/hydrogen projects at the margin where the subsidy makes up a larger portion of total project costs. However, no compelling evidence demonstrates that the gas line subsidies are actually necessary, or are the tipping point, to encourage these larger customers to make the "cleaner" gas investments. Rather, many factors are involved in a developer deciding to develop or not develop a project. While we understand that the elimination of these subsidies would make some projects more expensive, simply pointing this out does not prove it is the driving or controlling factor in a decision, and we are not convinced, absent specific evidence or examples of representative projects, that it is a significant enough change to halt such projects altogether. This is especially true given that there are existing subsidies and programs that offer incentives for the development of alternative fuels, including $40 million for bio-SNG (synthetic natural gas) incentives that was authorized in D.22-02-025.[106]

The Commission also disagrees with Clean Energy that by making these projects more expensive, we are decelerating the move towards the use of cleaner fuels in the transportation/mobility sector that would otherwise reduce GHG emissions and help displace SLCPs. Many factors affect the use of alternative fuels in transportation, such as technology and state policy. As discussed above, gas line subsidies date back to the 1970s and the current rules on gas line subsidies were adopted in 2007. Yet, Clean Energy's data shows that only

[106] D.22-02-025, Ordering Paragraph 43.

3 percent of trucks in large fleets are powered by natural gas, and 0.01 percent are powered by hydrogen.[107]

Although we agree with Clean Energy that the use of CNG/RNG/ hydrogen is a preferred option over diesel and other "dirtier" fuels during a transition to full electrification, it is still not the preferred option in the long term over full electrification.[108] Our priority in the long term is to move away from fossil fuels altogether, including in the transportation sector, as opposed to supporting less harmful fossil fuels. This has been consistent and reiterated in several Commission proceedings.[109] It is also the policy of our sister agencies, which have also encouraged the move away from fossil fuel investment. For example, the CEC's California Clean Transportation Program has shifted focus significantly since 2019 to heavily prioritize zero emission vehicles (ZEVs) over near zero emission vehicles. CARB has adopted rules requiring 100 percent medium duty and heavy duty ZEVs by 2045 (to the fullest extent feasible). It has explained that "Infrastructure for methane trucks is expensive and would become a stranded asset if use of those [electric-fueled] trucks continued to expand; EV infrastructure, in contrast, will be needed indefinitely."[110] In light of these state policies, long term gas line subsidies to expand CNG infrastructure does not merit a categorical exemption from our overall policy adopted here.

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107 Opening Brief of Clean Energy at 28.

108 Further, even though electrification is our preferred option, we recognize that for now, RNG plays an important role in reducing GHG emissions. This decision is not intended to conflict with that policy, as outlined in D.22-02-025.

109 D.22-03-006, D.19-09-051, D.22-02-025, and Rejection of SoCalGas's AL 5590.

110 CARB Technical Analysis of End of Useful Life Scenarios at 2 (https://ww2.arb.ca.gov/resources/documents/technical-analysis-end-useful-life-scenarios-statewide).

Additionally, we note that most of the cleaner fuels are already heavily subsidized, and eliminating the gas line subsidies would not undermine their development in any significant way. The table below summarizes these subsidies as approved by the Commission, and does not include additional subsidies that may be available from other sources.

Table 6. Commission Approved Subsidies for Alternate Fuels

Fuel type	Subsidy Budget	Authorized By
Bio-SNG	$40 million	D.22-02-025
Biomethane	$40 million	D.15-06-029
Biomethane (augment)	$40 million	D.20-12-031

Lastly, we reiterate that the elimination of these subsidies does not remove the builder or developer's choice to build the CNG/RNG facility, it only requires that the costs caused by new customers be paid by those customers. And, in the limited cases where a gas line subsidy may still be warranted, we provide an application process below to consider specific, unique projects that claim to be unable to proceed without a gas line subsidy.

6.4.4. Application Process for Select Projects that Provide Environmental or Financial Benefits: Approved with Modifications

This decision approves the Joint Parties and TURN's proposal for an application process, with modifications, for those specific, unique non-residential projects where a gas line subsidy may still be warranted. For these projects, the gas IOUs shall evaluate the project based on the criteria established in this decision and file an application with the Commission for approval of a gas line subsidy on behalf of the project applicant(s).

The IOUs shall ensure that projects seeking a gas line subsidy shall meet the following minimum criteria based on the information provided by the applicant(s) before including it in an annual filing to the Commission seeking such subsidies. These minimum requirements are:

(1) The project will lead to a demonstrable reduction in GHG emissions;

(2) The gas line extension required for the project is consistent with California's climate goals, including those articulated in SB 32 (Pavley, 2016); and

(3) The project applicant demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

We do not include the other criteria proposed by the Joint Parties and TURN (the extension is not located in an environmental and social justice community, and the project does not claim any environmental credits) at this time. We are not persuaded that these additional criteria are necessary in assessing the impacts of the project.

If there are projects seeking gas line subsidies that an IOU determines meets the above criteria, the IOU shall file an annual application, by July 1 of each year beginning in 2023, and include all qualified projects requesting a gas line subsidy. Even though this decision eliminates gas line subsidies for all customer classes, it does not change the methodology for the calculation of gas line subsidies if the Commissions grants gas line subsidies for specific projects through the application process. In its annual filing, each IOU should include an update to the non-residential gas line extension allowance calculations based on the current methodology (including all inputs used, *e.g.*, cost of service factor). The IOUs, on behalf of the project applicant(s), must demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum requirements have been met based on the information provided by applicants.[111] The Commission will evaluate the types of applications that are found to be deserving of gas line subsidies over the next few application cycles, and may revisit the need for categorical exemptions at a later time. The IOUs may propose potential categorical exemptions in their annual filing after two application cycles. The IOUs may also reference similar projects that have received gas line subsidies in their annual filing, and over time, this could reduce the burden on applicants and IOUs in demonstrating eligibility for these subsidies.

Lastly, the Commission denies TURN's proposal to modify the cost allocation/collection methodology of these subsidies to only require non-residential customer classes to subsidize the costs.[112] We do this because these projects, if approved for subsidies through this application process, would have demonstrated that they will reduce GHG emissions and be consistent with California's climate goals. This benefits all ratepayers, not just the non-residential customer class. The Commission also believes the resulting subsidies, if any, will not be so large as to justify the additional administrative burden to distribute the costs in proportion to the benefits received by customer class.

6.4.5. Assistance for Low Income, Rural and Small Businesses: Approved with Modifications

We approve SBUA's proposal to further investigate the needs of small businesses not currently connected to gas infrastructure that move towards electrification. Although this decision does not make any special exceptions for

[111] Each IOU must determine that each applicant's project meets the criteria based on the information provided by the applicants. In addition, each IOU's application may include prepared proposed testimony from the applicant in support of the application.

[112] Reply Brief of TURN at 8.

the treatment of small businesses in regard to electrification, we are committed to considering the unique challenges to electrification faced by small businesses in future phases of this proceeding.

7. Compliance with Pub. Util. Code Section 783(b)-(d)

Pub. Util. Code Section 783(b) states that:

> Whenever the commission institutes an investigation into the terms and conditions for the extension of services provided by gas and electrical corporations to new or existing customers, or considers issuing an order or decision amending those terms or conditions, the commission shall make written findings on all of the following issues:
>
> (1) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development.
>
> (2) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future.
>
> (3) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation.
>
> (4) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts.
>
> (5) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers.

(6) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy.

(7) The extent to which there is cost-justification for a special line and service extension allowance for agriculture."[113]

Pub. Util. Code Section 783(c) states that:

The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.[114]

Lastly, Pub. Util. Code Section 783(d) requires:

Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.[115]

7.1. Staff Proposal

In response to Pub. Util. Code Section 783(b) the Staff Proposal addresses each of the seven issues as follows.[116]

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[113] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[114] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[115] *See* https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=783&lawCode=PUC.

[116] Phase III Scoping Memo, Appendix A at 33-36, 38-40, and 42-45.

On Issue 1, Staff expects that the elimination of gas line subsidies would increase the number of newly constructed all-electric buildings and that prices for those all-electric buildings will likely be less than those for an equivalent newly constructed dual fuel building. Dual fuel buildings constructed without gas line subsidies would be expected to cost more than they do today, but minimally (anywhere from 0.07 percent to 0.25 percent depending on the gas line subsidies type). Whether or not customer bills would be higher or lower in a new all-electric building vis-à-vis a new dual fuel building would depend on numerous factors that include tariff type, climate zone, future electricity prices, future gas prices, customer energy consumption habits, and time of energy usage.

On Issue 2, Staff does not expect the elimination of gas line subsidies to affect the current methods of providing transmission or distribution facilities for future customers, as the Staff Proposal is not proposing to modify such rules. If gas line subsidies are eliminated as proposed, and builders increase their rate of all-electric new construction, builders building dual fuel new construction further away from a point of gas pipeline interconnection could expect to pay more than they otherwise would be expected to if they have to pay for additional trenching and infrastructure that neighboring all-electric buildings did not need and thus did not help pay to extend from its current cut-off location.

On Issue 3, Staff expects the elimination of gas line subsidies for all new construction to result in increased costs to any customer seeking to extend a gas line. Depending on what infrastructure upgrades are necessary to extend gas service to the customer's building, the increased costs would vary.

On Issue 4, Staff does not expect the elimination of gas line subsidies for all new construction to result in changes specific to projects sponsored by cities, counties, or districts, as the Staff Proposal is not proposing any such changes. Should those projects be constructed all-electric, they will be less expensive than they are today, and should those projects be constructed dual fuel, they are anticipated to be only slightly more expensive than they are today.

On Issue 5, Staff expects the elimination of gas line subsidies for all new construction to lead to an annual reduction of approximately $115,528,305 in allowances,[117] $2,625,678 in refunds,[118] and $26,195,639 in discounts[119] (with partial data for SDG&E) as a result of gas ratepayers no longer having to pay for gas line subsidies.[120] If a new building were to be constructed dual fuel without a gas line subsidy, gas ratepayers would save even more as a result of an additional customer sharing in costs necessary to maintain the common carrier pipeline network.

On Issue 6, Staff expects the elimination of gas line subsidies for all new construction to result in less gas consumption and more electricity consumption. Because gas consumed in California is overwhelmingly non-renewable and electricity is increasingly carbon-free, the encouragement of fuel substitution associated with adoption of Staff's recommendation would result in fewer GHG emissions and less air pollution. However, additional electrical load will gradually result in the need for additional electricity procurement and could pose challenges to managing winter peak electric demand if not properly planned for.

[117] Phase III Scoping Memo, Appendix A at 35.

[118] Phase III Scoping Memo, Appendix A at 39.

[119] Phase III Scoping Memo, Appendix A at 44.

[120] We note that since the publication of the Staff Proposal, the gas IOUs provided updated projections. (*See* April 18, 2022 ALJ Ruling, Attachment 5.)

On Issue 7, Staff does not recommend any special allowance for agricultural customers and, as such, there is no cost-justification for such an allowance. Agricultural operations typically use gas primarily for greenhouse heating and grain drying, both of which can be done using electricity. Additionally, the small property price increase for new dual fuel construction that can be expected if Staff's recommendation is adopted is insufficiently high to merit a special allowance for any customer class.

In response to Pub. Util. Code Section 783(c), Commission staff requested the assistance of the California State Transportation Agency, California Department of Food and Agriculture, DCA, DRE,[121] and HCD in developing the recommendations in its Staff Proposal. Staff states that the feedback that was received was considered as part of Staff's recommendations. Additionally, Staff consulted with CARB, CEC, and the California Strategic Growth Council.[122]

Lastly, in response to Pub. Util. Code Section 783(d), Staff recommends an effective date of July 1, 2023, in compliance with the minimum time required.

7.2. Positions of Parties Supporting the Staff Proposal

Of the 14 parties commenting on the Staff Proposal's findings pursuant to Pub. Util. Code Section 783(b), 10 parties agree with the Staff Proposal's assessment of the seven issues and agree that eliminating gas line subsidies is within the Commission's legal purview. These parties are: Cal Advocates, CEJA, EDF, NRDC, Sierra Club, TURN, EBCE, MCE, SCP, and PCE. They make several points in support.

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[121] Statute requires the CPUC to request the assistance of the Bureau of Real Estate, which has since become DRE.

[122] Phase III Scoping Memo, Appendix A at 2.

- The Staff Proposal sufficiently addresses the seven issues to make the requisite written findings;
- Statute does not specify the exact nature of the economic analysis required for the Commission to make the necessary findings pursuant to this section; and
- Statute does not require that new rules result in any particular findings (*e.g.*, favorable rate effects for customers) simply that they be documented.

7.3. Positions of Parties Opposing the Staff Proposal

Of the 14 parties commenting on the Staff Proposal's findings pursuant to Pub. Util. Code Section 783(b), four parties disagree with the Staff Proposal's assessment of the seven issues citing insufficient analysis. These parties are: SDG&E, SoCalGas, SBUA, and Clean Energy. They make several points in opposition.

- The record of this proceeding does support written findings on all seven issues;
- There has been no examination of the impacts on agriculture, mobile home parks, rural and urban customers, employment, or commercial and industrial buildings and development (Pub. Util. Code Section 783(b)(1));
- There has been no examination of the impacts to customer bills (Pub. Util. Code Section 783(b)(5));
- There has been no discussion of the impact on the development of RNG fueling stations or hydrogen production sites;
- The Staff Proposal does not address the equity concern between the customer applying for the extension now and future customers applying for line extensions at a later time (Pub. Util. Code Section 783(b)(2));
- The Staff Proposal failed to show that staff consulted any city, county or district before arriving at the conclusion that

eliminating gas line subsidies would not have any effect on redevelopment projects, funded or sponsored by cities, counties, or districts (Pub. Util. Code Section 783(b)(4)); and

- A study should be conducted on the economic effects on residential housing, rural customers and urban customers and must include low-income customers, disadvantaged communities, and the affordable housing sector.

7.4. Discussion

7.4.1. Compliance with Pub. Util. Code Section 783(b)

In this decision, the Commission makes findings on each of the seven issues included in Pub. Util. Code Section 783(b). We do so by relying on the best information we have in the record of this proceeding.

We agree with the Joint Parties and TURN that the statute requires the Commission to make findings on questions such as "the effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future." However, it does not require that the Commission arrives at any particular conclusions (*e.g.*, favorable rate effects for customers) simply that the Commission arrives at written findings for all seven issues set out in Pub. Util. Code Section 783(b).[123]

Moreover, the statute does not require the Commission to conduct or commission a study, or specify the exact nature of the economic analysis required before the Commission can make the necessary findings.

The Commission has considered the potential impacts of these changes as further discussed below and concludes that eliminating gas line subsidies will

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[123] Opening Comments of Joint Parties and TURN on Phase III Staff Proposal at 4.

have a net positive impact on all sectors mentioned in Pub. Util. Code Section 783(b) for all the reasons discussed in earlier sections of this decision. The record in this proceeding provides the Commission sufficient basis to eliminate gas line subsidies for all customer classes and we determine that this decision is in California's best interest and is consistent with other Commission decisions and legislative intent. More specifically, we make the following findings on each of the seven issues.

(1) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development.

The Commission finds that the elimination of the gas line subsidies will have an overall net positive economic effect on these groups of customers. Gas rates paid by all gas customers will be reduced due to the reduction in gas line subsidies, estimated at an annual savings of $164 million.

The Commission agrees with the Joint Parties that in light of state climate and equity objectives and the importance of price signals to discourage the expansion of the gas system and reliance on gas appliances, the benefits of ending gas line extensions outweigh the economic impact upon those customers that may incur additional line or service extension costs by continuing to choose to build an extension connecting to the gas system.[124] We also note that there are programs that can help reduce any potential cost increase for these groups including the Manufactured and Mobile Homes Program, the Mobile Home Park Utility Conversion Program, and BUILD.

[124] Opening Brief of Joint Parties at 19-21.

In terms of employment, and as discussed in this decision, the Commission finds that there will likely be a net positive impact as we are likely to see an increase in demand for skilled workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

In terms of commercial and industrial building and development, and as discussed in this decision, the Commission finds that there will likely be an increase in the number of newly constructed all-electric buildings which will likely cost less than newly constructed dual fuel buildings.

Therefore, the Commission finds the "economic effect of gas line and service extension terms and conditions upon agricultural, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development" to be overall net positive.

(2) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future.

The Commission agrees with the Staff Proposal[125] and the Joint Parties[126] that the elimination of gas line subsidies will have no effect on the current methods of providing transmission or distribution facilities for future customers.

We note that the elimination of gas line allowances may shift who pays which costs, but there is no change in the extent to which new or existing customers applying for an extension provide transmission or distribution facilities for future customers. We acknowledge that builders building dual fuel

[125] Phase III Scoping Memo, Appendix A at 34, 39, and 42-43.

[126] Opening Brief of Joint Parties at 21.

new construction away from a point of gas pipeline interconnection may pay more (*e.g.*, for additional trenching and infrastructure) than neighboring all-electric buildings (who do not need the additional trenching and gas infrastructure).

With respect to the magnitude of any such cost shift, no party presented credible evidence that it would be material and significantly disrupt necessary expansion of utility service. In light of the state's climate and equity objectives, the benefits of ending these subsidies to all gas customers outweigh any economic impact of developers that may receive lower subsidies due to neighboring developments opting for all-electric designs.

Therefore, we find that the actions in this decision do not have the "effect of requiring new or existing customers applying for a gas line extension to provide transmission and distribution facilities to other customers who receive line and service extension in the future." We find that the effect of this decision is limited to a shift in who pays which costs, this is not a material effect, and the negative effects on some customers, if any, are offset by the overall positive effects of reducing GHG emissions, improved quality of life and health for customers, hundreds of millions of dollars in total ratepayer savings annually, greater equity for low-income customers, and greater certainty for the builder and contractor community.

> (3) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation.

The Commission agrees with the Staff Proposal[127] and the Joint Parties[128] that the elimination of gas line subsidies for all new construction will result in increased costs to any customer choosing to extend a gas line, with costs depending on what infrastructure upgrades are necessary to extend gas service to the customer's building. However as mentioned above, the benefits of ending these subsidies to all gas customers outweigh any economic impact on developers seeking to extend gas lines. Therefore, we find the "effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation" to be: the new or existing customer will be responsible for and must pay the costs that are caused by that customer's line extension (including reinforcements, relocations, or additions). These costs are outweighed by the economic and environmental effects along with increased equity of having the cost-causer pay the costs that are incurred.

(4) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts.

The Commission agrees with the Joint Parties that the elimination of gas line subsidies may increase project costs (including those that are funded or sponsored by cities, counties, or districts) that choose to connect to the gas system.[129] However, as discussed above, the rates paid by all gas customers (including cities, counties, or districts as utility customers themselves) will be

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[127] Phase III Scoping Memo, Appendix A at 34, 39, and 43.

[128] Opening Brief of Joint Parties at 21.

[129] Opening Brief of Joint Parties at 21-22.

reduced due to the millions of dollars in ratepayer savings from eliminating the gas line subsidies. As such, we find that the "economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts" to be higher costs for those projects that choose to connect to the gas system but offset (at least in part) by reduced gas rates, and also offset by the environmental and social benefits of ending gas line subsidies.

(5) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers.

The Commission estimates that the elimination of gas line subsidies for all new construction (residential and non-residential) will lead to an annual savings of approximately $164 million per year, as noted above. In addition to the ratepayer savings, other benefits to the ratepayers include reduction in GHG emissions and improving public health outcomes due to improved air quality. Thus, we find that the "effect of the line and service extension regulations, and any modifications to them, on existing ratepayers" is a savings of at least $164 million per year, plus additional environmental, social and health benefits.

(6) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy.

The Commission agrees with the Staff Proposal that the elimination of gas line subsidies for all new construction will result in less gas extensions, less gas consumption, and more electricity consumption.[130] This will also result in fewer GHG emissions and less air pollution. That is because electric generation is now produced by a substantial amount of non-GHG polluting power plants, and the

[130] Phase III Scoping Memo, Appendix A at 35, 40, and 44.

percentage of non-GHG producing power plants will increase over time as California meets its 100 percent clean electricity mandate of SB 100. With regard to energy conservation, to the extent elimination of these subsidies results in more all-electric construction, we agree with the Joint Parties that energy conservation will likely increase due to the efficiency of electric appliances.[131] Thus, we find the "effect of the line and service extension regulations, and any modifications to them, on consumption and conservation of energy" to be a reduction in gas consumption, an increase in electricity consumption, lower GHG emissions, less air pollution, and more energy conservation, with overall environmental, social and health benefits.

(7) The extent to which there is cost-justification for a special line and service extension allowance for agriculture.

The Commission find no impacts here as the proposal to eliminate gas line subsidies for all customer classes does not include special allowances for agricultural loads. No credible evidence was presented on a cost-justification, if any, for a special line and service extension allowance for agriculture.

Therefore, we conclude on these seven issues that the record in the proceeding provides the Commission sufficient basis to end gas line subsidies for all customer classes as this change is in California's best interest and is consistent with other Commission decisions and legislative intent. As attested by numerous parties, there are significant economy-wide climate, health, affordability, and equity benefits to eliminating gas line subsidies, in addition to the significant ratepayer savings as supported by the data in the Staff Proposal and the IOUs' ED-DR responses. In light of California's climate objectives and the importance of market signals to discourage further reliance on gas, we find that the benefits

[131] Opening Brief of Joint Parties at 22.

of ending these subsidies as discussed thoroughly in this decision outweigh any potentially negative economic effects to any particular customer classes described within these seven issues.

7.4.2. Compliance with Pub. Util. Code Section 783(c)

In compliance with Pub. Util. Code Section 783(c), the Phase III Scoping Memo requested the assistance and input of the agencies and departments included in the statute. The Commission served the Phase III Scoping Memo on these agencies and invited them to participate in this proceeding (*e.g.*, submit comments and reply comments on the Staff Proposal).[132] Additionally, on November 17, 2021, the assigned Commissioner sent a follow up e-mail to the Executive Directors (or an equivalent position) of these agencies and departments and invited them to provide input on the Staff Proposal by December 20, 2021. No comments or responses from the state agencies and state departments were received.

7.4.3. Compliance with Pub. Util. Code Section 783(d)

Lastly, the revisions to the gas rules adopted in this decision are effective July 1, 2023, consistent with Pub. Util. Code Section 783(d).

8. Conclusion

Based on the record and the analysis above, we conclude that, consistent with the policy objectives of this rulemaking and the state's climate goals, the current gas line subsidies for all customer classes should be eliminated, effective July 1 of the year following today's order pursuant to Pub. Util. Code Section 783(c), on July 1, 2023. We also adopt an application process through which the

[132] Phase III Scoping Memo at 1 and 12.

IOUs may seek gas line subsidies for individual projects meeting the criteria set out in this decision. This decision meets the statutory requirements as set forth in Pub. Util. Code Section 783(b)-(d).

9. Comments on Proposed Decision

The proposed decision of Commissioner Clifford Rechtschaffen in this matter was mailed to the parties in accordance with Pub. Util. Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). Comments were filed on August 30, 2022 by PG&E; SDG&E; SoCalGas; SCE; SWG; Clean Energy; the Joint Parties; SBUA; and The California Manufactures and Technology Association (CMTA). Reply comments were filed on September 6, 2022 by PG&E; SDG&E; SoCalGas; Clean Energy; the Joint Parties; SBUA; CMTA; and TURN.

Consistent with the Rules, we give no weight to comments that fail to focus on factual, legal, or technical errors (Rule 14.3(c)). In particular, we disregard comments that only reargue a party's position. In response to comments, we make the following revisions and clarifications:

- Corrections to non-substantive typographical errors and omissions.
- Clarification on the requirement of the IOUs, on behalf of the project applicant(s) seeking gas line subsidies, to demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum requirements have been met based on the information provided by applicants.
- Removal of the requirement of the IOUs, on behalf of the project applicant(s) seeking gas line subsidies, to disclose all other incentives received by each project.

10. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Scarlett Liang-Uejio and Ava Tran are the assigned ALJs in this proceeding.

Findings of Fact

1. The Commission initiated this proceeding to consider policy frameworks supporting decarbonization of buildings, including ongoing efforts to reduce GHG emissions associated with energy use in buildings.

2. The Phase I decision established the BUILD Program and the TECH Initiative pursuant to SB 1477.

3. The BUILD Program provides incentives to new residential housing projects that are all-electric and have no hookup to the gas distribution grid.

4. The TECH Initiative is a market transformation program providing incentives to advance the adoption of low-emission space and water hearing technologies.

5. The Phase II decision adopted: (a) guiding principles for the layering of incentives provided by multiple building decarbonization programs; (b) the WNDRR Program; (c) guidance on data sharing of customer and other information; and (d) requirements for the three large electric IOUs to conduct studies on bill impacts that result from fuel substitution for water heaters from natural gas to electric.

6. The Phase III Scoping Memo determined the issues to be resolved in Phase III including: (a) whether the Commission should modify or eliminate gas line extension allowances for some or all customer classes (residential and non-residential); (b) whether the Commission should modify or eliminate gas line extension refunds for some or all customer classes (residential and non-residential); and (c) whether the Commission should modify or eliminate

gas line extension discounts for some or all customer classes (residential and non-residential).

7. The Energy Division Staff Proposal recommends revisions to the current gas rules to eliminate the gas line subsidies for all customer classes effective July 1, 2023.

8. Of the parties commenting on eliminating the gas line subsidies for residential customers, there is wide support for the Staff Proposal among parties representing a substantial range of social, economic, and environmental interests.

9. Of the parties commenting on eliminating the gas line subsidies for non-residential customers, there is substantial support for the Staff Proposal among parties representing a wide range of interests.

10. The current gas line subsidies were established during a period when the state's energy needs and policy goals were very different from today's, and are no longer consistent with today's GHG emission reduction goals, the urgent need to reduce gas rates to ensure affordability, and the long term need to minimize future stranded investment.

11. The Commission adopted a uniform set of rules for gas utility line and service extensions beginning in 1915.

12. Under current rules, gas IOUs are not obligated to extend gas lines free of cost but must provide the opportunity for customers to be connected to the utility system at reasonable prices, terms, and conditions.

13. Current gas rules incentivize the installation of more gas appliances which perpetuate reliance on gas service and lock in all associated GHG emissions for the life of the appliance unless the appliance is retired early and replaced with an electric alternative.

14. The elimination of gas line subsides would make gas line and service extensions more expensive to the applicant for new gas service, and dual fuel new construction less desirable and financially riskier.

15. Eliminating gas line subsidies for all customer classes will result in significant ratepayer savings over the life of the gas line extensions.

16. Eliminating gas line subsidies for all customer classes is a logical step toward building decarbonization, consistent with state objectives and the Commission's policy frameworks. It will further the state's climate goals of reducing GHG emissions 40 percent by 2030 and achieving carbon neutrality by 2045 or sooner.

17. Eliminating gas line subsidies for all customer classes will improve overall quality of life (GHG emissions reductions, ratepayer savings, benefits to low income customers), and provide greater certainty for the builder community and the contractor community.

18. Eliminating gas line subsidies for all customer classes will result in a net positive impact on the workforce, as any potential decrease in demand for jobs within the gas industry is offset by the likely increase in demand for workers in several economic sectors, including in the electric industry, construction jobs for energy efficiency improvements and building retrofits.

19. Eliminating gas line subsidies for all customer classes does not remove customer choice as customers can continue to select their choice of fuel, with the difference being that existing and future gas customers will no longer have to subsidize investments in the gas infrastructure for new customers.

20. Eliminating gas line subsidies for all customer classes will not negatively impact energy reliability.

21. Eliminating gas line subsidies for all customer classes will have minimal impacts on property prices.

22. Eliminating gas line subsidies for all customer classes and supporting the hydrogen/RNG/CNG sector to reduce SLCPs can be successfully achieved together.

23. Large non-residential customers are the most significant contributors to GHG emissions.

24. There may be limited circumstances where gas line extensions for some non-residential projects can be beneficial, and gas line subsidies for these projects may be warranted.

25. Consideration of modifying or eliminating gas line subsidies is governed by Pub. Util. Code Section 783(b), which requires the Commission to make written findings on the following seven issues:

(a) The economic effect of the line and service extension terms and conditions upon agriculture, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development;

(b) The effect of requiring new or existing customers applying for an extension to an electrical or gas corporation to provide transmission or distribution facilities for other customers who will apply to receive line and service extensions in the future;

(c) The effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation;

(d) The economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts;

(e) The effect of the line and service extension regulations, and any modifications to them, on existing ratepayers;

(f) The effect of the line and service extension regulations, and any modifications to them, on the consumption and conservation of energy; and

(g) The extent to which there is cost-justification for a special line and service extension allowance for agriculture.

26. Eliminating gas line subsidies will have the following impacts on the seven issues governed by Pub. Util. Code Section 783(b):

(a) The "economic effect of gas line and service extension terms and conditions upon agricultural, residential housing, mobile home parks, rural customers, urban customers, employment, and commercial and industrial building and development" will be overall net positive;

(b) The "effect of requiring new or existing customers applying for a gas line extension to provide transmission and distribution facilities to other customers who receive line and service extension in the future" will be limited to a shift in who pays which costs, will not be a material effect, and any negative effects on some customers, if any, will be offset by the overall positive effects of reducing GHG emissions, improved quality of life and health for customers, hundreds of millions of dollars in total ratepayer savings annually, greater equity for low-income customers, and greater certainty for the builder and contractor community;

(c) The "effect of requiring a new or existing customer applying for an extension to an electrical or gas corporation to be responsible for the distribution of, reinforcements of, relocations of, or additions to that gas or electrical corporation" will be that the new or existing customer will be responsible for and must pay the costs that are caused by that customer's line extension (including reinforcements, relocations, or additions). These costs will be outweighed by the economic and environmental effects along with increased equity of having the cost-causer pay the costs that are incurred;

(d) The "economic effect of the terms and conditions upon projects, including redevelopment projects, funded or sponsored by cities, counties, or districts" will be higher costs for those projects that choose to connect to the gas system but will be offset (at least in part) by reduced gas rates, and also offset by the environmental and social benefits of ending gas line subsidies;

(e) The "effect of the line and service extension regulations, and any modifications to them, on existing ratepayers" will be savings of at least $164 million per year, plus additional environmental, social and health benefits;

(f) The "effect of the line and service extension regulations, and any modifications to them, on consumption and conservation of energy" will be a reduction in gas consumption, an increase in electricity consumption, lower GHG emissions, less air pollution, and more energy conservation, with overall environmental, social and health benefits; and

(g) There will be no "extent to which there is cost justification for a special line and service extension allowance for agriculture."

27. Pub. Util. Code Section 783(c) requires that:

The commission shall request the assistance of appropriate state agencies and departments in conducting any investigation or proceeding pursuant to subdivision (b), including, but not limited to, the Transportation Agency, the Department of Food and Agriculture, the Department of Consumer Affairs, the Bureau of Real Estate, and the Department of Housing and Community Development.

28. Pub. Util. Code Section 783(d) requires that:

Any new order or decision issued pursuant to an investigation or proceeding conducted pursuant to subdivision (b) shall become effective on July 1 of the year which follows the year when the new order or decision is adopted by the commission, so as to ensure that the public has at least six months to consider the new order or decision.

29. During the course of this proceeding, the Commission provided notice and an opportunity to comment to those agencies identified in Pub. Util. Code Section 783(c).

Conclusions of Law

1. The Commission should eliminate gas line extension allowances, refunds, and discounts for all customer classes, with limited exceptions.

2. The Commission should allow limited exceptions to the elimination of gas line subsidies by permitting a utility to file an application for projects that meet specific criteria.

3. The application should be filed each year by July 1 and must demonstrate that each project meets the following criteria:

   (a) The project shows a demonstrable reduction in GHG emissions;

   (b) The project's gas line extension is consistent with California's climate goals, including those articulated in SB 32 (Pavley, 2016); and

   (c) The project demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

4. The changes adopted in this decision to the gas rules comply with the statutory requirements of Pub. Util. Code Section 783(b)-(d).

5. The gas IOUs should each submit a Tier 2 AL to revise their gas line extension rules to eliminate gas line extension subsides in conformance with this decision. The revised rules should include the application process adopted in this decision allowing limited projects meeting the specific eligibility criteria set out in this decision to seek gas line extension allowances, refunds, and discounts.

O R D E R

IT IS ORDERED that:

1. Gas line extension allowances, the 10-year refundable payment option, and the 50 percent discount option in current utility gas line extension rules shall be eliminated, as provided below:

   (a) Gas Line Extension Allowances: All allowances set forth in utilities' Gas Rule Nos. 15 and 16 (for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation) (collectively, the three gas utilities) and Gas Rule Nos. 20 and 21 (for Southern California Gas Company (SoCalGas)) shall be removed effective July 1, 2023, subject to the application process described in Ordering Paragraph (OP) 2 of this decision;

   (b) 10-Year Refundable Payment Option: All refunds set forth in utilities' Gas Rule Nos. 15 and 16 (for the three gas utilities) and Gas Rule Nos. 20 and 21 (for SoCalGas) shall be removed effective July 1, 2023, subject to the application process described in OP 2 of this decision; and

   (c) 50 Percent Discount Option: All discounts set forth in utilities' Gas Rule Nos. 15 and 16 (for the three gas utilities) and Gas Rule Nos. 20 and 21 (for SoCalGas) shall be removed effective on July 1, 2023, subject to the application process described in OP 2 of this decision.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company and Southwest Gas Corporation (collectively, the gas utilities) may request approval from the California Public Utilities Commission (Commission) by an annual application for a gas line extension allowance, a 10-year refundable payment option, or a 50 percent discount payment option (gas line subsidy) for specific, unique non-residential projects meeting the criteria established in this decision. For those eligible projects, the gas utility shall file an application with the Commission, on behalf of the

applicant(s), for approval of a gas line subsidy, by July 1 of each year starting in 2023. In its annual filing, each investor-owned gas utility shall include an update to the non-residential gas line extension allowance calculations based on the current methodology (including all inputs used, *e.g.*, cost of service factor). The criteria are:

(a) The project shows a demonstrable reduction in greenhouse gas emissions;

(b) The project's gas line extension is consistent with California's climate goals, including those articulated in Senate Bill 32 (Pavley, 2016); and

(c) The project demonstrates that it has no feasible alternatives to the use of natural gas, including electrification.

3. For those specific, unique non-residential projects where a gas line extension allowance, the 10-year refundable payment option, and the 50 percent discount payment option may still be warranted, the gas utilities, on behalf of the project applicants, shall demonstrate the factual basis for the project applicants' assertions, and confirm that the minimum requirements have been met based on the information provided by applicants before filing the annual application with the California Public Utilities Commission.

4. Within 30 days of the date of this order, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each submit a Tier 2 Advice Letter to revise tariffs for their respective gas line extension rules that eliminate gas line extension subsides in conformance with this decision. The revised tariffs shall include the application process adopted in this decision allowing limited projects meeting the specific eligibility criteria set out in this decision to seek gas line extension allowances, 10-year refunds, or 50 percent discounts payment option.

5. Rulemaking 19-01-011 remains open.

This order is effective today.

Dated September 15, 2022, at Clovis, California.

ALICE REYNOLDS
President
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE L. HOUCK
JOHN REYNOLDS
Commissioners

APPENDIX A
Abbreviations, Acronyms, and Definitions

APPENDIX A

Abbreviations, Acronyms, and Definitions

A.	Application
ALJ	Administrative Law Judge
Allowances	Gas line extension allowances
Applicant	An entity (e.g., builder, developer, individual customer) who seeks connection to the utility system
AL	Advice Letter
April 18, 2022 ALJ Ruling	An ALJ ruling receiving into the evidentiary record the gas utilities' responses to the ED-DR
BUILD Program	Building Initiative for Low Emissions Development Program.
Cal Advocates	The Public Advocates Office of the Commission
CARB	California Air Resources Board
CCUE	Coalition of California Utility Employees
Commission	California Public Utilities Commission
CEC	California Energy Commission
CEJA	California Environmental Justice Alliance
CNG	Compressed Natural Gas
DCA	California Department of Consumer Affairs
DRE	California Department of Real Estate
EBCE	East Bay Community Energy
ED-DR	A March 14, 2022, Energy Division data request (ED-DR) sent to PG&E, SoCalGas, SDG&E and SWG; directed the gas utilities to verify and serve their responses to the ED-DR on all parties
EDF	Environmental Defense Fund
FY	Fiscal Year
GHG	Greenhouse Gas
Gas Line Subsidies	Gas line extension allowance, 10-year refundable payment option, or 50 percent discount payment option
Gas Rules	Gas line extension rules:

	Gas Rules 15-16 for PG&E (https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_15.pdf, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_16.pdf), SDG&E (https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE15.pdf, https://tariff.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE16.pdf), and SWG (https://www.swgas.com/1409184638489/rule15.pdf, https://www.swgas.com/1409184638517/RULE_16--GRC_Eff-April-1-2021.pdf), and Gas Rules 20-21 for SoCalGas (https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/20.pdf, https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/21.pdf). Rule 15/20 pertains to gas distribution main extensions and Rule 16/21 pertains to gas service line extensions.
HCD	California Department of Housing and Community Development
IOUs	Investor-owned utilities
Joint CCAs	EBCE, Marin Clean Energy, Peninsula Clean Energy, and Sonoma Clean Power
Joint IOUs	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company
Joint Parties	California Environmental Justice Alliance, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club
MCE	Marin Clean Energy
NRDC	Natural Resources Defense Council
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
PCE	Peninsula Clean Energy
PG&E	Pacific Gas and Electric Company
Phase I Decision	D.20-03-027 established the two building decarbonization pilot programs required by SB 1477: the BUILD Program and the TECH Initiative.
Phase II Decision	D.21-11-002 (1) adopted guiding principles for the layering of incentives when multiple programs fund the same equipment; (2) established the WNDRR Program to provide financial incentives to help victims of wildfires and natural disasters rebuild all-electric properties; (3) provided guidance on data sharing; and (4) directed California's three large electric investor-owned utilities (IOUs)

Phase III Scoping Memo	An Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase III of this proceeding issued on November 16, 2021.
Pub. Util. Code	Public Utilities Code
R.	Rulemaking
RNG	Renewable Natural Gas
SCE	Southern California Edison Company
SCP	Sonoma Clean Power
SB	Senate Bill
SBUA	Small Business Utility Advocates
SDG&E	San Diego Gas & Electric Company
SLCPs	Short Lived Climate Pollutants
SoCalGas	Southern California Gas Company
Staff Proposal	Staff Proposal on Phase III issues (Appendix A, Phase III Scoping Memo).
SWG	Southwest Gas Corporation
TECH Initiative	Technology and Equipment for Clean Heating Initiative.
TURN	The Utility Reform Network
WNDRR Program	Wildfire and Natural Disaster Resiliency Rebuild Program

(END OF APPENDIX A)

Service Date: October 29, 2021

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology to Calculate Natural Gas Line Extension Allowances	DOCKET UG-210729 ORDER 01 AUTHORIZING AND REQUIRING TARIFF REVISIONS

INTRODUCTION

1 **PROCEDURAL HISTORY.** On September 21, 2021, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Item to be Considered at the Commission's Regularly Scheduled Open Meeting and Notice of Opportunity to File Written Comments (Notice). The Notice explained that Commission Chair David Danner, on his own motion, seeks input from regulated natural gas companies and stakeholders addressing whether natural gas utilities should continue to use the current Perpetual Net Present Value (PNPV) methodology for calculating natural gas line extension allowances.

2 The Notice explained that the Commission would address this issue at its October 28, 2021, regularly scheduled open meeting and requested that interested persons file written comments by October 25, 2021.

3 **BACKGROUND.** Natural gas utilities provide line extension allowances to partially offset the cost of expanding the natural gas distribution system to new customers. In 2014, the Commission opened Docket UG-143616 to discuss the need for natural gas distribution infrastructure expansion as well as the options available to implement such an expansion. Part of that discussion included adopting the PNPV methodology,[1] which significantly increased the credit provided to customers through natural gas line extension allowances.

4 On February 25, 2016, Avista Corporation d/b/a Avista Utilities (Avista) proposed tariffs adopting the PNPV method for calculating line extension allowances. The Commission

[1] Under the PNPV method, a line extension allowance is calculated using the anticipated revenue from the customer divided by the authorized rate of return, which results in the net present value of the customer's presence on the system. The current calculation assumes that a customer will remain on the natural gas system in perpetuity. See Commission Staff's Comments, page 1-2.

authorized the change and increased Avista's natural gas line extension allowance from $1,920 to $4,482 for residential customers. The PNPV method for calculating Avista's natural gas line extensions was made permanent on February 19, 2019.[2]

5 On July 29, 2016, Cascade Natural Gas Corporation (Cascade) filed proposed revisions to its Tariff WN U-3 that adopted the PNPV method to calculate line extension allowances. This change increased the company's line extension allowance from $572 to $3,255 for residential customers. The tariff revisions became effective by operation of law on September 1, 2016.[3]

6 On December 6, 2016, Puget Sound Energy (PSE) filed a tariff revision proposing to implement Rule No. 6 – Extension of Distribution Facilities, which adopted the PNPV methodology consistent with Avista's and Cascade's line extension tariffs. This change increased PSE's natural gas line extension allowance from $1,932 to $4,179 for residential customers. The Commission authorized the tariff change at its January 12, 2017, open meeting.[4]

7 In PSE's 2019 General Rate Case, the Commission received testimony from the Northwest Energy Coalition (NWEC) noting that the current PNPV calculation can result in subsidies from current natural gas customers to new customers and recommending that the Commission require PSE to revert to its previous line extension allowance calculation methodology or to revisit the issue in a broader forum. The Commission declined to adopt NWEC's recommendation as part of that rate case but signaled its intention to revisit the issue in a future proceeding.[5] Chair Danner dissented from this decision. In a concurring statement, Commissioner Rendahl supported revisiting the issue because the record evidence in the rate case was insufficient to support making a change.

8 **STAKEHOLDER COMMENTS.** The Commission received written comments from numerous stakeholders, including Commission staff (Staff). Most comments recommend discontinuing natural gas line extension allowances entirely or at least discontinuing the use of the PNPV methodology. The Alliance of Western Energy Consumers (AWEC) filed comments recommending the Commission retain the PNPV methodology, but later revised its comments at the open meeting to support Staff's or Northwest Natural Gas Company's proposals.

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[2] Docket UG-152394, Staff Memo (Feb. 25, 2016).

[3] Docket UG-160967, Staff Memo (Aug. 29, 2016).

[4] Docket UG-161268, Staff Memo (July 10, 2017).

[5] Docket UE-190529 *et. al.*, Final Order 08 ¶ 614 (July 8, 2020).

9 The City of Seattle urged the Commission to consider the costs of expanding fossil fuels, including the social cost of greenhouse gas, and whether benefits would still accrue for ratepayers, including low-income and vulnerable customers.

10 The Public Counsel Unit of the Attorney General's Office (Public Counsel) recommends the Commission discontinue the use of PNPV and provide line extension allowances that minimize the socialized costs of line extensions while still providing adequate access to natural gas for new customers. At the open meeting, Public Counsel noted that reducing the use of natural gas is consistent with legislative clean energy goals and recommended the Commission adopt an alternative to PNPV that is consistent with Washington state clean energy policy.

11 Avista supports discontinuing the use of the current PNPV methodology and reverting to its prior methodology, or, in the alternative, adopting Staff's recommendation. Avista proposes to use values from its Natural Gas Decoupling Mechanism baseline to determine the natural gas line extension allowance, resulting in an allowance for residential customers of $2,100 (compared to the present allowance of $4,678) and a Non-Residential per therm allowance of $1.36/therm (compared to the present allowance of $3.44/therm). At the Commission's open meeting, Avista stated that it has 272 customers currently under construction and receiving line extension allowances and more than 1,000 customers in the design phase. Avista thus requests a transition date of April 1, 2022, to allow customers who have already begun the line extension process to move forward under the current PNPV calculation.

12 Northwest Natural Gas Company (NW Natural) does not currently use PNPV. Rather, NW Natural calculates its line extension construction allowance as five times the delivery margin for the applicable rate schedule multiplied by the annual estimated therm usage attributable to the customer's installation. NW Natural believes that its existing Schedule E tariff is designed to determine the fair cost of providing fuel choice while economically eliminating cross-subsidization between existing ratepayers and new customers.

13 PSE supports discontinuing the PNPV methodology because it is increasingly out of step with the evolution of the State's energy policy. PSE supports a methodology that reasonably ensures existing natural gas customers are not subsidizing the connection of new natural gas customers and better aligns with both Washington's and PSE's decarbonization goals. To that end, PSE believes that promptly reverting to something like its previous methodology for determining natural gas line extension allowances may be appropriate. PSE's previous line extension allowance used a discounted cash flow

Facilities Investment Analysis (FIA) methodology.[6] PSE supports immediately changing back to the FIA methodology in the interim and addressing this issue more fully in Docket U-210553, the Commission's examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets. At the Commission's open meeting, PSE reiterated its recommendation to conduct a broader investigation into this issue and stated that it supports Staff's recommendation.

14 The Department of Commerce (Commerce) asserts that PNPV is contrary to state policy and urges the Commission to consider discontinuing line extension allowances altogether. In the alternative, Commerce supports Staff's recommendation to modify the PNPV calculation.

15 RMI and the Natural Resources Defense Council observe that the line extension allowances generated by the PNPV method are 1.5 to 3 times higher than allowances in Colorado and California, both of which use revenue-based formulas to calculate allowances.

16 Cascade proposes reverting to its previous calculation method of 3.3 times margin allowance for service connections and an additional 3.3 times margin allowance if main extensions are also required. Cascade proposes a transition period to allow the company to complete line extensions already in progress using the current PNPV method.

17 350Seattle recommends ending all natural gas line extension allowances and instead providing allowances for beneficial electrification.

18 The Sierra Club urges the Commission to implement a complete moratorium on new natural gas collections or, in the alternative, to end natural gas line extension allowances.

19 NWEC recommends the Commission evaluate and potentially discontinue line extension allowances completely. NWEC further recommends the Commission evaluate the need for regulatory tools for natural gas utilities to meet state greenhouse gas emission reduction targets.

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[6] The FIA methodology provides a line extension allowance based on a calculation that includes, for example, consideration of the natural gas powered appliances being installed, annual therm assumptions estimated using square footage, whether a main extension is required, and whether other new customers would be included along the same extension the FIA methodology does allow more precise assumptions that can be tailored to reflect current state policy including building codes and to align with PSE's decarbonization goals.

20 The 37th Legislative District Democratic Environmental Caucus recommends discontinuing the use of PNPV or any rate-based fees for extending natural gas distribution infrastructure.

21 Staff recommends retaining the PNPV method but updating the discount timeframe as a matter of policy. Overall, Staff believes this revised PNPV method results in a simpler tariff structure and makes the relevant calculations easier to understand, perform, and apply. Staff also believes that this PNPV method ensures that line extension allowances are economically justified. Staff recommends adopting a Net Present Value (NPV) method that updates the discount timeframe based on consideration of the following policy factors:

- Cost of greenhouse gas emissions
- Environmental impact from oil furnaces and wood-burning stove emissions
- Economic development from expanding service to areas not currently served by natural gas
- Increasing energy efficiency
- Historical equity in access to natural gas for marginalized communities and vulnerable populations
- The treatment of natural gas versus electric infrastructure by the State of Washington

22 Staff recommends using an eight-year timeframe because it aligns the margin allowance discount timeframe with the implementation of the Clean Energy Transformation Act (CETA).[7] Additionally, Staff believes that a calculation using the 8-year timeframe will be closer to or lower than an updated margin allowance calculation using PSE's FIA model.

23 Chair Danner proposes to adopt Staff's recommendation, in part, and modify the PNPV method to include a timeline of seven years, which will result in a limited line extension allowance more consistent with state policy and closer to the amount allowed in 2014 prior to the adoption of PNPV.

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[7] Chapter 19.405 RCW.

DISCUSSION AND DECISION

24 We agree with Staff's recommendation, in part, and require PSE, Avista, and Cascade to file tariff revisions by November 17, 2021, adopting a Net Present Value (NPV) methodology using a seven-year timeline for calculating natural gas line extension allowances for the reasons discussed below.

25 In recent years, the legislature has enacted several laws aimed at reducing greenhouse gas emissions, including emissions from natural gas. In 2019, the legislature passed CETA, which requires electric utilities to eliminate coal by 2025 and all carbon-emitting resources by 2045. In 2021, the legislature amended RCW 80.28.074 to clarify that advancing the availability of natural gas services to Washington residents is no longer state policy. Additionally, as several commenters noted, the legislature directed that Washington's energy code be revised to make new construction more efficient, which will result in new homes and buildings using less natural gas than existing structures currently use.

26 Further, this year, the legislature also passed the Climate Commitment Act,[8] under which gas companies must meet specific emissions reductions requirements and must surrender allowances to cover the greenhouse gas emissions from the use of their product. While gas companies will receive free emissions allowances to address cost impacts to current customers, almost all new customers are excluded from this part of the program.

27 We appreciate the thoughtful perspectives offered by the companies, consumers, and stakeholders, most of whom agree that the current PNPV methodology is contrary to the legislature's clear direction to reduce greenhouse gas emissions and the use of fossil fuels. As many commenters aptly observed, it is imperative that we address climate change, including the health impacts of greenhouse gases and methane emissions on Washington's communities and citizens. Recognizing the urgency of this issue, we view our decision today as an interim measure that will substantially reduce line extension allowances while we continue to engage in dialogue with regulated utilities and other stakeholders in Docket U-210553, the Commission's broader examination of energy decarbonization impacts and pathways for electric and gas utilities to meet state emissions targets.

28 The comments we received in this docket offer several important factors to consider as we move forward, including the likelihood that natural gas lines will not be serving customers in Washington in perpetuity, the laws and rules in Washington related to greenhouse gas emissions, new requirements in the State Energy and Building Codes,

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[8] RCW 70A.65.900.

ensuring that utility tariffs do not increase the likelihood of stranded assets in the future, and ensuring that line extension policies do not shift the cost burden from new to current customers. Although the proceeding in Docket U-210553, which is already underway, provides a more appropriate forum to ensure that these factors are thoroughly considered, we conclude that discontinuing use of the current PNPV calculation immediately is in the public interest because it can result in existing customers subsidizing new customers while significantly increasing reliance on fossil fuels. Given the recent changes to laws and policies discussed above, we conclude that the current PNPV calculation is no longer a valid line extension allocation method for Washington utilities or their customers.

29 Accordingly, we agree Staff's recommendation and require PSE, Avista, and Cascade to adopt an NPV calculation for natural gas line extension allowances. This methodology is simple to calculate because it requires a single assumption — the length of time the service will be installed — and relies on information from recent rate cases. Imposing a seven-year calculation timeline will reduce the line extension allowance for the residential customers of each company to approximately $2,000, which is a substantial, but gradual, decrease from current values.

30 Finally, Avista, Cascade, and PSE request that we provide a transition period for customers who have received approval for a line extension allowance under the current tariff. We agree that the companies should be authorized to exempt from the new tariff provisions those customers who have submitted applications that are approved or pending as of the date the revised tariffs become effective, as well as those customers who can demonstrate or attest that their applications have been submitted to local permitting offices. This exemption will expire on April 1, 2022.

FINDINGS AND CONCLUSIONS

31 (1) The Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including natural gas companies, and has jurisdiction over the parties and subject matter of this proceeding.

32 (2) PSE, Avista, and Cascade are natural gas companies subject to Commission regulation.

33 (3) This matter came before the Commission at its regularly scheduled open meeting on October 28, 2021.

34 (4) The PNPV methodology currently in effect for calculating natural gas line extension allowances significantly increases the margin allowances for each utility and thus increases reliance on fossil fuels contrary to state policy and laws.

38 (5) The NPV methodology proposed by Staff and calculated using a seven-year timeline provides a substantial but gradual decrease in natural gas line extension allowances that is better aligned with the legislature's direction and policy goals and is therefore in the public interest.

39 (6) The Commission should require PSE, Avista, and Cascade to file by November 17, 2021, tariff revisions that reflect the use of the NPV methodology using a seven-year timeframe for calculating natural gas line extension allowances.

ORDER

THE COMMISSION ORDERS THAT:

35 (1) Puget Sound Energy, Avista Corporation d/b/a Avista Utilities, and Cascade Natural Gas Corporation are required and authorized to file by November 17, 2021, tariff revisions necessary and sufficient to effectuate the terms of this Order.

36 (2) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective October 29, 2021.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chair

ANN E. RENDAHL, Commissioner

Service Date: December 12, 2022

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, d/b/a AVISTA UTILITIES, Respondent	DOCKETS UE-220053, UG-220054, UE-210854 *(Consolidated)* FINAL ORDER 10/04
In the Matter of the Electric Service Reliability Reporting Plan of AVISTA CORPORATION, d/b/a AVISTA UTILITIES.	REJECTING TARIFF SHEETS; GRANTING PETITION; APPROVING AND ADOPTING FULL MULTIPARTY SETTLEMENT STIPULATION SUBJECT TO CONDITIONS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission (Commission) approves and adopts subject to conditions a full multiparty settlement stipulation (Settlement) that resolves all contested issues and is agreed to by all Parties except the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel), which contests some portions of the Settlement.*

Public Counsel opposes the Settlement's resolution of power costs, insurance expense balancing account, wildfire-related issues, cost of capital, and the overall revenue requirement, but either supports or does not oppose all other terms of the Settlement, including: cost of service, rate spread, and rate design; the Residual Tax Customer Credit; Colstrip investments, tracker, and Tariff Schedule 99; the escalation study; capital planning; distributional equity analysis; capital projects review; natural gas transition issues; transportation electrification; performance-based ratemaking; low-

income issues; the Climate Commitment Act; small business energy efficiency; electric service reliability report plan; depreciation rates and regulatory amortizations; annual filing dates; annual reporting obligations of Docket U-210151; software licensing; and the decoupling earnings test.

The Commission finds that the Settlement is lawful, supported by an appropriate record, and consistent with the public interest, subject to the conditions outlined in paragraphs 78, 85, 99, 112, and 146 of this Order. Accordingly, the Commission determines that approval of the Settlement, subject to conditions and in concert with other findings, will establish rates, terms, and conditions for Avista's electric and natural gas service to Washington customers that are equitable, fair, just, reasonable, and sufficient.

The Settlement is results-focused and provides a results-only resolution for Avista's overall revenue requirement.[1]

By approving the Settlement, the Commission authorizes revenue requirement increases for Avista over a multi-year rate plan (MYRP) covering the upcoming two-year period. The Settlement returns Residual Tax Customer Credit amounts of approximately $27.6 million and $12.5 million to electric and natural gas customers, respectively, over the term of the MYRP. Prior to the impact of the Residual Tax Customer Credit, the Settlement provides a $38.0 million annual increase to the Company's electric revenues, and a $7.5 million in natural gas revenues in Rate Year 1, and, in Rate Year 2, an additional increase of $12.5 million to the Company's electric revenues, and $1.5 million in natural gas revenues.

As a result of the Settlement, a typical residential electric customer using 932 kWhs per month will pay $4.47 more per month in Rate Year 1, for an average monthly bill of $89.99, and a typical residential electric customer using 932 kWhs per month will pay $2.24 more per month in Rate Year 2, for an average monthly bill of $92.23. A typical residential natural gas customer using 67 therms per month will pay $0.20 more per month in Rate Year 1, for an average monthly bill of $65.06; and a typical residential natural gas customer using 67 therms per month will pay $0.52 more per month in Rate Year 2, for an average monthly bill of $65.58.

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[1] The Commission is working to adopt more inclusive language in its documents, and therefore describes a settlement as "results-focused" or "results-only" when underlying components of a settlement are not enumerated or supported by calculations. We encourage all investor-owned utilities, parties to proceedings, and interested persons to do the same. Please refer to footnote 239 for a more detailed explanation.

Other noteworthy terms the Commission approves as part of the Settlement include the establishment of a new Tariff Schedule 99 (the Colstrip Tracker) with an annual true-up to separately track and recover certain costs related to the Colstrip generating plant.

The Commission's approval of the Settlement also results in the historic first set of performance metrics (Attachment B to the Settlement and two metrics related to transportation electrification plus the commitment to develop additional reliability metrics) that will track data agreed to by the Settling Parties related to Avista's performance during the MYRP. The results of these metrics will be published, maintained, and tracked on Avista's website for public access and reported to the Commission. The metrics will be reported on either a quarterly or annual basis beginning 45 days after the end of the first quarter of 2023.

In addition to approving the Settlement, the Commission fulfills its obligation under RCW 80.28.425(7) to determine a set of performance measures to use in assessing Avista's operations during the MYRP. In particular, the Commission adopts nine performance measures related to operational efficiency, earnings, affordability, and energy burden for the purpose of assessing how much expense Avista incurs for every dollar it earns; the efficient use of Avista's assets to generate revenue, maintaining liquidity; how much net profit Avista gains through the revenues it earns; the amount of earnings retained by Avista vis-à-vis its total equity; and tracking affordability for, and the energy burden of, residential customers.

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BACKGROUND

1 This case concerns Avista Corporation's d/b/a Avista Utilities (Avista or Company) 2022 electric and natural gas general rate case (GRC) and its electric service reliability reporting plan.

2 On November 11, 2021, Avista filed with the Washington Utilities and Transportation Commission (Commission) its Electric Service Reliability Reporting Plan in Docket UE-210854 pursuant to Washington Administrative Code (WAC) 480-100-393, modifying its previous plan.

3 On January 21, 2022, Avista filed with the Commission revisions in Docket UE-220053 to its currently effective electric service tariff, Tariff WN U-28, and in Docket UG-220054 to its natural gas service tariff, Tariff WN U-29 (Avista 2022 GRC). The Company proposed a two-year rate plan with increases for electric and natural gas operations for Rate Year 1 effective December 21, 2022, and for Rate Year 2 effective December 21, 2023, as depicted in Table 1, below.

4 Concurrent with the effective date of its 2022 GRC, Avista proposes to partially offset the Company's requested increases, and return to customers the estimated incremental customer tax Accumulated Deferred Income Tax (ADIT) benefits of approximately $25.5 million for electric and $12.5 million for natural gas over a two-year amortization period through separate Tariff Schedules 78 (electric) and 178 (natural gas).[2] We refer to this return of tax benefits as the "Residual Tax Customer Credit" throughout this Order.[3] Rate Year 1 rates are offset by this tax credit to result in an increase of 7.4 percent to *billed* rates for electric operations and 2.5 percent for natural gas operations.[4] Rate Year 2 rates, as proposed by Avista, already embed the tax credit in base rates, but Avista notes that the resulting increase to *billed* rates is 3.0 percent for electric operations and 1.1 percent for natural gas operations.[5]

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[2] Andrews, Exh. EMA-1T at 5:29-6:7. The amount of ADIT benefits to be returned to customers was updated during these consolidated proceedings to $27.6 million for electric.

[3] Avista refers to this return of tax benefits as the "Tax Customer Credit" under its initial proposal. Vermillion, Exh. DPV-1T at 18:18-23.

[4] *Id.* at 18:23-19:14.

[5] *Id.* at 19:5-14; *see* Avista Electric Summaries for Rate Year 1 & Rate Year 2 (filed Mar. 28, 2022) and Natural Gas Summaries for Rate Year 1 & Rate Year 2 (filed Jan. 21, 2022).

5 **Table 1. Avista's Initial Proposal for Net Revenue Increases *(in millions)***

	Electric		Natural Gas	
Rate Year 1	$ 52.9	9.6%	$ 10.9	9.5%
Residual Tax Customer Credit[6]	$ (12.8)		$ (6.3)	
Net Increase	**$ 40.1**	**7.4%**	**$ 4.6**	**2.5%**
Rate Year 2	$ 17.1	2.8%	$ 2.2	1.7%
Residual Tax Customer Credit[7]	$ (0.0)		$ (0.0)	
Net Increase	**$ 17.1**	**2.8%**	**$ 2.2**	**1.7%**

6 On January 27, 2022, the Commission entered Order 01, consolidating Dockets UE-220053 and UG-220054, suspending the tariff revisions, and setting the matters for adjudication.

7 The Commission entered a Protective Order, Order 02, in Dockets UE-220053 and UG-220054 *(Consolidated)* on January 31, 2022.[8]

8 On February 14, 2022, the Commission convened a virtual prehearing conference before Administrative Law Judge Andrew J. O'Connell.

9 On February 16, 2022, the Commission issued Order 03, Prehearing Conference Order; Notice of Hearing, adopting with minor modifications the agreed procedural schedule and setting a hearing to begin on September 21, 2022. Order 03 also granted intervention to the Alliance of Western Energy Consumers (AWEC), the NW Energy Coalition (NWEC), The Energy Project (TEP), Sierra Club, and Small Business Utility Advocates (SBUA).

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[6] Amortized over two years, Avista's initial proposal for the Residual Tax Customer Credit of approximately $25.5 million for electric would result in approximately $12.8 million annually, and of approximately $12.5 million for natural gas would result in approximately $6.3 million annually.

[7] Amortization of the Residual Tax Customer Credit is embedded in year two base rates.

[8] The Commission would later consolidate these dockets with Docket UE-210854 by Order 07/01.

10 On February 16, 2022, Walmart, Inc., (Walmart) filed a late-filed petition to intervene.

11 On February 28, 2022, the Commission convened a second virtual prehearing conference to address processes, procedures, and applications for participatory funding. Pursuant to RCW 80.28.430, utilities must enter into funding agreements with organizations that represent broad customer interests. The Commission is directed to determine the amount of financial assistance, if any, that may be provided to any organization; the way the financial assistance is distributed; the way the financial assistance is recovered in a utility's rates; and other matters necessary to administer the agreement.[9]

12 The Commission's Policy Statement on Participatory Funding for Regulatory Proceedings (Policy Statement) provides "high-level guidance regarding the amount of financial assistance that may be provided to organizations, the manner in which it is distributed to participants and recovered in the rates of gas or electrical companies, and other matters necessary to administer agreements."[10] In Docket U-210595, the Commission approved and adopted an interim agreement on participatory funding, subject to certain modifications.[11]

13 On March 1, 2022, the Commission entered Order 04, Second Prehearing Conference Order, granting Walmart's unopposed late-filed petition to intervene and adopting the schedule discussed at the February 28, 2022, conference. Order 04 required organizations seeking a fund grant to file a request for case certification and notice of intent to request a fund grant by March 9, 2022.

14 By March 9, 2022, AWEC, TEP, NWEC, and SBUA had each filed with the Commission a request for case certification and notice of intent to request a fund grant.

15 On March 16, 2022, the Commission issued a Notice of Bench Requests Nos. 1 and 2, requesting additional information relevant to participatory funding from NWEC, TEP, and SBUA. NWEC, TEP, and SBUA each filed its response with the Commission on March 18, 2022.

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[9] RCW 80.28.430(2).

[10] *In re Examination of Participatory Funding Provisions for Regulatory Proceedings,* Docket U-210595, Policy Statement, ¶ 3 (Nov. 19, 2021) [hereinafter Participatory Funding Policy Statement].

[11] *In re Petition of Puget Sound Energy, et al.*, Docket U-210595, Order 01 (Feb. 24, 2022).

16 On March 24, 2022, the Commission entered Order 05, Granting Requests for Case Certification. Order 05 granted case certification to AWEC, NWEC, TEP, and SBUA, and directed each to file a proposed budget within 30 days.

17 AWEC, TEP, NWEC, and SBUA all timely filed with the Commission proposed budgets by April 25, 2022.

18 On May 27, 2022, the Commission entered Order 06, Approving and Rejecting Proposed Budgets for Fund Grants. Order 06 approved the proposed budgets of AWEC, NWEC, and TEP, but rejected the proposed budget of SBUA, finding that SBUA failed to establish a sufficient connection to Washington ratepayers.

19 Also on May 27, 2022, the Commission entered Order 07/01, consolidating Dockets UE-220053 and UG-220054 with Docket UE-210854 pursuant to Commission staff's (Staff) unopposed motion to consolidate.

20 On June 6, 2022, SBUA filed with the Commission a petition for interlocutory review, requesting the Commission modify Order 06 and approve SBUA's proposed budget.

21 On July 11, 2022, the Commission entered Order 08/02, Granting Petition for Interlocutory Review, In Part; Approving Proposed Budget Subject to Condition (Order 08). Order 08 approved SBUA's proposed budget in the amount of $20,000 to be used for attorney fees and expert witness fees only, subject to the condition that SBUA file a confidential list of its members concurrent with its request for reimbursement later in these consolidated proceedings.[12]

22 On June 13, 2022, the Commission suspended the procedural schedule in these consolidated matters pursuant to a joint request from the parties, indicating that the parties had reached a full multiparty settlement.

23 On June 22, 2022, the Commission issued a Notice Adopting Agreed Procedural Schedule and Notice of Hearing, setting a virtual hearing on the full multiparty settlement

[12] Order 08 found that requiring the confidential submission of its membership list is neither unusual nor extraordinary, observing that other organizations have provided confidential membership lists in other proceedings and would assist the Commission with evaluating SBUA's connection to Washington ratepayers (citing AWEC's confidential filing of its membership lists in Cascade Natural Gas Corporation's general rate case, Docket UG-210755, in support of its proposed budget and in Puget Sound Energy's general rate case, Dockets UE-220066 and UG-220067 *(Consolidated)*, in support of its petition to intervene). Order 08 at 6, ¶ 20, n. 4.

for September 21, 2022. Avista, Staff, AWEC, NWEC, TEP, Sierra Club, SBUA, and Walmart (Settling Parties) agreed to the full multiparty settlement.

24 On June 28, 2022, the Settling Parties filed with the Commission their Full Multiparty Settlement Stipulation (Settlement). The Settlement and Attachment A to the Settlement are attached to this Order as Appendix A.

25 On July 8, 2022, the Settling Parties filed with the Commission their joint testimony in support of the Settlement.

26 On July 29, 2022, the Settling Parties filed with the Commission their supplemental joint testimony in support of the Colstrip Tracker and Tariff Schedule 99, one of the items addressed by the Settlement.

27 Also on July 29, 2022, the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel) filed with the Commission its testimony opposing the Settlement.

28 On August 19, 2022, Avista filed with the Commission rebuttal testimony responding to Public Counsel's opposition testimony.

29 On September 7, 2022, the Commission issued Order 09/03, granting an unopposed motion by Avista to revise Attachment C to the Settlement.

30 Also on September 7, 2022, the Commission held a virtual public comment hearing in these consolidated matters. No person offered comments.

31 On September 21, 2022, the Commission held a virtual settlement hearing and received testimony from a panel of witnesses representing the Settling Parties and Avista witnesses. At the hearing, the parties stipulated to the admission of all exhibits into the record. Due to time constraints, the Commission continued a portion of the hearing until a later date.

32 On September 23, 2022, the Commission issued a notice reconvening the virtual settlement hearing for September 30, 2022, to receive testimony from Avista witnesses whose testimony could not be heard on September 21, 2022.

33 On September 30, 2022, the Commission reconvened the virtual settlement hearing and received all remaining testimony from witnesses.

34 On October 14, 2022, Public Counsel filed with the Commission its response to Bench Request No. 3, which contained all public comments received in these consolidated dockets. Over the course of the proceeding, including the public comment hearing, the Commission and Public Counsel received 30 comments from Washington customers regarding the proposed rate increases. All comments opposed a rate increase.[13] The comments focused on a variety of topics, including the unaffordability of residential rates (especially for those on fixed incomes), insufficient or inadequate programs, and rate design.[14]

35 On October 20, 2022, Avista filed with the Commission its responses to Bench Requests Nos. 4-6, which regarded details of how the Residual Tax Customer Credit was to be passed back to customers during the proposed two-year rate plan, the cumulative impact on net plant balances related to removing Colstrip Dry Ash from Rate Year 1 and Rate Year 2, and the resulting monthly bill for average electric and natural gas residential customers if the Settlement were approved, respectively.

36 On October 21, 2022, Avista, Staff, Public Counsel, AWEC, NWEC, TEP, and SBUA filed post-hearing briefs with the Commission. Walmart filed a letter with the Commission indicating it would not file a post-hearing brief.

37 Also on October 21, 2022, Avista filed with the Commission its 2022 Draft Electric Service Reliability Reporting Plan for informational purposes.

38 On November 23, 2022, Avista filed with the Commission its response to Bench Request No. 7 related to the Settling Parties' reference to Avista's updated cost of debt during the pendency of these consolidated proceedings and the source material for that update.

39 David J. Meyer, Vice President and Chief Counsel for Regulatory and Governmental Affairs, Spokane, Washington, represents Avista. Sally Brown, Senior Assistant Attorney General, Jeff Roberson, and Nash I. Callaghan, Assistant Attorneys General, Olympia, Washington, represent Staff.[15] Nina Suetake, Ann Paisner, and Lisa Gafken, Assistant

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[13] Public Comments, Exh. BR-3.

[14] *See id.*

[15] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

Attorneys General, Seattle, Washington, represent Public Counsel. Tyler Pepple and Sommer J. Moser, Davison Van Cleve, P.C., Portland, Oregon, represent AWEC. Irion Sanger, Joni Sliger, and Ellie Hardwick, Sanger Law P.C., Portland, Oregon, represent NWEC. Yochanan Zakai and Stacy Lee, Shute, Mihaly & Weinberger LLP, San Francisco, California, represent TEP. Gloria D. Smith, Managing Attorney, Sierra Club Environmental Law Program, Oakland, California; James M. Van Nostrand, Oakland, California; and Jim Dennison, Colorado, represent Sierra Club. Jeff Winmill, James M. Birkelund, and Jennifer Weberski, San Francisco, California, represent SBUA. Vicki M. Baldwin, Parsons Behle & Latimer, Salt Lake City, Utah, represents Walmart.

DISCUSSION AND DECISION

40 The Commission's statutory duty is to establish rates, terms, and conditions for electric and natural gas services that are equitable, fair, just, reasonable, and sufficient. In doing so, the Commission must balance the needs of the public to have safe, reliable, and appropriately priced service with the financial ability of the utility to provide that service. The rates thus must be equitable, in that the distribution of burdens and benefits should reduce, rather than perpetuate, ongoing systemic harms; fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.

41 The Commission is presented with a Settlement that proposes to resolve all disputed issues. The Commission approves settlements "when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the commission."[16] The Commission may approve the Settlement, with or without conditions, or reject it. We determine that, subject to conditions, the Settlement is lawful, its terms are supported by an appropriate record, and its result is consistent with the public interest in light of all the information available. We explain our reasoning, below.

42 In the decisions we make in this Order, we also consider recent federal legislative action that will impact Washington investor-owned utilities. On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (IIJA), which provides a strategic opportunity to upgrade the nation's energy infrastructure for a clean, resilient,

[16] WAC 480-07-750(1).

and secure energy future.[17] The IIJA funds over 350 programs to be overseen through more than a dozen federal departments and agencies.[18] On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA) into law.[19] The IRA is a fiscal policy instrument enacted by the federal government to counterbalance the effects of inflation in specific areas of the economy. It also represents the United States' single largest investment to date to modernize its energy system.[20]

43 The impacts of these laws on rates are not yet known, but it is apparent that both could greatly impact Avista's utility operations during the multi-year rate plan (MYRP) agreed by the Settling Parties. Many aspects of Avista's operations, costs, funding, and financial health may be impacted by these new laws including extension of investment tax credits, creation of new tax credits, accelerated depreciation of clean electricity facilities, and extension of tax credits for investment in certain energy properties, among other aspects.[21] The Biden administration announced additional funding to provide increased

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[17] Infrastructure Investment and Jobs Act of 2021, Pub. L. No. 117-58, 135 Stat. 429 (2021) [hereinafter IIJA].

[18] The White House, *A Guidebook to the Bipartisan Infrastructure Law for State, Local, Tribal, and Territorial Governments, and Other Partners* (May 2022), https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.

[19] Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818 (2022) [hereinafter IRA].

[20] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, Rocky Mountain Institute, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[21] Several sections of the law are included for reference:

Modifies and extends through 2024 the tax credit for producing electricity from renewable resources. IRA at § 13101.

Creates a new clean electricity investment tax credit for investment in qualifying zero-emissions electricity generation facilities or energy storage technology. IRA at § 13702.

Allows a five-year recovery period for the depreciation of clean electricity facilities placed in service after 2024. IRA at § 13703.

Extends through 2024 the tax credit for investment in certain energy properties (*e.g.*, solar, fuel cells, waste energy recovery, combined heat and power, small wind property, microturbine property, and microgrid controllers). Increases credit rate for projects that pay prevailing wages and meet registered apprenticeship requirements. Allows a bonus credit amount for facilities that meet domestic content requirements for steel, iron, and manufactured projects and for facilities located in an energy community. IRA at § Sec. 13102.

Modifies the energy tax credit to allocate 1.8 gigawatts for environmental justice solar and wind capacity credits in low-income communities and Indian lands in 2023 and 2024. Facilities support for low- and moderate-income families, and complementary tax credits that families and building owners can use under the IRA to install energy-saving equipment and to make building upgrades.[22] More specifically, new resources have been allocated for the federal Low-Income Home Energy Assistance Program (LIHEAP), which has funds that will go to states, territories, and Tribes.[23]

44 Other regulatory commissions have taken action to engage in participative processes to allow interested parties to discuss their thoughts on implementation and to take advantage of the benefits that the laws provide.[24] The impacts of tax credits and other financial provisions will result in changes that impact utility revenue requirement and, ultimately, changes in customers' bills. The IRA could bring significant reductions to energy costs

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receiving allocations must be placed in service within four years after the allocation date. IRA at § 13103.

Creates a new tax credit for qualified commercial clean vehicles. IRA at § 13403.

[22] The White House, *FACT SHEET: White House Announces Additional $385 Million to Lower Home Energy Bills for American Families* (Apr. 21, 2022), https://www.whitehouse.gov/briefing-room/statements-releases/2022/04/21/fact-sheet-white-house-announces-additional-385-million-to-lower-home-energy-bills-for-american-families/.

[23] *Id.*; Department of Energy, *Biden-Harris Administration Announces State and Tribe Allocations for Home Energy Rebate Program* (Nov. 2, 2022), https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate.

[24] *See In re Utility Infrastructure Improvements from the Federal Funding Available Under the Infrastructure Investment and Jobs Act of 2021: Alpena Power Co., et. al.*, Order, Docket U-21227, Mich. Pub. Serv. Comm'n (May 12, 2022), *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002tmfNAAQ; *In re Infrastructure Investment and Jobs Act Investigation*, Order Requesting Comment Regarding the Infrastructure Investment and Jobs Act, Docket PU-22-143, N.D. Pub. Serv. Comm'n (Mar. 9, 2022), *available at* https://www.psc.nd.gov/database/documents/22-0143/002-020.pdf; *In re Consideration of the Federal Funding Available Under the Infrastructure Investment and Jobs Act*, Order Allowing Comments Regarding Federal Funding for Utility Service in North Carolina, Docket M-100, Sub 164, N.C. Utils. Comm'n (Feb. 1, 2022), *available at* https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ee9659cf-dbd6-4ce6-b34f-e8073fcf744e; *In re Investigation into the Implementation of the Federal Infrastructure Investment and Jobs Act*, Docket 22-755-AU-COI, Pub. Utils. Comm'n of Ohio (Aug. 10, 2022), *available at* https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A22H10B43213C01798; *In re Petition to Open an Administrative Docket to Consider the Federal Infrastructure Investment and Jobs Act of 2021*, Directive Order Establishing Procedural Schedule for Written Comments and Reply Comments, Docket 2022-168-A, Pub. Serv. Comm'n of S.C. (Jun. 9, 2022), *available at* https://dms.psc.sc.gov/Attachments/Matter/3f9d6c58-65f7-41c5-989c-7de70ef7cd2c.

for customers, up to $500 in energy bills savings per year.[25] At least one utility, the Florida Power & Light Company, is planning to phase in nearly $360 million in additional federal tax savings for future planned solar projects starting in 2023 and through 2025. Other, more immediate, savings to customers will be provided in a one-time refund of $25 million in the month of January 2023.[26]

45 All testimony and exhibits were prefiled prior to the enactment of the IRA except for Avista's rebuttal testimony in support of the Settlement. The parties to these consolidated proceedings had no opportunity to consider any of the possible impacts of the IRA and IIJA while negotiating, drafting, or presenting the Settlement to the Commission. Because these changes are significant, we make minor, prudent modifications to the Settlement where necessary to include the impacts of the IRA and IIJA in our retrospective review of provisional plant. In addition, for any other IRA and IIJA benefits unmentioned or unaddressed by this Order, we expect Avista will file with the Commission an accounting petition requesting to defer those benefits.

A. FULL MULTIPARTY SETTLEMENT STIPULATION[27]

46 The Settlement submitted by the Settling Parties proposes to resolve all disputed issues in the proceeding. The Settlement's resolutions of many issues are uncontested or supported by Public Counsel. In its opposition testimony filed with the Commission on July 29, 2022, Public Counsel affirmatively states that many of the Settlement's terms are in the public interest.[28] These issues include:

- Performance Metrics;

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[25] Jessie Ciulla, Gennelle Wilson, and Rachel Gold, *What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service*, Rocky Mountain Institute, 2022, https://rmi.org/insight/what-utility-regulators-need-know-about-ira/.

[26] *FPL proposes plan to refund customers nearly $400 million in federal corporate tax savings*, News Releases, NEXTera Energy (Sep. 23, 2022), *available at* https://www.investor.nexteraenergy.com/news-and-events/news-releases/2022/09-23-2022-133107538.

[27] The Settlement is included as Appendix A to this Order. Appendix A is incorporated into, and made part of, this Order by this reference. In this Order, we briefly summarize the Settlement's proposed commitments. To the extent any arguable inconsistency exists between our summary and the terms of the Settlement, the terms of the Settlement control.

[28] Dahl, Exh. CJD-1T at 5:17-18.

- Colstrip Cost Recovery: investments in the Dry Ash Disposal System, Colstrip Tracker – Tariff Schedule 99;
- Low-Income Programs;
- Capital Projects Review;
- Residual Tax Customer Credit;
- Cost of Service, Rate Spread, and Rate Design;
- Climate Commitment Act (CCA);
- Small Business Energy Efficiency;
- Natural Gas Transition;
- Distributional Equity Analysis; and,
- Transportation Electrification.

47 However, Public Counsel argues that the Settlement as a whole is not in the public interest, and contests several of the Settlement's terms.[29] Public Counsel asserts that "many components of the Settlement are unreasonable and lack the evidence necessary to support the included terms."[30] Public Counsel recommends that the Commission accept its proposals to resolve certain issues differently than the Settlement.[31] Those contested issues include:

- Overall Revenue Requirement;[32]
- Cost of Capital;
- Projected Energy Imbalance Market (EIM) Benefits;
- Insurance Balancing Account; and,
- Wildfire Issues.

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[29] *Id.* at 5:15-20.

[30] *Id.* at 5:18-19.

[31] *Id.* at 5:21-6:2.

[32] Public Counsel witness Dahl includes "Rate Escalation Study Terms" in Public Counsel's list of Settlement terms it contests. Dahl, Exh. CJD-1T at 8:11. Upon further examination, we understand that Public Counsel's opposition to the rate escalation study is tethered to its opposition to the Settlement's revenue requirement, which Public Counsel argues are derived by use of the rate escalation study. *See* Brief of Staff at 3, n. 3. Public Counsel witness Coppola testifies that Public Counsel agrees with the Settling Parties that the escalation study filed by Avista is not reasonable and should not be used in future rate cases. Coppola, Exh. SC-1CT at 35:3-6. Because this reflects the Settlement's terms regarding the rate escalation study, we consider this an uncontested issue in the remaining discussion of this Order but will consider Public Counsel's arguments as part of its opposition to the Settlement's revenue requirement.

48 It is clear from testimony supporting the Settlement that the Settling Parties entered into an agreement through a complex negotiating process that required them to give and take in different areas to arrive at a combination of resolutions that, taken as a whole, they support as consistent with the public interest.[33] Ultimately, Public Counsel's recommendations would require the Commission to upset the balance struck by the Settling Parties and reject the Settlement as a whole, including the many terms that Public Counsel asserts are in the public interest.[34] We decline to take such action. Instead, in review of the entire record before the Commission, we determine that the Settlement strikes an appropriate balance among the varied and diverse interests presented and find that it meets the standard for the Commission's approval, subject to certain conditions.

49 We address the uncontested and contested issues of the Settlement, in turn, below.

1. UNCONTESTED TERMS

50 Although a number of elements in the Settlement were uncontested, our statutory obligation to regulate in the public interest requires us to evaluate whether the Parties' agreed resolution of issues complies with applicable legal requirements, is supported by an appropriate record, and is consistent with the public interest based on all of the information available to the Commission. Upon review, we find that the Settlement's proposed resolutions of the uncontested issues are lawful, supported by an appropriate record, and consistent with the public interest.

i. Cost of Service: Rate Spread, Rate Design

51 The Settling Parties agree to Avista's rate design proposal in its initial filing but agree not to change the basic charge for Schedules 01/02 (electric) and Schedules 101/102 (natural gas).[35] Public Counsel supports the rate design agreed by the Settling Parties and believes it is in the public interest.[36] The Settling Parties agree to the rate spread illustrated in Table 2 and Table 3, below.[37] Public Counsel neither supports nor opposes the electric

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[33] Settling Parties, Exh. JT-2 at 5, 20, ¶¶ 10, 29-30 [hereinafter Settlement].

[34] *See* Dahl, Exh. CJD-1T at 5:15-6:2.

[35] Settlement at 7, ¶ 12(b). Attachment A to the Settlement provides a summary of the current and revised rates and charges for electric and natural gas services.

[36] Dahl, Exh. CJD-1T at 28:8-29:2; Brief of Public Counsel at 44, ¶ 96.

[37] Settlement at 5-6, ¶ 12(a).

rate spread terms of the Settlement but does support and believe the natural gas rate spread is in the public interest.[38]

52 **Table 2. Electric Rate Spread**

Electric Rate Schedule	**Increase in Base Rates**		**Increase in Billing Rates**	
Rate Year 1	*(in thousands)*		*before Offset*	*with Offsets*
Residential Service, 01/02	$ 26,025	10.3%	10.8%	5.5%
General Service, 11/12	$ 3,264	4.0%	3.7%	3.7%
Large General Service, 21/22	$ 5,247	4.0%	3.7%	3.7%
Extra Large General Service, 25	$ 823	2.0%	2.0%	2.0%
Extra Large Special Contract	$ 435	2.0%	2.0%	2.0%
Pumping Service, 31/32	$ 1,497	10.3%	9.5%	4.9%
Street & Area Lights, 41-48	$ 709	10.3%	10.0%	5.1%
Overall (Rate Year 1)	***$ 38,000***	***6.9%***	***6.8%***	***4.3%***
Rate Year 2	*(in thousands)*			
Residential Service, 01/02	$ 6,318	2.3%	2.5%	
General Service, 11/12	$ 1,919	2.3%	2.1%	
Large General Service, 21/22	$ 3,087	2.3%	2.1%	
Extra Large General Service, 25	$ 420	1.0%	1.0%	
Extra Large Special Contract	$ 222	1.0%	1.0%	
Pumping Service, 31/32	$ 362	2.3%	2.2%	
Street & Area Lights, 41-48	$ 172	2.3%	2.3%	
Overall (Rate Year 2)	***$ 12,500***	***2.1%***	***2.2%***	

[38] Dahl, Exh. CJD-1T at 27:12-28:7; Brief of Public Counsel at 44, ¶ 96.

53 **Table 3. Natural Gas Rate Spread**

Natural Gas Rate Schedule	**Increase in Base Rates**		**Increase in Billing Rates**	
Rate Year 1	*(in thousands)*		*before Offset*	*with Offsets*
General Service, 101/102	$ 5,931	6.6%	4.3%	0.7%
Large General Service, 111/112/116	$ 1,325	6.6%	3.1%	0.5%
Interruptible Service, 131/132	$ 15	6.6%	2.8%	0.5%
Transportation Service, 146	$ 229	6.6%	7.1%	1.2%
Overall (Rate Year 1)	***$ 7,500***	***6.6%***	***4.0%***	***0.7%***
Rate Year 2	*(in thousands)*			
General Service, 101/102	$ 1,185	1.2%	0.8%	
Large General Service, 111/112/116	$ 265	1.2%	0.6%	
Interruptible Service, 131/132	$ 3	1.2%	0.6%	
Transportation Service, 146	$ 47	1.2%	1.4%	
Overall (Rate Year 2)	***$ 1,500***	***1.2%***	***0.8%***	

Commission Determination

54 We find the Settlement's proposed rate spread and rate design are appropriate and in the public interest. The Settling Parties' agreement moves the electric schedules gradually closer towards cost of service parity by allocating a larger share of the electric rate increase to residential customers – a consideration in cost of service that we discussed at length in Avista's 2020 GRC Final Order.[39] While this attributes more of the electric revenue requirement increase to residential customers, the Settling Parties relieve some of this burden by agreeing to return a larger share of the Residual Tax Customer Credit, discussed in detail later, to residential customers, as can be seen by comparing the percentage increase attributed to the residential schedules identified in the column labeled

[39] Miller, Exh. JDM-1T at 7:20-8:3; *see Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-200900, UG-200901, and UE-200894 (*Consolidated*), Final Order 08/05, 109-13, 116, 120-21, ¶¶ 307-20, 328-29, 341-42 (Sep. 27, 2021) [hereinafter 2020 Avista GRC Final Order].

"before Offset" with the column labeled "after Offsets" in Table 2 and Table 3, above.[40] Prior to offsets, which include the Residual Tax Customer Credit, residential customers will see a 10.8 percent increase in billing rates in Rate Year 1, while the average increase in billing rates across all electric customers is 6.8 percent. After offsets including the Residual Tax Customer Credit, the increase in billing rates is reduced to 5.5 percent for residential customers and an average 4.3 percent increase across all electric customers.

55 All parties support the electric rate design, natural gas rate design, and natural gas rate spread. The Settling Parties' agreement removes Avista's initially proposed increase to all electric basic charges and residential natural gas basic charges but maintains increases to the natural gas basic charge for some non-residential schedules.[41] Lastly, all parties support the agreed natural gas rate spread terms that will share an equal percentage of margin increase to the schedules.

56 As a result of the Settlement, in Rate Year 1 a typical residential electric customer using 932 kWhs per month will pay $4.47 more per month, for an average monthly bill of $89.99. In Rate Year 2, a typical residential electric customer using 932 kWhs per month will pay $2.24 more per month, for an average monthly bill of $92.23. In Rate Year 1, a typical residential natural gas customer using 67 therms per month will pay $0.20 more per month, for an average monthly bill of $65.06. In Rate Year 2, a typical residential natural gas customer using 67 therms per month will pay $0.52 more per month, for an average monthly bill of $65.58.[42]

57 We find the Settlement's resolution of the cost of service issues, including the electric and natural gas rate spread and rate design, appropriate and in the public interest. Accordingly, we determine that the cost of service, rate spread, and rate design terms should be approved.

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[40] Joint Testimony, Exh. JT-1T at 17:21-18:2. While stating that it does not oppose or support the Settlement's electric rate spread terms, Public Counsel recognizes that the Settling Parties' agreement provides a larger share of the tax refund amounts to residential customers and "is intended to offset a portion of the increased rates allocated to residential customers." Dahl, Exh. CJD-1T at 27:7-11.

[41] Joint Testimony, Exh. JT-1T at 16:12-17:20, 18:9-19:7, 20:7-21:5.

[42] Response to BR-6.

ii. Residual Tax Customer Credit

58 On March 11, 2021, the Commission entered Order 01 in Dockets UE-200895 and UG-200896, which granted Avista's petition requesting the Commission (1) authorize changing the Company's accounting method from normalization to flow-through for regulatory purposes for federal income tax expense associated with Industry Director Directive No. 5 (IDD #5) and meters, and (2) allow Avista to defer for later ratemaking treatment the tax benefits associated with the change. That change in methodology resulted in amounts due to be returned to customers of approximately $58.1 million, electric, and $28.2 million, natural gas (Tax Customer Credit).[43] In the Final Order of Avista's 2020 GRC, the Commission determined that the Tax Customer Credit amounts should be returned to customers through Tariff Schedules 76 and 176 over a two-year period beginning October 1, 2021, according to the rate spread approved in the 2020 Avista GRC Final Order to offset exactly, in conjunction with the AFUDC Deferral established by the settlement agreement in the 2020 Avista GRC, the rate increase approved by the 2020 Avista GRC Final Order.[44]

59 A portion of the Tax Customer Credit remains unreturned to ratepayers.[45] This unused portion is approximately $27.6 million, electric, and $12.5 million, natural gas (Residual Tax Customer Credit).[46] In the 2020 Avista GRC Final Order, the Commission stated it would reexamine the Residual Tax Customer Credit amount and how to appropriately return it to customers in this current GRC.[47]

60 The Settling Parties agree that Avista will return the Residual Tax Customer Credit of approximately $27.6 million, electric, and $12.5 million, natural gas, to customers through separate Tariff Schedules 78 (electric) and 178 (natural gas) over a two-year amortization period beginning December 21, 2022. Public Counsel supports accelerating the pass-through of tax benefits to customers.[48]

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[43] 2020 Avista GRC Final Order at 44, ¶ 115.

[44] *Id.* at 45, ¶ 120.

[45] Miller, Exh. JDM-1T at 31:14-17.

[46] *See id.* at 31:17-32:2; Settlement at 7, ¶ 13.

[47] 2020 Avista GRC Final Order at 46, ¶ 121.

[48] Coppola, Exh. SC-1CT at 13:13-14:11.

Commission Determination

61 We find the Settlement's proposed treatment of the Residual Tax Customer Credit to be in the public interest. The Residual Tax Customer Credit will be amortized over the two-year rate plan to provide a substantial reduction to customer bills as illustrated in Table 2 and Table 3, above. No party opposes this treatment. As the Commission reasoned in the 2020 Avista GRC Final Order, we likewise find the Settling Parties' proposal to return the Residual Tax Customer Credit through separate Tariff Schedules 78 (electric) and 178 (natural gas) appropriate because it will allow the Commission to best track the return of these benefits to customers. We also find that beginning the process of returning these benefits to customers on the effective date of December 21, 2022, to coincide with the MYRP proposed by the Settlement, will appropriately offset a significant portion of the revenue requirement increases we approve with this Order. Accordingly, we determine that the Settling Parties' agreed treatment of the Residual Tax Customer Credit should be approved.

iii. Colstrip Cost Recovery: Investments in the Dry Ash Disposal System, Colstrip Tracker – Tariff Schedule 99

62 The Settlement contains two terms, in addition to their incorporation into the agreed rate spread and rate design, related to the Colstrip generation plant: the Dry Ash Disposal System, and a new Colstrip Tracker using Tariff Schedule 99.[49] First, the Settling Parties agree that the Settlement's revenue requirement does not include any costs related to the Dry Ash Disposal System.[50]

63 Second, the Settling Parties propose a mechanism with an annual true-up to separately track and potentially recover, subject to a prudence review, certain costs through Tariff Schedule 99 (Colstrip Tracker).[51] The Colstrip Tracker will allocate costs to the rate schedules using a proportional allocation of the first rate year's base revenue spread

[49] Settlement at 7-9, ¶ 14. Regarding Schedule 99's rate spread and rate design, the Settling Parties agree that the costs removed from base rates will be allocated to the rate schedules through Schedule 99 using a proportional allocation of the Rate Year 1 base revenue spread and that the revenue will be recovered through volumetric charges on a uniform cent per kWh basis. *Id.*

[50] Joint Testimony, Exh. JT-1T at 21:18-20; Joint Testimony, Exh. JT-3T at 4:16-5:1.

[51] Joint Testimony, Exh. JT-1T at 22:2-6; Joint Testimony, Exh. JT-3T at 3:1-5, 4:6-11.

recovered through volumetric charges.[52] The following Colstrip costs, totaling approximately $23.9 million, will be removed from base rates and tracked, reported, and recovered, subject to review, through the Colstrip Tracker:

a. Colstrip Unit 3 and 4 utility plant net of accumulated depreciation (A/D) and ADFIT, excluding all costs associated with the Dry Ash Disposal System project as agreed in the Settlement;

b. Colstrip Regulatory Asset and Liability balances related to decommissioning and remediation (D&R) costs, as first agreed by the settling parties in the 2019 Avista GRC;[53]

c. Production O&M;

d. Depreciation and amortization expense, including the recovery of plant and the Colstrip Regulatory Asset/Liability for D&R costs; and

e. Other costs, including the amortization expense of the Deferred Colstrip Transition Fund, Federal income tax expense, and the tax benefit of debt interest.[54]

64 The Colstrip Tracker will begin December 21, 2022, with the effective date authorized by this Order, and Avista will make an annual filing every October 31 to true up and reset the mechanism effective each January 1.[55] Parties will have 60 days to review Avista's Colstrip Tracker filing and any new Colstrip capital investment for prudency.[56] The Settlement prohibits opposition to either a request for an adjudication or an extension of the 60-day review period.[57]

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[52] Joint Testimony, Exh. JT-3T at 5:4-10, 9:27-32. The proportion of Tariff Schedule 99 allocated to each rate schedule is the same as the proportion of revenue being removed from the base rates of each schedule. *Id.* The Settling Parties agree that this allocation will be used for the life of Tariff Schedule 99. *Id.* Tariff Schedule 99's rate design recovers the revenue through the volumetric charges on a uniform cent per kWh basis. *Id.*

[53] *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Final Order 09, ¶¶ 47-50 (Mar. 25, 2020).

[54] Joint Testimony, Exh. JT-3T at 3:1-12, 4:6-6:5, 8:6-9:19; Joint Testimony, Exh. JT-1T at 22:2-6. The costs removed do not include Dry Ash Disposal costs (which will not be recovered according to the Settlement), or the transmission investment and costs included in the Energy Recovery Mechanism, which would both remain in base rates.

[55] Joint Testimony, Exh. JT-3T at 6:7-10.

[56] *Id.* at 10:13-15.

[57] *Id.*

65 According to the Settlement, the review of Avista's Colstrip Tracker filing will include a prudency review of incurred costs; O&M and other expense items (production O&M and amortization expense) on the test period/restated basis during the two-year rate plan agreed in this case and forecasted thereafter; updated lifetime D&R cost estimates; actual non-O&M costs from the filing year through August 31 and estimated through December 31 (which creates a one-year lag in the recovery of these actual costs), and a true-up to actuals of any forecasted amounts.[58]

66 Finally, the Settlement outlines how it accommodates the requirements of Washington's Clean Energy Transformation Act (CETA) to remove the total costs for Colstrip capital investment and operating expenses, excluding Colstrip transmission investments and ongoing D&R costs, from customer rates after December 31, 2025.[59] The Settling Parties state that "after December 31, 2025, the net Colstrip rate base balances included within Tariff Schedule 99 on a 2025 AMA basis and the appropriate Colstrip expenses would be removed from Tariff Schedule 99."[60] Thus, beginning January 1, 2026, the Colstrip Tracker will include only annually-updated ongoing D&R net rate base balances and Colstrip Regulatory amortization expense (items b. and d. from the above list of costs to be removed from base rates).[61] While the Colstrip D&R cost accounting was included in this GRC, it will not be included in future GRCs because the Settlement removes the costs from base rates.[62] Instead, the accounting for these D&R costs will continue according to the settlement approved in Avista's 2019 GRC, but the recording and tracking will be included in the annual Colstrip Tracker.[63] Public Counsel supports the Settlement's Colstrip terms.

Commission Determination

67 We find the Settlement's agreement related to Colstrip reasonable and appropriate. Public Counsel argues that the Settlement's terms regarding Colstrip are in the public interest

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[58] *Id.* at 6:11-21.

[59] *Id.* at 12:8-13, 13:11-23.

[60] *Id.* at 12:10-13.

[61] *Id.* at 13:1-4.

[62] *Id.* at 13:24-26, 14:18-20.

[63] *Id.* at 14:20-23; *Wash. Utils. & Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-190334, UG-190335, UE-190222 *(Consolidated)*, Final Order 09, ¶ 49 (Mar. 25, 2020). Avista's share of these D&R costs is currently estimated at $28 million, $4.0 million of which has been incurred by Avista through September 30, 2021. Joint Testimony, Exh. JT-3T at 15:1-2.

because "they will assist in the Company's CETA compliance obligations" and will "assist the Commission and other [interested persons to] identify which Colstrip-related costs should and should not be included in customer rates as the clean energy transition proceeds."[64] We agree.

68 CETA requires each Washington electric utility to "eliminate coal-fired resources from its allocation of electricity" exclusive of "costs associated with decommissioning and remediation of" coal-fired facilities.[65] The Settling Parties' agreement will aid the Commission and all interested parties in identifying and tracking costs appropriately recovered from Washington ratepayers. In addition, the Settlement establishes expectations and procedures that will ensure a transparent and fair review of the amounts to be recovered through the Colstrip Tracker. Accordingly, we determine that the Settling Parties' agreements regarding Colstrip should be approved.

iv. Escalation Study

69 In its initial filing, Avista presented an escalation study with a growth rate methodology to use "for the purposes of escalating certain regulatory balances in the determination of future revenue requirements during multi-year rate plans, and beyond first or second year pro forma study levels."[66] The escalation study is described in Avista's initial filing by its witness Andrews and utilizes Dr. Forsyth's Escalator Growth Rates.[67] The Settlement provides that "[t]he Settling Parties do not agree that the escalation study filed by Avista is reasonable or should be used in future rate cases."[68] Public Counsel agrees with the Settling Parties.[69]

Commission Determination

70 We find the Settlement's agreement related to Avista's escalation study reasonable. Accordingly, we determine that the Settling Parties' agreement regarding Avista's escalation study should be approved.

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[64] Dahl, Exh. CJD-1T at 25:17-26:5.

[65] RCW 19.405.030(1)(a).

[66] Andrews, Exh. EMA-1T at 76:5-8.

[67] *Id.* at 75:1-79:5; Forsyth, Exh. GDF-1T at 5:5-8:9.

[68] Settlement at 9, ¶ 17.

[69] Coppola, Exh. SC-1CT at 35:4-6; *see supra* n. 32.

v. Capital Planning

71 As a term of the Settlement, Avista agrees to make a compliance filing in these Dockets by the end of the MRYP, demonstrating how it considers equity in its capital planning process.[70] Specifically, Avista will include in its compliance filing a process or procedure for how its Board of Directors and senior management will incorporate equity into its business planning, including how Avista will plan for equitable outcomes when evaluating business cases.[71] Avista will also include templates to be used in its business cases.[72] These templates will require sponsors to demonstrate how they planned for equitable outcomes in each business case.[73] In addition, Avista will work with its Equity Advisory Group (EAG) and interested persons to develop new equity-related measures, costs, and benefits to be included in its benefit and cost analysis, including qualitative and non-qualitative measures related to societal impacts, non-energy benefits and burdens, indoor and outdoor air quality, the Social Cost of Carbon, and Named Communities.[74]

72 Avista will also include in its post-MYRP compliance filing a plan for measuring and tracking the impacts from each business case after the project's completion, "with a specific eye towards identifying equitable outcomes, and how the Company will engage in adaptive management to correct course during Business Cases when it is necessary to avoid inequitable outcomes."[75] The plan for measuring and tracking impacts must include assessments of impacts from business cases and, wherever possible, feedback from interested persons and communities impacted by the business case.[76] The plan for measuring and tracking impacts should also demonstrate the importance of the issues to Named Communities along with "a holistic picture of the current conditions faced in those communities."[77]

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[70] *See* Settlement at 10, ¶ 18.

[71] Settlement at 10, ¶ 18.

[72] *Id.*

[73] *Id.*

[74] *Id.* "Named Communities" refers to highly impacted communities and vulnerable populations.

[75] Settlement at 10, ¶ 18.

[76] *Id.*

[77] *Id.*

Commission Determination

73 We find the Settlement's terms related to Avista's capital planning and the inclusion of equity considerations in that planning appropriate. As we stated in our final order in Cascade Natural Gas Company's most recent general rate case (Cascade Final Order), "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[78] Accordingly, the Settlement terms requiring Avista to make a compliance filing demonstrating changes to its capital planning to include equity considerations will provide an opportunity for Avista to demonstrate its progress towards addressing the principles identified in the Cascade Final Order, and in particular a comprehensive understanding of the ways systemic and historical inequities are present and continue to operate. We therefore approve the terms.

74 The processes or procedures Avista considers for all capital planning should consider and implement energy justice and its core tenets. The core tenets of energy justice are:

- Distributional justice, which refers to the distribution of benefits and burdens across populations. This objective aims to ensure that marginalized and vulnerable populations do not receive an inordinate share of the burdens or are denied access to benefits.

- Procedural justice, which focuses on inclusive decision-making processes and seeks to ensure that proceedings are fair, equitable, and inclusive for participants, recognizing that marginalized and vulnerable populations have been excluded from decision-making processes historically.

- Recognition justice, which requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequalities.

- Restorative justice, which is using regulatory government organizations or other interventions to disrupt and address distributional, recognitional, or procedural injustices, and to correct them through laws, rules, policies, orders, and practices.[79]

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[78] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.,* Docket UG-210755, Order 09, 19, ¶ 58 (Aug. 23, 2022) (citing RCW 80.28.425(1) [hereinafter Cascade Final Order].

[79] *Id.* at 18, ¶ 56.

vi. Distributional Equity Analysis

75 To better incorporate equity into its capital planning processes, the Settling Parties agree to develop methods and standards for distributional equity analysis (consistent with guidance provided in the New York University Institute for Policy Integrity, 2022), and to file those methods and standards for Commission approval within 24 months of this Order.[80] The Settlement provides that Staff will direct this process and select a facilitator for Avista to hire.[81] If the Settling Parties disagree regarding these methods and standards, the Settling Parties agree that each will file separate proposals for Commission consideration and approval.[82] Public Counsel agrees with the Settling Parties that the agreement to develop methods and standards for distributional equity analysis is in the public interest.[83]

Commission Determination

76 There is a clear need for a process to develop methods and standards for distributional equity analysis. Additionally, we agree that of all the Settling Parties, Staff possesses an expertise and impartiality that makes its selection as the directing party in the proposed process appropriate. We disagree, however, that the process proposed by the Settling Parties is the most appropriate option and find that it is appropriate for the Commission to establish a Commission-led collaborative proceeding to address these issues.

77 The issue of equity, broadly, and the need to consider distributional equity in planning processes affects all utility companies regulated by the Commission. The development of a plan for distributional equity requires input, collaboration, and buy-in from persons and parties not included or represented in Avista's general rate case. Lastly, the importance of this work demands a shared burden of responsibilities and a process that shares and allocates power inclusively. For the above reasons, the Commission finds it appropriate to require the modification of the Settling Parties' agreement for distributional equity analysis and determines that it will facilitate a broader Commission-led collaborative involving all regulated utilities and interested persons. In their post-hearing briefs, both

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[80] Settlement at 11, ¶ 19.

[81] *Id.*; Joint Testimony, Exh. JT-1T at 27:19-20.

[82] Settlement at 11, ¶ 19.

[83] Dahl, Exh. CJD-1T at 24:12-13.

Staff and Avista conveyed comfort with and support for a Commission-led collaborative or generic proceeding.[84]

78 Accordingly, we determine that approving the Settlement should be conditioned on certain modifications to the process outlined by the Settling Parties' agreement to develop methods and standards for distributional equity analysis.

> **Condition.** We condition our approval of the Settlement on the modification of the portion regarding distributional equity analysis. Instead of the process the Settling Parties have agreed (that Staff will direct this process and select a facilitator for Avista to hire), we determine that the Commission should establish a broad, Commission-led collaborative process to establish methods and standards for distributional equity analysis and that Avista should be required to participate, as is the expectation for all Washington investor-owned utilities. Subject to this condition, we determine that the Settling Parties' agreement regarding distributional equity analysis is in the public interest and should be approved.

vii. Capital Projects Review

79 The Settling Parties agree to the reporting process for reviewing capital projects outlined in Avista witness Andrews's testimony, with certain changes.[85] Avista's provisional capital reporting will include assurance that the "provisional capital included prior to the rate effective period (for 2022 capital) and during [Rate Year 1] (2023 capital) and [Rate Year 2] (2024 capital) is in service for customers during the rate effective periods, or will be subject to refund."[86] The Settling Parties' proposed changes extend the review period from three to four months to allow parties to review and respond to Avista's annual capital report filing. Within 30 days of completing the capital projects review, Avista would be required to file with the Commission an accounting petition to provide refunds, and create a separate tariff through which rate refunds to customers will be returned and spread to schedules based on an equal share of base rate revenues, exclusive of tax credit refunds.[87] For the purposes of the Capital Projects Review only (*i.e.*, for the comparison of provisional capital additions included in Rate Year 1 and Rate Year 2), the Settling Parties further agree that Rate Year 1 and Rate Year 2 capital additions and rate base are

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[84] Brief of Staff at ¶ 23; Brief of Avista at ¶ 38, n. 26.

[85] Settlement at 11-12, ¶ 20; Andrews, Exh. EMA-1T at 45:10-48:2.

[86] Andrews, Exh. EMA-1T at 46:1-4.

[87] Settlement at 11-12, ¶ 20.

adopted as initially filed by Avista except with the exclusion of the Dry Ash Disposal System.[88] Table 4, below, illustrates the updates from the Settlement to net plant balances for Rate Year 1 and Rate Year 2.[89] Public Counsel supports the terms regarding Capital Project Review and believes they are in the public interest.[90]

80 **Table 4. Two-Year Rate Plan Net Plant After ADFIT Balances *(in thousands)*[91]**

	Electric Rate Base	Natural Gas Rate Base
Test Period	$ 1,797,278	$ 438,149
Adjustments	*$ 189,878*	*$ 71,999*
Rate Year 1	$ 1,987,156	$ 510,148
Dry Ash Disposal System	$ (3,123)	---
Settlement Balances[92]	$ **1,984,033**	$ **510,148**
Adjustments	*$ 80,506*	*$ 22,198*
Rate Year 2	$ 2,067,662	$ 532,346
Dry Ash Disposal System	$ (2,112)	---
Settlement Balances[93]	$ **2,065,550**	$ **532,346**

Commission Determination

81 We find the Settlement's agreement related to Capital Projects Review reasonable for the resolution of the issues presented in this GRC.

82 We expressly limit our approval, however, to this GRC and emphasize that our decision should not be considered precedential for future proceedings. Some impacts from the

[88] Joint Testimony, Exh. JT-1T at 28:13-16.

[89] *Compare with* Andrews, Exh. EMA-1T at 31:17-22.

[90] Brief of Public Counsel at 43-44, ¶ 96.

[91] Net Plant for each calendar year represents "all actual additions, retirements, offset by Accumulated Depreciation (A/D) and [ADFIT]." Andrews, Exh. EMA-1T at 46:10-15.

[92] Net Plant balance for Rate Year 1 effective 12/31/2022.

[93] Net Plant balance for Rate Year 2 effective 12/31/2023.

IRA and IIJA will affect capital investment and could provide immediate customer savings, as we highlighted previously.[94]

83 The Commission intends to initiate a collaborative or generic proceeding to include all affected, or potentially affected, utilities as well as interested persons to discuss, address, and plan for benefits and opportunities resulting from the IRA and IIJA that may impact the companies' costs. This is not a condition of our approval of the Settlement, but an indication of action tangential to this GRC that the Commission will take to appropriately address impacts to all regulated utilities, not only Avista.

84 As it concerns the Settling Parties' agreement for capital projects review during the MYRP, we take a particular interest in how the IRA and IIJA may impact the retrospective review of provisional plant (capital projects). The precise impacts and extent of those impacts is currently unknown. However, it is apparent that there are opportunities for benefits to Avista for planning of capital projects, and more urgently in capturing any changes that will result in immediate customer savings. We find it imperative that Avista pursue what opportunities the IRA and IIJA might offer during the time the MYRP is effective. For that purpose, we find it appropriate for Avista to record and share its efforts for identifying opportunities for rate mitigation, its efforts in seeking federal benefits, as well as those benefits it actually receives under the federal programs.

85 Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settling Parties' agreement for the review of capital projects during the MYRP.

> **Condition.** We condition our approval of the Settlement on the modification of the capital projects review, requiring that Avista must demonstrate all offsetting benefits received or for which it has applied for through the IRA and IIJA for all retrospective review of provisional plant (capital projects). Further, we require Avista's reporting to include all funding for which it has applied and the reasons justifying any decision not to pursue IRA and IIJA funding options for which it may be eligible. Subject to this condition, we determine that the Settling Parties' agreement regarding capital projects review is in the public interest and should be approved.

[94] *Supra* paragraphs 42-45.

viii. Natural Gas Transition Issues

86 The Settling Parties agree to several terms related to natural gas transition, including terms regarding line extension allowances, non-pipe alternatives, customer reporting requirements, and the development of a natural gas decarbonization plan.[95] In particular, the Settlement establishes a timeline to phase out the Natural Gas Line Extension Allowance by January 1, 2025.[96] It also requires Avista to consider "non-pipe alternatives" in its gas distribution planning process and to discuss this consideration in future natural gas integrated resource plans.[97] Avista must also provide quarterly reporting on the number of new gas customers relative to new electric customers.[98] Last, in its 2023 Natural Gas IRP, Avista must include a plan for complying with the CCA.[99] Public Counsel supports the Settlement's natural gas transition terms and believes that they are in the public interest.[100]

Commission Determination

87 We find the Settling Parties' agreements regarding natural gas transition issues appropriate. The CCA implements a statewide cap-and-invest program that will make Washington carbon-neutral by 2050, cut Washington's carbon emissions by 95 percent compared to 1990 emission levels by 2050, and offset the remaining 5 percent using carbon reduction, removal, or avoidance projects.[101] The CCA sets a limit on overall carbon emissions in the state and requires emitters to obtain "emission allowances" equal to their covered greenhouse gas (GHG) emissions.[102] Avista, as an electric and natural gas utility, must comply with the CCA.

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[95] Settlement at 12-13, ¶ 21.

[96] *Id.* Line extension allocation will be based on the net present value methodology using a two-year timeframe for 2023 and one-year timeframe for 2024. Joint Testimony, Exh. JT-1T at 29:6-19.

[97] Settlement at 12-13, ¶ 21(b). The Settlement provides that at minimum, "non-pipe alternatives" include demand-side management measures, envelope efficiency measures, electrification, and gas demand response. *Id.*

[98] Settlement at 13, ¶ 21(c).

[99] *Id.* ¶ 21(d); Joint Testimony, Exh. JT-1T at 29:6-31:3.

[100] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 30:1-7.

[101] *See* RCW 70A.65.005(2)-(7).

[102] RCW 70A.45.020; RCW 70A.65.060; RCW 70A.65.070; RCW 70A.65.080; RCW 70A.65.200.

88 The Settling Parties' agreement will promote prudent planning and, in many ways, will aid Avista's compliance with the requirements of the CCA. Accordingly, we determine that the Settlement's natural gas transition terms agreed by the Settling Parties are reasonable, in the public interest, and should be approved.

ix. Transportation Electrification

89 Consistent with RCW 80.28.360, the Settling Parties agree that Avista's request for an incentive rate of return (ROR) on transportation electrification investments is embedded within the revenue requirement for the duration of the MYRP subject to the establishment of two performance metrics.[103] The transportation electrification performance metrics are: (a) percent of utility-owned and supported electric vehicle supply equipment (EVSE) by use case located within and/or providing direct benefits and services to Named Communities; and, (b) percent of load shifted to off-peak periods attributable to transportation electrification tariff offerings by use case, including electric vehicle load subject to managed charging.[104] The Settling Parties also agree to minimum payment method requirements for publicly-accessible charging stations and agree that any party can oppose or propose alternative approaches to incentive return on equity (ROE) for transportation electrification in future cases.[105] The Settlement does not establish any performance incentive mechanisms. Public Counsel supports the Settlement's transportation electrification terms and believes that they are in the public interest.[106]

Commission Determination

90 We find the Settlement's transportation electrification terms, including authorizing an incentive rate of return (ROR) on transportation electrification investments, to be reasonable. It is appropriate that the terms of the Settlement do not prevent parties from opposing or proposing new and alternative solutions related to incentivizing transportation electrification in the future.

91 In addition, the incentive ROR included in revenue requirement for transportation electrification investments is subject to the establishment of the related performance

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[103] Settlement at 13-14, ¶ 22; *see* RCW 80.28.360.

[104] Settlement at 14, ¶ 22.

[105] Settlement at 13-14, ¶ 22.

[106] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 30:15–31:10.

metrics.[107] As we describe in further detail below regarding the Settlement's agreed performance metrics, we accept the establishment of the performance metrics proposed by the Settling Parties related to Avista's transportation electrification investments. We also find it important to note that the Settling Parties' agreement incorporates the incentive ROR for transportation electrification into the results-only revenue requirement and is not *in addition to* the agreed results-only revenue requirement agreement.[108] We find it appropriate that, in the context of a results-only revenue requirement agreement, the agreed amount of the incentive ROR for transportation electrification is not in addition to the agreed revenue requirement. Accordingly, we determine that the Settlement's transportation electrification terms agreed by the Settling Parties are reasonable, in the public interest, and should be approved.

x. Performance Based Ratemaking

92 The Settling Parties agree to 92 performance metrics included in Attachment B, which includes two metrics related to transportation electrification plus the commitment to develop additional reliability metrics.[109] The Settling Parties' agreement does not include the proposal by Avista in its initial filing regarding financial performance incentive mechanisms (PIMs).[110] The 92 metrics identified in Attachment B to the Settlement regard numerous topics, which are categorized by Table 5, below.

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[107] Settlement at 13, ¶ 22.

[108] *See* Joint Testimony, Exh. JT-1T at 31:17-19.

[109] Settlement at 14-15, ¶ 23.

[110] *Id.*; Joint Testimony, Exh. JT-1T at 32:1-6, 32:11-14, 34:6-7; Settlement Stipulation Attachment B.

93 **Table 5. Settlement Performance Metrics by Topic and Sub-Topic**

Topic	Sub-Topic	# of Metrics
Affordable Service		15
Capital Formation		2
Equitable Service		17
Satisfy Customer Needs	Electric Reliability	15
	Wildfire	17
	Customer Experience	6
Advance Societal Outcomes	Pollution, GHG Emissions Reduction	7
	Electric Grid Benefits	10
Natural Gas System Benefits		3
Total		92

94 The metrics listed in Attachment B will be used for tracking purposes.[111] As part of the Settlement, Avista agrees to report and publish, on either a quarterly or annual basis starting 45 days after the first quarter of 2023, the results of each metric on its website and to maintain and make public the historical results.[112] Each metric will be reported in real terms while "using an appropriate measure of inflation."[113] Additionally, the Settling Parties propose to develop by March 31, 2023, reliability metrics to be tracked and reported by the beginning of Rate Year 2.[114]

95 Public Counsel supports the Settlement's terms regarding performance-based ratemaking and believes that they are in the public interest.[115]

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[111] Settlement at 14-15, ¶ 23.

[112] Joint Testimony, Exh. JT-1T at 31:17-19, 32:14-34:4.

[113] *Id.* at 34:5-6.

[114] *Id.* at 34:6-9; *see supra* Section ix., above, for the two metrics established for transportation electrification.

[115] Public Counsel Brief at 43-44, ¶ 96; Crane, Exh. ACC-1T at 10:11-18:16.

Commission Determination

96 We find the Settlement's agreed performance metrics appropriate but find that Avista should be required to report all of the Settlement's metrics to the Commission. The Commission finds that the performance metrics are measures consistent with RCW 80.28.425, that these metrics will be informed by the Commission's performance-based regulation proceeding in Docket U-210590, and that establishing metrics and measures for performance-based ratemaking is an iterative process. In Docket U-210590, a Performance Metric or Performance Measure is defined as measurable and quantifiable data used to track specific actions, outcomes, or results. It is often expressed in terms of standard power system measures or consumer impact measures. Additionally, we agree with Public Counsel who, in brief, explains that:

> Approval of these performance metrics and associated Company activities included in the Settlement meets the requirements of the Multiyear Rate Plan statute. The statute does not define "measure," but the dictionary definitions of the word include "an action to achieve something" and "a step planned or taken as a means to an end." The statute is not prescriptive as to the types of actions that constitute a "measure." The list of performance metrics, coupled to the requirement that Avista track each of the ninety-two separate metrics, are an action intended to collect and track utility performance in nine different performance categories through the multiyear rate plan.[116]

97 The terms of the Settlement provide that these performance metrics are for tracking purposes and do not state whether these metrics should be used to evaluate the MYRP.[117] The Settlement lacks detailed information identifying or directing how the Commission might use these metrics to evaluate the MYRP or the agreed calculations for all metrics under RCW 80.28.425(7). The Commission therefore finds it necessary to meet its statutory obligation under RCW 80.28.425(7) by adopting a limited number of performance measures, described later in Section C of this Order, that it will use to

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[116] Brief of Public Counsel at 45, ¶ 98 (citing MacMillian Education Limited: MacMillian Dictionary.com, *MacMillian Dictionary* https://www.macmillandictionary.com/us/dictionary/american/measure_1 (last accessed Oct. 20, 2022); Merriam-Webster, Merriam-Webster.com Dictionary, https://www.merriam-webster.com/dictionary/measure (last accessed Oct. 20, 2022)).

[117] Settlement at 14-15, ¶ 23.

evaluate Avista's operations during the MYRP. The Settling Parties do not oppose adding requirements for Avista to report the performance metrics to the Commission, and we determine that such reporting will be useful as the Commission and parties refine their use of performance metrics over time. Further, the Settlement's agreed performance metrics are not binding on the Commission, and we expressly determine that our approval of the Settlement should not impute precedential value to their continuation should the Commission determine that other or additional metrics or measures are more appropriate in the future for the same or other purposes.

98 Last, the Commission declines to provide guidance on PIMs in this Order. These issues and their relation to the statutory requirements of RCW 80.28.425(7) will be explored in Phase 3 of the Commission's performance-based ratemaking proceeding in Docket U-210590. Staff and all other parties are invited to provide comments and proposals in that proceeding.

99 Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settlement's agreed performance metrics.

> **Condition.** We condition our approval of the Settlement on the inclusion of requirements for reporting the performance metrics to the Commission. Avista must report each of the performance metrics in a filing with the Commission within 45 days of the conclusion of the relevant reporting period. We also require the Settling Parties to review reported performance metrics and provide feedback and recommendations for the Commission to consider within 45 days from the filing date of the report. Subject to these conditions, we determine that the Settling Parties' proposed metrics and proposal for performance-based ratemaking is reasonable, consistent with applicable law, in the public interest, and should be approved.

xi. Low-Income

100 The Settling Parties agree to several terms affecting Avista's low-income programs.[118] First, the Settling Parties agree to recommend that the Commission not approve certain proposals in Avista's initial filing, and that the proposals will be further discussed and developed in consultation with the Company's Energy Assistance Advisory Group (EAAG), with Avista filing the resulting proposals with the Commission on July 1,

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[118] Settlement at 15-17, ¶ 24.

2023.[119] Specifically, Avista agrees to consult and seek consensus with its EAAG concerning program design and implementation issues, including the joint administration of enrollment by Avista or the Community Action Agencies (CAAs); the use of self-attestations of income along with random audits instead of verifying all participating customers' income, and, the management of overlap between the federal Low-Income Home Energy Assistance Program (LIHEAP) and Avista's Bill Discount program.[120]

101 Second, the Settling Parties agree that Avista's proposal for the administration and program support budget apportioned to the CAAs is the minimum amount that will be made available for the 2023-2024 and 2024-2025 Low-Income Rate Assistance Program (LIRAP) years.[121] Avista agrees to collaborate with its EAAG to determine the appropriate method, amounts, and administrative structure for future LIRAP years.[122] Any funding increases proposed by its EAAG will be included in the July 1, 2023, filing , and Avista's 2024 annual filing in September.[123]

102 Third, the Settling Parties agree that Avista may only recover the following expenses through Schedules 92 and 192: Direct Services to customers, CAA Administration and Program Delivery, CAA Conservation Education Staff and Labor, Avista Conservation Education, and LIRAP Outreach.[124]

103 Fourth, Avista agrees that it will work with its EAAG to identify a new renewable energy project or projects for the direct benefit of low-income customers.[125] In addition, the Settling Parties agree that Avista may identify a new renewable energy project or projects

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[119] Settlement at 15, ¶ 24(a).

[120] Settlement at 15, ¶ 24(a)(i).

[121] Settlement at 15, ¶ 24(b); *see* Bonfield, Exh. SJB-1T.

[122] Settlement at 15-16, ¶ 24(b).

[123] Settlement at 16, ¶ 24(b).

[124] Settlement at 16, ¶ 24(c). The Settling Parties agree that Avista cannot recover other expenses through Schedules 92 and 192, including Avista's associated labor; EAAG expenses, including facilitator and participant payments; labor or other costs associated with the reporting of metrics concerning low-income customers and energy burden pursuant to CETA or performance-based regulation metrics, and labor and other costs associated with reporting to the Washington Department of Commerce. *Id.*; *but cf.* Settlement at 16-17, ¶ 24(d).

[125] Settlement at 16, ¶ 24(d). The Settling Parties agree that funding may come from Schedules 92 or 192 but may only fund projects benefitting eligible low-income customers. Settlement at 16-17, ¶ 24(d). *See* Cebulko, Exh. BTC-1T at 9:12-18.

for the direct benefit of customers residing in Named Communities.[126] Avista agrees to file with the Commission a work plan describing its plan to facilitate the development of a new renewable energy project or projects, including the budget, funding sources, timeline, and community partners, by December 1, 2023.[127]

104 Last, Avista agrees to low-income conservation and weatherization terms, including increasing low-income conservation and weatherization funding through Schedules 91 and 191 up to $4.0 million in 2023 and $4.25 million in 2024; developing a pilot program in consultation with its EEAG to overcome the inability to weatherize homes because of deferred maintenance or large repairs, and surveying actual installed measure costs and, based on the results of the survey, adjusting the rebate amounts if warranted and fully funding low-income conservation measures.[128]

105 Public Counsel supports the Settlement's low-income terms and believes that they are in the public interest.[129]

Commission Determination

106 We find that the Settlement's low-income terms are positive steps designed to remove barriers to access and seek greater engagement with Highly-Impacted Communities and Vulnerable Populations. As the Commission determined in the Cascade Final Order, advancing energy justice is integral to achieving equity in Washington's energy regulation. Among other things, energy justice focuses on ensuring that individuals have access to energy that is affordable, safe, sustainable, and affords them the ability to sustain a decent lifestyle. Here, the low-income provisions of the Settlement propose that

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[126] Settlement at 16, ¶ 24(d). The Settling Parties agree that funding may come from Avista's Named Communities Investment Fund. *Id.*

[127] Settlement at 17, ¶ 24(d). The Settling Parties agree that this requirement is independent of and incremental to condition 10 of Avista's CEIP. *Id.* Condition 10 of Avista's CEIP states:

> By December 1, 2022, in collaboration with its EAG and EAAG and per WAC 480-100-640(5)(a) and (c), Avista agrees to identify at least one specific action that will serve a designated subset of Named Communities, to be funded by the Named Communities Investment Fund, and to identify and track all CBIs relevant to this specific action. The location identified for the specific action will be at the granularity of the designated Named Communities subset.

Cebulko, Exh. BTC-1T at 9, n. 13.

[128] Settlement at 17, ¶ 24(e).

[129] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 18:10-23:4.

the Company work with its EAAG to make significant changes to Avista's low-income programs that will increase access to, and enrollment in, those programs. Specifically, the Settlement increases the EAAG's involvement in program design and implementation, demonstrates a deeper understanding of the flexibility necessary for certain budgeting structures, and demonstrates the Settling Parties' intent to proactively incorporate considerations for including low-income and Named Communities in new renewable energy projects. Consistent with our decision on the retrospective review of provisional plant, we find it imperative that Avista seek out IRA and IIJA funding opportunities related to supporting and promoting low-income programs, projects, and interests.

107 Public Counsel, while not a party to the Settlement, highlights several barriers that the Settlement will, or at least will attempt to, remove. Regarding barriers to enrolling customers in need of assistance, Public Counsel witness Dahl explains that

> removing barriers to customers qualifying for and receiving energy assistance funds has been a major point of conversation among stakeholders. Determining how to use and assess the accuracy of self-attested income to demonstrate qualifications is an important step toward reducing the administrative barriers customers with high energy burdens face. These assessments should strike a balance between gathering information necessary to determine compliance rates and creating new, unintended barriers to program participation.[130]

108 We agree and find that the Settlement's terms requiring Avista and its EAAG to engage in consensus-seeking consultations on the new program design, including self-attestation of income with random audits, should remove barriers and result in increased enrollment. We also find that the terms requiring Avista to file the resulting design recommendations will create a fair procedure, an appropriate timeline, and incentives for productive engagement.

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[130] Dahl, Exh. CJD-1T at 19:19-20:4. The Commission is working to eliminate from its documents the non-inclusive and historically problematic term "stakeholders" and instead use terms like "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge others to do the same.

109 Regarding low-income weatherization, witness Dahl explains that

> In many cases, weatherization measures are unable to be installed or would be ineffective without addressing maintenance issues in customers' homes. This is an issue agencies who coordinate funding and implementation of low-income weatherization projects raise regularly. Piloting a program to remove this important obstacle to completing projects is in the public interest.[131]

We agree. While some programs do not require a pilot, we find that the Settling Parties' agreement to begin a pilot program for these purposes is appropriate because it will likely expedite its implementation.

110 TEP, a party to the Settlement, filed separate testimony in support of the Settlement, addressing its support of many of Avista's low-income proposals. In particular, TEP witness Cebulko discussed Avista's proposed five-tier bill discount program as it is paired with programs that address arrearages. Witness Cebulko explains that

> TEP strongly supports the use of a five-tier bill discount program, where customers with the lowest incomes receive the largest bill discount in the first tier, customers with slightly higher incomes receive a slightly lower bill discounts in the second tier, and so on. Similarly, TEP strongly supports the Past Due Payoff (PDP) program immediately forgiving past due balances for the customers with the lowest incomes, and the Arrearage Management Plan (AMP), which forgives past due balances for other low-income customers who sustain regular payments. Taken together the five-tier bill discount program and PDP/AMP show promise as a cornerstone strategy to reduce household energy insecurity and retain access to essential utility service in Washington.[132]

111 We agree that reducing household energy insecurity and retaining access to essential utility services in Washington are important equity considerations that are consistent with the public interest. It appears, however, from the absence of terms in the Settlement

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[131] Dahl, Exh. CJD-1T at 23:16-20.

[132] Cebulko, Exh. BTC-1T at 6:19-7:7.

outlining the PDP, AMP, or five-tier bill discount program, that more discussion is needed regarding these programs and their designs. We support the Settlement's terms under which Avista will further engage with the EAAG to collaboratively develop program designs that promote equity and access to those in need of its energy assistance programs.

112 We find the low-income terms in the Settlement remarkable for the progress they make towards reducing barriers and promoting equity and access.[133] However, we find that some elements are missing, albeit due to circumstances and timing beyond the parties' control. Funding available through the IRA and IIJA might be attainable for supporting and promoting many programs, including low-income programs, projects, and interests. Critically, we find that considerations of what funding may be available cannot wait and should be undertaken immediately in appropriate forums. Here, we find that Avista's consultations with its EAAG is an appropriate forum. We observe, unfortunately, that the Settlement lacks any indication of how the IRA and IIJA might be beneficial for low-income considerations. Accordingly, we determine that approval of the Settlement should be conditioned on certain modifications to the Settlement's low-income terms.

> **Condition.** We condition our approval of the Settlement on the inclusion in Avista's consultations and consensus-seeking with its EAAG, as well as its July 1, 2023, and September filings with the Commission, of its considerations for how funds through the IRA and IIJA might be used to support and promote low-income programs, projects, and interests. Further, Avista will report in future low-income annual filings during the MYRP its actions to seek funding through the IRA and IIJA to support and promote low-income programs, projects, and interests. Subject to this condition, we determine that the Settling Parties' agreed low-income terms are reasonable, consistent with applicable law, in the public interest, and should be approved.

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[133] Neither Avista, nor any other regulated company, should consider the equity considerations in this Order comprehensive, as we will continue to expand upon this discussion of equity in future proceedings. We decline to provide specific programmatic guidance, as our discussion of equity and the low-income terms of this Settlement is only the beginning of a broader understanding and expectation of equity considerations in Washington's energy regulation going forward. For now and the near future, we reiterate our expectation set out in the Cascade Final Order that Avista, and all other regulated investor-owned utility companies, must integrate considerations of equity into every proposal through an energy justice lens.

xii. Climate Commitment Act

113 The Settlement provides that, within 60 days of the adoption of the final Department of Ecology rules implementing the CCA (Chapter 173-446 WAC), Avista will begin consulting with its applicable advisory groups to develop plans for compliance with the CCA, including reporting requirements, proper treatment of revenues from the consignment of allowances, and the investment of any proceeds from the sale of allowances during the MYRP.[134] Public Counsel supports the Settlement's CCA terms and believes that they are in the public interest.[135]

Commission Determination

114 We find the Settlement's terms related to the CCA appropriate. At hearing, Commissioner Doumit inquired whether the parties would find it helpful and if they would support Commission efforts to schedule consultative and collaborative meetings to discuss utility compliance with the CCA, generally.[136] Both Avista and NWEC stated that work sessions around compliance with the CCA would be helpful.[137]

115 We agree with the Settling Parties that Avista should begin consulting with its advisory groups concerning the requirements of the CCA, CCA allowances, and the accounting treatment of proceeds under the CCA. Additionally, the Commission intends to schedule meetings, workshops, or collaborative work sessions as described by Commissioner Doumit during these consolidated proceedings' hearing to discuss utility compliance, generally, with the CCA. Accordingly, we determine that the Settlement's CCA terms are in the public interest and should be approved.

xiii. Small Business Energy Efficiency

116 The Settling Parties agree that Avista will begin, by June 30, 2023, discussions with its Energy Efficiency Advisory Group (EEAG) and other interested persons concerning eligibility criteria for small business customers in its energy efficiency offerings.[138] Avista will also further explore mirroring residential customer offerings for small

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[134] Settlement at 17-18, ¶ 25.

[135] Brief of Public Counsel at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 31:3-10.

[136] Commissioner Doumit, TR at 146:9-24.

[137] Ehrbar, TR at 147:2-7; McCloy, TR at 147:9-11.

[138] Settlement at 18, ¶ 26.

business customers.[139] The Settlement provides that discussions must begin no later than June 30, 2023, and must include a conversation of budget impacts, which will be funded through Schedules 91 and 191, and a timeline for completing the pursuit of additional program offerings for small business customers no later than December 31, 2023.[140] Public Counsel supports the Settlement's terms regarding small business energy efficiency and believes that they are in the public interest.[141]

Commission Determination

117 We find the Settlement's small business energy efficiency terms appropriate. It is equitable, reasonable, fair, just, and in all cases appropriate that small business customers should be included in considerations regarding how they also can participate in and benefit from energy efficiency efforts. This is both for their benefit as well as Avista's because the Company must maintain compliance with statutory requirements for energy efficiency, conservation, and for providing energy to its customers while reducing GHG emissions. Accordingly, we determine that the terms regarding small business energy efficiency are timely, reasonable, and should be approved.

xiv. Electric Service Reliability Report Plan

118 Avista also agrees that it will include its final electric service reliability reporting plan with the compliance filing in these consolidated proceedings.[142] The Settlement proposes two terms regarding Avista's electric service reliability report plan: first, Avista agrees to clarify its presentation and distinction of "Washington-only" metrics as compared with "system-wide" metrics, including with the presentation and distinction of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI) performance and historical trends; second, Avista agrees to participate in any multi-party collaborative seeking to establish common measures and reporting formats among Washington's investor-owned utilities for electric distribution system reliability.[143]

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[139] *Id.*

[140] *Id.*

[141] Public Counsel Brief at 43-44, ¶ 96; Dahl, Exh. CJD-1T at 29:16-21.

[142] Settlement at 18, ¶ 27.

[143] *Id.*

Commission Determination

119 We find the Settlement's agreement related to Avista's electric service reliability report plan appropriate. No party opposes this portion of the Settlement. Clarifying and differentiating the metrics of service reliability to exclude Avista's system performance in other states from Washington holds unquestionable value. Service reliability provided by Avista in Idaho or Oregon is only tangentially relevant, due to the unique and different circumstances in those jurisdictions for Avista's service to its customers residing there, for our consideration of the reliability of service provided by Avista to Washington customers. Accordingly, we determine that the Settlement's electric service reliability report plan terms are equitable, reasonable, just, and should be approved.

xv. Miscellaneous Uncontested Terms

120 The Settling Parties agree to several other terms identified in the Settlement as "miscellaneous." We summarize and address these terms together.

a. *Depreciation Rates and Regulatory Amortizations*

121 The Settling Parties agree to terms regarding the depreciation rates and regulatory amortizations as included in Avista's initial filing for certain adjustments, which are detailed in Attachment D to the Settlement.[144] These relate to the amortization of deferrals and remaining balances previously approved by the Commission.[145] Without Commission authorization, the Company would be unable to amortize or depreciate these balances.[146]

b. *Annual Filing Dates*

122 The Settling Parties agree to the proposals in Avista's initial filing to change the rate effective dates for several annual filings. First, the Settling Parties agree to move the annual Schedule 98 Renewable Energy Credit (REC) filing from July 1 to August 1 to coincide with other rate changes.[147] Second, the Settling Parties agree to move the proposed low-income rate assistance program (LIRAP) Schedule 92/192 effective dates

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[144] Settlement at 19, ¶ 28(a); *see* Settlement at Attachment D.

[145] Settlement at 19, ¶ 28(a) and accompanying notes.

[146] *Id.*

[147] Settlement at 19, ¶ 28(b); *see* Miller, Exh. JDM-1T, 34:10-14.

from October 1 to November 1.[148] Last, the Settling Parties agree to move the Wildfire Deferral filing date from July 31 to September 1 and to also move the effective date from October 1 to November 1.[149]

c. *Annual Reporting Obligations of Docket U-210151*[150]

123 Avista agrees to provide recommendations in its initial filing of its next GRC regarding how it will streamline its existing required annual reporting obligations (provided in Docket U-210151).[151] Avista also agrees to provide a detailed matrix of all reporting obligations annually along with a matrix of any recommendations for streamlining, as provided in Docket U-210151.[152]

d. *Software Licensing*

124 Avista agrees to provide templates and vendor contact information for any vendor software licensing agreements, such as Energy Exemplar, with each filing.[153]

e. *Decoupling Earnings Test*

125 The Settling Parties agree to replace the current earnings test with the earnings test provided in RCW 80.28.425(6).[154]

Commission Determination

126 We find the Settlement's miscellaneous terms, described above, appropriate. No party opposes any of the agreements contained in these terms. We find the Settling Parties' agreement to continue authorization of depreciation rates and regulatory amortizations previously authorized by the Commission reasonable. In addition, we find nothing

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[148] Settlement at 19, ¶ 28(b); *see* Bonfield, Exh. SJB-1T, 36:9-17.

[149] Settlement at 19, ¶ 28(b); *see* Andrews, Exh. EMA-1T, 63:6-17.

[150] In error, the Settling Parties refer in the Settlement and in their Joint Testimony to Docket U-210501. Settlement at 19, ¶ 28(c); Joint Testimony, Ext. JT-1T at 40:7-11. The relevant docket is U-210151. We have made this ministerial correction to the Settlement's referenced docket throughout this Order.

[151] Settlement at 19, ¶ 28(c).

[152] *Id.*

[153] Settlement at 19, ¶ 28(d).

[154] Settlement at 19, ¶ 28(e); *see* Ehrbar, Exh. PDE-1T, 37:14-38:25, describing how the existing earnings test conflicts with the earnings test provided in RCW 80.28.425(6).

objectionable to the Settlement's terms allowing Avista to modify certain filing dates and effective dates to create greater efficiencies, those terms encouraging streamlining in reporting obligations, and those requiring the sharing of vendor contact information. Each of these terms are reasonable and will promote greater efficiency for the Commission's regulation and review, as well as that of interested persons. Lastly, recently enacted legislation requires the deferral of earnings that are more than 0.5 percent higher than the ROR authorized by the Commission and reported annually through a company's Commission Basis Report (CBR).[155] The Commission authorizes replacing the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6). Further, the Commission clarifies that the decoupling deferral must include accruing ROR on the balance of the deferral. Lastly, the Commission determines that Avista should be authorized and required to defer any earnings greater than 0.5 percent above its authorized ROR, consistent with this Order, the Settlement, and RCW 80.28.425(6).

127 Accordingly, we determine that the Settlement's miscellaneous terms – regarding depreciation rates and regulatory amortizations, modifications to filing and effective dates, recommendations for streamlining reporting obligations, sharing of contact information for vendor agreements, and the decoupling earnings test – are reasonable, not contrary to law, in the public interest, and should be approved.

2. POWER COSTS

128 The Settling Parties agree to two terms regarding power costs. First, the Settling Parties agree to accept the 2023 Pro Forma Power Supply expense and Energy Recovery Mechanism (ERM) Baseline included in Avista's initial filing.[156] Second, they agree that Avista will not perform the 60-day power cost updates that it had proposed in its initial filing.[157] Instead, the ERM Baseline will remain as indicated in Avista's initial filing for the duration of the MYRP and is included as Attachment C to the Settlement.[158] Public Counsel generally supports the Settlement's power cost terms.[159] It takes issue, however,

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[155] RCW 80.28.425(6). On April 25, 2022, during the pendency of these consolidated proceedings, Avista filed its 2021 electric and natural gas CBRs in Dockets UE-220288 and UG-220289, respectively, indicating the Company's actual cost of capital as of December 31, 2021.

[156] Settlement at 9, ¶ 15.

[157] *Id.*

[158] *Id.*; *see* Kalich, Exh. CGK-6.

[159] Earle, Exh. RLE-1T at 2:9-10.

with the energy imbalance market (EIM) benefit projections embedded in Avista's initially-filed ERM baseline and revenue requirement because they are based on a 2017 study by Energy and Environmental Economics (2017 E3 Study).[160] Public Counsel, therefore, contests this term of the Settlement and proposes that the Commission either annualize one month of the California Independent System Operator's (CAISO) estimated benefits amounts or direct Avista to update the 2017 E3 Study prior to the effective date in these consolidated proceedings.

Commission Determination

129 We find that the power supply terms proposed by the Settlement are reasonable and supported by the record. To calculate the EIM benefits included in the ERM baseline, Avista relies on the 2017 E3 Study that estimates benefits of approximately $5.8 million on a system basis.[161] Public Counsel argues that the study should not be used to approximate the EIM benefits because the study is denominated in 2017 dollars.[162] Instead, Public Counsel recommends that the study be updated based on actual data from Avista's participation in the market.[163] In the absence of an updated study, Public Counsel recommends using the results from CAISO's benefits estimation. Because only one month of results was available at the time testimony was filed, Public Counsel annualizes one month of benefits to derive an annual amount.[164] Public Counsel's revenue requirement proposal incorporates this alternative position.

130 Public Counsel's preferred proposal is that the 2017 E3 Study be updated using more recent input data.[165] Avista argues in rebuttal that it is impossible for the 2017 E3 Study to be updated before the statutory deadline in these consolidated proceedings.[166] We agree. Directing Avista to update its 2017 E3 Study prior to the effective date of these consolidated proceedings is impractical and we decline to set such a requirement.

131 In the alternative, Public Counsel proposes annualizing the March 2022 EIM benefits from CAISO's benefits study to estimate the benefits in all of 2023. Avista opposes

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[160] *See* Kinney, Exh. SJK-3.

[161] Kinney, Exh. SJK-1T at 8:5-7.

[162] Earle, Exh. RLE-1T at 7:12-16.

[163] *Id.* at 9:18-21.

[164] *Id.* at 10:1-12.

[165] *Id.* at 9:18-10:3.

[166] Kinney, Exh. SJK-13T at 6:13-20.

Public Counsel's proposal, arguing that "[w]ithout any operating experience it is too early for the Company to tell whether the CAISO benefit calculation methodology . . . will accurately reflect estimated benefits for Avista. . . ."[167] Further, at hearing and in prefiled written testimony, Avista witness Kinney explained a number of factors that either influenced CAISO's benefits study in the beginning of 2022 or will present an unknown degree of influence, including the amount of hydro, price volatility, transmission interconnection, availability, the CCA and its potential interaction with California markets, Bonneville's entrance into the EIM market, and a new, long-term power purchase agreement that will begin during the MYRP.[168]

132 We agree with Avista. We find that annualizing amounts into rates based on one month of data is not a sound methodology, cannot account for the unknown influences of a number of factors in 2023, and is more flawed than retaining the current 2017 E3 Study's estimates. Public Counsel's proposal is also problematic due to the uncertain timing of how and when EIM benefits will accrue.

133 While the 2017 E3 Study is not without flaws, its selection by the Settling Parties is supported by the record and reasonably balanced by the terms of the Settlement. The 2017 E3 Study was conducted several years ago, and while supported in this record and that of prior GRCs, the Settlement does not propose any update or comparison with any additional data. We find, however, that the flaws and associated risks of the Settling Parties' selection of the 2017 E3 Study are balanced by Avista's negotiated risk to forgo a 60-day power cost update, which will maintain the power cost level established in Avista's initial filing for the entirety of the MYRP.

134 We accept the Settling Parties' agreement to use the 2017 E3 Study to estimate EIM benefits included in the ERM baseline and reject Public Counsel's proposals to either annualize one month of CAISO's estimated benefits amounts or direct the Company to update the 2017 E3 Study prior to the effective date in these consolidated proceedings. None of the three options advanced are ideal, but the Settlement's proposal is reasonable and a well-balanced resolution to the issue.

135 Further, there is a balance struck by the Settlement between Avista and its customers. Avista argues that Public Counsel "cherry-picks" one element of Avista's power supply levels by updating for a decrease in the ERM baseline, while ignoring updates to different

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[167] *Id.* at 7:2-4.

[168] *Id.* at 3:8-11; Kinney, TR at 295:11-298:14.

offsetting factors that could increase the baseline.[169] We acknowledge the risk Avista explains in testimony that it has agreed to as part of the give and take of negotiations. In addition, we agree that the Settling Parties have reached a balanced result with shared risk and some protection for both the Company and its customers, via the ERM, should power supply components vary from the baseline levels.[170]

136 Ultimately, we find that in lieu of using a more recent or updated benefits study, Avista's agreement to incur additional risk by agreeing to not include a 60-day power cost update prior to new rates going into effect for each year of the MYRP is supported by the record and is a fair, reasonable, and balanced resolution of this issue. Accordingly, we determine that the Settlement's power costs terms are in the public interest and should be approved.

3. INSURANCE BALANCING ACCOUNT

137 The Settling Parties agree to two balancing accounts: a Wildfire Expense Balancing Account; and an Insurance Expense Balancing Account.[171] We address the former later in this Order, along with other wildfire-related issues.

138 The Settling Parties agree to the proposal in Avista's initial filing to create an Insurance Expense Balancing Account for the MYRP.[172] The Settling Parties recognize that Avista will bear the burden of supporting deferrals for the account when seeking recovery in a future rate proceeding.[173] The Settling Parties specify that the establishment of an Insurance Expense Balancing Account is not precedential and its continued existence may be challenged by any party in a future proceeding.[174] The Insurance Balancing Account Baseline over the MYRP will be approximately $8.3 million for electric and $1.7 million for natural gas.[175]

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[169] Kinney, Exh. SJK-13T at 4:3-7.

[170] *See id.* at 2:10-3:23.

[171] Settlement at 9, ¶ 16.

[172] Settlement at 9, ¶ 16(b).

[173] *Id.*

[174] *Id.*

[175] Joint Testimony, Exh. JT-1T at 25:7-11; Andrews, Exh, EMA-1T at 64:23; Coppola, Exh. SC-6Cr (Public Counsel Data Request No. 103C).

139 Public Counsel opposes the creation of an insurance balancing account, including any establishment of a baseline.[176] Instead of the Settlement's proposal to accept Avista's expected insurance expense amounts of approximately $8.3 million for electric and $1.7 million for natural gas for each year of the MYRP and use them to establish a baseline for the balancing account, Public Counsel proposes to identify its own insurance expense adjustment within the revenue requirement authorized in this GRC but not allow that amount to be used as a baseline in a balancing account.[177] We address Public Counsel's expense adjustment later in this Order, in our discussion of the Settlement's agreed revenue requirement, but as part of our consideration of the Settlement's insurance balancing account terms we note the amounts presented by Public Counsel in this section.

Commission Determination

140 We find the Settlement's terms establishing a non-precedential Insurance Balancing Account appropriate, subject to a documenting and reporting condition. We agree with the principle underpinning Public Counsel's opposition to the creation of the Insurance Balancing Account: generally, authorizing a pass-through such that a company is guaranteed recovery of its costs in a certain area removes the business incentive for the company to control those costs. However, we find that the record supports the creation of an Insurance Balancing Account, as agreed to in the Settlement, in particular because of the unique circumstances and terms presented.

141 Namely, we find that Avista has demonstrated unprecedented increases and volatility in its insurance costs.[178] We agree that Avista has shown the insurance expense increases in recent years are "extraordinary" and "volatile" and caused an under-recovery of approximately $5.3 million in 2022.[179] We also find that Avista has demonstrated that it has taken and is taking appropriate steps to try to control these costs, but has shown unprecedented recent increases in insurance that are largely out of its control. These increases have been driven primarily by the Company's general liability premiums, which cover wildfire risk and property insurance premiums, and which tend to react to insurance industry losses due to natural disasters.[180] In addition, we agree that these costs

[176] Brief of Public Counsel at 17, ¶ 35; Coppola, Exh. SC-1T at 24:19.

[177] *See* Coppola, Exh. SC-1T at 23:15-24:16; Coppola, Exh. SC-8.

[178] This results from significant increases in insurance expenses in recent years, which have increased approximately 107 percent from 2020 to 2022. Andrews, Exh. EMA-7T 25:16-18.

[179] Andrews, Exh. EMA-1T at 66:16-19 and Exh. EMA-7T 28:5-11.

[180] *See* Andrews, EMA-1T at 64:2-74:19; Brandkamp, Exh. REB-1CT at 3:22-8:12.

have increased due to factors outside the Company's control and despite the Company's best efforts under its Wildfire Resiliency Plan.[181]

142 We also observe that the amounts proposed as a baseline by the Settlement and as insurance expense calculated by Public Counsel are similar,[182] but find that Public Counsel's methodology would present risks, flaws, and precedent that strongly disfavor its adoption. Public Counsel disagrees with Avista's method of projecting its insurance expense, preferring to use a Consumer Price Index (CPI) inflation factor.[183] We are unpersuaded by Public Counsel's arguments to adopt an unrelated inflation factor to calculate projections for insurance costs during the MYRP. Public Counsel's proposal to use inflation factors projecting growth in this area is incongruous with its support for the Settlement's terms excluding escalation factors projecting growth – a portion of the Settlement supported by all parties. In addition, as Avista notes in the record, the insurance market does not generally correlate with CPI factors, as shown by increases in recent years.[184]

143 Conversely, Avista's estimates are based on consultations with insurance brokers to identify overall trends and projected movements in future premiums in the industry.[185] We agree with Avista that the inflation factors projecting growth in this area are unrelated to insurance or utility costs and have no bearing on the insurance risks being borne by Avista or its expected insurance premiums.[186] The Settlement proposes a balancing account baseline representing increases to Avista's total system invoiced 2022 insurance levels of 12.9 percent (electric and natural gas). After allocation, this results in an increase of 6.7 percent (WA electric) and 0.6 percent (WA natural gas) above invoiced 2022 levels.[187] Public Counsel proposes increases to Avista's total system invoiced 2022 insurance expense levels during the MYRP of 2.4 percent (electric and natural gas) in 2023 and 2.3 percent (electric and natural gas) in 2024.[188] Thus, we find the method supported by Avista and the Settlement to establish the Insurance Balancing Account

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[181] Andrews, Exh. EMA-1T at 67:16-68:2.

[182] *Compare* Coppola, Exh. SC-8 *with* Coppola, Exh. SC-6Cr.

[183] Coppola, Exh. SC-1T at 22:1-20.

[184] Forsyth, Exh. GDF-3T at 9:24-10:3.

[185] Brandkamp, Exh. REB-1CT at 3:22-4:6; Andrews, Exh. EMA-7T at 27:7-10.

[186] Andrews, Exh. EMA-7T at 27:15-28:2.

[187] *See* Coppola, Exh. SC-6Cr.

[188] Coppola, Exh. SC-1T at 23:17-24:16; Coppola, Exh. SC-8.

baseline is appropriate, and the method proposed by Public Counsel for calculating the insurance expense, or to substitute it as the baseline, is not.

144 Last, we find that the Settlement reasonably addresses the concerns from both perspectives as it counterbalances the creation of the account as a protection for both customers and the Company as well as with non-precedential treatment and a limited timeframe of two years. The proposed balancing account would protect ratepayers and the Company from over- or under-collection, by deferring actual insurance expense above or below the baseline amount (the amount included in base rates), similar to that approved in the 2020 Avista GRC for the Company's wildfire expense balancing account. The deferred accounting mechanism would ensure that customers pay no more and no less than the actual expenses incurred over the two-year rate plan. Recovery or refund of any deferred balance would be made through an annual compliance filing beginning September 1, 2023, to become effective November 1, 2023, where the insurance expense deferred balance as of July 31 would be rebated or surcharged through a separate tariff.

145 We emphasize that this is not precedential, but for this case only, and the authorization granted by this Order will cease at the conclusion of the MYRP. In addition, we find a condition necessary to underpin and safeguard the delicate balance in this term of the Settlement to ensure Avista will continue to seek the best insurance at the best price and any savings below the baseline will be returned to customers.

146 Accordingly, we determine that approval of the Settlement should be conditioned on a modification to this term to ensure Avista takes appropriate action to negotiate and attain the best insurance at the lowest costs.

> **Condition.** We condition our approval of the Settlement on the modification of this term to include the requirement that Avista document its action to seek out, negotiate, and attain the best insurance at the lowest costs and file with the Commission such documentation, with explanatory narratives, in Avista's annual filing beginning September 1, 2023. Subject to this condition, we determine that the Settling Parties' agreement to create an Insurance Balancing Account, including the proposed baselines for electric and natural gas, is in the public interest and should be approved.

4. WILDFIRE

147 As previously discussed, the Settling Parties agree to 16 performance metrics related to wildfires and to move the filing date for the Wildfire Deferral from July 31 to September 1 as well as the effective date for the Wildfire Deferral from October 1 to November 1.[189] In addition to these terms already discussed, the Settling Parties agree to accept Avista's proposal to update its Wildfire Expense Balancing Account baseline to $5.1 million, as initially filed by Avista, for the duration of the MYRP.[190]

148 Public Counsel does not oppose any of the above terms of the Settlement. Instead, Public Counsel proposes several general modifications to Avista's Wildfire Plan. In particular, Public Counsel recommends that the Commission require Avista to clarify the definitions, purpose, and cost basis of wildfire activities in order to provide the Commission and ratepayers information on what wildfire activities customers are paying for with supporting evidence for cost recovery.[191] Public Counsel also proposes adjustments to decrement wildfire expenses and capital additions.[192]

Commission Determination

149 Public Counsel proposes revenue requirement adjustments to Avista's wildfire expenses and capital additions.[193] While the Settling Parties agree to update the Wildfire Balancing Account baseline, the Settlement does not accept Avista's initially-filed proposals related to wildfire adjustments for purposes of calculating an agreed revenue requirement.[194] We find it sufficient and appropriate, therefore, to further address Public Counsel's proposed adjustments to Avista's wildfire expenses and capital additions only as part of this Order's discussion of the Settlement's revenue requirement agreements.[195] Below, we turn to Avista's Wildfire Resiliency Plan and Public Counsel's proposed modifications.

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[189] *Supra* Sections A.1.x., A.1.xv.b.

[190] Settlement at 9, ¶ 16(a) and accompanying notes; *see* Andrews, Exh. EMA-1T, 57:16-59:17.

[191] Tam, Exh AT-1T at 11:19-12:2.

[192] Tam, Exh. AT-1T at 10:16-19; Coppola, Exh. SC-1CT at 25:22-26:19, 80:9-12.

[193] *See* Brief of Public Counsel at 19, 33-34, ¶¶ 40, 74-75; Tam, Exh. AT-1T at 10:16-19; Coppola, Exh. SC-1CT at 25:22-26:19, 80:9-12.

[194] *See* Settlement at 4-5, 9, ¶¶ 10, 16(a).

[195] *See infra,* Section A.6.

150 We find the Settlement's wildfire-related terms appropriate and find insufficient cause to condition our approval of these terms. Avista's Wildfire Resiliency Plan was first published in May of 2020. It has four major categories: grid hardening, enhanced risk-based vegetation management practices, grid control and monitoring technology and use of Dry Land Mode, and emergency operations and planning.[196] In the 2020 Avista GRC Final Order, the Commission approved a two-way balancing account to track variability in wildfire expenses, setting the initial baseline at $3.065 million.[197] The Settlement proposes to update the account's baseline to $5.1 million for the duration of the MYRP.[198]

151 Public Counsel recommends that the Commission require several changes to Avista's Wildfire Resiliency Plan to "clarify the use and definitions of terminology and purpose of activities; improve risk and fire event tracking; add reliability metrics; and improve communications, outreach, and stakeholder collaboration with a clear communications and outreach plan with associated metrics."[199] Regarding terminology, Public Counsel requests that the Commission issue specific guidance, in these consolidated proceedings or in Docket U-210254, regarding wildfire plan elements including a glossary of terms for standardization purposes.[200] Public Counsel further asserts that Avista could improve mitigation components of the Plan by having the Company specify the exact purpose of each wildfire program component and what risk each component attempts to mitigate.[201] Public Counsel recommends that Avista track and report additional wildfire metrics related to risk events, ignition events, reliability, and communications and outreach.[202]

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[196] Howell, Exh. DRH-1T at 7:10-20.

[197] 2020 Avista GRC Final Order at 81-91, ¶¶ 231-259 and accompanying notes; Joint Testimony, Exh. JT-1T at 24:5-8.

[198] Settlement at 9, ¶ 16(a) and accompanying notes.

[199] Public Counsel Brief at 38-39, ¶ 85; Tam, Exh AT-1T at 11:19-12:2. As the Commission has become aware that the term "stakeholder" is non-inclusive and historically problematic, we are working to substitute terms like "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge others to do the same.

[200] Public Counsel Brief at 39, ¶ 86; Tam, Exh AT-1T at 16:11-16.

[201] Public Counsel Brief at 40, ¶ 87; Tam, Exh AT-1T at 16:19-20.

[202] Public Counsel Brief at 40-43, ¶¶ 88-95; Tam, Exh AT-1T at 30:17-31:9; 32:7-9; 37:13-39. Public Counsel's requests include one that the Commission adopt best practices from "California Energy Safety and issue specific guidance in Docket U-210254 which should include uniform, regular risk event and ignition reporting requirements across all Washington investor-owned utilities." Brief of Public Counsel at 41, ¶ 90; *see* Tam, Exh. AT-1T at 31:17-32:4.

152 Avista indicates that it will be incorporating many of Public Counsel's recommendations as helpful and constructive improvements.[203] Avista agrees to add a glossary of terms into its reports and will make an effort to use the same terminology in most wildfire documents to promote consistency and understanding.[204] In addition, Avista contends it cannot enforce standardization of terminologies with other utilities, but agrees to be open to updating, improving, and refining its own definitions and descriptions in light of these interactions.[205] Avista also updated and provided a new table to better describe how programs will mitigate wildfires, detailing the work category, program, primary purpose, and mitigation value.[206] Avista provided a second table to detail the distributed grid hardening treatment with the risk reduction outcome expected.[207]

153 For Public Counsel's other critiques, Avista responds that it is either currently working on or improving numerous aspects of its Wildfire Resiliency Plan, including: equipment replacement; wildfire metrics for performance measures; tracking of pole fires and fiberglass cross-arm replacements alongside each other; limitations of existing Outage Management System; the need for geographic tracking of risk events and ignitions; additional metrics used by California utilities; tracking of outages and ignitions from trees outside the utility corridor; tracking outages during different Dry Land Mode settings; tracking wildfire-related communication and outreach metrics; improve Access and Functional Needs outreach; provide translated wildfire-related materials; and engaging with community-based organizations related to special-needs and limited English proficiency customers.[208] Avista explains that some of the improvement areas are due to technical constraints during the transition of new programs.

154 We are satisfied with Public Counsel's and Avista's dialogue in these consolidated proceedings and Avista's adoption of many of Public Counsel's recommendations. We find that the record demonstrates Avista's openness to feedback and willingness to adopt constructive suggestions. Many of Public Counsel's suggestions have either already been adopted or will be adopted by Avista when technically feasible. We decline to require or condition approval of the Settlement upon Avista adopting additional proposals but

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[203] Howell, Exh. DRH-5T at 3:18-22.

[204] *Id.* at 3:23-27, and 26:6-9.

[205] *Id.* at 26:14-27:6.

[206] *Id.* at 28:1-23.

[207] *Id.* at 29:1-30:1.

[208] *Id.* at 3:18-27, 10:4-15:9; 16:1-19:14; 21:15-25:22; 26:6-27:6; 28:1-37:20.

expect Avista to remain open to more improvements going forward and to continue its involvement and participation in Docket U-210254, which is a more appropriate forum for pursuing many of Public Counsel's recommendations.[209] We encourage Public Counsel to redeliver its suggestions and recommendations, in particular those that have universal effect for Washington's investor-owned utilities, in Docket U-210254 to help promote, among other things, standardization of wildfire terminology and risk event and ignition reporting concerns that might aid further development of utility preparedness.

155 Accordingly, we determine that the Settlement's wildfire terms, exclusive of the expense and capital additions that we include in our discussion of the Settlement's revenue requirement terms, should be approved without condition.

5. COST OF CAPITAL

156 The Settling Parties agree to an ROR of 7.03 percent for both years covered by the Settlement.[210] Like the revenue requirement for both electric and natural gas operations discussed later in this Order, this term of the settlement is a results-only agreement. The Settlement identifies no component of the cost of capital used to calculate the agreed ROR, namely: return on equity (ROE), cost of debt, and capital structure. In a footnote to their joint testimony (Footnote 8), however, the Settling Parties provide hypothetical components illustrating how the agreed ROR "could be derived using Avista's currently-authorized Return on Equity of 9.4 percent, 48.5 percent equity layer, 51.5 percent debt layer, and a 4.8 percent cost of debt that was updated during the case."[211] The Settling Parties state that this would produce "a result within the zone of reasonableness."[212]

157 Public Counsel opposes the Settlement's proposed ROR of 7.03 percent. In addition, Public Counsel opposes all hypothetical components of the proposed ROR that are implied by Footnote 8: the capital structure, ROE, and cost of debt. Table 6, below, illustrates Avista's currently authorized cost of capital, Avista's actual cost of capital reported to the Commission in its 2021 Commission Basis Report, and the cost of capital positions presented in this proceeding.

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[209] Docket U-210254 is the Commission's docket for utility wildfire preparedness.

[210] Settlement at 5, ¶ 11.

[211] Joint Testimony, Exh. JT-1T at 14, n. 8.

[212] *Id.*

Table 6. Cost of Capital Positions

Component	Current	Settlement	Public Counsel	*Initial Filing*[213]	*2021 CBR*[214]	*Footnote 8*[215]
Equity	48.5 %	-	45.6 %	*48.5 %*	*47.56%*	*48.5 %*
ROE	9.4 %	-	8.75%	*10.25%*	*9.4 %*	*9.4 %*
Weighted Cost	4.56%	-	3.99%	*4.97%*	*4.47%*	*4.56%*
Debt	51.5 %	-	54.4 %	*51.5 %*	*52.44%*	*51.5 %*
Cost	4.97%	-	4.54%	*4.54%*	*4.78%*	*4.8 %*
Weighted Cost	2.56%	-	2.47%	*2.34%*	*2.51%*	*2.47%*
ROR	**7.12%**	**7.03%**	**6.46%**	*7.31%*	*6.98%*	*7.03%*

Commission Determination

158 We find the Settlement's agreed ROR of 7.03 percent appropriate. The record supports the cost of capital terms agreed by the Settling Parties and we find that the Settlement's agreed ROR falls within a range of reasonableness. In this case, the Commission received three cost of capital testimonies: Avista's initial testimony, Public Counsel's opposition testimony, and the Settling Parties' rebuttal testimony (Avista's witnesses).[216] Ultimately, we find that the Settlement's agreed ROR is supported by the record and falls within a

[213] With its support of the Settlement and the Settling Parties' proposal to a results-only ROR of 7.03 percent, Avista no longer supports the testimony and evidence it initially filed regarding cost of capital.

[214] *See* Avista's 2021 Electric & Natural Gas CBRs, Dockets UE-220288 and UG-220289 (Apr. 25, 2022).

[215] The cost of capital elements provided as hypothetical illustration only are not agreed to by the Settling Parties and are not included as a term in the Settlement. Settling Parties provide the information in Footnote 8 only as a hypothetical illustration of how the ROR *could be derived* using Avista's currently authorized capital structure, ROE, and updated cost of debt. *See* Response to BR-7.

[216] *See, e.g.,* Garrett, Exh. DJG-1T at 9:1-12, stating "In my opinion, an authorized ROE greater than the 8.75 percent ROE I recommend would be unreasonable." *See, e.g.,* McKenzie, Exh. AMM-1T at 6:1-4, stating "Based on the results of my analyses shown on Exh. AMM-4, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for the proxy group of utilities is in the 9.5 percent to 10.9 percent range."

range of reasonableness and find Public Counsel's arguments unconvincing that the agreed ROR is unsupported and unreasonable.

159 Public Counsel's arguments regarding cost of capital, like most of its opposition testimony, are presented in contrast to Avista's initial filing. Specifically, Public Counsel focuses its testimony on components of cost of capital not specified in the Settling Parties' agreement. Public Counsel's argument might have been more persuasive if it were focused more on its opposition to the Settlement terms that we must evaluate.[217] Public Counsel's proposed cost of capital would reduce the initial filing's revenue requirement in the first rate year by $23.0 million for electric and $5.8 million for natural gas, and in the second rate year by $0.9 million for electric and $0.2 million for natural gas.[218] Public Counsel's direct recommendation regarding the Settlement's ROR is that the Commission should reject it because it fails to reduce the initial filing's revenue requirement *as much as* Public Counsel's.[219] We find this argument unpersuasive.

160 Public Counsel focuses its arguments on ROE and capital structure, while accepting the initial filing's cost of debt. Public Counsel witness Garrett argues that the agreed ROR is unreasonable because it is derived from an implied ROE of 9.68 percent.[220] Garrett also argues that the level of equity in the capital structure proposed by Avista in its initial filing is too high.[221] Again these arguments focus opposition on Avista's initial filing, instead of the Settlement, which is what we must evaluate and consider. This flaw is particularly fatal given the lack of ROE, capital structure, or cost of debt enumerated in

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[217] Public Counsel witness Coppola testifies that

> Public Counsel's lower cost of capital represents the largest adjustment to Avista's proposed revenue requirement, reflecting primarily the excessive ROE rate of 10.25 percent the Company proposed and an inflated equity ratio of 48.5 percent. The Commission should not accept the Company's overstated rate of return, and instead should accept Public Counsel's proposed overall cost of capital . . . .

Coppola, Exh. SC-1CT at 16:13-14.

[218] *Id.* at 16:4-7.

[219] The Settlement ROR would reduce the initial filing's revenue requirement in the first rate year by only $7.6 million for electric and $1.9 million for natural gas, and in the second rate year by only $0.3 million for electric and $0.1 million for natural gas. *Id.* at 16:18-17:8.

[220] Garrett, Exh. DJG-1T at 9:1-4; 15, Figure 3. Garrett uses Avista's currently authorized capital structure and the cost of debt in the initial filing. *Id.* Garrett also argues that an ROE of 9.4 percent is unreasonable. *Id.* at 56:3-14.

[221] *See* Garrett, Exh. DJG-1T at 57:2-64:7.

the Settlement. The only element of cost of capital agreed by the Settling Parties is the resulting ROR, which they present as a fair end result that falls within the range of reasonableness supported by the testimony in these consolidated proceedings and as the result of a negotiated settlement. Nevertheless, we examine the evidence presented by Public Counsel and explain our determinations.

161 Public Counsel employs CAPM and DCF models supporting ROE results of 7.5 percent and 8.3 percent.[222] Avista witness McKenzie, on behalf of the Settling Parties, critiques Public Counsel's analyses, arguing that they misapply risk philosophies and are undermined by methodological flaws.[223] We agree and note, first, flaws with Public Counsel's over reliance on long-term forecast of Gross Domestic Product (GDP) from the Congressional Budget Office (CBO) due to CBO's own characterization of its projections as "very uncertain" and exacerbated by the unknown effects of the pandemic, and, second, Public Counsel's reliance on a market risk premium based upon the assumption that a long term growth rate would equal the then-current yield on United States' Treasury bonds.[224] During these consolidated proceedings, the CIP inflation increased to over 9 percent.[225] In part due to changing economic conditions since its filed testimony, Public Counsel's proposals based upon assumptions of a 3.8 percent nominal growth rate are simply too tenuous to be persuasive.[226] Thus, we determine the Settlement's agreed ROR should not be modified based upon Public Counsel's ROE arguments and proposal.

162 We are likewise unpersuaded by Public Counsel's arguments that the Settlement's agreed ROR should be modified by Public Counsel's proposed capital structure. Public Counsel recommends a capital structure with an equity ratio of 45.6 percent, which is less than Avista's current authorized ratio of 48.5 percent.[227] Public Counsel argues that a utility, like Avista, would have an incentive to keep less equity and fund its operations with a greater portion of debt than reflected in its authorized capital structure because equity

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[222] Garrett, Exh. DJG-1T at 56:4-6.

[223] McKenzie, Exh. AMM-15T at 5:6-10, 25:6-13, 26:3-28:8, 32:3-36:16, 37:7-38:2, 47:15-48:1; Ehrbar, Exh. PDE-2T at 4:9-11.

[224] *See* Garrett, Exh. DJG-1T at 36:3-46:21, 50:11-53:12; Garrett, Exh. DJG-6, Garrett, Exh. DJG-8; McKenzie, Exh. AMM-15T at 35:10-36:2, 39:5-13.

[225] McKenzie, Exh. AMM-15T at 8:15-19.

[226] *See id.*; Garrett, Exh. DJG-1T at 43:3-44:4; McKenzie, Exh. AMM-15T at 35:19-36:2 and accompanying notes.

[227] Garrett, Exh. DJG-1T at 64:9-11.

receives a larger return than debt, and debt has a lower cost.[228] We are reassured by testimony supporting the Settlement that establishes Avista's intent and practice of maintaining a level of equity near its authorized level. We find no concern at this time that Avista is manipulating its level of equity in the ways Public Counsel says are possible.[229] Further, due to the terms' results-only nature, the level of equity and debt is undefined and, therefore, impossible for us to determine without upsetting the Settlement. In addition, Avista's recent CBRs add support to the conclusion that Avista is not at this time manipulating its authorized level of equity. The CBRs show the Company's actual equity ratio as of December 31, 2021, at 47.56 percent, which is closer to Avista's authorized equity ratio than Public Counsel's proposed equity ratio.[230] Thus, we determine the Settlement's agreed ROR should not be modified based on Public Counsel's capital structure proposal.

163 The resulting ROR that Public Counsel recommends is 6.46 percent and would represent a 66 basis point decrement upon Avista's currently-authorized ROR if adopted.[231] Public Counsel's recommendation is based upon a 7.9 percent ROE, 4.45 percent cost of debt, and an equity ratio of 45.6 percent. The Settling Parties argue that Public Counsel's proposal is unreasonably low. Avista witness McKenzie, on behalf of the Settling Parties, provides the most updated five-year average ROE of 9.44 percent and a median of 9.49 percent approved by state utility commissions.[232] With this context, the Settling Parties argue that Public Counsel's estimate of Avista's cost of equity as 7.9 percent is not credible, fails to meet accepted benchmarks, and would be an extreme result falling "far below the lowest ROE awarded by any state regulatory commission in modern history."[233] We agree, but recognize that basing our approval of ROE on the results of other state utility commissions represents a circular and self-fulfilling argument because those commissions may be making decisions the same way. Public Counsel's recommendation to set an ROR of 6.46 percent based, in part, upon decrementing Avista's currently authorized ROE by approximately 150 basis points below the average

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[228] *See* Garrett, Exh. DJG-1T at 56:16-60:15.

[229] Thies, TR at 433:7-438:2.

[230] *See* Avista's 2021 Electric & Natural Gas CBRs, Dockets UE-220288 and UG-220289 (Apr. 25, 2022).

[231] Garrett, Exh. DJG-1T at 3:1–7; Coppola, Exh. SC-1CT at 11:3-4.

[232] McKenzie, Exh. AMM-15T at 5:3-5. McKenzie's data is taken from S&P Global Market Intelligence, Major Rate Case Decisions – January-June 2022.

[233] Ehrbar, Exh. PDE-2T at 3:19-24 (citing McKenzie, Exh. AMM-15T); *see* McKenzie, Exh. AMM-15T at 4:11-19:9.

allowed ROE for other electric utilities in the first half of 2022 would be a shock to Avista's financial integrity and impact its ability to attract capital on reasonable terms.[234] The record's demonstrated and explained economic circumstances scarcely justify any consideration of authorizing an unprecedented decrement to Avista's authorized ROR. Ultimately, we find Public Counsel's analyses and recommendations unconvincing and unpersuasive because they are too speculative and unreliable.

164 ROR is the most important element of cost of capital for regulatory purposes. For example, the ROR is reported in Avista's annual CBR and used in Avista's decoupling mechanism to trigger a refund to customers. Prior to this GRC, that earnings test would return half the Company's earnings that exceeded its authorized ROR (currently 7.12 percent).[235] The Settlement replaces this earnings test with language from RCW 80.28.425(6), triggering a refund to customers of *all* earnings more than one-half percent above Avista's authorized ROR.[236]

165 The Settlement's agreement would reduce Avista's currently authorized ROR from 7.31 percent to 7.03 percent. Using Avista's currently authorized ROR would create a refund threshold of 7.81 percent, but the Settlement lowers the threshold for a refund of *all* earnings to 7.53 percent. While the Settlement increases Avista's revenue requirement, the agreed decrement to Avista's ROR is a gradual step that benefits Avista's ratepayers. The give and take of the Settling Parties through negotiation of this term is, therefore, readily apparent in achieving a fair balance of opposing interests. Accordingly, we determine that the Settlement's agreed ROR is a fair end result that falls within a range of reasonableness, that it is supported by the record, and that it should be approved.

6. OVERALL REVENUE REQUIREMENT

166 As described above in Table 1, Avista proposed in its initial filing an annual revenue increase for Rate Year 1 for its electric operations of approximately $52.9 million, or 9.6 percent, and for its natural gas operations of approximately $10.9 million, or 9.5 percent. For Rate Year 2, Avista proposed an annual revenue increase for its electric operations of

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[234] *See* McKenzie, Exh. AMM-15T at 20:18-21:21.

[235] Avista Tariff Schedules 75 (electric) and 175 (natural gas).

[236] Settlement at 20, ¶ 28(e); Ehrbar, Exh. PDE-1T at 37:14-38:24. One-half percent above the agreed ROR of 7.03 percent.

approximately $17.1 million, or 2.8 percent, and an increase for its natural gas operations of $2.2 million, or 1.7 percent.[237]

167 The Settlement provides for a $38.0 million annual increase to Avista's electric revenues, and a $7.5 million annual increase to its natural gas revenues in Rate Year 1. In Rate Year 2, the Settling Parties agree to an additional $12.5 million annual increase to Avista's electric revenues, and $1.5 million to its natural gas revenues.[238] The Settlement also includes a proposal to return the Residual Tax Customer Credit of $25.5 million for electric (approximately $12.8 million annually) and of $12.5 million for natural gas (approximately $6.3 million annually) to partially offset the revenue increases.

168 The Settling Parties' agreement regarding Avista's revenue requirement during the MYRP is a "results-only" settlement.[239] The Settling Parties agree that the overall resulting rate increases in the MYRP are equitable, fair, just, reasonable, and sufficient, and with the exception of certain items (*e.g.*, ROR), do not agree to any specific adjustments necessary to reach the agreed revenue requirement. Specifically, no individual adjustments made to net operating income or rate base were enumerated to calculate the revenue requirement. The parties attest that the results-only Settlement represents a give-and-take on multiple issues that characterizes settlement discussions and reflects a reasonable balance of differing interests.[240]

169 While Public Counsel accepts nearly all the Settlement's terms, it contests the overall revenue requirement and argues that the Commission should adopt a revenue requirement that relies on its adjustments to the revenue requirement models presented in Avista's initial filing.

170 In general, the revenue requirement is the increase or decrease in additional or reduced annual revenue derived from a calculation using a modified historical test year based on

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[237] Vermillion, Exh. DPV-1T at 18:11-17.

[238] Joint Testimony, Exh. JT-1T at 2:15-22.

[239] Previously, the Commission has described such agreements as "black-box" settlements. However, as we have become aware that this description has negative connotations that reinforce anti-Blackness by using colorist language, we intend to reference such agreements as "results-only" or "results-focused" settlements. Similarly, as noted above, we intend to substitute for the historically problematic term "stakeholder" terms such as "interested persons," "participants," "persons," or "non-company parties," depending on the situation. We urge parties before the Commission to adopt the same or similarly informed and updated language.

[240] Joint Testimony, Exh. JT-1T at 12:3-9.

adjustments to a company's currently authorized ROR to its rate base, expenses, and revenues. A results-focused Settlement means that its revenue requirement components are neither articulated in a way that allows others to reproduce the calculation nor identified for purposes of allowing any numerical increase or decrease.

171 Table 7, below, summarizes the revenue requirement proposals and adjustments presented by Avista's initial filing, Public Counsel's opposition testimony, and the Settlement.

172 **Table 7. Revenue Requirement Summary (*before* Residual Tax Customer Credit)**
(in millions)

Position		**Electric**		**Natural Gas**	
		Rate Year 1	Rate Year 2	Rate Year 1	Rate Year 2
Initial Filing		**$ 52.9**	**$ 17.1**	**$ 10.9**	**$ 2.2**
Public Counsel Adjustments to Initial Filing	*ROR Reduction*	*$ (23.0)*	*$ (0.9)*	*$ (5.8)*	*$ (0.3)*
	O&M Reductions	$ (10.4)	$ (4.9)	$ (2.1)	$ (0.9)
	Rate Base Reductions	$ (7.2)	$ (8.7)	$ (1.4)	$ (0.8)
	O&M Offsets Reversal	$ 0.2	$ (0.2)	$ (0.04)	$ (0.01)
	EIM Benefit	$ (12.1)	-	-	-
Public Counsel		**$ 0.4**	**$ 2.8**	**$ 1.7**	**$ 0.2**
Settlement		**$ 38.0**	**$ 12.5**	**$ 7.5**	**$ 1.5**

Commission Determination

173 Ultimately, we find the revenue requirement Settlement terms balance appropriately with all terms of the Settlement, are supported by the record, and result in rates across the MYRP that are equitable, fair, just, reasonable, and sufficient. We are not troubled by the results-only nature of the Settlement's revenue requirement terms. Results-only revenue requirement agreements that propose fair and just end results without specifying most, or any, underlying adjustments used to arrive at the resulting revenue requirement would be troubling only if the record, and Settlement, lacked sufficient support demonstrating that

the revenue requirement are equitable, fair, just, reasonable, and sufficient. Here, the Settlement's terms are supported sufficiently, including explanations of the delicate balance struck between the Settling Parties in consideration of the revenue requirement and the non-revenue related terms.

174 In evaluating settlements, we consider the entire record. Here, the record for our consideration includes all initial testimony and exhibits, the Settlement and supporting testimony and exhibits, and the testimony and exhibits opposing the Settlement. The Settlement's proposed revenue requirement provide no indications as to any adjustment that may be included in or excluded from the resulting revenue requirement calculations. Considering Public Counsel's opposition, this has two consequences. First, a results-only revenue requirement provides approval for no investment or adjustment for which Avista sought recovery in this case. By approving the proposed revenue requirement, the rate base approved in Avista's most recent rate case remains undisturbed and no determination relating to prudence or any party's proposed adjustments would be affected.

175 Second, should we agree with Public Counsel on any of its proposed adjustments to the revenue requirement, we would be unable to identify whether the adjustment advocated for had already been incorporated into and made part of the results-only revenue requirement terms and would, therefore, be unable to effectuate any single adjustment. Taking into consideration our rejection of Public Counsel's cost of capital proposals, the revenue requirement proposed by Public Counsel is similar enough to the agreed revenue requirement that it could be calculated by selecting and rejecting some, but not all, of Public Counsel's adjustments. This illustrates the probability that some, but perhaps not all, of the considerations raised by Public Counsel to arrive at its proposed revenue requirement may already have been considered by the Settling Parties. We cannot, however, speculate upon which issues the Settling Parties entered into negotiated agreements and, ultimately, determined to resolve their further disputes by agreeing to the results-only revenue requirement. All the Settling Parties agree the revenue requirement amounts are fair even if they are unable to enumerate the specific adjustments agreed to in order to arrive at the fair, just, and reasonable end results.

176 This is different and distinct from our recent Cascade Final Order. That case presented a settlement that adopted much of the company's initial filing, including the enumeration of adjustments to arrive at an agreed revenue requirement. The Commission was able to determine in that case which revenue requirement adjustments the settling parties adopted that could be modified. Here, we cannot. Instead, we must consider the aggregate and whether the results-only revenue requirement to which the Settling Parties agreed represents, when considered as part of the Settlement as a whole and balanced by the numerous non-revenue terms, a fair, just, and reasonable end result. Here, we determine that the end-results revenue requirement is supported by an appropriate record and, in the context of the entirety of the Settlement, is in the public interest and should be approved. We explain in greater detail, below.

177 Rather than responding to the merits of the resulting revenue requirement in the context of the entire Settlement, which contains many terms Public Counsel asserts are in the public interest, Public Counsel responds primarily to the merits of the proposals and adjustments presented in Avista's initial testimony, relying on its adjustments to Avista's revenue requirement models to present its own revenue requirement recommendations. Public Counsel's proposed revenue requirement reductions stem from adjustments to the Settlement's cost of capital, which we have previously addressed in this Order, eight expense items in the Company's initial filing, and 16 capital additions included in the Company's initial filing.

178 The specific expense items Public Counsel recommends adjusting are: Insurance Expense, Vegetation Management, Customer Service Expense, Pension Expense and Other Post-Employment Benefits Expense, Miscellaneous Operations and Maintenance Expense, Information Systems and Information Technology Expense, and CETA Labor Expense.[241] The capital additions Public Counsel recommends adjusting are: Distribution Management System, Gas Non-Revenue Program, EV Transportation, Customer Experience Platform, Customer Transaction Systems, Distribution System Enhancements, Electric Relocation and Replacement Program, Energy Delivery Modernization, Energy Resources Modernization, Gas Aldyl-A Pipe Replacement Program, Gas Meter Change Program, Substation – New Distribution Station Capacity Program, Substation – Station Rebuilds Program, Wildfire Resiliency Plan, Wood Pole Management, and Enterprise and Control Network Infrastructure.[242]

179 Public Counsel opposes the Settlement's agreed revenue requirement on two bases. First, Public Counsel argues that the proposed revenue requirement is excessive given current economic conditions and, if the Commission were to accept the Settlement's revenue

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[241] Coppola, Exh. SC-1CT at 18:1-25:17, 25:18-27:8, 27:9-30:5, 30:8-32:9, 33:3-36:3, 36:7-38:12, 38:14-41:4.

[242] *Id.* at 46:14-49:9, 49:11-50:18, 51:2-53:18, 54:3-57:16, 57:18-60:12, 60:14-63:9, 63:13-68:4, 68:6-72:3, 72:5-74:13, 74:18-79:4, 79:6-84:3, 84:5-86:14, 86:16-89:4.

requirement, the resulting bill impacts would unfairly compound the effects of inflation on customers.[243] Further, Public Counsel argues that growing corporate profit margins are partially responsible for inflation growth and that the Company seeks to earn excessive profits at a time when its customers are struggling.[244] Second, Public Counsel argues that the proposed revenue requirement is inequitable. Referencing the relevant statute for MYRPs, Public Counsel argues that the revenue requirement and resulting rate increase will disproportionately burden low-income and marginalized customers who are already experiencing the impacts of high inflation and other economic challenges.[245] Because of this, Public Counsel argues that the Settlement does not result in equitable rates.[246]

180 Public Counsel's presentation is neither persuasive nor well-founded. The Settling Parties' revenue requirement agreements are results-focused and provide no detail as to which adjustments may have been negotiated by the Settling Parties to reach the resulting agreements. Public Counsel's strategy of recommending adjustments to a results-only revenue requirement makes it difficult, if not impossible, for the Commission to effectuate any of Public Counsel's positions because we cannot determine which, if any, of Public Counsel's positions were already adopted or considered in the negotiations of the Settling Parties when arriving at the agreed revenue requirement. Thus, contrary to Public Counsel's arguments, we find its presentation cannot serve as an appropriate basis to decrement the Settlement's revenue requirement. We decline to break the results-only terms of the Settlement's revenue requirement in order to specify or enumerate any of the adjustments proposed by Public Counsel that might be considered in a fully litigated proceeding or a settlement that enumerated specific adjustments.

181 Avista's initial filing and Public Counsel's adjustments to that filing are record evidence that provide essential context for our evaluation of what balance the Settling Parties have struck between their revenue requirement agreements and the Settlement's other non-revenue terms. However, Avista no longer supports the revenue requirement proposed in its initial filing. That filing does not provide insight into the formulation of the Settling Parties' results-only revenue requirement agreements. Likewise, Public Counsel's arguments against Avista's initial filing provide no insight into what reductions to the

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[243] Dahl, Exh. CJD-1T at 13:9-14:2.

[244] *Id.* at 14:9-19.

[245] RCW 80.28.425 permits the Commission to consider environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity in determining whether rates are in the public interest.

[246] Dahl, Exh. CJD-1T at 17:10-18:2.

results-only revenue requirement agreements could be justified. In consideration of all the record evidence, we are persuaded that the many terms in the Settlement are fair, just, and reasonable and represent an appropriately negotiated balance between the needs of the Company and the needs of its customers.

182 In addition, we are not merely approving rates that will remain static without oversight of Avista's performance. We assure Public Counsel and Avista's customers that the regulation of Avista going forward will be quite the opposite. For all capital additions during the MYRP, Avista will annually file in these consolidated dockets support for the additions that will be reviewed by the parties and the Commission to determine if any refunds are due customers. We accept and adopt the Settlement's many performance metrics, requiring that Avista file reports on these metrics with the Commission, and place additional assessment measures (pursuant to RCW 80.28.425(7)) for evaluating the MYRP going forward. We address and explain this in greater detail in Section C of this Order. We fully expect, encourage, and welcome Public Counsel's and other ratepayer representatives' engagement in the evaluating investments in the provisional capital review process, evaluating Avista's performance during the MYRP reporting periods, in the Docket U-210590 performance-based ratemaking collaborative, as the regulation of Washington's investor-owned utilities continues to move towards more performance-based regulation as required by statute.

183 Accordingly, for the reasons explained above, we determine that the Settlement's revenue requirement terms should be approved. Based on the decisions we make in this Order for the purposes of authorizing rates that are equitable, fair, just, reasonable, and sufficient, we authorize an increase to Avista's revenue requirement prior to the inclusion of the Residual Tax Customer Credit as set forth in the Settlement of approximately $38.0 million, or 6.9 percent over base rates, for the Company's electric operations in Rate Year 1 of the MYRP, and $12.5 million, or 2.1 percent over base rates, for the Company's electric operations in Rate Year 2 of the MYRP. For the Company's natural gas operations, we authorize an increase of $7.5 million, or 6.6 percent over base rates, in Rate Year 1 of the MYRP, and $1.5 million, or 1.2 percent over base rates in Rate Year 2.

B. SETTLEMENT DETERMINATION

184 Having reviewed the Settlement, its supporting evidence, and all evidence in the record, we conclude that the Settlement is lawful, supported by an appropriate record, and consistent with the public interest, subject to the conditions outlined in this Order.

Accordingly, we determine that approval of the Settlement subject to conditions in concert with the other findings we have made and explained, above, will establish rates, terms, and conditions for Avista's electric and natural gas service to Washington customers that are equitable, fair, just, reasonable, and sufficient. We therefore approve the Settlement subject to the conditions outlined in paragraphs 78, 85, 99, 112, and 146.

185 The Commission's procedural rules require, if we condition our approval of a settlement on terms that are not included in the settlement agreement, as we do here, that we provide the Settling Parties with an opportunity to accept or reject the Commission's conditions.[247] If any of the Settling Parties reject any of the conditions or does not unequivocally and unconditionally accept all of the conditions of our approval of the Settlement as set out in this Order, the Commission will notify the parties that it deems the Settlement to be rejected and will return the adjudication to its status at the time the Commission suspended the procedural schedule for the purpose of considering the settlement subject to compliance with any statutory deadline.[248] Because the statutory deadline in this case is December 21, 2022, the Commission would be unable to complete this proceeding absent the Company's agreed extension of the suspension date.[249] Accordingly, if any of the Settling Parties objects to any of the conditions of our approval of the Settlement in this Order, the Settlement will be deemed denied on the basis that it proposes rates that are not equitable, fair, just, reasonable, or sufficient.

186 We authorize and require Avista to make a compliance filing by December 14, 2022, consistent with the Settlement's terms, our directions and conditions in this Order in these consolidated dockets to recover in prospective rates its revenue deficiency.

C. PERFORMANCE MEASURES PURSUANT TO RCW 80.28.425(7)

187 The Commission must, by law, "determine a set of <u>performance measures</u> <u>that will be used to assess</u> a gas or electrical company <u>operating under a multiyear rate plan</u>."[250] This statutory obligation is placed on the Commission, not any company or party to a GRC. Measures that the Commission might determine appropriate *may* be based on a company's filing, record testimony and evidence, or the proposals made by a company or

[247] WAC 480-07-750(2)(b).

[248] WAC 480-07-750(2)(b)(ii); WAC 480-07-750(2)(c).

[249] WAC 480-07-750(2)(c).

[250] RCW 80.28.425(7) (emphasis added).

other party throughout the proceeding.[251] The Commission's determination, therefore, need not be based upon a company's initial filing, the record testimony and evidence, or the proposals made by a company or party throughout the proceeding. It is not only within the Commission's authority and its discretion to determine a set of performance measures to assess an MYRP, but a requirement of law.

188 As the Settling Parties noted during hearing, the Commission has initiated a proceeding in Docket U-210590 to examine and establish performance metrics, performance incentives and penalties.[252] The Commission's efforts in that docket are proceeding in parallel with the efforts to establish performance measures in this and other general rate case proceedings. Because the Settlement was filed before the Commission issued a Notice of Opportunity to File Written Comment in Docket U-210590 on August 5, 2022, the Settlement's 92 performance metrics do not necessarily reflect the Commission's regulatory goals and desired outcomes or design principles provided in Docket U-210590, which is the Commission's collaborative proceeding concerning performance-based ratemaking.

189 The Settlement proposes 92 performance metrics to be recorded and tracked, but these metrics are not specifically measures appropriate for evaluating Avista's operations under the MYRP. The Settlement's 92 performance metrics also fail to aid the Commission in meeting its statutory obligation because the Settlement lacks detailed information related to how the Commission should use the 92 metrics to evaluate Avista's MYRP or provide all the agreed metric calculations.

190 We therefore determine that certain measures, independent and aside from the 92 metrics included in the Settlement, are necessary for the Commission's future assessment of Avista's operations under the MYRP. We adopt the measures outlined in Table 8, below, regarding operational efficiency, company earnings, affordability, and energy burden. All required reporting should use the same formatting for reporting usage by kilowatt-hours and therms as identified in paragraph 56, above.

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[251] RCW 80.28.425(7).

[252] Section (1) of Engrossed Substitute Senate Bill 5295, Chapter 188, Laws of 2021, directs the Commission initiate a proceeding to address performance based regulation, among other things: "To provide clarity and certainty to stakeholders on the details of performance-based regulation, the utilities and transportation commission is directed to conduct a proceeding to develop a policy statement addressing alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms."

191 **Table 8. MYRP Performance Measures and Outcomes**

Topic	Measure/Calculation	Outcome[253]
Operational Efficiency	O&M Total Expense *divided by* Operating Revenue	Assesses how much expense was incurred for every dollar earned. Results at 1.00 or greater might reflect reduced efficiency in controlling O&M spending.
	Operating Revenue *divided by* AMA Total Rate Base and[254] Operating Revenue *divided by* EOP Total Rate Base	Assesses efficient use of rate base to generate revenue. Results less than 1.00 or excessively low results might reflect reduced efficiency in utilizing rate base to generate revenue.
	Current Assets *divided by* Current Liabilities[255]	Assesses liquidity of current assets covering current liabilities. Results less than 1.00 might reflect issues or concerns with liquidity.
Earnings	Net Income *divided by* Operating Revenue	Assesses the amount of net profit gained through revenues earned. Results should be multiplied by 100, to calculate a percentage result, and compared to the authorized ROR.
	Retained Earnings *divided by* Total Equity	Assesses the amount of earnings retained by a company compared to its total equity. Excessively low or high deviations might indicate that the company is paying out more earnings than reinvesting or that the company is retaining more than it needs, respectively. This metric will require baseline information to understand reinvesting and payout patterns.
Affordability[256]	Average Annual Bill Impacts (by Census Tract)	Assesses the average annual residential bill impacts to better understand, over time and by location, affordability of residential rates using the same average energy usage from year to year for better comparability over time.
	Average Annual Bill Impacts (by Zip code)	
Energy Burden[257]	Average Annual Bill *divided by* Average Median Income (by Census Tract)	Assesses the average energy burden of residential customers over time and by location. Results greater than 6 percent indicate energy burden concerns.[258]
	Average Annual Bill *divided by* Average Median Income (by Zip code)	

192 The measures we require Avista to track and report, outlined above, will provide essential and critically important business and customer equity data for the Commission's evaluation of Avista's performance during this MYRP. We also observe that the measures we require, outlined above, will likely continue to be consequential, even beyond this MYRP, for assessing the Company's performance during future MYRPs. Performance-based ratemaking is an iterative process and flexibility is critical. We encourage the parties to these consolidated proceedings to continue to participate in Docket U-210590 through collaboration with the Commission to further assess and define these metrics

193 Likewise, we would find extraordinary benefit from all the historical data related to these measures. At this time, we will not require Avista to search, collect, compile, and provide to the Commission *all* historical data it might have related to these measures. For now, we find that only recent history is necessary for our ability to understand and evaluate Avista's performance at the end of this MYRP. Thus, we require Avista to make a compliance filing within 45 days of this Order to provide the measures and calculations outlined in Table 8, above, for the years 2019-2022 (beginning January 1 and ending December 31 of each year) in order to establish a baseline for our understanding and evaluation. In addition, we require Avista to report the performance measures outlined in Table 8, above, for each year of the MYRP (beginning January 1 and ending December 31 of each year and within 45 days of the end of the reporting period). We will utilize the information gathered through these measures to evaluate the MYRP only, for now, at its conclusion and consider such in our determinations of Avista's next GRC and future MYRPs.

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[253] Outcome descriptions are approximate. Baseline data is required prior to a full understanding of outcomes and results.

[254] Provide results for both calculations but indicate in report whether the Commission authorized the use of AMA or EOP.

[255] "Current" means all current assets that can be converted into cash within one year and all current liabilities with maturities within one year.

[256] These measures are similar to metric 1 in Attachment B to the Settlement. These measures track both by census tract and by zip code. Avista should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[257] These measures are similar to the metric 2 in Attachment B to the Settlement. These measures track both by census tract and by zip code. Avista should provide separate results for electric-only customers, gas-only customers, and combined electric and gas customers.

[258] *See* Chapter 480-100 WAC.

FINDINGS OF FACT

Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the Parties and the reasons therefore, the Commission now makes the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

194 (1) The Commission is an agency of the State of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers of property and affiliated interests of public service companies, including electric and natural gas companies.

195 (2) Avista is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. Avista provides electric and natural gas utility service to customers in Washington.

196 (3) Avista's currently effective rates were determined by the Commission's Final Order in *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, and UE-200894 *(Consolidated)*, Order 08/05 (Sep. 27, 2021).

197 (4) On January 21, 2022, Avista filed with the Commission revisions to its currently effective Tariffs WN U-28, Electric Service, and WN U-29, Natural Gas Service, proposing a two-year rate plan with increases for its electric and natural gas operations for Rate Year 1 effective December 21, 2022, and for Rate Year 2 effective December 21, 2023.

198 (5) Avista initially requested an increase in its annual electric revenue requirement of approximately $52.9 million (9.6 percent) in Rate Year 1 and of approximately $17.1 million (2.8 percent) in Rate Year 2, and an increase to its annual natural gas revenue requirement of approximately $10.9 million (9.5 percent) in Rate Year 1 and of approximately $2.2 million (1.7 percent) in Rate Year 2.

199 (6) Avista initially requested to partially offset its requested increases with the Residual Tax Customer Credit of approximately $25.5 million for electric and $12.5 million for natural gas. This modified Avista's initial request for an increase during Rate Year 1 to approximately $40.1 million (7.4 percent) for electric and $4.6 million (2.5 percent) for natural gas.

200 (7) On May 27, 2022, the Commission entered Order 07/01, consolidating Dockets UE-220053 and UG-220054 with Docket UE-210854 pursuant to Staff's unopposed motion to consolidate. Avista had filed in Docket UE-210854 its Electric Service Reliability Reporting Plan pursuant to Washington Administrative Code (WAC) 480-100-393, modifying its previous plan.

201 (8) On June 28, 2022, the Settling Parties filed the Settlement, which proposes to resolve all disputed issues and is attached to this Order as Appendix A. Public Counsel contests certain terms of the Settlement, but either supports or does not oppose the other terms.

202 (9) Subject to the conditions we outline in paragraphs 78, 85, 99, 112, and 146 of this Order, the Settlement proposes equitable, reasonable, fair, just, and well-balanced resolutions, supported by the record, to all disputed issues: overall revenue requirement; cost of capital; cost of service, rate spread, and rate design; the Residual Tax Customer Credit; Colstrip investments, tracker, and Tariff Schedule 99; power costs; the insurance expense balancing account; the escalation study; capital planning; distributional equity analysis; capital projects review; natural gas transition issues; transportation electrification; performance-based ratemaking; low-income issues; the CCA; small business energy efficiency; electric service reliability report plan; depreciation rates and regulatory amortizations; annual filing dates; annual reporting obligations of Docket U-210151; software licensing; decoupling earnings test; and wildfire issues including the wildfire expense balancing account.

203 (10) Avista's currently effective electric and natural gas rates do not provide sufficient revenue to recover the costs of its operations.

204 (11) The performance measures outlined in paragraph 191 and their related reporting requirements are fair, reasonable, consistent with applicable law, in the public interest, and will provide necessary information to allow the Commission to evaluate Avista's operations during the MYRP.

CONCLUSIONS OF LAW

Having discussed above all matters material to this decision, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

205 (1) The Commission has jurisdiction over the subject matter of, and parties to, this proceeding.

206 (2) Avista is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction.

207 (3) At any hearing involving a proposed change in a tariff schedule the effect of which would be to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable will be upon the public service company. RCW 80.04.130 (4). The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

208 (4) Avista's existing rates for electric and natural gas service are neither equitable, fair, just, reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

209 (5) Subject to the conditions in paragraphs 78, 85, 99, 112, and 146, the rates, terms, and conditions in the Settlement are equitable, fair, just, reasonable, and sufficient.

210 (6) The Commission should approve the Settlement subject to the conditions in paragraphs 78, 85, 99, 112, and 146, because it is lawful, supported by an appropriate record, consistent with the public interest in light of all the information available to the Commission. The Settlement, subject to conditions, should be incorporated by reference into the body of this Order, as if set forth in full.

211 (7) The Commission is legally obligated by RCW 80.28.425(7) to determine a set of performance measures that will be used to assess Avista's operations under the MYRP.

212 (8) The Commission's determination of a set of performance measures need not be based upon a company's initial filing, the record testimony and evidence, or the proposals made by a company or party throughout the proceeding.[259]

213 (9) The Commission should adopt the performance measures outlined in paragraph 191 and Avista should be authorized and required to make necessary and sufficient future compliance filings in accordance with the directions and conditions of this Order.

214 (10) Avista should be authorized and required to make a compliance filing within 45 days of this Order to provide the measures and calculations outlined in paragraph 191 for the years 2019-2022 (beginning January 1 and ending December 31 of each year).

215 (11) Avista should be authorized and required to make an annual compliance filing to report the performance measures outlined paragraph 191 for each year of the MYRP (beginning January 1 and ending December 31 of each year and within 45 days of the end of the reporting period).

216 (12) Avista should be authorized and required to make a compliance filing by December 14, 2022, and make future compliance filings consistent with the directions and conditions in this Order in these consolidated dockets to recover in prospective rates its revenue deficiency prior to the inclusion of the Residual Tax Customer Credit of approximately $38.0 million for its electric operations in Rate Year 1, $12.5 million for its electric operations in Rate Year 2, $7.5 million for its natural gas operations in Rate Year 1, and $1.5 million for its natural gas operations in Rate Year 2.

217 (13) The Commission should authorize and require Avista to replace the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6), including accruing ROR on the balance of the decoupling deferral, and deferring any earnings greater than 0.5 percent above its authorized ROR, consistent with the Settlement and RCW 80.28.425(6).

218 (14) The Commission should authorize and require all Settling Parties to separately notify the Commission by December 19, 2022, by a letter to the Commission

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[259] *See* RCW 80.28.425(7).

Secretary filed in these consolidated dockets whether each accepts the conditions of approval set by this Order on the settlement stipulation.

219 (15) The Commission Secretary should be authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

220 (16) The Commission should retain jurisdiction over the subject matter and the Parties to effectuate the terms of this Order.

ORDER

THE COMMISSION:

221 (1) Rejects the proposed tariff revisions Avista Corporation d/b/a Avista Utilities filed in these dockets on January 21, 2022, and suspended by prior Commission order.

222 (2) Determines the settlement stipulation is lawful, supported by an appropriate record, and consistent with the public interest and therefore approves it subject to the conditions set by the Commission in paragraphs 78, 85, 99, 112, and 146.

223 (3) Authorizes and requires replacing the existing decoupling earnings test with the earnings test provided in RCW 80.28.425(6), including accruing a rate of return on the balance of the decoupling deferral, and deferring any earnings greater than 0.5 percent above its authorized rate of return, consistent with the settlement stipulation and RCW 80.28.425(6).

224 (4) Authorizes and requires all Settling Parties to separately notify the Commission by December 19, 2022, by a letter to the Commission Secretary filed in these consolidated proceedings whether each accepts the conditions of approval set by this Order on the settlement stipulation.

225 (5) Adopts the performance measures outlined in paragraph 191.

226 (6) Authorizes and requires Avista Corporation d/b/a Avista Utilities to make all compliance filings determined by this Order in these consolidated dockets, including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order as well as including the compliance filing within 45 days of this

Order to provide the measures and calculations outlined in paragraph 191 for the years 2019-2022 (beginning January 1 and ending December 31 of each year).

227 (7) Authorizes the Commission Secretary to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

228 (8) Retains jurisdiction to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective December 12, 2022.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

ANN E. RENDAHL, Commissioner

MILT DOUMIT, Commissioner

APPENDIX A

MULTIPARTY SETTLEMENT STIPULATION

Who Will Pay for Legacy Utility Costs?

Lucas W. Davis, Catherine Hausman

Abstract: The growing "electrify everything" movement aims to reduce carbon dioxide emissions by transitioning households and firms away from natural gas toward electricity. This paper considers what this transition means for the customers who are left behind. Using historical evidence from growing and shrinking US natural gas utilities, we show that utilities add pipelines but rarely remove them, even when the customer base from which to recover costs is shrinking. Correspondingly, we find that utility revenues decrease less than one for one when a customer base is shrinking, consistent with higher bills for remaining customers. We then use our empirical estimates to predict how customer bills might increase in the future for different levels of building electrification. We highlight the equity implications of our results and conclude by discussing alternative utility financing options such as recouping fixed costs through taxes rather than prices.

JEL Codes: L95, L97, Q40, Q48, R11

Keywords: natural monopoly, stranded costs, sunk costs, natural gas, energy utilities, building electrification, inequality, energy transition, energy justice

NATURAL MONOPOLIES TYPICALLY RECOVER FIXED COSTS by spreading fees out over their customer base across time, whether through per-unit fees, per-customer fees, or a combination. In the United States, this is true of privately held utilities, municipally run utilities, and utilities run by other governmental agencies (e.g., federal) across a

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broad range of goods: electricity, natural gas, water, wastewater services, garbage collection, and more. Seldom discussed in the literature is that in times of a shrinking customer base, this approach can lead to difficulties recovering fixed costs; either prices must rise, or costs (such as maintenance of infrastructure) must be cut.

This dynamic is important for understanding the effects of environmental policies that target utilities. In particular, this issue is currently coming to a head with US natural gas utilities due to a growing number of policies aimed at transitioning customers away from natural gas toward electricity.[1] Building electrification has been called “a linchpin solution for decarbonization” (National Academies of Sciences, Engineering, and Medicine 2021), and recent proposals for a transition to carbon neutrality rely on scenarios in which the vast majority of the building stock is transitioned to all electric in a few decades (Larson et al. 2020; National Academies of Sciences, Engineering, and Medicine 2021; Williams et al. 2021).

This paper considers what such a transition would look like for the natural gas customers who are left behind. The current push for building electrification is still in its early stages, so it is too soon for an empirical analysis of how utility behavior responds to this policy push. Instead, we use historical evidence from growing and shrinking utilities. Although mostly driven by reasons other than building electrification, this evidence is nonetheless a valuable opportunity to learn how utilities change their operations and finances when large numbers of customers enter or exit.

First, we demonstrate that both customer base growth and customer base loss are commonplace among US natural gas distribution utilities during our sample period of 1997–2019. We observe, for example, 320 utilities that experienced five or more consecutive years of customer growth, and 250 utilities that experienced five or more consecutive years of customer base decline. Although the total number of natural gas customers in the United States has increased 25% over this time period, many specific regions have lost population, and we show that customer base declines are associated with net migration patterns. For example, Alabama Gas Corp—a large utility serving Birmingham and much of central Alabama—has consistently experienced a shrinking customer base at the same time the city of Birmingham has lost population.

Second, we examine what these customer base changes mean for utility operations. For most natural gas distribution utilities, the pipeline infrastructure is the single largest asset and the single largest fixed cost. We compile annual data on the total number of pipeline miles operated by each utility and test how this responds to changes in the customer base. We find that when utilities are growing, they add pipelines. A 10% increase

1. A number of policies have been introduced to encourage electrification, including municipal bans on natural gas in new construction, electric preferred building codes, and subsidies for heat pumps. These policies are in part motivated by the ongoing decline in emissions from the electricity sector (Holland et al. 2020), which means that transitioning households and firms from natural gas to electricity could significantly reduce environmental damages.

in the number of residential customers leads to a 4% increase in the length of the distribution network. However, when utilities are shrinking, they do not remove pipelines. A 10% decrease in the number of residential customers has a precisely estimated 0% effect on the length of the distribution network. Utilities add pipelines but rarely remove them, even when the customer base from which to recover costs is shrinking.[2]

Third, we test for changes in utility finances. As with pipelines, we find that utility revenues respond asymmetrically to changes in the customer base. New customers lead to one-to-one revenue increases, with a 10% increase in residential customers increasing revenues by 10%. In contrast, customer losses lead to a less than one-to-one decrease in revenue, with a 10% decrease in residential customers decreasing revenues by only about 5%. This pattern implies that remaining customers make up about half of the lost revenue through increased prices. The remaining half may represent cost savings, or it may represent losses to shareholders, an issue we discuss. While previous white papers have pointed to the possibility of bill impacts, we provide the first empirical evidence on the magnitude of these effects using comprehensive data and a quasi-experimental strategy.

These increased bills for remaining customers have significant equity implications. We show that many shrinking utilities in our data serve cities with high rates of poverty and with large African American populations in parts of the Rust Belt and Appalachia and in some rural areas. Looking forward, the current push for building electrification is likely to lead to a very different pattern of customer exit. Nonetheless, in both cases there is a set of remaining customers left facing higher bills, and our results underscore the potential for these impacts to be highly uneven across income levels and racial groups.

We use our empirical estimates to predict how customer bills might increase in the future for different levels of building electrification, absent regulatory changes. We find that bill impacts are modest as small numbers of households transition away from natural gas: for a 20% reduction in residential gas customers, we calculate bill increases of around $40 per year for remaining customers. However, impacts increase nonlinearly as an increasing number of households leave natural gas. For a 40% reduction in customers, we calculate bill increases of $115 per year.

To understand how customer exit could lead to these outcomes, we next examine ancillary data on categories of expenditures for a sample of large US natural gas utilities. We show that a substantial portion of expenditures are fixed costs that, at least in the short run, are unlikely to change as customers leave natural gas service. This includes capital costs (25%), maintenance and operations (10%), and administrative expenses such as pension payments (10%).

Finally, we discuss various alternatives for financing legacy costs. While the norm has been to pay for these costs through monthly bills, we explore, for example, the

2. A similar asymmetry arises with “durable housing” and the idea that it is relatively easy to build more homes as demand increases but that those homes remain even after demand decreases (Glaeser and Gyourko 2005).

possibility of collecting hook-up and exit fees. We also raise the possibility of shifting costs to utility shareholders, across utilities, or to the general tax base. With each alternative we briefly discuss the likely impacts for remaining customers as well as the broader implications for efficiency and equity.

Several features of the natural gas market make it a particularly good setting for such an analysis. First, natural gas distribution is a quintessential natural monopoly, making it an ideal setting for studying what happens to legacy utility costs during market transitions. Second, even relative to other utilities like electricity distribution companies, both the physical pipeline infrastructure and financial data such as revenue are particularly well observed, a product of the highly regulated nature of the industry. We note that the industry is regulated in part precisely because it is a natural monopoly but also because proper maintenance of the distribution network is important for safety and environmental reasons—inadequate maintenance can lead to pipeline explosions and to methane leaks. Finally, natural gas has historically provided important services (heating, cooking, and water heating) to a large portion of US households and firms. As of 2019, natural gas was used in the United States by 70 million households and 6 million commercial establishments, and sales in these two sectors totaled $70 billion.

Our paper contributes to a broader literature on infrastructure investment, fixed cost recovery, and the optimal regulation of natural monopolies. This literature has emphasized a number of regulatory challenges in this environment, including how to create incentive-compatible regulations that allow for cost-minimization without sacrificing infrastructure quality or other goals (Bonbright 1941; Averch and Johnson 1962; Viscusi et al. 2005; McRae 2015). We consider a previously understudied dynamic issue: customer base loss and the recovery of legacy infrastructure costs. While we focus on natural gas in our empirical example, the mechanisms we document are likely to apply to other natural monopolies that recover fixed costs by spreading fees across customers, including water utilities, urban transit, the transition from landlines to wireless, the impact of rooftop solar on electricity distribution, and so forth.[3]

Our paper also contributes to a broader literature on natural gas utilities. Natural gas combustion currently makes up around one-third of total US fossil-fuel related CO_2 emissions (Environmental Protection Agency 2021), and papers exploring how the natural gas sector contributes to climate change include Newell and Raimi (2013), Hausman and Kellogg (2015), Mason et al. (2015), and Marks (2022). Focusing on distribution utilities, Hausman and Muehlenbachs (2019) look at regulatory impacts on the incentives for environmental and safety protection. Natural gas rate design has been explored

3. Cost recovery difficulties associated with customer base changes have been pointed out for water utilities (Beecher et al. 1990; Beecher et al. 1992; Faust et al. 2016; Beecher 2020; Swain et al. 2020); and Galster (2017) makes this connection for population loss and the provision of city services. Gabel and Burns (2012) similarly discuss cost recovery issues in the transition from landlines to wireless and voice-over internet.

by Knittel (2003), Davis and Muehlegger (2010), Borenstein and Davis (2012), Hausman (2019), and Auffhammer and Rubin (2021). Perhaps most closely related is the work on bypass, which examines industrial customer retention (Laffont and Tirole 1990), for instance, at the time of deregulation of wholesale natural gas prices.[4]

Our paper speaks directly to policy issues around building electrification. Davis (2021) empirically examines the customer decision making around home heating technologies, calculating willingness to pay to avoid an all-electric transition. A number of white papers have examined costs and benefits of building electrification in California (Bilich et al. 2019; Greenlining Institute 2019; Gridworks 2019; Mahone et al. 2019; Aas et al. 2020). But we are not aware of any statistical analysis applying to the broader United States.

Our work also speaks to questions of the incidence of environmental policies, an issue explored at depth in Bento (2013) and Fullerton and Muehlegger (2019). In particular, our analysis is related to a recent and growing literature on equity issues in energy transitions. This is crucial for analyzing climate policies, including how to best structure them and who will be the winners and losers of the policies. For instance, Van der Ploeg and Rezai (2020) discuss how an unanticipated transition could result in billions of dollars in stranded assets in fossil fuel industries.

Most closely related in this vein is the work examining how rooftop solar can push fixed cost recovery onto low-income customers (Burger 2019; Borenstein et al. 2021)—this is a function of high mark-ups in high-solar penetration areas like California. In contrast, the mechanism in our paper is a function of customer losses, which applies even when fixed costs are recovered through fixed fees. Thus the standard rate reforms that are frequently suggested for rooftop solar would still lead to fixed cost recovery issues and equity challenges in our setting. A similar mechanism could apply to the electricity sector in future scenarios with so-called "grid defection," in which the installation of storage along with the rooftop solar allows a customer to disconnect from an electric utility altogether (Gorman et al. 2020). More broadly, the equity issues we document may interact with preexisting equity issues in residential energy markets (Reames 2016; Carley and Konisky 2020; Lyubich 2020).

Finally, our results on economic and racial inequities also contribute to the literature on rural depopulation (Johnson and Lichter 2019) and on shrinking cities (Beauregard 2009), where a combination of economic forces and racial antagonism has been identified

4. Relatedly, studies of electricity market deregulation have emphasized the crucial role played by stranded costs, i.e., utility investments which would be unrecoverable in a deregulated market. White (1996, 242) argues that "this stranded cost problem is by far the most controversial aspect of regulatory reform in the electric power industry." Borenstein and Bushnell (2015, 443) argue that US electricity market deregulation was motivated largely by "an opportunity to shift responsibility for paying the sunk costs of what were considered uneconomic stranded assets." Although the catalyst is quite different (deregulation vs. energy transition), the economics of these fixed, mostly sunk costs is similar to the legacy costs that would be borne in a transition away from natural gas.

(Boustan 2010; Galster 2017). We empirically show that these broad migration patterns in the United States can directly impact the ability of utilities to provide the basic services that households require. While we focus on natural gas, similar mechanisms are expected in water and other utility services.

1. DATA

1.1. Data Sources

Our empirical analysis takes advantage of the unusually rich data available for the US natural gas distribution sector. The highly regulated nature of this sector means that detailed information is available from multiple government agencies, including the Department of Energy and the Department of Transportation. We are able to observe key aspects relating to both physical infrastructure and to the utilities' financials, including sales, revenues, and prices.

Our core data set is an annual panel describing essentially the universe of US natural gas distribution utilities for the years 1997–2019. Most of this information comes from an annual census of natural gas distribution utilities conducted by the US Department of Energy's Energy Information Administration (EIA).

This EIA-176 data set reports customer count, volume sold, and revenue collected by end-user sector (e.g., residential vs. commercial).[5] These data also report the utility's ownership structure (investor-owned, municipal, etc.).[6] For utilities that operate across multiple states, there is a separate entry for each state's operations. From EIA, we also observe average citygate prices at the state level, that is the average price (in dollars per thousand cubic feet [mcf]) paid by utilities in that state when purchasing natural gas. We deflate all revenue and prices by the annual consumer price index from the Federal Reserve Economic Data (FRED), reporting all dollar amounts in 2019 dollars.

One of our primary outcome variables is "net revenue," which we calculate by taking total utility revenue and subtracting off the portion of revenue that is collected to pay for purchasing natural gas. These additional revenues are collected to pay for pipeline investments, maintenance and operations, administrative salaries, and other costs. Whereas natural gas purchases can be easily adjusted upward and downward in response to changes in customer counts and fluctuating consumption levels, this net revenue stream is how the utility pays for fixed costs. Focusing on net revenue means that throughout the analysis we

5. Our analysis throughout ignores industrial customers, as they make up a very small fraction of total customers and because there is too little change in the number of industrial customers to support an empirical analysis.

6. We simplify the designations somewhat by combining some categories. For instance, we combine "investor-owned utilities" and "privately owned utilities," regardless of whether they are, for instance, publicly traded. We also group into the "municipal" category some rural cooperatives and a few other kinds of government-run agencies such as county-run utilities. See the appendix for details.

are able to largely ignore variation in natural gas commodity prices, weather, macroeconomic shocks, and other factors that lead to short-run fluctuations in utility total revenue.

Our other key data source is an annual utility-level census (1997–2019) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation. Natural gas distribution utilities are required under federal law to submit annual reports to PHMSA. This information is used by PHMSA and other government agencies to enforce pipeline safety regulations, track and investigate incidents, and plan inspections. Utilities are required to submit separate reports for each state in which they operate.

The primary variable we use from this data set is the total "distribution main mileage" per utility per year. Distribution mains are the pipelines that carry natural gas under city streets. To merge the EIA and PHMSA data, we use a fuzzy string match on utility names and an exact match on the state within which the utility operates. We are able to match 83% of the EIA observations to PHMSA data (representing 87% of residential customers). See the appendix (available online) for details.

Finally, we collect weather data from the National Oceanic and Atmospheric Administration (NOAA), specifically annual heating and cooling degree days at the state level.

1.2. Summary Statistics

Table 1 provides summary statistics. Our sample consists of an unbalanced panel with around 1,300 utilities per year. Of these, around one-quarter are investor-owned utilities and three-quarters municipal utilities. The summary statistics reveal the tremendous variation in utility size, including substantial skew. The mean number of residential customers is 41,000, but the median number is 1,000. This skewness reflects the fact that there are many small municipally operated natural gas utilities, as well as a much smaller number of large investor-owned utilities like Southern California Gas Company, which serves nearly six million households.

Our main specification limits the sample in a few ways to reduce measurement error. First, we focus on utilities for which at least 90% of residential customers are "bundled," rather than "retail choice." Fewer than 2% of utilities are dropped because of this exclusion. Second, we assign new utility identification numbers when we observe an annual residential customer change of more than 20 log points or a commercial change of more than 50 log points. These large changes likely indicate service territory adjustments, mergers, or acquisitions rather than true customer growth or loss. In specifications using differences, this assignment of a new identification number drops the year with the large change but keeps subsequent years. Third, we drop a small number of extreme outliers for the other variables, which we attribute to clerical errors and other reporting mistakes. See the appendix for details.

Finally, in our regression analysis we focus on utility-years that are part of at least a two-year period of sustained growth or loss. That is, we drop observations where a utility grows in one year, shrinks in the next, and so forth. We do this for two reasons.

Table 1. Summary Statistics

	N	Mean	Median	SD	Min	Max
Residential:						
Customers, '000s	29,392	41.31	1.07	229.60	.00	5,607.69
Bundled customers, proportion	29,392	1.00	1.00	.01	.90	1.00
Dummy, customer base growing	27,671	.51	1.00	.50	.00	1.00
Sales, bcf	29,388	2.91	.06	14.58	.00	277.72
Average price, $/mcf	29,382	13.56	12.95	5.41	.58	445.40
Revenue, '000,000s	28,977	27.54	.72	129.95	.00	3,515.88
Net revenue, '000,000s	28,644	17.44	.37	86.02	.00	2,101.42
Per customer, '000s	28,630	.37	.35	.19	.00	3.40
Per mcf	28,641	6.99	6.27	4.02	.00	52.48
Citygate price, $/mcf	29,392	6.77	6.13	2.53	2.03	36.07
Miles of pipeline, '000s	24,452	.77	.06	3.07	.00	51.25
= 1 if investor-owned utility	29,392	.24	.00	.43	.00	1.00
= 1 if municipal utility	29,392	.76	1.00	.43	.00	1.00

Note. This table provides summary statistics for our main estimation sample, an unbalanced panel covering the period 1997–2019, with approximately 1,300 natural gas distribution utilities per year. The sample excludes a small number of utilities for which more than 10% of customers buy natural gas from a retail choice provider. There are fewer observations for the "Dummy, customer base growing" variable because it cannot be calculated for the first year a utility appears in the sample. There are fewer observations for the "Miles of pipeline" variable because of imperfect matches across data sources. Commercial customer summary statistics are in the appendix. bcf = billion cubic feet; mcf = thousand cubic feet.

First, for our thought experiment of a utility losing customers because of electrification, we are interested in sustained patterns of loss. Second, if the miles and customer counts are measured at different times in a year, the year-on-year changes may not match up in time. This would be most concerning if a utility grows in one part of a year but shrinks in another part of the year. In the appendix, we show results relaxing this and each of the other sample selection criteria.

2. GROWING AND SHRINKING UTILITIES

We are interested in how utility operations and infrastructure investments respond to changes in the size of the customer base. Of course, historical evidence of these patterns is only valuable to the degree that utilities actually experience meaningful changes in the customer base. In this section, we describe the patterns of customer base growth and loss over the past two decades. Absent from most policy discussions about the energy transition is ex post evidence on how utilities have historically managed customer base loss. We show that such experiences are commonplace, and we argue that important lessons can be drawn from these utilities.

2.1. Preliminary Graphical Evidence

Figure 1 plots residential customer counts over time for a random 4% of utilities. We normalize each utility's count to 1 at the beginning of the sample. As illustrated by the figure, there are widely differing experiences across utilities. Even though the US population is growing, a substantial portion of utilities lose customers over this 22-year period. There are many utilities that grow by 20% or more, but also many utilities that shrink by 20% or more.

The figure also reveals considerable persistence in both growth and loss. Recall that table 1 shows that about half of all utility-year observations involve customer base loss; figure 1 illustrates that this is not due to one-year "blips." For example, we observe around 320 utilities that experience five or more consecutive years of customer base growth but also around 250 utilities that experience five or more consecutive years of customer base loss.

2.2. Compositional Patterns

To better understand the patterns driving these periods of growth and loss, we summarize in table 2 the "proportion growing" variable across different utility types. Investor-owned

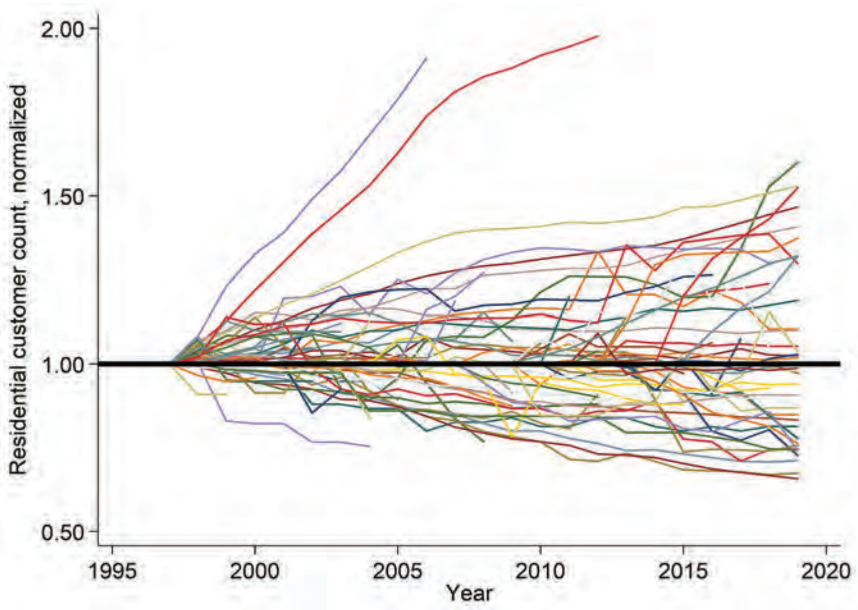

Figure 1. We observe growing and shrinking utilities. This figure shows residential customer counts for a random 4% sample of utilities, normalized to 1 in their first year. Large changes have been assigned a new utility ID to account for the possibility of mergers and acquisitions. The graph has been zoomed in to a maximum of 2.0 on the y-axis; the two utilities with the largest growth continued on an upward trend (not shown).

Table 2. What Types of Utilities Are Growing?

	N	Proportion with Residential Growth
All utility-years	24,543	.52
By ownership type:		
Investor-owned utilities	6,094	.71
Municipally owned utilities	18,449	.46
By number of residential customers in first year:		
1 million or more	156	.92
100,000–1 million	1,811	.82
10,000–100,000	2,695	.75
1,000–10,000	8,710	.56
100–1,000	10,678	.39
1–100	493	.31
By time period:		
1997–2007	10,921	.54
2008–19	13,622	.51
By geographic region:		
New England (CT, MA, ME, NH, RI, VT)	504	.89
Pacific (CA, OR, WA)	465	.83
Mountain (AZ, CO, ID, MT, NM, NV, UT, WY)	1,230	.74
Middle Atlantic (NJ, NY, PA)	642	.70
East North Central (IL, IN, MI, OH, WI)	3,134	.55
West North Central (IA, KS, MN, MO, ND, NE, SD)	4,541	.54
East South Central (AL, KY, MS, TN)	5,483	.53
South Atlantic (DC, DE, FL, GA, MD, NC, SC, VA, WV)	3,640	.48
West South Central (AR, LA, OK, TX)	4,904	.37

Note. This table describes our main estimation sample, classifying observations along several different dimensions. For each subset of the sample, the table reports the total number of utility-year observations as well as the proportion of utility-year observations for which the residential customer base grew.

utilities are more likely to be growing than are municipal utilities, but even for investor-owned utilities more than one-quarter of utility-year observations are not growing. The high loss portion in municipally owned utilities is likely related to rural depopulation in the United States, discussed further below.

In addition, we find that medium and large utilities tend to be growing, while small utilities tend to be shrinking. For these statistics we measure the number of residential customers during the first year the utility appears in our sample. The proportion of all utility-year observations growing is monotonic across size categories, ranging from 92% for very large utilities to 31% for very small utilities.

Finally, we see a clear geographic pattern. The regions with the most customer growth include New England and the West ("Pacific" in the census region nomenclature), with over 80% growth in each. The regions with the most customer loss include the South Atlantic and the Gulf Coast/Oklahoma/Texas area ("West South Central" in the census region nomenclature). These geographic differences are difficult to interpret by themselves, because different regions have different utility sizes and different utility ownership patterns, for historical reasons. As such, we next analyze these regional differences separately for investor-owned utilities and municipal utilities.

2.3. Additional Geographic Evidence

In figure 2, we provide two maps aimed at better understanding the geographic pattern. We plot, at the state level, the proportion of utility-year observations with residential customer growth for investor-owned utilities (fig. 2*A*) versus municipal utilities (fig. 2*B*). The high proportion of growth in New England reflects that the region is served only by investor-owned utilities and not by any municipal utilities. In contrast, the high proportion of growth in the Pacific region is seen in both the investor-owned and municipal utility maps.

These maps suggest that customer base changes are somewhat correlated with regional population changes. Western states such as New Mexico, Washington, Utah, Nevada, and Idaho experienced growth at all investor-owned utilities in all years. Notably, all of these states also experienced substantial population growth over the 1997–2019 time period, with Nevada, Arizona, and Utah experiencing the largest population growth rates in the country. In contrast, West Virginia lost population over this time period, and southern states like Mississippi and Louisiana had fairly slow population growth rates compared to much of the country.

To corroborate this pattern, we merged population estimates from the US Census Bureau with the geographic boundaries of US natural gas distribution utilities as of 2017.[7] This exercise is imperfect because it fails to capture changes in service territory boundaries over time and because overlapping service territory boundaries and other issues introduce measurement error. Nevertheless, we are able to show using these merged data that population changes are highly correlated with changes in residential customer counts, particularly for larger utilities. Although there are many factors driving residential customer counts, it seems clear that population changes are the primary driver. See table A3 (tables A1–A11 are available online).

2.4. Anecdotal Evidence from Selected Utilities

The correlation between customer count changes and population changes matches anecdotes from several utilities. In a rate case filing for DTE—a large utility serving Detroit and southeast Michigan—one analyst testified that "the poor local economic

7. Details are in the appendix.

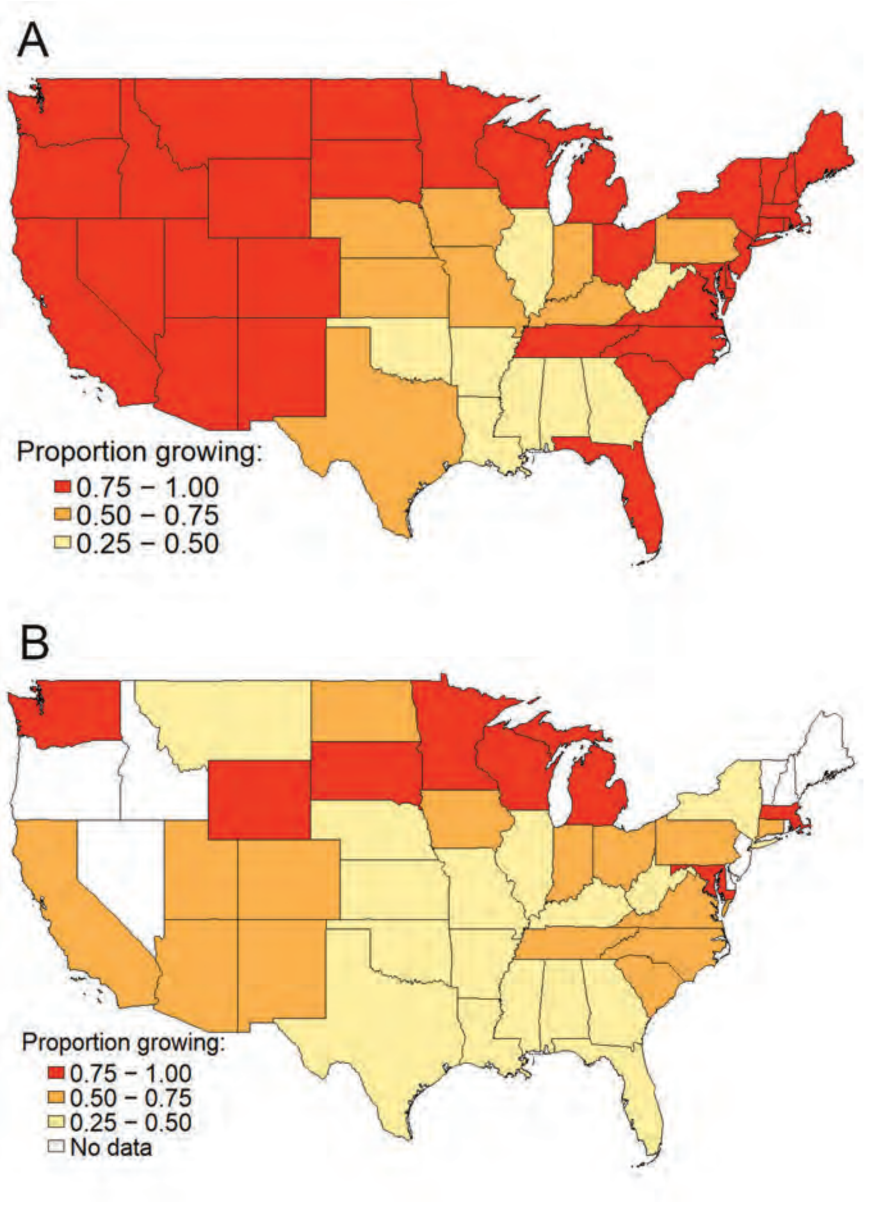

Figure 2. Regional patterns in residential customer base changes. These maps show by state the proportion of utility-year observations with residential customer growth separately for investor-owned (*A*) and municipally owned (*B*) utilities. White states in panel *B* do not have any municipal utilities.

conditions in DTE Gas's service territory as well as declining population exacerbate the effect of declining sales in increasing the downside risk that DTE Gas may not be able to fully recover its fixed costs."[8] National Fuel, serving upstate New York and parts of Pennsylvania (such as Pittsburgh) similarly argued that "it grapples with a declining population and a weak economy in its service territory" (Robinson 2001). A rate case for Centerpoint Arkla (Arkansas) discusses related challenges, with a growing number of pipeline miles but a decreasing number of customers: "declining revenues and increasing costs make it difficult, if not impossible, for the Company to recover its cost of service."[9]

An especially compelling case study is that of Philadelphia Gas Works, the largest municipally owned gas distribution utility in the country. A white paper details the financial struggles, noting: "The challenging demographics of PGW's customer base are a byproduct of Philadelphia's shrinking population and high concentration of poverty. The City has lost nearly 30% of its population over the past half-century." The report goes on to note implications for prices that we discuss further below: "with a declining customer base characterized by a high concentration of poverty, the need for additional price increases to cover fixed expenses seems inevitable" (Economy League of Greater Philadelphia 2008).

Municipal utilities tend to serve rural populations, and as such their customer base loss (with the exception of some urban utilities like Philadelphia Gas Works) may reflect rural depopulation. For this utility type, Cairo Public Utility Co. of Illinois provides a clear case study. A series of news articles from 2017 summarizes the financial challenges facing this rural utility and the high bills facing its customers. As one of the articles notes, "[utility administrators] said that part of the issue with Cairo Public Utility Co. is that they are managing a system that was originally built for 20,000 people, and today Cairo is home to only about 2,500" (Smith 2017).

In contrast to these anecdotes from rural areas, the Rust Belt, and parts of the Southeast, utilities in the Southwest and the West note a very different experience. For instance, the annual report for Southwest Gas (serving Arizona, Nevada, and California), notes, "Southwest Gas remains among the top utilities for customer growth with 26,000 net new customer additions in 2015. This is due in part to a growing economic recovery across Southwest Gas service territories," going on to describe how projected population growth rates in its major metro areas are much higher than for the United States as a whole.[10]

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8. LARA Filing U-17999-0002, December 18, 2015, DTE Energy Company, Testimony, case no. U-17999. https://mi-psc.force.com/s/filing/a00t0000005pl9SAAQ/u179990002 (accessed May 18, 2021).

9. Docket no. 04-121-U, filed December 3, 2004. http://www.apscservices.info/pdf/04/04-121-u_35_1.pdf (accessed February 2, 2021).

10. Southwest Gas 2015 Annual Report. https://www.swgas.com/www/flipbooks/Swgas_Annual_Report_2015/mobile/index.html#p=2 (accessed May 18, 2021).

Similarly, Questar Gas's annual report notes, "The population of the Company's service area in Utah continues to grow faster than the national average."[11]

Overall, the main takeaway is that many US natural gas utilities have faced years of customer base loss. This is especially true of small utilities and of municipal utilities, and a major factor appears to be population changes. The experience of these utilities might be informative as policies seek to transition building energy use from natural gas to electricity. We next turn to an empirical examination of utility operations and finances.

3. RESULTS

3.1. Pipelines

We begin by examining the relationship between the physical pipeline network and the number of customers. Figure 3 plots the relationship between the log change in pipeline miles and the log change in residential customer counts. The figure also shows a histogram of log residential customer count changes—matching the summary statistics in table 2, the histogram shows that roughly half of residential customer changes are positive and half are negative.[12]

A clear positive relationship emerges in figure 3. As utilities grow, they add pipelines. However, a clear asymmetry is also visible. In addition to the scatterplot (with markers sized by initial utility size), we overlay a lowess smoother. Importantly, this lowess smoother does not impose any asymmetry—but one emerges naturally. With growth in the residential count, that is, on the right-hand side of the plot, there is an upward-sloping, nearly linear fit between the log growth in miles and the log growth in residential customers. With loss in the customer count, that is, on the left-hand side of the plot, there is essentially no change in the log mile count. There is a slight upward tick on the far left side of the plot, but there are almost no observations in that region, as shown in the histogram along the bottom. In contrast, there is a substantial mass of observations closer to the origin, that is, at around zero to five log points of loss. Typically when a utility loses a small percentage of customers, it experiences no change in its pipeline miles.

We next formalize this intuition with two sets of regressions. First, we regress the log change in pipeline miles on the log change in residential and commercial customer counts. The regression takes the form:

$$\Delta \ln M_{i,t} = \alpha + \beta \Delta \ln R_{i,t} + \gamma \Delta \ln C_{i,t} + \varepsilon_{i,t}, \tag{1}$$

11. Questar Gas 1999 Annual Report. https://www.sec.gov/Archives/edgar/data/68589/0000068589-99-000002.txt (accessed May 18, 2021).

12. In the appendix, we show a histogram for the change in log miles. Five percent of observations involve a reduction in log miles from one year to the next; these observations have a median log change of –0.006.

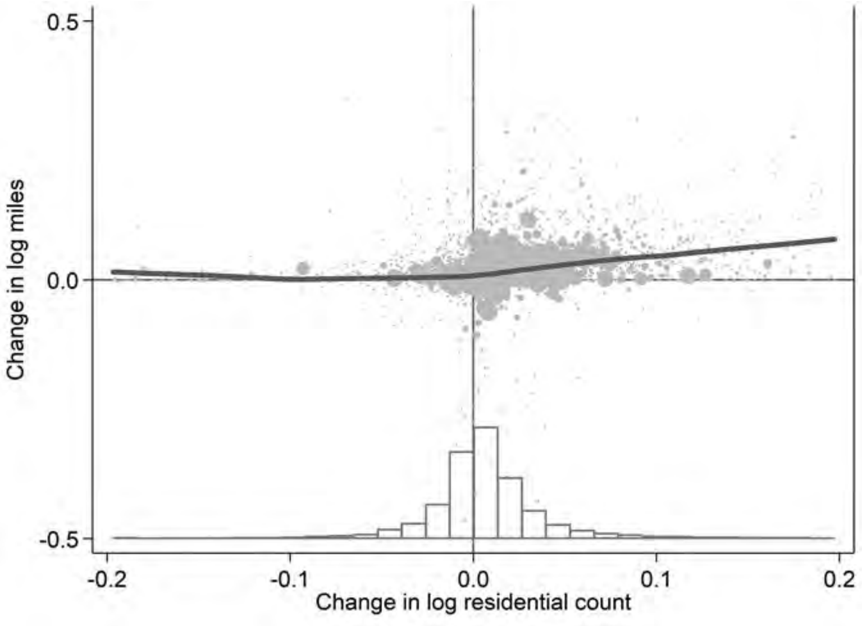

Figure 3. The asymmetric relationship between pipelines and customers. The thick dark line shows a lowess fit. The lowess has been fit to the full estimation sample, but the scatterplot is zoomed in to [−0.5, 0.5] on the *y*-axis to make the lowess slope more visible. A histogram for changes in residential counts is included at the bottom of the figure. Color version available as an online enhancement.

where $M_{i,t}$ is the miles of pipeline mains at utility i in year t, $R_{i,t}$ is the count of residential customers, and $C_{i,t}$ is the count of commercial customers. Standard errors are clustered by utility to account for serial correlation.

We use logs to ease comparisons across large and small utilities. We use differencing because we are interested in what happens as utilities grow or shrink, rather than in cross-sectional differences between large and small utilities. One could instead use fixed effects, which we show in the appendix. In our baseline specification, we do not use any controls, as we do not expect there to be factors that require a utility to grow its pipeline network other than the growth of its customer base, but we examine specifications with additional controls in the appendix.

Table 3, column 1, shows the estimation results for equation (1). A 10% increase in the residential customer count is associated with a roughly 2.5% increase in pipeline miles, statistically significant at the 1% level. A 10% increase in the commercial customer count is associated with a 0.3% increase in pipeline miles, statistically significant at the 1% level. The magnitude difference between the residential and commercial estimates is intuitive: as shown in the appendix, the typical utility has 10 times as many residential

Table 3. The Impact of Customer Base Changes on Pipeline Infrastructure

	Pipeline Miles (log) (1)	Pipeline Miles (log) (2)
Residential customers (log)	.249***	
	(.023)	
Commercial customers (log)	.034***	
	(.011)	
Residential customers (log), when growing		.385***
		(.037)
Residential customers (log), when shrinking		−.001
		(.039)
Commercial customers (log), when growing		.028
		(.020)
Commercial customers (log), when shrinking		−.007
		(.016)
Constant	.011***	.003***
	(.000)	(.001)
Observations	9,538	9,538
R^2	.04	.06
Miles per 100 residential customers	1.09	
When growing		1.68
When shrinking		−.01
p-value: null of symmetry:		
Residential		.00
Commercial		.18
Combined		.00

Note. This table shows point estimates and standard errors corresponding to two separate least squares regressions. In both columns the dependent variable is the total number of miles of pipeline mains in logs. The regressions are estimated in differences. The *p*-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The “miles per 100 customers” rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample includes annual observations from 1997 to 2019, with around 400 utilities per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they likely indicate service territory changes. The sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the appendix. Standard errors are clustered by utility.

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant a the 1% level.

customers as commercial customers, so a 1% change in residential customers is a much larger change in customers than is a 1% change in commercial customers. This can be seen by looking at level effects of the estimates at the median values. The elasticity of 0.25 for residential customers translates into 1.1 miles for every 100 residential customers, as shown at the bottom of the table. The elasticity of 0.03 for commercial customers translates into 1.3 miles for every 100 commercial customers (not shown, for space).

3.2. Asymmetric Impacts

The first regression results, however, mask important differences between periods of customer base growth and loss. Once a pipeline is built, a utility is unlikely to remove it or to stop selling gas via it. This is particularly true if customer base loss is geographically dispersed, for instance, if driven by urban vacancy rates.

We next estimate an asymmetric specification, allowing for differential impacts of customer growth and loss:

$$\Delta M_{i,t} = \alpha + \sum_{s\in R,C} \beta_s^{+} (\Delta N_{i,t}^{s})^{+} + \sum_{s\in R,C} \beta_s (\Delta N_{i,t}^{s}) + \sum_{s\in R,C} \eta_s \mathbf{1}(\Delta N_{i,t}^{s})^{+} + \varepsilon_{i,t}. \qquad (2)$$

For the sake of brevity, we omit "ln" in the equation above but all variables are in logs as in equation (1). The dependent variable $\Delta M_{i,t}$ is again the log change in pipeline miles for utility i in year t. The coefficient β_s^{+} is the impact of the log change in customer counts for sector s (residential or commercial) at utility i ($\Delta N_{i,t}^{s}$) when the log change is strictly positive, and β_s is the impact when the log change is weakly negative. Because $(\Delta N_{i,t}^{s})^{+}$ is an interaction term between the log change in customer counts $\Delta N_{i,t}^{s}$ and an indicator for whether that change is positive, we also include this indicator on its own: $\mathbf{1}(\Delta N_{i,t}^{s})^{+}$. We expect the coefficient on this indicator to be close to zero, as we do not expect a differential change in miles for utilities with very slightly positive versus very slightly negative customer count changes.

Results are presented in the second column of table 3. In keeping with figure 3, this specification shows statistically and economically significant asymmetry in the impact of a changing customer base on pipeline infrastructure. A 10% increase in the number of residential customers is associated with a 3.9% increase in pipeline length. This coefficient is precisely estimated, and statistically different from 0.25, the coefficient in column 1. In contrast, for decreases in the number of residential customers, the typical utility sees essentially no decrease in the number of miles; the coefficient is −0.001 and is not statistically different from zero. As shown at the bottom of the table, symmetry can be rejected at the 1% level for the residential specification. As in the symmetric specification, the coefficient for commercial count growth is fairly small, and again, there is essentially no response for commercial loss.

The evidence in table 3 implies less than one-for-one pipeline growth in response to residential customer increases. This is somewhat surprising. However, there are several likely explanations. First, residential customers do not make up all of the utility network; one must also consider commercial customers. That is, when a utility grows its residential customer base by 1%, it is not growing its entire customer base by 1%. So, a test of the linear combination across sectors is a more appropriate comparison. Second, some of the time when utilities are growing, they are adding customers to existing neighborhoods and therefore not constructing new pipelines. Finally, there may be differences in the timing of when utilities measure the addition of new pipelines versus the addition of new customers (e.g., year-end vs. mid-year). In the appendix, we consider long-run estimates that address these latter two potential explanations, using an error correction model. The long-run results again show an asymmetry, with a larger coefficient when growing (0.65) and a near-zero coefficient when shrinking.

Finally, it is worth noting that the constant is positive and statistically significant in both columns. The positive constant implies that even a utility with flat residential and commercial counts tends to see a modest increase in pipeline miles. This is consistent with some churn within the service territory, for instance, if urban customers leave the city center to move to new suburban developments within the same utility's service territory.

3.3. Finances

We next perform a similar analysis using data on utility revenues. Utilities collect revenue from customers to pay for capital and operating costs, and we want to understand how these revenues respond to changes in the customer base. Part of our motivation for the paper is that many categories of utility expenditures are likely to be "legacy costs" that do not necessarily disappear as customers leave the system.

We use regression specifications very similar to the specifications used for pipeline miles. Specifically, we regress net revenue (total revenue collected minus gas costs, as described above) on customer counts. We begin with a symmetric specification, as in equation (1) and then proceed to an asymmetric specification, as in equation (2). As with the pipeline analysis, we drop large changes in customer counts that likely indicate mergers, acquisitions, and so forth.

These specifications differ from the estimation with pipeline miles in a few ways. First, our sample size is larger, as we can now include the utilities for which we were unable to merge the EIA data on customer counts and revenues with the PHMSA data on pipeline miles. Second, because we observe net revenue separately for the residential and commercial sectors (whereas we only observed combined miles), we can now estimate separate regressions by sector.

These regressions are designed to ask, "If the customer base grows or shrinks, while weather remains unchanged and while the quantity sold to the typical customer remains unchanged, what happens to a utility's revenue net of gas costs?" Accordingly, we introduce three new control variables. We include the log change in quantity sold per customer (also in differences). Utility net revenues are directly impacted by changes in quantity, as the typical utility includes a substantial per-unit mark-up to cover fixed costs. As a result, exogenous changes in quantity consumed per customer as a result of weather changes or economic shocks can substantially change net revenues. In addition, we include weather, both heating degree days and cooling degree days (also in differences). Together, this quantity sold variable and the two weather variables assist in two ways. First, they reduce noise in the net revenue variable and thus improve the precision of our estimates. Second, it is possible that new customers and departing customers have different consumption patterns. Thus growing or shrinking the customer base could change the average quantity sold and thus net revenues. By controlling for quantity sold per customer, our primary specification purges our estimates of the customer base impact of this effect on average.

Results are shown in table 4 (for brevity, we display only the coefficients on customer counts; point estimates on the control variables are shown in table A6). The first column shows that a 10% change in residential customers is associated with a roughly 6.5% change in residential net revenue. The estimate in column 2 is slightly higher for commercial. These estimates translate into roughly $200 of net revenue per residential customer and $1,000 per commercial customer.

Table 4. The Impact of Customer Base Changes on Net Revenue

	Residential Net Revenue (1)	Commercial Net Revenue (2)	Residential Net Revenue (3)	Commercial Net Revenue (4)
Customers (log)	.65***	.75***		
	(.09)	(.06)		
Customers (log), when growing			1.01***	.86***
			(.13)	(.10)
Customers (log), when shrinking			.47**	.77***
			(.20)	(.11)
Constant	.00*	.00*	.00	.01**
	(.00)	(.00)	(.01)	(.01)
Observations	14,437	14,017	14,437	14,017
R^2	.02	.08	.02	.08
Dollars per customer	211	988		
When growing			328	1,137
When shrinking			152	1,015
p-value: null of symmetry			.02	.53

Note. This table reports point estimates and standard errors corresponding to four separate least squares regressions. The dependent variable in cols. 1 and 3 is net revenue from the residential sector, in logs. The dependent variable in cols. 2 and 4 is net revenue from the commercial sector, in logs. The regressions are estimated in differences. The p-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The "dollars per customer" rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample includes annual observations from 1997 to 2019, with around 600 utilities per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they may indicate service territory changes. The sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the appendix. Standard errors are clustered by utility.

* Significant at the 10% level.

** Significant at the 5% level.

*** Significant a the 1% level.

Columns 3 and 4, however, show marked asymmetry, particularly for residential customers. Although the point estimates suggest less asymmetry for commercial customers, the standard errors are wide enough that we are hesitant to draw strong distinctions between customer classes. A utility that adds 10% more residential customers increases its net revenue by 10%, an elasticity of one. This translates into $328 per customer (as shown at the bottom of the table), roughly matching the median net revenue per customer in our sample (table 1). This is intuitive if utilities do not change their pricing structure when they are growing, so that new customers translate directly into new revenues.

In contrast, a utility that experiences a 10% decrease in residential customers decreases its net revenue by only 5%. It is intuitive that this is not equal to zero (and is statistically different from zero at the 5% level), since costs may fall when a customer departs. These may represent falling costs of service provision (e.g., meter reading becomes easier with fewer customers), or they may represent decreased returns to investors, as we discuss below.

However, it is also important to note that the growing and shrinking estimates are statistically different from one another at the 5% level, as shown in the bottom row of the table. In level terms, losing one customer translates into a revenue decrease of $152, whereas gaining one customer translates into a revenue increase of $328. That is, utilities with shrinking customer bases do not experience shrinking revenues at a one-for-one rate. This asymmetry is interesting and important because it indicates that utility shareholders are not bearing the full brunt of legacy costs. With shrinking utilities, it appears that ratepayers are bearing a large share of these costs—consistent with utilities raising prices to increase total revenue collection per customer for those customers who continue to receive natural gas service.

A hypothetical numerical example is helpful. Suppose a utility initially has 10,000 customers and collects $300 per customer each year, so that its net revenue is $3 million. It then loses 5% of its residential customer base, that is 500 customers. If prices do not change, net revenue would be $2.85 million. But according to the estimates in table 4, the utility's residential net revenue would decrease by 2.5%, leaving it with a net revenue of $2.925 million. This translates into $308 per customer—prices for the remaining customers have risen by about 2.5%. We further explore this under future potential scenarios below.

3.4. Robustness Checks and Additional Specifications

In the appendix, we show a large number of robustness checks and additional specifications, ultimately concluding that our results on the impacts of a changing customer base on pipeline miles and on net revenue collected are robust.

Results for the impact of customer base changes on pipeline miles are shown in table A4. We include utilities with a large fraction of retail choice customers; this adds around 300 observations but essentially does not change the point estimates. We next include large year-on-year customer changes that likely indicate mergers, acquisitions, and so forth.

We next include one-year periods of growth or loss. This has the greatest impact on our observation count of any robustness check—in the raw data, many utility-year observations are one-year blips in either customer growth or customer loss. This is especially true because we drop the observations that experience such a blip in either the residential or the commercial sector. The robustness check that includes these one-year periods yields qualitatively similar coefficients and conclusions. Most importantly, the asymmetry we see in customer growth or loss is still notable in this robustness check. The coefficient on residential customer growth is somewhat smaller, which is intuitive if pipeline miles do not need to grow in response to one-year blips that do not represent sustained customer growth.

We include utilities with small mile counts, which somewhat attenuates the coefficient on growing miles but does not change our conclusions about asymmetry.[13] We next include large changes in miles that may indicate measurement error. Alternatively, we use a more stringent definition of outliers in this variable.

We next limit the sample just to investor-owned utilities, dropping municipal utilities. Alternatively, we limit the sample to medium and large utilities, that is, those with at least 10,000 residential customers in every year. Next we include the additional weather and quantity-per-customer controls that we include in the net revenue specifications. Next we add either year effects or fixed effects, while still estimating the regression in differences.

Across all of these additional specifications, we continue to find an asymmetric impact of customer base changes on miles. The estimates for residential customer growth are all qualitatively similar, and all specifications have comparable statistical significance. The impact of customer loss is generally close to zero. The one exception is the specification that limits the sample to investor-owned utilities. For that specification, we are unable to precisely estimate the impact of residential customer loss because, as we show in table 2, most investor-owned utilities are growing over our sample period.

We similarly estimate several additional specifications for the net revenue variable, concluding that our main results are robust (tables A7, A8). We estimate regressions using alternative samples as we did for the miles specification (e.g., including retail choice, limiting to investor-owned utilities, etc.). In addition, we include a specification that has both residential and commercial counts on the right-hand side, a specification with an alternative net revenue measurement, and a specification that limits the sample to just those utilities for which we observe pipeline miles. Across this broad suite of robustness checks, we continue to estimate a coefficient close to 1 when residential customer count is growing and a coefficient of around 0.5 when the residential customer count is shrinking. As with the miles specification, we lose power on the shrinking coefficient when we limit to investor-owned utilities; we also lose power when we limit to large utilities or when we add fixed effects (akin, in this differences specification, to

13. This is explored in greater depth in table A5.

utility-specific trends). Commercial results are similarly robust across these additional specifications.

To summarize, we show that growing utilities add new pipeline infrastructure, but utilities with shrinking customer bases continue to maintain the same amount of legacy pipeline infrastructure. In keeping with this, utility revenues rise (with an elasticity of one) when the customer base grows but shrink by a smaller amount when the customer base shrinks. That is, prices for remaining customers rise. We next turn to a discussion of the implications for equity across customers as well as an examination of utility expenditures.

4. DISCUSSION AND POLICY IMPLICATIONS

4.1. Income and Racial Equity

Increasing prices for remaining customers at a shrinking utility will clearly have equity implications. This is true both historically, for the customer base shrinking that we observe in our sample, and in the future, for example, with customers leaving the utility due to building electrification. As customers leave natural gas service, they stop paying for the pipeline infrastructure that they leave behind. How this interacts with income, racial, or other inequality depends on the characteristics of the customers who leave, as well as on the characteristics of the customers who get left behind.

Table 5 describes the eight utilities that experienced the largest loss in residential customers as well as the eight utilities that experienced the largest increase in residential customers. These 16 utilities are generally large utilities (almost all have more than 100,000 residential customers at the beginning of our sample, and the largest serves more than 4 million residential accounts). They are generally investor-owned utilities, with the exception of the municipally operated Philadelphia Gas Works and a municipal utility in Albany, GA. And, they generally experienced prolonged periods of either growth or loss over our time period, as opposed to one-time changes (fig. A2; figs. A1–A8 are available online).

For each utility, we list the largest city served, according to the utility's website. Our data are at the utility level, not household level, and we do not have demographic or socioeconomic information about the composition of customers who exit or enter natural gas service, nor do we have comprehensive information on service territories over time. Nonetheless, broader city-level demographic and socioeconomic information for the largest city served can shed light on the type of communities that have experienced customer loss and gain.

We list four demographic characteristics for each city: the population change over the 2000–2019 period, the percentage of the city's population that is Black or African American, the poverty rate, and the annual per capita income (in thousands of dollars).[14]

14. The socioeconomic variables are reported at the city level by the Census Bureau using data from the American Community Survey five-year estimates; we report vintage year 2019 estimates.

There are several striking features of table 5. First, the utilities with the largest customer losses generally serve cities with declining or flat populations. Several cities experienced large losses in population: Birmingham, AL, and Charleston, WV, each with a drop of 13%; also Mobile, AL, Albany, GA, and Shreveport, LA. In contrast, the utilities with the largest customer gains generally served cities with growing populations: Aurora, IL, experienced a 37% increase in population and Las Vegas 35%. The growing utilities nearly all serve states in the West and Southwest, consistent with regional demographic trends in the United States over this time period.

Second, the utilities with large customer losses overwhelmingly serve cities with large African American populations. With the exceptions of Charleston, WV, and Lawton, OK, the largest cities served by the shrinking utilities have populations that are 40% or more African American. In contrast, the utilities with growing customer bases generally serve cities with much smaller African American populations. A number of economic and social forces may be at play here; Beauregard (2009) identifies several factors responsible for shrinking cities over the 1980–2000 period, including suburbanization, racial antagonisms, and more. For instance, one important force behind migration in the United States has been White flight and suburbanization, the latter frequently racially restricted. While most work has emphasized the postwar period, Crowder and South (2008) and Beauregard (2009) suggest that this legacy continues in more recent decades. Future work could look at whether historical White flight has led to a stranded pipeline infrastructure that must be maintained by the remaining African American population.

Table 5 also shows a pattern of income inequality that is correlated with shrinking or growing customer bases. The median poverty rate in the large cities served by shrinking utilities is 23%, and the median rate for the growing utilities is 16%. Similarly, the median per capita income in the shrinking sample is $27,000, compared to $34,000 in the growing utilities. This pattern matches that explored by Faust et al. (2016), who examine water infrastructure management in four shrinking cities. They focus on the Rust Belt and not the South but, like us, show that the shrinking cities have low incomes, and therefore “shrinking cities face not only a decline in [water] customers but also the inability of the existing customers to afford drastically increasing rates” (133). The pattern is also consistent with the vicious cycle of urban economic decline described by both Faust et al. (2016) and Galster (2017); the latter writes that “selective outflow renders the city increasingly occupied by the disadvantaged,” noting also that “out-mobility of disadvantaged households who are African-American or Latino may be further constrained by illegal discrimination in housing markets outside of declining cities” (357).

The evidence on mostly larger, mostly urban utilities in table 5 complements the evidence shown earlier on declining residential customer counts for municipal utilities (table 2), which are typically small and rural. This customer base loss for municipalities is intuitive given the rural depopulation of much of the United States. As Johnson and Lichter (2019, 4) write, “population loss has seemingly become the new demographic norm across broad regions of rural America.”

Table 5. Demographic Characteristics of Shrinking and Growing Utilities

State (1)	Utility (2)	Initial Residential Count (3)	Change (4)	Largest City Served (5)	Pop. Change 2009–19 (6)	% Black or African American (7)	Poverty Rate (8)	Income per Capita $000's (9)
A. Utilities with Largest Customer Loss								
AL	Alabama Gas Corp	423,130	–29,865	Birmingham	–13	70	26	24
AR	Centerpoint Energy Arkla	386,572	–25,949	Little Rock	8	42	17	36
AL	Spire Gulf Inc	95,021	–16,279	Mobile	–7	52	21	27
OK	Centerpoint Energy Arkla	100,850	–13,385	Lawton	0	20	19	24
PA	Philadelphia Gas Works	492,945	–10,100	Philadelphia	5	42	24	28
WV	Hope Gas Inc	111,216	–9,553	Charleston	–13	16	21	35
LA	Centerpoint Energy Entex	116,781	–9,085	Shreveport	–6	57	26	26
GA	Albany Water Gas & Light Comm	16,298	–5,864	Albany	–7	74	31	20

B. Utilities with Largest Customer Gain								
IL	Nicor Gas	1,722,299	342,511	Aurora	37	10	11	31
NV	Southwest Gas Corporation	337,465	393,567	Las Vegas	35	12	15	31
UT	Questar Gas Company	560,717	411,496	Salt Lake City	10	3	17	37
CO	Pub Service Co of Colorado	889,902	419,749	Denver	31	9	13	44
AZ	Southwest Gas Corporation	598,050	453,019	Phoenix	27	7	18	29
TX	Centerpoint Energy Entex	1,103,814	545,829	Houston	18	23	20	33
CA	Pacific Gas	3,493,097	791,719	San Jose	13	3	9	47
CA	Southern California Gas	4,599,840	1,007,849	Los Angeles	8	9	18	35

Note. This table describes the eight natural gas utilities in our sample which experienced the largest loss in residential customers along with the eight utilities which experienced the largest gain in residential customers from 1997 to 2019. Columns 3 and 4 list the initial count of residential customers and the change in residential customers over our sample, respectively. The last four columns provide demographic statistics from the US Census Bureau for the largest city served by each utility.

Overall, we highlight three equity-related implications of our work. All three are suggestive, but future work could explore these on a national scale. First, we show patterns of customer base loss in predominantly African American cities, which may contribute to higher energy bills for urban African American populations. Second, rural depopulation may also lead to a rural/suburban divide in energy bills and infrastructure quality. Finally, if future electrification leads to inequality in energy expenditures (an issue we next explore in depth), it may be worth investigating how these future issues interact with the past inequities described above.

4.2. Simulating Bill Impacts of Customer Exit

As we discuss above, building electrification is emerging as a central policy issue for climate change mitigation. Our results point to a thorny issue during a transition period in which some, but not all, buildings electrify. If building electrification occurs in a geographically dispersed manner, utilities will need to continue to pay for pipeline networks but will have fewer customers to bear these costs. As we show above, shrinking customer bases lead to rising prices for remaining customers, with implications for equity. In this section, we explore potential price impacts in greater detail. We focus on the residential sector, for which the equity implications are clearest, but we note that similar mechanisms are at play in the commercial sector. We assume throughout this analysis that there is no cross-subsidization across sectors, that is, the revenue requirement in the residential sector does not depend on what occurs in the commercial sector, consistent with traditional utility practice.

In figure 4 we plot (thick, middle line) the implications of the estimates from table 4 for a rise in prices under different magnitudes of natural gas customer exit. Specifically, in a scenario in which 0% of residential natural gas customers exit, we assume that the typical customer pays $328 per year in net revenue.[15] Then we assume that each 1% of lost gas customers leads to a 0.53% rise in prices for everyone else, based on the 0.47 coefficient in column 3 of table 4.

Figure 4 shows that bill impacts are small when only a small percentage of customers exit the natural gas sector but increase substantially as a higher percentage of customers exit. To understand why this relationship is nonlinear, imagine that all customers but one exit, and that remaining customer must cover all of the utility's legacy costs. Recent papers on US economy-wide decarbonization assume a rapid electrification of residential buildings (Aas et al. 2020; Larson et al. 2020; National Academies of Sciences, Engineering, and Medicine 2021; Williams et al. 2021). Larson et al. (2020) and Williams et al. (2021) assume something on the order of a 15% reduction in natural gas residential customers by 2030 and 40% or more by 2040. Our estimates imply that customer

15. Our estimate for net revenue at growing utilities in table 4 is $328; it is also similar to the median residential net revenue value of $350 in table 1.

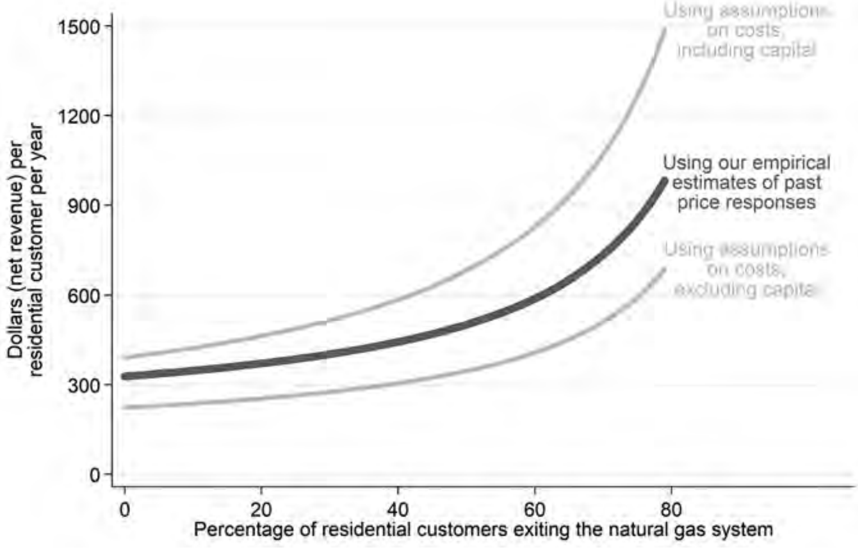

Figure 4. Utility bills rise nonlinearly with customer exit. This figure plots how the net revenue per residential customer (i.e., bill totals net of gas costs) changes as other customers exit, for instance, because they switch to electric heating and cooking. The thick, middle line uses empirical estimates from past utility behavior, specifically the estimates in table 4. The top and bottom lines provide approximate bounds for these estimates, calculated based on financial data from a sample of utilities as described in section 4.3. The upper and lower bounds reflect a representative utility at the beginning and end of the depreciation schedule, respectively. If gas costs were included, it would simply shift all three lines up by a constant amount, equal to around $300 per customer per year (table 6) but fluctuating with weather, macroeconomic conditions, and natural gas wholesale prices. Color version available as an online enhancement.

exit of this level this would translate into annual bill increases of $31 and $116 per customer, respectively. These higher natural gas bills will then prompt additional customer exit, in the natural gas version of the "utility death spiral."[16]

This general pattern is similar to previous calculations by policy analysts. Gridworks (2019) calculates a roughly 100% increase in residential natural gas bills for a 60% decrease in residential gas demand in California (although note that figure includes gas

16. Several previous papers document a negative price elasticity of demand for natural gas. Davis and Muehlegger (2010) estimate short-run elasticities of –0.28 and –0.21 for residential and commercial customers, respectively. Hausman and Kellogg (2015) estimate short-run elasticities of –0.11 and –0.09 and long-run elasticities of –0.20 and –0.23 for residential and commercial customers, respectively. Auffhammer and Rubin (2021) estimate a medium-run elasticity of –0.20. Finally, Davis (2021) shows that natural gas prices also matter for extensive margin decisions, with a 10% increase in natural gas prices increasing adoption of electric heating by 2 percentage points.

commodity costs, which we have not included). As another point of comparison, a California Energy Commission analysis (Aas et al. 2020) describes a scenario in which prices increase by 80% by 2030 and 480% by 2050, although that includes other cost drivers too.

Nonetheless, it is important to emphasize that these calculations are based on our empirical analysis of past customer losses. However, under a transition away from natural gas, the composition of customer exit could be quite different from the historical pattern. Moreover, utility and regulator behavior could change, for example, resulting in larger reductions in maintenance expenditures than have been observed historically. To better understand how the impact of future electrification might differ from the past impact of customer base loss, and to inform potential policy options, we next examine data on expenditure patterns at US natural gas utilities and discuss how different categories of expenditure might change with widespread building electrification.

4.3. Utility Expenditures

In this section, we turn to financial data from an ancillary data source in order to provide additional details about the different categories of utility expenditures. The American Gas Association (AGA), a large trade organization, conducts an annual benchmarking survey of around 80 natural gas distribution utilities. The utilities represented are a mix of investor-owned and municipal utilities. They are not a random sample, but together they represent a substantial portion (around 70%) of all customers nationwide. Details on this AGA report, and the calculations we make using it, are in the appendix.

In table 6, we describe the expenditures of a typical natural gas distribution utility. Perhaps not surprisingly, the single largest expenditure is purchasing natural gas (over \$300 per residential customer per year). Recall that our previous analysis netted out this expenditure to focus on fixed costs related to pipelines.

The second largest expenditure for a typical utility (around \$170 per residential customer per year) is for past capital expenditures. The largest capital expenditures are main and service pipelines, but examples of smaller categories are compressor station equipment, building structures, tools, and trucks. The capital expenditures category is composed of both annual write-downs of past capital (i.e., depreciation)—around \$63 per residential customer per year—and a payment to investors for their return on past capital expenditures (around \$105). At any given utility, this amount will depend on depreciation to date as well as the rate of return allowed by utility regulators. These first two categories, expenditures for natural gas and capital expenditures, together account for about two-thirds of total utility expenditures.

The remaining one-third consists of operating expenditures and taxes. The next category (\$85 per residential customer per year) is administrative expenses, including salaries to executives, pension payments, and so forth. Distribution operations and maintenance (averaging around \$66 per residential customer annually) refers to labor and materials for operating and maintaining the distribution network (pipelines as well

Table 6. Expenditure Categories for US Natural Gas Distribution Utilities

Category	Example	Average Dollars per Customer Annually	Assumed Portion Leaving with the Customer
Gas cost	Cost of purchasing natural gas	312	1.0
Capital-related expenditures:			
Depreciation	Annual write-down of past capital expenditures	63	.0
Return on net utility plant	Return for investors on past capital expenditures	105	.0
Operations-related expenditures:			
Administrative	Administrative salaries, outside services, pensions, injuries and damages, customer assistance, advertising	85	.5
Distribution operations and maintenance	Maintenance of distribution mains, service lines, and meters	66	.1
Accounts	Meter reading, customer records, and uncollectibles	25	.9
Taxes	Sales, income, property, etc.	47	.6
Total expenditures		703	.6

Note. This table was constructed by the authors based on financial data from the American Gas Association's "2016–2018 Performance Benchmarks for Natural Gas Utilities" report EA 2020-03. The last column shows the assumptions we make regarding what portion of the category's expenditures are eliminated when a customer leaves; for instance, a utility no longer needs to purchase any gas for that customer (first row) but must still recover all of its past capital expenditures (second and third rows). Note that the "Total expenditures" row at the bottom includes gas costs and is therefore higher than the net revenue plotted in fig. 4. The 0.6 calculations in the "Taxes" and "Total" rows reflect a weighted average of the assumed portion for the individual categories. Details on the AGA report and on the assumed portion column are in the appendix.

as customer meters). Finally, utilities have expenditures related to servicing accounts ($25 per residential customer per year), which includes meter reading but also expenses related to nonpayment.

The last column of table 6 shows our assumptions about how each of these categories of expenditure change in response to customer base loss. First, we assume that 100% of expenditures on natural gas are eliminated when a customer exits. The utility no longer needs to procure natural gas on that customer's behalf so these costs are clearly marginal to the customer. Second, we assume that 0% of past capital expenditures are eliminated when a customer exits, reflecting the fact that these are a sunk cost that must still be recovered even when a customer exits.[17]

Third, we assume that between 10% and 90% of operating expenses are eliminated when a customer exits, with the exact percentage varying across categories. We assume that half of administrative expenses are eliminated but half are not. Pensions, for instance, must still be paid when a customer exits. However, expenditures on customer assistance can presumably decrease as there are fewer customers to assist. In contrast, we assume that almost none of the distribution operations and maintenance expenditures are eliminated—since the pipeline network has not changed, the same amount of maintenance must be conducted for safety to not be compromised.[18] We assume that some are eliminated because, for instance, the departing customer's meter may no longer need the same maintenance. We assume that most customer-related account expenditures are eliminated, as a meter reader is no longer needed for that household. We assume that not all of these expenses are eliminated since, for instance, a utility without internet-connected meters must still send a person down the street to read nearby meters of remaining customers, so the cost of meter reading does not decrease one for one in some cases. For taxes, we use the weighted average portion from the other categories.

Based on these assumptions, we plot two additional lines in figure 4, intended to represent upper and lower bounds. As explained earlier, this figure describes how net revenue per customer would change under increasing levels of customer exit, and the central estimate is based on our empirical estimates in table 4. We construct the bounds using cost information and baseline assumptions from table 6. For the upper bound, we use all cost categories, including the two categories of capital costs. For the lower bound, we include all cost categories except for the two categories of capital costs.

The upper and lower bounds can be thought of as the price paths for a representative utility at the beginning and end of the depreciation schedule. Going forward, natural gas utilities may choose to cease new capital investments if they expect a high degree of building electrification. Without new capital investments, the capital cost component of bills would decrease until eventually reaching zero as these assets are fully depreciated. Thus we would expect the actual price path to be between these upper and lower bounds, but closer to the lower bound in the long run.

Overall, this bounding exercise yields price paths that are remarkably similar to the path we constructed using our empirical estimates. This similarity provides reassurance that our empirical estimates are broadly representative, even though the utilities that experienced customer losses during our sample period tend to be municipally owned,

17. While cost disallowances are relatively rare in practice, there is precedent for public utility commissions to disallow cost recovery, as we discuss in the following section.

18. It is also possible that a struggling utility would cut back on maintenance (Evans and Gilpatric 2017). We discuss potential policy implications in the Conclusion.

smaller, and rural. Probably the most important take-away from the broader analysis is that a considerable portion of capital and operating expenses is not eliminated by customer exit. This is consistent with our empirical analysis of net revenue as well as with these calculations based on financial data, and it implies that under electrification scenarios remaining natural gas customers can expect significantly rising bills.

4.4. Policy Alternatives

The main takeaway from our empirical analysis is that as customers exit natural gas service, this increases bills for customers left behind. These bill increases have important implications for equity, and we show that there has tended historically to be a pronounced pattern in which these remaining customers disproportionately come from disadvantaged groups. In this section, we discuss alternative options for utility financing that could break this historical pattern, and what these alternatives could mean for efficiency and equity.[19]

4.4.1. Changing the Composition of Customer Exit

We first discuss a set of policies that would change the composition of customer exit. For example, one type of policy intervention would be to subsidize building electrification for low-income households or other disadvantaged groups, thereby changing the composition of customer exit (and perhaps accelerating overall electrification). While this approach could improve equity, simply funding low-income electrification projects will still result in higher natural gas bills for remaining users, which may prove burdensome for low- and middle-income customers who do not enroll in the program. Some of these customers may prefer natural gas over electricity (Davis 2021), may fail to qualify if they are middle income (Forrester and Reames 2020), or may have trouble accessing the program (Fowlie et al. 2015; Raissi and Reames 2020). In addition, such a policy by itself would not solve the underlying financial difficulties of the natural gas utility.

A related set of policies would target electrification policies geographically. Targeted electrification has been suggested as one way to reduce ongoing operations and maintenance costs; in this scenario, whole areas are electrified so that entire sections of the pipeline network can be shut down. One could imagine targeting based on safety and climate goals, particularly in areas where aging pipelines would otherwise be replaced to prevent methane leaks and pipeline accidents—incurring capital costs that would need to be paid by future customers. Such a targeted electrification policy could lead to a more equitable or a less equitable transition, depending on which areas are targeted. Of course, this policy alone does not solve the problem of how to pay for system-wide legacy costs.

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19. These alternative policies have been previously discussed in Bilich et al. (2019), Greenlining Institute (2019), Gridworks (2019), Mahone et al. (2019), Aas et al. (2020), Larson et al. (2020), Karas et al. (2021), National Academies of Sciences, Engineering, and Medicine (2021), and Williams et al. (2021).

4.4.2. Changing How Utility Customers Pay

Another set of policies would change how customers pay for natural gas service. For example, one alternative would be to accelerate the depreciation schedules used by utility commissions in rate making. Accelerated depreciation allows the utility to recover capital costs more quickly, meaning that these investments remain in the rate base for fewer years. This approach could reduce the degree to which these capital costs are shifted over time onto a smaller set of remaining customers. However, this approach does not address the problem of ongoing maintenance costs associated with sparsely used pipelines; as we show above, these are not trivial. Another limitation of accelerated depreciation is that it will, in the short term, raise prices for remaining customers even further.

Other related policies would target more directly the underlying incentive problems. Fundamentally, utility financing relies on a stable or growing customer base to recover past costs; in this way, incentives for customer entry and exit are not correctly aligned. One could imagine pricing schemes that correctly align incentives for customer entry and exit. For instance, customers could pay hook-up fees that cover the future stream of capital and operations and maintenance costs, so that if they later exit, they are not leaving remaining customers on the hook.

This approach has some promise but also faces challenges. Utilities have generally wanted to grow their customer base to bring in new sources of revenue, and a high connection fee disincentivizes future growth (Sherman and Visscher 1982).[20] This kind of policy may also face pushback from ratepayer advocates who value energy access.

A closely related alternative would be to charge exit fees. That is, customers departing the system would be asked to cover a portion of the capital and operations and maintenance costs they leave behind. Our empirical analysis implies that exit fees would need to be large—in excess of $1000 per household—if they were to completely cover the present discounted value of legacy costs. Such a solution could be very effective at reducing cost shifts but is likely to be politically and logistically challenging and would, of course, be highly unpopular with customers, who would correctly claim that they were not warned about such fees when they initially signed up for natural gas service. In addition to these substantial obstacles, exit fees would delay the transition of households away from on-site consumption of fossil fuels.

20. It is worth noting that the discussion around widespread customer loss is relatively new—as recently as 2013, some states were instead investigating policy issues related to natural gas distribution extensions, because of low commodity prices induced by fracking. Costello (2013, 35) discusses rate-setting principles in this setting, for instance "growth should pay for itself by requiring new customers to pay the full costs for extending service to their areas"—but does not consider how this principle might account for the potential exit of customers in the future.

4.4.3. Shifting Costs to Utility Owners

There is also the possibility that utility owners would bear some of these legacy costs. For the hundreds of investor-owned and privately owned utilities in the United States, legacy costs could be disallowed or partially disallowed by regulators, thereby mitigating additional price increases. Cost disallowances would shift the burden away from ratepayers and toward shareholders and other owners. Municipal utilities are not privately owned, so this alternative does not apply. There is a large literature in law and economics on the question of what costs can be disallowed by regulators versus what costs they must allow utilities to recover. Prominent court cases like *Hope Natural Gas Co.*, *Market Street Railway*, and *Duquesne Light Co.* have considered this question in a number of different contexts. While *Hope* offers utilities the right to a fair rate of return, the *Market Street* decision by the Supreme Court makes clear that this does not protect a utility from market forces that are rendering its service obsolete. See, for example, Kahn (1997), Graffy and Kihm (2014), and Raskin (2014).

Some of the questions that have arisen in these and related cases are (1) whether the investments were prudent at the time they were made, versus whether the investments continue to be economically viable (i.e., used and useful), (2) whether the utility's very existence is at risk, (3) whether the utility has an obligation to serve remaining customers, and (4) whether the risk faced by the utility arises from market forces or from actions taken by regulators. In some of these cases, commissions have allowed utilities to recover investment costs themselves (i.e., depreciation) but not a rate of return on those investments (Rose 1996). Any whole or partial disallowances would decrease the value of the utility, leading shareholders to bear some of these legacy costs.

It is still too early to say what approach utility commissions will take. From an economic perspective, there are clear efficiency benefits from making sure that shareholders have some "skin in the game." A central tenet of law and economics is that agents should bear the costs of their actions. Utilities are constantly making long-term investments and the threat of disallowances helps encourage utilities to make these decisions efficiently, for example, avoiding expensive pipeline replacement projects in locations undergoing rapid building electrification. On the other hand, it is unrealistic to think that shareholders could be made responsible for the entire legacy gas infrastructure. Disallowing too many of these costs would raise the cost of capital for utilities, making it hard for them to finance basic operations and potentially leading to bankruptcy.

4.4.4. Paying for Costs Elsewhere

In addition, there are policy alternatives that would involve shifting legacy costs out of the natural gas sector altogether. One possibility is that customers of electric utilities could instead cover the transition costs associated with the electrification transition. How this is structured would depend on whether the same utility serves gas and electric customers and, if not, on the way in which each utility is regulated. In the United States there are large numbers of both "single-fuel" (selling only natural gas) and "dual-fuel" utilities (selling both natural gas and electricity) (Knittel 2003). An interesting question moving forward is whether dual-fuel utilities might begin cross-subsidizing natural gas customers by increased revenue collection from electricity customers. This type of cross-subsidization has not been widely done historically and tends to go against the utility ethos of "cost allocation." In addition, electricity rates already include considerable fixed costs of their own, resulting in a price per unit of electricity that exceeds social marginal cost in most parts of the United States (Borenstein and Bushnell 2022).

Finally, utility fixed costs could be recovered through the general tax base rather than from utility customers. This could include transfers from federal, state, or local government. Indeed, this is done for other natural monopolies, such as the postal service. This approach has also been proposed for electric utilities facing declining cost recovery because of residential rooftop solar adoption (Borenstein et al. 2021).[21] A variant on this would use cap and trade or carbon tax revenues, rather than the general tax base.[22]

4.4.5. Summary

To summarize, a number of policies have been suggested. Our results can contribute to these discussions in a number of ways. First, by recognizing that the transition difficulties associated with electrification are fundamentally a result of the way that natural monopolies in the United States recover their fixed costs, proposals that address the underlying issue can be crafted. Second, we point out that there are multiple issues to be addressed, and as such multiple policies may be needed: capital cost recovery, ongoing maintenance cost recovery for safety and environmental reasons, and equity issues. Fully addressing all of these will likely require a combination of policies. Finally, researchers and policy makers may be able to learn from successful policies used in other domains (natural gas, electricity, water, transportation), since the underlying market structure is similar and the underlying economic issues nearly the same.

5. CONCLUSION

The utility business is often thought of as stable and predictable. But we show that US natural gas utilities have experienced a surprisingly large amount of recent change, with many utilities consistently gaining customers while other utilities consistently lost customers over our sample period, 1997–2019. Our paper leverages these changes to test

21. Beecher (2020) also discusses the possibility of funding fixed costs via local property taxes, arguing that it may be less regressive than current pricing structures (although note that local taxes would not decouple cost recovery from migration impacts).

22. Such a policy has been proposed for low-income energy assistance; see Fowlie (2021). A related policy has also been proposed for a more general reform of electricity sector pricing (Shawhan 2016). The pros and cons of recovering fixed costs through the general tax base are discussed in Viscusi et al. (2005)—particularly political economy questions and incentives to control costs.

how utility operations and finances evolve during growth and loss. We show that utilities expand the distribution network during years of customer growth but rarely shrink the network during periods of customer loss. Moreover, we find that utility revenues increase one for one during years of growth but decrease by only half as much during years of loss, implying that remaining customers make up the difference through increased prices.

These dynamics have important implications for a growing set of climate policies aimed at transitioning households and firms away from natural gas toward electricity. We show that during our sample period the utilities experiencing customer losses tended to be in cities with higher poverty rates and a higher percentage of African American residents. Future energy transitions will not follow the exact same pattern, but our results nonetheless highlight the potential for bill impacts to be distributed across households in ways that exacerbate existing societal inequalities. In addition, we use simulation evidence and ancillary data on typical expenditures for US natural gas utilities to show the large potential magnitude of bill impacts. Based on our empirical estimates, for example, we show that bills can be expected to increase by $115 dollars per year in response to 40% of residential customers exiting the system. In our calculations, residential bills increase sharply and nonlinearly in response to additional customer exit.

These dynamics also have major implications for efficiency. A central theme in energy economics is the importance of pricing energy efficiently (Borenstein and Bushnell 2022). Putting more fixed costs into retail prices threatens to increase deadweight loss for remaining customers. At the same time, higher retail prices for natural gas will also accelerate the transition away from natural gas, prompting further exits, and thus additional price increases, in the natural gas version of the “utility death spiral.” Of course, if the environmental externalities of natural gas are very large, this is a “virtuous cycle” in that it accelerates decarbonization. While these dynamics will not last forever, an energy transition of this magnitude affects a large number of US households and businesses, so it is critical to trace out the implications for both efficiency and equity.

Our findings are also relevant for ongoing policy debates about how to handle aging infrastructure in the natural gas system, which carries safety risks and environmental risks. Several of the states that are leading on building electrification are also states working to ameliorate methane leaks and explosion risks (e.g., California, Massachusetts, and New York). Future work could examine the optimal suite of policies to meet multiple goals, especially in older utility service territories with aging pipelines. Future work could also investigate whether there are perverse incentives for utilities with customer base loss—either to cut back on important maintenance, as in Evans and Gilpatric (2017), or to overinvest in capital-intensive replacement projects to earn a future rate of return (Averch and Johnson 1962).

Finally, it is worth highlighting that this issue of legacy utility costs is not unique to this particular sector. While our analysis focuses on natural gas distribution utilities, customer exit raises similar challenges for funding inter- and intrastate natural gas pipeline infrastructure. As the amount of gas flowing through these long-distance pipelines decreases, the fixed costs associated with these investments are spread over a smaller number of customers. The extent to which this occurs in the future depends not just on what happens with building electrification but also on whether a transition away from natural gas occurs in the industrial and electric power sectors. More generally, our work highlights a broader dynamic that can occur in many sectors with large fixed costs, including public transportation, water distribution, mail delivery, and traditional telephone service.

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CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Staff’s Line Extension Allowance Model

April 18, 2024

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2025
Workpaper: Line Extension Allowance Model - Supplemental
Concentric Energy Advisors
Supplemental Filing Workpaper for NW Natural/2000, Kravitz-Therrien
UG 490 OPUC DR 378 Attachment 2

Directives in Order No. 22-388:

- The company's best reasonable estimate of present and future CPP compliance costs;
- An analysis of how each new customer addition changes the costs of CPP compliance for other customers;
- An explanation of how the proposed LEA incorporates and recognizes the costs of CPP compliance;
- An analysis supporting the company's assumptions about the expected time frame over which new customers will remain on the system, and how changing policy dynamics were factored in; and
- A demonstration of the expected year-by-year economic impact on existing customers from the addition of new customers under the proposed LEA, such that the "breakeven" year is shown, along with the costs and benefits expected in other years, and a demonstration of when rate-based investments for customer additions covered by the LEA are depreciated and removed.

Testimony Exhibits*:	Description:
Exhibit 1902R	DCF Summary Example

**Note: Exhibits with an "R" indicate revised exhibits for Supplemental Testimony. See tabs in this workbook for these exhibits with formulae intact.*

			Year 1	Year 2	Year 3	Year 4	Year 5
1	**Revenue from New Connection Tariff**	*Exh 1905R*	684	1,026	1,026	1,026	1,026
2	**Proxy CPP Revenue**	*Exh 1906R*	28	41	488	541	667
3	**Proxy CPP Cost**	*Exh 1906R*	(335)	(335)	(3,000)	(3,000)	(3,000)
4	**Nominal Change in Base Rate Revenue per Customer**	*Exh 1903*	0	(22)	(44)	(66)	(88)
5	**Contribution to New Non-Growth Capex**	*Exh 1904*	44	101	149	192	233
6	**Operations & Maintenance**		(79)	(79)	(79)	(79)	(79)
7	**Franchise Tax**	2.74%	(19)	(28)	(28)	(28)	(28)
8	**Property Tax**	1.50%	66	62	62	62	62
9	**Net Before Taxes**		389	766	(1,426)	(1,352)	(1,207)
10	**Income Tax**	27.00%	105	207	(385)	(365)	(326)
11	**Net After Tax**		284	559	(1,041)	(987)	(881)
12	**Tax Benefit on Investment**		(45)	(86)	(80)	(74)	(68)
13	**Total Operating Cash (ROR Analysis)**	$4,419	239	473	(1,121)	(1,060)	(950)

		Rate	Year 1	Year 2	Year 3	Year 4	Year 5
1	**Plant**		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	**Depreciation (per model term)**	6.667%	295	295	295	295	295
3	**Net Plant**		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	**Deferred Taxes**		35	(51)	(131)	(205)	(273)
5	**Net Rate Base**		(4,159)	(4,073)	(3,993)	(3,920)	(3,851)
6	**Average Rate Base**		(4,289)	(4,116)	(4,033)	(3,956)	(3,886)
	Basis for interest expense		-2,145	-2,058	-2,017	-1,978	-1,943

			Year 1	Year 2	Year 3	Year 4	Year 5
Tax Depreciation			**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
1	**Tax Depreciation Rate**		3.75%	7.22%	6.68%	6.18%	5.71%
2	**Plant Additions**		(4,419)				
3	**Total Tax Depreciation**		(166)	(319)	(295)	(273)	(252)
4	**Tax Benefit @**	27.00%	(45)	(86)	(80)	(74)	(68)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**		(4,419)				
3	**Book Depreciation**		(295)	0	0	0	0
4	**Total Book Depreciation**		(295)	0	0	0	0
5	**Total Tax Depreciation**		(166)	(319)	(295)	(273)	(252)
6	**Difference**		129	(319)	(295)	(273)	(252)
7	**Deferred Taxes**	27.00%	35	(86)	(80)	(74)	(68)
	20 year MACRS		3.75%	7.22%	6.68%	6.18%	5.71%

			Year 6	Year 7	Year 8	Year 9	Year 10
1	**Revenue from New Connection Tariff**	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	**Proxy CPP Revenue**	*Exh 1906R*	792	873	1,004	1,134	1,265
3	**Proxy CPP Cost**	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	**Nominal Change in Base Rate Revenue per Customer**	*Exh 1903*	(110)	(132)	(155)	(177)	(199)
5	**Contribution to New Non-Growth Capex**	*Exh 1904*	269	302	333	362	390
6	**Operations & Maintenance**		(79)	(79)	(79)	(79)	(79)
7	**Franchise Tax**	2.74%	(28)	(28)	(28)	(28)	(28)
8	**Property Tax**	1.50%	62	62	62	62	62
9	**Net Before Taxes**		(1,069)	(977)	(837)	(699)	(563)
10	**Income Tax**	27.00%	(289)	(264)	(226)	(189)	(152)
11	**Net After Tax**		(780)	(713)	(611)	(510)	(411)
12	**Tax Benefit on Investment**		(63)	(58)	(54)	(53)	(53)
13	**Total Operating Cash (ROR Analysis)**	$4,419	(843)	(771)	(665)	(564)	(464)

		Rate	Year 6	Year 7	Year 8	Year 9	Year 10
1	**Plant**		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	**Depreciation (per model term)**	6.667%	295	295	295	295	295
3	**Net Plant**		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	**Deferred Taxes**		(336)	(394)	(448)	(501)	(555)
5	**Net Rate Base**		(3,788)	(3,730)	(3,676)	(3,623)	(3,570)
6	**Average Rate Base**		(3,820)	(3,759)	(3,703)	(3,649)	(3,596)
	Basis for interest expense		-1,910	-1,880	-1,852	-1,825	-1,798

			Year 6	Year 7	Year 8	Year 9	Year 10
Tax Depreciation			**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
1	**Tax Depreciation Rate**		5.29%	4.89%	4.52%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(234)	(216)	(200)	(197)	(197)
4	**Tax Benefit @**	27.00%	(63)	(58)	(54)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(234)	(216)	(200)	(197)	(197)
6	**Difference**		(234)	(216)	(200)	(197)	(197)
7	**Deferred Taxes**	27.00%	(63)	(58)	(54)	(53)	(53)
	20 year MACRS		5.29%	4.89%	4.52%	4.46%	4.46%

			Year 11	Year 12	Year 13	Year 14	Year 15
1	Revenue from New Connection Tariff	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	Proxy CPP Revenue	*Exh 1906R*	1,395	1,481	1,566	1,652	1,738
3	Proxy CPP Cost	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer	*Exh 1903*	(221)	(243)	(265)	(287)	(309)
5	Contribution to New Non-Growth Capex	*Exh 1904*	416	440	462	483	502
6	Operations & Maintenance		(79)	(79)	(79)	(79)	(79)
7	Franchise Tax	2.74%	(28)	(28)	(28)	(28)	(28)
8	Property Tax	1.50%	62	62	62	62	62
9	Net Before Taxes		(429)	(341)	(255)	(171)	(88)
10	Income Tax	27.00%	(116)	(92)	(69)	(46)	(24)
11	Net After Tax		(313)	(249)	(186)	(125)	(64)
12	Tax Benefit on Investment		(53)	(53)	(53)	(53)	(53)
13	Total Operating Cash (ROR Analysis)	$4,419	(366)	(302)	(239)	(178)	(118)

		Rate	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	Depreciation (per model term)	6.667%	295	295	295	295	295
3	Net Plant		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	Deferred Taxes		(608)	(661)	(714)	(768)	(821)
5	Net Rate Base		(3,516)	(3,463)	(3,410)	(3,357)	(3,303)
6	Average Rate Base		(3,543)	(3,490)	(3,437)	(3,383)	(3,330)
	Basis for interest expense		-1,771	-1,745	-1,718	-1,692	-1,665

			Year 11	Year 12	Year 13	Year 14	Year 15
Tax Depreciation			**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
1	**Tax Depreciation Rate**		4.46%	4.46%	4.46%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
4	**Tax Benefit @**	27.00%	(53)	(53)	(53)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
6	**Difference**		(197)	(197)	(197)	(197)	(197)
7	**Deferred Taxes**	27.00%	(53)	(53)	(53)	(53)	(53)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%

			Year 16	Year 17	Year 18	Year 19	Year 20
1	**Revenue from New Connection Tariff**	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	**Proxy CPP Revenue**	*Exh 1906R*	1,823	1,909	1,994	2,080	2,166
3	**Proxy CPP Cost**	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	**Nominal Change in Base Rate Revenue per Customer**	*Exh 1903*	(585)	(585)	(585)	(585)	(585)
5	**Contribution to New Non-Growth Capex**	*Exh 1904*	519	535	549	561	571
6	**Operations & Maintenance**		(79)	(79)	(79)	(79)	(79)
7	**Franchise Tax**	2.74%	(28)	(28)	(28)	(28)	(28)
8	**Property Tax**	1.50%	62	62	62	62	62
9	**Net Before Taxes**		(261)	(160)	(61)	37	133
10	**Income Tax**	27.00%	(70)	(43)	(16)	10	36
11	**Net After Tax**		(191)	(117)	(44)	27	97
12	**Tax Benefit on Investment**		(53)	(53)	(53)	(53)	(53)
13	**Total Operating Cash (ROR Analysis)**	$4,419	(244)	(170)	(97)	(26)	44

		Rate	Year 16	Year 17	Year 18	Year 19	Year 20
1	**Plant**		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	**Depreciation (per model term)**	6.667%	295	295	295	295	295
3	**Net Plant**		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	**Deferred Taxes**		(874)	(927)	(981)	(1,034)	(1,087)
5	**Net Rate Base**		(3,250)	(3,197)	(3,144)	(3,090)	(3,037)
6	**Average Rate Base**		(3,277)	(3,224)	(3,170)	(3,117)	(3,064)
	Basis for interest expense		-1,638	-1,612	-1,585	-1,559	-1,532

			Year 16	Year 17	Year 18	Year 19	Year 20
Tax Depreciation			**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**
1	**Tax Depreciation Rate**		4.46%	4.46%	4.46%	4.46%	4.46%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
4	**Tax Benefit @**	27.00%	(53)	(53)	(53)	(53)	(53)
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(197)	(197)	(197)	(197)	(197)
6	**Difference**		(197)	(197)	(197)	(197)	(197)
7	**Deferred Taxes**	27.00%	(53)	(53)	(53)	(53)	(53)
	20 year MACRS		4.46%	4.46%	4.46%	4.46%	4.46%

			Year 21	Year 22	Year 23	Year 24	Year 25
1	**Revenue from New Connection Tariff**	*Exh 1905R*	1,026	1,026	1,026	1,026	1,026
2	**Proxy CPP Revenue**	*Exh 1906R*	2,251	2,337	2,422	2,508	2,593
3	**Proxy CPP Cost**	*Exh 1906R*	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
4	**Nominal Change in Base Rate Revenue per Customer**	*Exh 1903*	(585)	(585)	(585)	(585)	(585)
5	**Contribution to New Non-Growth Capex**	*Exh 1904*	580	587	594	600	605
6	**Operations & Maintenance**		(79)	(79)	(79)	(79)	(79)
7	**Franchise Tax**	2.74%	(28)	(28)	(28)	(28)	(28)
8	**Property Tax**	1.50%	62	62	62	62	62
9	**Net Before Taxes**		227	320	413	504	594
10	**Income Tax**	27.00%	61	87	111	136	161
11	**Net After Tax**		166	234	301	368	434
12	**Tax Benefit on Investment**		(27)	0	0	0	0
13	**Total Operating Cash (ROR Analysis)**	$4,419	139	234	301	368	434

		Rate	Year 21	Year 22	Year 23	Year 24	Year 25
1	**Plant**		(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
2	**Depreciation (per model term)**	6.667%	295	295	295	295	295
3	**Net Plant**		(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
4	**Deferred Taxes**		(1,114)	(1,114)	(1,114)	(1,114)	(1,114)
5	**Net Rate Base**		(3,011)	(3,011)	(3,011)	(3,011)	(3,011)
6	**Average Rate Base**		(3,024)	(3,011)	(3,011)	(3,011)	(3,011)
	Basis for interest expense		-1,512	-1,505	-1,505	-1,505	-1,505

			Year 21	Year 22	Year 23	Year 24	Year 25
Tax Depreciation			**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**
1	**Tax Depreciation Rate**		2.23%	0.00%	0.00%	0.00%	0.00%
2	**Plant Additions**						
3	**Total Tax Depreciation**		(99)	0	0	0	0
4	**Tax Benefit @**	27.00%	(27)	0	0	0	0
Book Depreciation							
1	**Book Depreciation Rate**		6.67%	6.67%	6.67%	6.67%	6.67%
2	**Plant Additions**						
3	**Book Depreciation**		0	0	0	0	0
4	**Total Book Depreciation**		0	0	0	0	0
5	**Total Tax Depreciation**		(99)	0	0	0	0
6	**Difference**		(99)	0	0	0	0
7	**Deferred Taxes**	27.00%	(27)	0	0	0	0
	20 year MACRS		2.23%	0.00%	0.00%	0.00%	0.00%

	Description		Year 1	Year 2	Year 3
	Revenue Requirement Calculations				
1	Gross Plant		$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation		$ (1,590,754,661)	$ (1,751,597,209)	$ (1,912,439,757)
3	Net Plant		$ 2,412,638,220	$ 2,251,795,672	$ 2,090,953,124
4	Deferred Taxes		$ (435,773,775)	$ (406,722,190)	$ (377,670,605)
5	Average Rate Base (Plant related)		$ 1,976,864,445	$ 1,845,073,482	$ 1,713,282,519
6	Pre-Tax ROR		8.7947%	8.7947%	8.7947%
7	Return and Taxes		$ 173,859,475	$ 162,268,843	$ 150,678,211
8	Book Depreciation		160,842,548	160,842,548	160,842,548
9	O&M		539,667,000	539,667,000	539,667,000
10	Property Taxes	1.5%	36,189,573	33,776,935	31,364,297
11	Franchise Tax and Comm Fees	2.7%	25,661,801	25,267,154	24,872,507
12	Annual Revenue Requirement		$ 936,220,397	$ 921,822,480	$ 907,424,564
13	No. of Customers		652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer		$ 1,435.33	$ 1,413.25	$ 1,391.18
15	YoY Change			$ (22.07)	$ (22.07)
16	Cumulative Change		$ -	$ (22.07)	$ (44.15)
17	Depreciation Expense (based on model term rate)	6.67%	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)		$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant		$ 1,964,464,000		

	Description	Year 4	Year 5	Year 6	Year 7
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,073,282,305)	$ (2,234,124,853)	$ (2,394,967,401)	$ (2,555,809,949)
3	Net Plant	$ 1,930,110,576	$ 1,769,268,028	$ 1,608,425,480	$ 1,447,582,932
4	Deferred Taxes	$ (348,619,020)	$ (319,567,435)	$ (290,515,850)	$ (261,464,265)
5	Average Rate Base (Plant related)	$ 1,581,491,556	$ 1,449,700,593	$ 1,317,909,630	$ 1,186,118,667
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 139,087,580	$ 127,496,948	$ 115,906,316	$ 104,315,685
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	28,951,659	26,539,020	24,126,382	21,713,744
11	Franchise Tax and Comm Fees	24,477,860	24,083,213	23,688,567	23,293,920
12	Annual Revenue Requirement	$ 893,026,647	$ 878,628,730	$ 864,230,813	$ 849,832,896
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,369.11	$ 1,347.03	$ 1,324.96	$ 1,302.89
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (66.22)	$ (88.29)	$ (110.37)	$ (132.44)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

	Description	Year 8	Year 9	Year 10	Year 11
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (2,716,652,497)	$ (2,877,495,045)	$ (3,038,337,593)	$ (3,199,180,141)
3	Net Plant	$ 1,286,740,384	$ 1,125,897,836	$ 965,055,288	$ 804,212,740
4	Deferred Taxes	$ (232,412,680)	$ (203,361,095)	$ (174,309,510)	$ (145,257,925)
5	Average Rate Base (Plant related)	$ 1,054,327,704	$ 922,536,741	$ 790,745,778	$ 658,954,815
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 92,725,053	$ 81,134,422	$ 69,543,790	$ 57,953,158
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	19,301,106	16,888,468	14,475,829	12,063,191
11	Franchise Tax and Comm Fees	22,899,273	22,504,626	22,109,979	21,715,332
12	Annual Revenue Requirement	$ 835,434,980	$ 821,037,063	$ 806,639,146	$ 792,241,229
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,280.81	$ 1,258.74	$ 1,236.67	$ 1,214.59
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (154.51)	$ (176.59)	$ (198.66)	$ (220.74)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

	Description	Year 12	Year 13	Year 14	Year 15
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (3,360,022,689)	$ (3,520,865,237)	$ (3,681,707,785)	$ (3,842,550,333)
3	Net Plant	$ 643,370,192	$ 482,527,644	$ 321,685,096	$ 160,842,548
4	Deferred Taxes	$ (116,206,340)	$ (87,154,755)	$ (58,103,170)	$ (29,051,585)
5	Average Rate Base (Plant related)	$ 527,163,852	$ 395,372,889	$ 263,581,926	$ 131,790,963
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ 46,362,527	$ 34,771,895	$ 23,181,263	$ 11,590,632
8	Book Depreciation	160,842,548	160,842,548	160,842,548	160,842,548
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	9,650,553	7,237,915	4,825,276	2,412,638
11	Franchise Tax and Comm Fees	21,320,685	20,926,038	20,531,391	20,136,745
12	Annual Revenue Requirement	$ 777,843,313	$ 763,445,396	$ 749,047,479	$ 734,649,562
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 1,192.52	$ 1,170.44	$ 1,148.37	$ 1,126.30
15	YoY Change	$ (22.07)	$ (22.07)	$ (22.07)	$ (22.07)
16	Cumulative Change	$ (242.81)	$ (264.88)	$ (286.96)	$ (309.03)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

	Description	Year 16	Year 17	Year 18	Year 19
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -	$ -	$ -
4	Deferred Taxes	$ -	$ -	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -	$ -	$ -
8	Book Depreciation	-	-	-	-
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	-	-	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69	$ 850.69	$ 850.69
15	YoY Change	$ (275.61)	$ -	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

	Description	Year 20	Year 21	Year 22	Year 23
	Revenue Requirement Calculations				
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -	$ -	$ -
4	Deferred Taxes	$ -	$ -	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -	$ -	$ -
8	Book Depreciation	-	-	-	-
9	O&M	539,667,000	539,667,000	539,667,000	539,667,000
10	Property Taxes	-	-	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69	$ 850.69	$ 850.69
15	YoY Change	$ -	$ -	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585	$ 29,051,585	$ 29,051,585
19	Net Utility Plant				

	Description	Year 24	Year 25
	Revenue Requirement Calculations		
1	Gross Plant	$ 4,003,392,881	$ 4,003,392,881
2	Accumulated Depreciation	$ (4,003,392,881)	$ (4,003,392,881)
3	Net Plant	$ -	$ -
4	Deferred Taxes	$ -	$ -
5	Average Rate Base (Plant related)	$ -	$ -
6	Pre-Tax ROR	8.7947%	8.7947%
7	Return and Taxes	$ -	$ -
8	Book Depreciation	-	-
9	O&M	539,667,000	539,667,000
10	Property Taxes	-	-
11	Franchise Tax and Comm Fees	15,209,155	15,209,155
12	Annual Revenue Requirement	$ 554,876,155	$ 554,876,155
13	No. of Customers	652,270	652,270
14	Existing Plant Revenue Requirement Per Customer	$ 850.69	$ 850.69
15	YoY Change	$ -	$ -
16	Cumulative Change	$ (584.64)	$ (584.64)
17	Depreciation Expense (based on model term rate)	$ 160,842,548	$ 160,842,548
18	Deferred Tax Amortization (based on model term rate)	$ 29,051,585	$ 29,051,585
19	Net Utility Plant		

	Description		Year 1	Year 2	Year 3	Year 4
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)		$ 227,700,000	$ 227,700,000	$ 191,700,000	$ 191,700,000
3	Cumulative Capex		$ 227,700,000	$ 455,400,000	$ 647,100,000	$ 838,800,000
4	Accumulated Depreciation		(15,180,000)	(45,540,000)	(88,680,000)	(144,600,000)
5	Net Plant		$ 212,520,000	$ 409,860,000	$ 558,420,000	$ 694,200,000
6	Deferred Tax Reserve		1,793,403	3,247,187	4,411,075	5,929,745
7	Year End Rate Base Additions		$ 214,313,403	$ 413,107,187	$ 562,831,075	$ 700,129,745
	Revenue Requirement Calculations					
8	Average Rate Base		$ 107,156,702	$ 313,710,295	$ 487,969,131	$ 631,480,410
9	Pre-Tax ROR		8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes		$ 9,424,120	$ 27,589,907	$ 42,915,465	$ 55,536,864
11	Book Depreciation	6.7%	15,180,000	30,360,000	43,140,000	55,920,000
12	O&M					
13	Property Taxes	1.5%	3,187,800	6,147,900	8,376,300	10,413,000
14	Annual Revenue Requirement - pre franch		27,791,920	64,097,807	94,431,765	121,869,864
15						
16	Franchise Tax and Comm Fees	2.7%	783,245	1,806,435	2,661,321	3,434,595
17	Annual Revenue Requirement		$ 28,575,165	$ 65,904,243	$ 97,093,086	$ 125,304,459
18	No. of Customers		652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)		$ 43.81	$ 101.04	$ 148.85	$ 192.11
20	Deferred Taxes:		1	2	3	4
21	20-year MACRS		3.750%	7.219%	6.677%	6.177%
		Invmt. Yr.				
22	Tax Depreciation	Year 1	8,538,750	16,437,663	15,203,529	14,065,029
23		Year 2		8,538,750	16,437,663	15,203,529
24		Year 3			7,188,750	13,838,823
25		Year 4				7,188,750
26		Year 5				

27		Year 6					
28		Year 7					
29		Year 8					
30		Year 9					
31		Year 10					
32		Year 11					
33		Year 12					
34		Year 13					
35		Year 14					
36		Year 15					
37		Year 16					
38		Year 17					
39		Year 18					
40		Year 19					
41		Year 20					
42		Sum		8,538,750	24,976,413	38,829,942	50,296,131
43	Book Depreciation			15,180,000	30,360,000	43,140,000	55,920,000
44	Variance			($6,641,250)	($5,383,587)	($4,310,058)	($5,623,869)
45	Deferred Taxes		27.00%	($1,793,403)	($1,453,784)	($1,163,888)	($1,518,670)

	Description	Year 5	Year 6	Year 7	Year 8	Year 9
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 191,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 1,030,500,000	$ 1,204,200,000	$ 1,377,900,000	$ 1,551,600,000	$ 1,725,300,000
4	Accumulated Depreciation	(213,300,000)	(293,580,000)	(385,440,000)	(488,880,000)	(603,900,000)
5	Net Plant	$ 817,200,000	$ 910,620,000	$ 992,460,000	$ 1,062,720,000	$ 1,121,400,000
6	Deferred Tax Reserve	8,035,810	10,802,063	14,596,122	19,575,079	25,712,932
7	Year End Rate Base Additions	$ 825,235,810	$ 921,422,063	$ 1,007,056,122	$ 1,082,295,079	$ 1,147,112,932
	Revenue Requirement Calculations					
8	Average Rate Base	$ 762,682,777	$ 873,328,937	$ 964,239,092	$ 1,044,675,601	$ 1,114,704,006
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 67,075,731	$ 76,806,738	$ 84,802,022	$ 91,876,179	$ 98,034,973
11	Book Depreciation	68,700,000	80,280,000	91,860,000	103,440,000	115,020,000
12	O&M					
13	Property Taxes	12,258,000	13,659,300	14,886,900	15,940,800	16,821,000
14	Annual Revenue Requirement - pre franch	148,033,731	170,746,038	191,548,922	211,256,979	229,875,973
15						
16	Franchise Tax and Comm Fees	4,171,958	4,812,047	5,398,324	5,953,746	6,478,475
17	Annual Revenue Requirement	$ 152,205,689	$ 175,558,085	$ 196,947,246	$ 217,210,725	$ 236,354,449
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 233.35	$ 269.15	$ 301.94	$ 333.01	$ 362.36
20	Deferred Taxes:	5	6	7	8	9
21	20-year MACRS	5.713%	5.285%	4.888%	4.522%	4.462%
22	Tax Depreciation	13,008,501	12,033,945	11,129,976	10,296,594	10,159,974
23		14,065,029	13,008,501	12,033,945	11,129,976	10,296,594
24		12,799,809	11,841,309	10,951,821	10,131,345	9,370,296
25		13,838,823	12,799,809	11,841,309	10,951,821	10,131,345
26		7,188,750	13,838,823	12,799,809	11,841,309	10,951,821

27			6,513,750	12,539,403	11,597,949	10,729,449
28				6,513,750	12,539,403	11,597,949
29					6,513,750	12,539,403
30						6,513,750
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42		60,900,912	70,036,137	77,810,013	85,002,147	92,290,581
43	Book Depreciation	68,700,000	80,280,000	91,860,000	103,440,000	115,020,000
44	Variance	($7,799,088)	($10,243,863)	($14,049,987)	($18,437,853)	($22,729,419)
45	Deferred Taxes	($2,106,066)	($2,766,253)	($3,794,058)	($4,978,958)	($6,137,852)

	Description	Year 10	Year 11	Year 12	Year 13	Year 14
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 1,899,000,000	$ 2,072,700,000	$ 2,246,400,000	$ 2,420,100,000	$ 2,593,800,000
4	Accumulated Depreciation	(730,500,000)	(868,680,000)	(1,018,440,000)	(1,179,780,000)	(1,352,700,000)
5	Net Plant	$ 1,168,500,000	$ 1,204,020,000	$ 1,227,960,000	$ 1,240,320,000	$ 1,241,100,000
6	Deferred Tax Reserve	32,952,159	41,265,510	50,634,205	61,039,937	72,480,305
7	Year End Rate Base Additions	$ 1,201,452,159	$ 1,245,285,510	$ 1,278,594,205	$ 1,301,359,937	$ 1,313,580,305
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,174,282,545	$ 1,223,368,835	$ 1,261,939,858	$ 1,289,977,071	$ 1,307,470,121
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 103,274,732	$ 107,591,729	$ 110,983,938	$ 113,449,729	$ 114,988,192
11	Book Depreciation	126,600,000	138,180,000	149,760,000	161,340,000	172,920,000
12	O&M					
13	Property Taxes	17,527,500	18,060,300	18,419,400	18,604,800	18,616,500
14	Annual Revenue Requirement - pre franch	247,402,232	263,832,029	279,163,338	293,394,529	306,524,692
15						
16	Franchise Tax and Comm Fees	6,972,409	7,435,441	7,867,516	8,268,586	8,638,627
17	Annual Revenue Requirement	$ 254,374,641	$ 271,267,470	$ 287,030,854	$ 301,663,115	$ 315,163,319
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 389.98	$ 415.88	$ 440.05	$ 462.48	$ 483.18
20	Deferred Taxes:	10	11	12	13	14
21	20-year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%
22	Tax Depreciation	10,157,697	10,159,974	10,157,697	10,159,974	10,157,697
23		10,159,974	10,157,697	10,159,974	10,157,697	10,159,974
24		8,668,674	8,553,654	8,551,737	8,553,654	8,551,737
25		9,370,296	8,668,674	8,553,654	8,551,737	8,553,654
26		10,131,345	9,370,296	8,668,674	8,553,654	8,551,737

27		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
28		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
29		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
30		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
31		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
32			6,513,750	12,539,403	11,597,949	10,729,449
33				6,513,750	12,539,403	11,597,949
34					6,513,750	12,539,403
35						6,513,750
36						
37						
38						
39						
40						
41						
42		99,792,018	107,394,372	115,066,269	122,805,963	130,554,540
43	Book Depreciation	126,600,000	138,180,000	149,760,000	161,340,000	172,920,000
44	Variance	($26,807,982)	($30,785,628)	($34,693,731)	($38,534,037)	($42,365,460)
45	Deferred Taxes	($7,239,227)	($8,313,351)	($9,368,695)	($10,405,731)	($11,440,369)

	Description	Year 15	Year 16	Year 17	Year 18	Year 19
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 2,767,500,000	$ 2,941,200,000	$ 3,114,900,000	$ 3,288,600,000	$ 3,462,300,000
4	Accumulated Depreciation	(1,537,200,000)	(1,733,280,000)	(1,940,940,000)	(2,160,180,000)	(2,391,000,000)
5	Net Plant	$ 1,230,300,000	$ 1,207,920,000	$ 1,173,960,000	$ 1,128,420,000	$ 1,071,300,000
6	Deferred Tax Reserve	84,954,745	98,463,823	113,006,972	128,584,758	145,196,615
7	Year End Rate Base Additions	$ 1,315,254,745	$ 1,306,383,823	$ 1,286,966,972	$ 1,257,004,758	$ 1,216,496,615
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,314,417,525	$ 1,310,819,284	$ 1,296,675,397	$ 1,271,985,865	$ 1,236,750,686
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 115,599,196	$ 115,282,741	$ 114,038,827	$ 111,867,455	$ 108,768,624
11	Book Depreciation	184,500,000	196,080,000	207,660,000	219,240,000	230,820,000
12	O&M					
13	Property Taxes	18,454,500	18,118,800	17,609,400	16,926,300	16,069,500
14	Annual Revenue Requirement - pre franch	318,553,696	329,481,541	339,308,227	348,033,755	355,658,124
15						
16	Franchise Tax and Comm Fees	8,977,634	9,285,608	9,562,548	9,808,455	10,023,329
17	Annual Revenue Requirement	$ 327,531,330	$ 338,767,149	$ 348,870,775	$ 357,842,210	$ 365,681,452
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 502.14	$ 519.37	$ 534.86	$ 548.61	$ 560.63
20	Deferred Taxes:	15	16	17	18	19
21	20-year MACRS	4.462%	4.461%	4.462%	4.461%	4.462%
22	Tax Depreciation	10,159,974	10,157,697	10,159,974	10,157,697	10,159,974
23		10,157,697	10,159,974	10,157,697	10,159,974	10,157,697
24		8,553,654	8,551,737	8,553,654	8,551,737	8,553,654
25		8,551,737	8,553,654	8,551,737	8,553,654	8,551,737
26		8,553,654	8,551,737	8,553,654	8,551,737	8,553,654

27		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
28		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
29		7,854,714	7,750,494	7,748,757	7,750,494	7,748,757
30		8,490,456	7,854,714	7,750,494	7,748,757	7,750,494
31		9,180,045	8,490,456	7,854,714	7,750,494	7,748,757
32		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
33		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
34		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
35		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
36		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
37			6,513,750	12,539,403	11,597,949	10,729,449
38				6,513,750	12,539,403	11,597,949
39					6,513,750	12,539,403
40						6,513,750
41						
42		138,305,214	146,053,791	153,804,465	161,553,042	169,303,716
43	Book Depreciation	184,500,000	196,080,000	207,660,000	219,240,000	230,820,000
44	Variance	($46,194,786)	($50,026,209)	($53,855,535)	($57,686,958)	($61,516,284)
45	Deferred Taxes	($12,474,440)	($13,509,077)	($14,543,149)	($15,577,786)	($16,611,857)

	Description	Year 20	Year 21	Year 22	Year 23	Year 24
1	**Rate Base Calculation**					
2	Capex (oregon share @90%)	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000	$ 173,700,000
3	Cumulative Capex	$ 3,636,000,000	$ 3,809,700,000	$ 3,983,400,000	$ 4,157,100,000	$ 4,330,800,000
4	Accumulated Depreciation	(2,633,400,000)	(2,887,380,000)	(3,152,940,000)	(3,430,080,000)	(3,718,800,000)
5	Net Plant	$ 1,002,600,000	$ 922,320,000	$ 830,460,000	$ 727,020,000	$ 612,000,000
6	Deferred Tax Reserve	162,843,110	184,654,449	213,629,550	249,297,346	291,206,472
7	Year End Rate Base Additions	$ 1,165,443,110	$ 1,106,974,449	$ 1,044,089,550	$ 976,317,346	$ 903,206,472
	Revenue Requirement Calculations					
8	Average Rate Base	$ 1,190,969,863	$ 1,136,208,779	$ 1,075,531,999	$ 1,010,203,448	$ 939,761,909
9	Pre-Tax ROR	8.7947%	8.7947%	8.7947%	8.7947%	8.7947%
10	Return and Taxes	$ 104,742,333	$ 99,926,255	$ 94,589,909	$ 88,844,453	$ 82,649,325
11	Book Depreciation	242,400,000	253,980,000	265,560,000	277,140,000	288,720,000
12	O&M					
13	Property Taxes	15,039,000	13,834,800	12,456,900	10,905,300	9,180,000
14	Annual Revenue Requirement - pre franch	362,181,333	367,741,055	372,606,809	376,889,753	380,549,325
15						
16	Franchise Tax and Comm Fees	10,207,169	10,363,856	10,500,985	10,621,689	10,724,824
17	Annual Revenue Requirement	$ 372,388,502	$ 378,104,911	$ 383,107,794	$ 387,511,442	$ 391,274,149
18	No. of Customers	652,270	652,270	652,270	652,270	652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$ 570.91	$ 579.68	$ 587.35	$ 594.10	$ 599.87
20	Deferred Taxes:	20	21	22	23	24
21	20-year MACRS	4.461%	2.231%	0.000%	0.000%	0.000%
22	Tax Depreciation	10,157,697	5,079,987	-	-	-
23		10,159,974	10,157,697	5,079,987	-	-
24		8,551,737	8,553,654	8,551,737	4,276,827	-
25		8,553,654	8,551,737	8,553,654	8,551,737	4,276,827
26		8,551,737	8,553,654	8,551,737	8,553,654	8,551,737

27		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
28		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
29		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
30		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
31		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
32		7,748,757	7,750,494	7,748,757	7,750,494	7,748,757
33		7,750,494	7,748,757	7,750,494	7,748,757	7,750,494
34		7,854,714	7,750,494	7,748,757	7,750,494	7,748,757
35		8,490,456	7,854,714	7,750,494	7,748,757	7,750,494
36		9,180,045	8,490,456	7,854,714	7,750,494	7,748,757
37		9,923,481	9,180,045	8,490,456	7,854,714	7,750,494
38		10,729,449	9,923,481	9,180,045	8,490,456	7,854,714
39		11,597,949	10,729,449	9,923,481	9,180,045	8,490,456
40		12,539,403	11,597,949	10,729,449	9,923,481	9,180,045
41		6,513,750	12,539,403	11,597,949	10,729,449	9,923,481
42		177,052,293	173,209,230	158,260,707	145,056,618	133,524,009
43	Book Depreciation	242,400,000	253,980,000	265,560,000	277,140,000	288,720,000
44	Variance	($65,347,707)	($80,770,770)	($107,299,293)	($132,083,382)	($155,195,991)
45	Deferred Taxes	($17,646,495)	($21,811,339)	($28,975,101)	($35,667,796)	($41,909,125)

	Description		Year 25
1	**Rate Base Calculation**		
2	Capex (oregon share @90%)	$	173,700,000
3	Cumulative Capex	$	4,504,500,000
4	Accumulated Depreciation		(4,019,100,000)
5	Net Plant	$	485,400,000
6	Deferred Tax Reserve		339,139,234
7	Year End Rate Base Additions	$	824,539,234
	Revenue Requirement Calculations		
8	Average Rate Base	$	863,872,853
9	Pre-Tax ROR		8.7947%
10	Return and Taxes	$	75,975,103
11	Book Depreciation		300,300,000
12	O&M		
13	Property Taxes		7,281,000
14	Annual Revenue Requirement - pre franch		383,556,103
15			
16	Franchise Tax and Comm Fees		10,809,563
17	Annual Revenue Requirement	$	394,365,666
18	No. of Customers		652,270
19	Rev Req per Cust (i.e., Cost Avoidance)	$	604.61
20	Deferred Taxes:		25
21	20-year MACRS		0.000%
22	Tax Depreciation		-
23			-
24			-
25			-
26			4,276,827

27		7,748,757
28		7,750,494
29		7,748,757
30		7,750,494
31		7,748,757
32		7,750,494
33		7,748,757
34		7,750,494
35		7,748,757
36		7,750,494
37		7,748,757
38		7,750,494
39		7,854,714
40		8,490,456
41		9,180,045
42		122,797,548
43	Book Depreciation	300,300,000
44	Variance	($177,502,452)
45	Deferred Taxes	($47,932,762)

1	**General Inputs:**		
2	Start Date:	11/1/2024	<-- *input*
3	Year 1:	2025	<-- *input*
4	UPC Therms - New Customers	1000	<-- *input*
5	NPV Number of Years:	15	<-- *input*
6	Model depreciation assumption	6.67%	
7	**Distribution Revenue Calculation:**		
8	UPC (therms)	1000	
9			
10	Customer Charge	**$10.00**	<-- *input (tariff)*
11	Rate per Therm	0.90649	<-- *input (tariff)*
12	**Annual Distribution Revenue (Real $)**	**$1,026.49**	
13	**NPV**	$0	
14			
15	**Construction Costs**	**($4,419)**	***Goal seek to produce 0 NPV***
16	**Times Margin**	-4.3	

UPC (Therms)	
LEA	
Times Margin	

17	**Cost of Capital**				
18				**Weighted**	**After-tax**
19		**% of Capital**	**Cost**	**Cost**	**Cost**
20					
21	**Debt**	50.00%	4.712%	2.356%	1.720%
22	**Common Equity**	50.00%	9.400%	4.700%	4.700%
23		100.00%		**7.056%**	**6.420%**

24	**Other Costs:**		
25	**State Tax Rate**	7.60%	<-- *input*
26	**Federal Tax Rate**	21.00%	<-- *input*
27	**Revenue Sensitive Rate (Franchise tax, Comm fee)**	2.741%	<-- *input*
28	**Property Tax Rate**	1.50%	<-- *input*
29	**Incremental O&M**	79.19	<-- *input*

Model Results at Proposed Consumption Levels (Therms)

250	450	650	1,000
-$144	-$1,284	-$2,424	-$4,419
-0.4	-2.4	-3.4	-4.3

Growth Rate
2022-24 CCI Cap
2025-27 CCI Cap
Beyond 2027

		Source		2024
1	**Normalized Load**	NWN internal data		1,088,444,642
2	**Non-Combustion Exclusion**	NWN internal data		20,733,841
3	**RNG**	NWN internal data		11,540,147
4	**MT CO2e**	NWN internal data		5,609,893
5	**Compliance Curve (MT CO2e)**	NWN internal data		5,316,897
6	**Over (Under) Compliance**			292,996
7	**CCI Cap**			560,989
8	**Over (Under) CCI Cap**			(267,994)
9	**Accumulated Over (Under) CCI Cap**			(267,994)
10	**New Customer Therms**	NWN internal data		450
11	**New Customer MT CO2e**	NWN internal data		2.39
12	**CPP Proxy Cost of New Customer**	NWN internal data - Revised	$	150.65
13	**CPP Proxy Cost per Therm**		$	0.33
14	**CPP Proxy Cost**		$	334.78
15	**2022 CPP Annual Cap (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps		28,081,335
16	**CPP Annual Caps (MT CO2e)**	DEQ Greenhouse Gas Emissions Calculations to supplement rulemaking GHGCR2021, Calculation for proposed OAR 340-271-9000 Table 2: Oregon Climate Protection Program Caps		25,921,232
17	**CPP Revenue Multiplier**			-7.69%
18	**CPP Revenue**		$	25.75

0.15%
10.00%
15.00%
20.00%

		2025	2026	2027	2028
1	**Normalized Load**	1,090,264,509	1,091,897,976	1,093,353,861	1,094,995,193
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	5,619,559	5,628,235	5,635,968	5,644,686
5	**Compliance Curve (MT CO2e)**	5,095,359	4,873,822	4,652,285	4,430,747
6	**Over (Under) Compliance**	524,200	754,413	983,683	1,213,939
7	**CCI Cap**	842,934	844,235	845,395	1,128,937
8	**Over (Under) CCI Cap**	(318,734)	(89,822)	138,288	85,002
9	**Accumulated Over (Under) CCI Cap**	(586,728)	(676,550)	(538,263)	(453,261)
10	**New Customer Therms**	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 150.65	$ 150.65	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm**	$ 0.33	$ 0.33	$ 2.20	$ 2.20
14	**CPP Proxy Cost**	$ 334.78	$ 334.78	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**				
16	**CPP Annual Caps (MT CO2e)**	25,763,209	24,637,057	23,510,904	23,013,190
17	**CPP Revenue Multiplier**	-8.26%	-12.27%	-16.28%	-18.05%
18	**CPP Revenue**	$ 27.64	$ 41.06	$ 358.07	$ 397.06

		2029	2030	2031	2032
1	**Normalized Load**	1,096,638,989	1,098,285,253	1,099,933,988	1,101,585,198
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	5,653,417	5,662,161	5,670,918	5,679,688
5	**Compliance Curve (MT CO2e)**	4,209,210	3,987,673	3,766,135	3,544,598
6	**Over (Under) Compliance**	1,444,207	1,674,488	1,904,783	2,135,090
7	**CCI Cap**	1,130,683	1,132,432	1,134,184	1,135,938
8	**Over (Under) CCI Cap**	313,523	542,056	770,599	999,153
9	**Accumulated Over (Under) CCI Cap**	(139,738)	402,318	1,172,917	2,172,070
10	**New Customer Therms**	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Proxy Cost**	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**				
16	**CPP Annual Caps (MT CO2e)**	21,842,149	20,671,108	19,910,424	18,688,088
17	**CPP Revenue Multiplier**	-22.22%	-26.39%	-29.10%	-33.45%
18	**CPP Revenue**	$ 488.80	$ 580.55	$ 640.14	$ 735.90

		2033	2034	2035	2036
1	Normalized Load	1,103,238,887	1,104,895,059	1,106,553,717	1,108,214,864
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,688,472	5,697,269	5,706,079	5,714,902
5	Compliance Curve (MT CO2e)	3,323,061	3,101,523	2,879,986	2,726,387
6	Over (Under) Compliance	2,365,411	2,595,746	2,826,093	2,988,515
7	CCI Cap	1,137,694	1,139,454	1,141,216	1,142,980
8	Over (Under) CCI Cap	1,227,717	1,456,292	1,684,877	1,845,534
9	Accumulated Over (Under) CCI Cap	3,399,786	4,856,078	6,540,955	8,386,490
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	17,465,752	16,243,416	15,021,080	14,219,956
17	CPP Revenue Multiplier	-37.80%	-42.16%	-46.51%	-49.36%
18	CPP Revenue	$ 831.67	$ 927.43	$ 1,023.19	$ 1,085.95

		2037	2038	2039	2040
1	Normalized Load	1,109,878,506	1,111,544,645	1,113,213,285	1,114,884,430
2	Non-Combustion Exclusion	20,733,841	20,733,841	20,733,841	20,733,841
3	RNG	11,540,147	11,540,147	11,540,147	11,540,147
4	MT CO2e	5,723,738	5,732,588	5,741,451	5,750,327
5	Compliance Curve (MT CO2e)	2,572,787	2,419,188	2,265,589	2,111,990
6	Over (Under) Compliance	3,150,951	3,313,400	3,475,862	3,638,337
7	CCI Cap	1,144,748	1,146,518	1,148,290	1,150,065
8	Over (Under) CCI Cap	2,006,203	2,166,882	2,327,572	2,488,272
9	Accumulated Over (Under) CCI Cap	10,392,693	12,559,575	14,887,147	17,375,418
10	New Customer Therms	450	450	450	450
11	New Customer MT CO2e	2.39	2.39	2.39	2.39
12	CPP Proxy Cost of New Customer	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	CPP Proxy Cost per Therm	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	CPP Proxy Cost	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	2022 CPP Annual Cap (MT CO2e)				
16	CPP Annual Caps (MT CO2e)	13,418,831	12,617,707	11,816,583	11,015,459
17	CPP Revenue Multiplier	-52.21%	-55.07%	-57.92%	-60.77%
18	CPP Revenue	$ 1,148.72	$ 1,211.48	$ 1,274.24	$ 1,337.01

		2041	2042	2043	2044
1	**Normalized Load**	1,116,558,083	1,118,234,249	1,119,912,932	1,121,594,134
2	**Non-Combustion Exclusion**	20,733,841	20,733,841	20,733,841	20,733,841
3	**RNG**	11,540,147	11,540,147	11,540,147	11,540,147
4	**MT CO2e**	5,759,217	5,768,119	5,777,036	5,785,965
5	**Compliance Curve (MT CO2e)**	1,958,390	1,804,791	1,651,192	1,497,593
6	**Over (Under) Compliance**	3,800,827	3,963,328	4,125,844	4,288,372
7	**CCI Cap**	1,151,843	1,153,624	1,155,407	1,157,193
8	**Over (Under) CCI Cap**	2,648,983	2,809,705	2,970,437	3,131,179
9	**Accumulated Over (Under) CCI Cap**	20,024,402	22,834,106	25,804,543	28,935,722
10	**New Customer Therms**	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Proxy Cost**	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**				
16	**CPP Annual Caps (MT CO2e)**	10,214,334	9,413,210	8,612,086	7,810,962
17	**CPP Revenue Multiplier**	-63.63%	-66.48%	-69.33%	-72.18%
18	**CPP Revenue**	$ 1,399.77	$ 1,462.53	$ 1,525.30	$ 1,588.06

		2045	2046	2047	2048	2049
1	**Normalized Load**					
2	**Non-Combustion Exclusion**					
3	**RNG**					
4	**MT CO2e**					
5	**Compliance Curve (MT CO2e)**					
6	**Over (Under) Compliance**					
7	**CCI Cap**					
8	**Over (Under) CCI Cap**					
9	**Accumulated Over (Under) CCI Cap**					
10	**New Customer Therms**	450	450	450	450	450
11	**New Customer MT CO2e**	2.39	2.39	2.39	2.39	2.39
12	**CPP Proxy Cost of New Customer**	$ 990.00	$ 990.00	$ 990.00	$ 990.00	$ 990.00
13	**CPP Proxy Cost per Therm**	$ 2.20	$ 2.20	$ 2.20	$ 2.20	$ 2.20
14	**CPP Proxy Cost**	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
15	**2022 CPP Annual Cap (MT CO2e)**					
16	**CPP Annual Caps (MT CO2e)**	7,009,837	6,208,713	5,407,589	4,606,465	3,805,340
17	**CPP Revenue Multiplier**	-75.04%	-77.89%	-80.74%	-83.60%	-86.45%
18	**CPP Revenue**	$ 1,650.82	$ 1,713.59	$ 1,776.35	$ 1,839.11	$ 1,901.87

LEA Determined ($4,419)

			Year 1	Year 2	Year 3	Year 4	Year 5
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		(64)	(59)	(55)	(51)	(46)
	Taxes on Equity Return						
4	State		(21)	(20)	(18)	(17)	(15)
5	Federal		(54)	(50)	(46)	(43)	(39)
6	Total Taxes		(75)	(70)	(65)	(59)	(54)
	Return on Rate Base						
7	Debt		(101)	(94)	(87)	(81)	(74)
8	Common Equity		(202)	(188)	(174)	(161)	(147)
9	Total Return		(303)	(283)	(262)	(241)	(221)
10	Subtotal Cost of Service		(656)	(627)	(597)	(567)	(537)
11	Revenue Sensitive Items		(18)	(18)	(17)	(16)	(15)
12	Total Cost of Service		-675	-645	-614	-583	-552
13	Cost of Proxy CPP ($/Therm)		0.33	0.33	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		335	335	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-28	-41	-488	-541	-667
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		0	22	44	66	88
18	Less: Contribution to New Non-Growth Capex		-44	-101	-149	-192	-233
19	Total Cost of Service (Net)		-412	-430	1,793	1,750	1,636
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		$1,438	$1,457	($767)	($724)	($610)

			Year 6	Year 7	Year 8	Year 9	Year 10
1	Depreciation (using book depreciation rates)	6.67%	(295)	(295)	(295)	(295)	(295)
2	O&M		79	79	79	79	79
3	Property Taxes		(42)	(37)	(33)	(28)	(24)
	Taxes on Equity Return						
4	State		(14)	(13)	(11)	(10)	(9)
5	Federal		(36)	(32)	(29)	(25)	(22)
6	Total Taxes		(50)	(45)	(40)	(35)	(31)
	Return on Rate Base						
7	Debt		(67)	(61)	(54)	(48)	(42)
8	Common Equity		(134)	(121)	(108)	(96)	(83)
9	Total Return		(201)	(182)	(163)	(144)	(125)
10	Subtotal Cost of Service		(508)	(479)	(451)	(423)	(395)
11	Revenue Sensitive Items		(14)	(14)	(13)	(12)	(11)
12	Total Cost of Service		-522	-493	-464	-435	-406
13	Cost of Proxy CPP ($/Therm)		3.00	3.00	3.00	3.00	3.00
14	UPC (Therms)		1,000	1,000	1,000	1,000	1,000
15	New Customer Proxy Cost of CPP		3,000	3,000	3,000	3,000	3,000
16	Less: New Customer Recovery of CPP (re class WACOD)		-792	-873	-1,004	-1,134	-1,265
17	Nominal Change in Base Rate Revenue per Customer (Rate Base)		110	132	155	177	199
18	Less: Contribution to New Non-Growth Capex		-269	-302	-333	-362	-390
19	Total Cost of Service (Net)		1,527	1,465	1,354	1,245	1,138
20	New Customer Revenue		$1,026	$1,026	$1,026	$1,026	$1,026
21	Revenue less cost of service (impact on existing customers)		($501)	($438)	($328)	($219)	($111)

			Year 11	Year 12	Year 13	Year 14	Year 15
1	**Depreciation (using book depreciation rates)**	6.67%	(295)	(295)	(295)	(295)	(295)
2	**O&M**		79	79	79	79	79
3	**Property Taxes**		(20)	(15)	(11)	(6)	(2)
	Taxes on Equity Return						
4	**State**		(7)	(6)	(5)	(3)	(2)
5	**Federal**		(19)	(15)	(12)	(9)	(5)
6	**Total Taxes**		(26)	(21)	(17)	(12)	(7)
	Return on Rate Base						
7	**Debt**		(35)	(29)	(23)	(16)	(10)
8	**Common Equity**		(71)	(58)	(45)	(33)	(20)
9	**Total Return**		(106)	(87)	(68)	(49)	(30)
10	**Subtotal Cost of Service**		(367)	(339)	(311)	(283)	(255)
11	**Revenue Sensitive Items**		(10)	(10)	(9)	(8)	(7)
12	**Total Cost of Service**		-377	-348	-320	-291	-262
13	**Cost of Proxy CPP ($/Therm)**		3.00	3.00	3.00	3.00	3.00
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000
15	**New Customer Proxy Cost of CPP**		3,000	3,000	3,000	3,000	3,000
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-1,395	-1,481	-1,566	-1,652	-1,738
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		221	243	265	287	309
18	**Less: Contribution to New Non-Growth Capex**		-416	-440	-462	-483	-502
19	**Total Cost of Service (Net)**		1,032	973	916	861	807
20	**New Customer Revenue**		$1,026	$1,026	$1,026	$1,026	$1,026
21	**Revenue less cost of service (impact on existing customers)**		($6)	$53	$110	$166	$219

			Year 16	Year 17	Year 18	Year 19	Year 20
1	**Depreciation (using book depreciation rates)**	6.67%	(295)	(295)	(295)	(295)	(295)
2	**O&M**		79	79	79	79	79
3	**Property Taxes**		2	7	11	16	20
	Taxes on Equity Return						
4	**State**		(1)	1	2	3	4
5	**Federal**		(2)	1	5	8	11
6	**Total Taxes**		(3)	2	7	11	16
	Return on Rate Base						
7	**Debt**		(4)	3	9	15	22
8	**Common Equity**		(7)	5	18	30	43
9	**Total Return**		(11)	8	27	46	65
10	**Subtotal Cost of Service**		(227)	(199)	(171)	(143)	(115)
11	**Revenue Sensitive Items**		(6)	(6)	(5)	(4)	(3)
12	**Total Cost of Service**		-233	-204	-176	-147	-118
13	**Cost of Proxy CPP ($/Therm)**		3.00	3.00	3.00	3.00	3.00
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000
15	**New Customer Proxy Cost of CPP**		3,000	3,000	3,000	3,000	3,000
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-1,823	-1,909	-1,994	-2,080	-2,166
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		585	585	585	585	585
18	**Less: Contribution to New Non-Growth Capex**		-519	-535	-549	-561	-571
19	**Total Cost of Service (Net)**		1,009	937	866	797	730
20	**New Customer Revenue**		$1,026	$1,026	$1,026	$1,026	$1,026
21	**Revenue less cost of service (impact on existing customers)**		$18	$90	$160	$229	$296

			Year 21	Year 22	Year 23	Year 24	Year 25
1	**Depreciation (using book depreciation rates)**	6.67%	(295)	(295)	(295)	(295)	(295)
2	**O&M**		79	79	79	79	79
3	**Property Taxes**		25	29	33	38	42
	Taxes on Equity Return						
4	**State**		6	7	8	9	10
5	**Federal**		15	17	20	23	26
6	**Total Taxes**		20	24	28	32	36
	Return on Rate Base						
7	**Debt**		28	33	38	43	48
8	**Common Equity**		55	66	76	86	96
9	**Total Return**		83	99	114	129	144
10	**Subtotal Cost of Service**		(88)	(63)	(40)	(17)	7
11	**Revenue Sensitive Items**		(2)	(2)	(1)	(0)	0
12	**Total Cost of Service**		-90	-65	-41	-17	7
13	**Cost of Proxy CPP ($/Therm)**		3.00	3.00	3.00	3.00	3.00
14	**UPC (Therms)**		1,000	1,000	1,000	1,000	1,000
15	**New Customer Proxy Cost of CPP**		3,000	3,000	3,000	3,000	3,000
16	**Less: New Customer Recovery of CPP (re class WACOD)**		-2,251	-2,337	-2,422	-2,508	-2,593
17	**Nominal Change in Base Rate Revenue per Customer (Rate Base)**		585	585	585	585	585
18	**Less: Contribution to New Non-Growth Capex**		-580	-587	-594	-600	-605
19	**Total Cost of Service (Net)**		663	595	527	460	393
20	**New Customer Revenue**		$1,026	$1,026	$1,026	$1,026	$1,026
21	**Revenue less cost of service (impact on existing customers)**		$363	$431	$500	$567	$633

NW Natural
Financial Statements

Income Statement			Year 1	Year 2	Year 3	Year 4
1	Revenue		1,026	1,026	1,026	1,026
2	CPP Revenue		28	41	488	541
3	CPP Cost		(335)	(335)	(3,000)	(3,000)
4	Nominal Change in Base Rate Revenue per Customer		0	(22)	(44)	(66)
5	Contribution to New Non-Growth Capex		44	101	149	192
6	Operations & Maintenance	$79.19	(79)	(79)	(79)	(79)
7	Depreciation (model assumed term)	6.67%	295	0	0	0
8	Franchise Tax	2.74%	(28)	(28)	(28)	(28)
9	Property Tax	1.50%	66	62	62	62
10	Interest Expense	4.71%	(101)	(97)	(95)	(93)
11	Net Income Before Tax		916	669	(1,521)	(1,445)
12	Income Tax	27.00%	247	181	(411)	(390)
13	Net Available to Common		668	489	(1,110)	(1,055)

Balance Sheet		Year 1	Year 2	Year 3	Year 4
Assets					
1	Gross Plant	(4,419)	(4,419)	(4,419)	(4,419)
2	Accumulated Depreciation	(295)	(295)	(295)	(295)
3	Net Plant	(4,124)	(4,124)	(4,124)	(4,124)
4	Total Assets	(4,124)	(4,124)	(4,124)	(4,124)
Liabilities and Equity					
5	Common Equity	(2,080)	(2,036)	(1,997)	(1,960)
6	Long Term Debt	(2,080)	(2,036)	(1,997)	(1,960)
7	Deferred Taxes	35	(51)	(131)	(205)
8	Total Liabilities and Equity	(4,124)	(4,124)	(4,124)	(4,124)

Cash Flow Statement		Year 1	Year 2	Year 3	Year 4

Operating Activities					
1	**Net Income**	668	489	(1,110)	(1,055)
2	**Depreciation**	(295)	0	0	0
3	**Deferred Taxes**	35	(86)	(80)	(74)
4	**Cash Provided by Operating Activities**	409	402	(1,190)	(1,128)
Investing Activities					
5	**Project**	4,419	0	0	0
6	**Cash Used in Investing Activities**	4,419	0	0	0
Financing Activities					
7	**Common Stock Issued**	(2,209)	0	0	0
8	**Long Term Debt Issued**	(2,209)	0	0	0
9	**Long Term Debt Retired**	130	43	40	37
10	**Common Stock Dividends**	(538)	(445)	1,150	1,092
11	**Cash Provided by Financing Activities**	(4,828)	(402)	1,190	1,128
12	**Net Cash Flow**	0	0	0	0

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026
667	792	873	1,004	1,134	1,265	1,395	1,481	1,566	1,652	1,738	1,823
(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
(88)	(110)	(132)	(155)	(177)	(199)	(221)	(243)	(265)	(287)	(309)	(585)
233	269	302	333	362	390	416	440	462	483	502	519
(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
0	0	0	0	0	0	0	0	0	0	0	0
(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
62	62	62	62	62	62	62	62	62	62	62	62
(92)	(90)	(89)	(87)	(86)	(85)	(83)	(82)	(81)	(80)	(78)	(77)
(1,299)	(1,159)	(1,065)	(924)	(785)	(648)	(512)	(423)	(336)	(250)	(167)	(338)
(351)	(313)	(288)	(250)	(212)	(175)	(138)	(114)	(91)	(68)	(45)	(91)
(948)	(846)	(777)	(675)	(573)	(473)	(374)	(309)	(245)	(183)	(122)	(247)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(1,926)	(1,894)	(1,865)	(1,838)	(1,811)	(1,785)	(1,758)	(1,732)	(1,705)	(1,678)	(1,652)	(1,625)
(1,926)	(1,894)	(1,865)	(1,838)	(1,811)	(1,785)	(1,758)	(1,732)	(1,705)	(1,678)	(1,652)	(1,625)
(273)	(336)	(394)	(448)	(501)	(555)	(608)	(661)	(714)	(768)	(821)	(874)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)

Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16

(948)	(846)	(777)	(675)	(573)	(473)	(374)	(309)	(245)	(183)	(122)	(247)
0	0	0	0	0	0	0	0	0	0	0	0
(68)	(63)	(58)	(54)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
(1,016)	(909)	(836)	(729)	(626)	(526)	(427)	(362)	(298)	(236)	(175)	(300)
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
34	32	29	27	27	27	27	27	27	27	27	27
982	877	807	702	600	499	400	335	272	209	148	274
1,016	909	836	729	626	526	427	362	298	236	175	300
0	0	0	0	0	0	0	0	0	0	0	0

Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026
1,909	1,994	2,080	2,166	2,251	2,337	2,422	2,508	2,593
(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
(585)	(585)	(585)	(585)	(585)	(585)	(585)	(585)	(585)
535	549	561	571	580	587	594	600	605
(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
0	0	0	0	0	0	0	0	0
(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
62	62	62	62	62	62	62	62	62
(76)	(75)	(73)	(72)	(71)	(71)	(71)	(71)	(71)
(236)	(135)	(36)	61	156	250	342	433	524
(64)	(37)	(10)	16	42	67	92	117	141
(172)	(99)	(27)	44	114	182	250	316	382

Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)	(4,419)
(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)	(295)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)
(1,598)	(1,572)	(1,545)	(1,519)	(1,505)	(1,505)	(1,505)	(1,505)	(1,505)
(1,598)	(1,572)	(1,545)	(1,519)	(1,505)	(1,505)	(1,505)	(1,505)	(1,505)
(927)	(981)	(1,034)	(1,087)	(1,114)	(1,114)	(1,114)	(1,114)	(1,114)
(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)	(4,124)

Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25

(172)	(99)	(27)	44	114	182	250	316	382
0	0	0	0	0	0	0	0	0
(53)	(53)	(53)	(53)	(27)	0	0	0	0
(225)	(152)	(80)	(9)	87	182	250	316	382
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
27	27	27	27	13	0	0	0	0
199	125	53	(18)	(101)	(182)	(250)	(316)	(382)
225	152	80	9	(87)	(182)	(250)	(316)	(382)
(0)	0	(0)	0	(0)	0	0	0	0

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Excerpt from Staff's Final Comments in LC 79

April 18, 2024

4.8 - RNG Modeling and Appendix K

Ted Drennan, Energy Policy Analyst

Appendix K

Staff appreciates the Company's response to Staff Request 24 from Opening Comments and the additional detail provided to describe the differences between the RNG Evaluation Methodology provided in UM 2030 and methodology ultimately presented in the IRP. Staff requests that future IRPs include a clear report of any key changes in the methodology similar to that included in the Company's Reply Comments.[100]

When the Company filed its IRP on September 23, 2022, it did so without including Appendix K. The Company subsequently filed Appendix K on October 21, 2022. The Company then met with Staff to discuss its modeling of RNG on January 20, 2023, in response to Staff Request 25, which requested a meeting with the Company to discuss questions about the RNG workbook. At that time NW Natural indicated it would file a corrected version of Appendix K in February, which, as of March 23, 2023, has not been filed.

Staff has been unable to resolve all concerns as it has yet to see an updated version of Appendix K the Company had indicated it would provide. Further, Staff continues to see opportunities to improve risk inputs and modeling. However, Staff is comfortable enough with the current RNG modeling in this IRP to recommend continued use of the methodology and delay discussion of workbook improvements until future proceedings. Staff's willingness to address these issues in a future proceeding does not imply prudence for projects selected using the method.

Recommendation 34: The Company should provide an updated Appendix K which correctly describes the Company's modeling for RNG projects.

RNG Workbook

The issues regarding the RNG workbook that were discussed at the January 20 meeting included: 1) selection of "Type of Project" and associated outboard modeling, and 2) risk inputs and associated modeling.

In its response to Staff's Data Request 13, the Company explained that the "Project Type" in the RNG models submitted by the Company might not reflect the actual project because there had been additional outboard modeling, i.e., modeling that occurs outside of the RNG workbook. This outboard modeling was used in a number of ways. One way was to determine the total revenue requirement to input in the RNG model, which was derived in a cost-of-service model. The Company also used outboard models to calculate the value associated with the sale of brown gas in some of its earlier models. Where this occurred, the Company selected

[100] NW Natural Reply Comments at 53.

"Unbundled Environmental Attribute Purchase" for the project type, when the actual project was "RNG with Sale of Brown Gas." The Company addressed Staff's concern about this discrepancy between modeled projects and actual projects at the January 20 meeting. Staff understands this to be an issue with earlier models and likely will not be an issue going forward.

Staff's concerns with NW Natural's risk modeling for the RNG model in opening comments remain. In summary, these include the choice of risk distribution, the lack of inclusion of downside risk, and the lack of information on how the risk bands are selected by internal experts. For risk distribution, the Company uses a lognormal distribution for asymmetric risks but has offered no foundation for this approach.[101] Staff raised a question regarding the approach using a hypothetical example in opening comments[102] of a +/-20 percent risk band versus one with -19 percent and +20 percent. The risk distribution for the former would be assumed normal, the latter assumed lognormal. At the January 20 meeting, the Company explained under this hypothetical that the results would be similar under either lognormal or normal distributions. While this may be true in the hypothetical posed, it still does not provide rationale for the assumptions of a lognormal risk distribution. For reference, an example of the hypothetical risk data for a project included with the Company's RNG Incremental Cost Workbook is included below.

Risk Analysis Key Inputs		
RNG Volume Uncertainty		
Annual Prob RNG Supply Ceases		0.5%
Prob of Delay (1 and 2 year)	30%	5%
% Δ From Base Case	5th %	95th %
Project Volume Output	-20%	10%
Project Cost Uncertainty		
% Δ From Base Case	5th %	95th %
Carbon Intensity	-15%	15%
Payments to Investments	-5%	30%
Other non-output costs	-3%	5%
Non-offtake Variable Costs	-20%	30%
Offtake/Biogas Price	0%	0%
Other Offsetting Revenues	-12%	30%

[103]

The Company did not provide additional information on the reasons for ignoring downside risk (i.e., risks that could lower expected costs) in their modeling. Staff provided a hypothetical in opening comments for this as well.[104] In Staff's hypothetical there should be a clear preference for one project over another, but due to the Company's modeling approach the Company would be indifferent between the projects.

[101] RNG Incremental Cost Workbook.
[102] See Staff Comments at 56-57.
[103] RNG Incremental Cost Workbook, RNG Dashboard Tab.
[104] Ibid at 57.

Finally, there is a lack of a standardized approach to risk modeling, or selection of risk bands, which is still concerning to Staff. Here the Company's internal experts assess risks associated with various factors included in Table k.2 Project Evaluation Component Description.[105] There are no formal rules or processes for assigning risks, so it is not clear that results of the analysis would be the same under two different subject-matter experts. Comments from CUB highlight concerns about relying on internal experts with regard to gas heat pump adoption rates which were more optimistic than adoption rates from NEEA experts.[106] NW Natural's RNG modeling likewise relies on internal experts to assess risks associated with different projects. It is not clear to Staff whether there are policies in place at the Company to assure modeling of risks related to RNG projects are standardized, or if expert biases might systemically favor one type of project versus another. As discussed in Section **3.6 - RNG: OWNERSHIP VS. CONTRACTUAL PURCHASES**, the approach of the electric utilities, especially PacifiCorp which allows self-scoring for non-price attributes, would bring standardization and transparency to this process. Appendix K, when corrected, could also allow for additional information related to RFP modeling and scoring.

Recommendation 35: In the next IRP, the Company should provide support for risk modeling approach (i.e. lognormal vs normal risk distributions, ignoring upside risks) and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 36: In the next IRP, the Company should standardize their approach to selecting risk values such that modeling could be duplicated and ensure this topic is discussed in a technical working group meeting for the next IRP.

Recommendation 37: The Company should provide an explanation for why it does not consider downside risks in its models and demonstrate that this approach results in least-cost, least-risk resources.

105 See NW Natural IRP, Appendices at 199.
106 See CUB comments at 10.

4.9 - RNG, Hydrogen, and Syngas

4.9.1 - RNG Availability and Cost

Ted Drennan, Energy Policy Analyst

As discussed in Opening Comments, NW Natural is placing a heavy reliance on non-emitting supply-side resources for decarbonizing their system. Staff appreciates the additional information provided by the Company regarding its cost assumptions for RNG, hydrogen, and synthetic methane. The Company's experience with RNG development and its exposure to market prices and availability helps support its near-term assumptions. However, Staff still has some concerns with how the Company's RNG costs compare to other forecasts and with the longer-term cost and availability trends. In particular, Staff has concerns regarding availability assumptions that rely on 'all-hands-on-deck' approach to RNG and the Company's minimal consideration to competition for RNG.

Staff has looked more in depth at the Company's reliance on a study from ICF. This further dive into the study has not alleviated concerns of the appropriateness of relying on the study.

The study was discussed in the Company's third technical workshop on March 28, 2022. At the discussion, it was reported the values are dependent on a deep decarbonization scenario that "requires aggressive deployment of emission reduction measures across the country."[107] This is also called an "all-hands-on-deck approach." While this approach helps demonstrate the role decarbonized fuel could play under a best-case scenario, Staff does not believe it provides a reasonable foundation for understanding potential availability because it is premised on a flawed policy assumption. Recent legislative actions in the US challenge the assumption that all groups are working together regarding emission reductions from natural gas. A few simple illustrative examples follow.

On January 6, 2023, a law in Ohio was signed that declared natural gas is green energy. From HB 507:[108]

> (43) "Green energy" means any energy generated by using an energy resource that does one or more of the following:
> (a) Releases reduced air pollutants, thereby reducing cumulative air emissions;
> (b) Is more sustainable and reliable relative to some fossil fuels.
> "Green energy" includes energy generated by using natural gas as a resource.

[107] See Supply Side Resources Technical Working Group No. 3 Presentation, slide 72 (March 28, 2022).
[108] See Sub. H.B. No. 507, 134th Ohio General Assembly (Effective Date April 7, 2023).

The Wyoming legislature considered a resolution titled "Phasing out new electric vehicle sales by 2035." While Senate Joint Resolution SJ004[109] died in committee, it was not in line with the 'all hand-on-deck" approach in the ICF study.

The Kentucky Senate approved a bill SB 4,[110] that will, "prohibit the Public Service Commission from approving a request by a utility to retire a coal-fired electric generator unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customer's electric utility rate".

More locally, parties need look no farther than the situation with the Colstrip generating plants. Here the Montana legislature passed laws that were designed to stop the majority owners from closing the power plant. The laws were found to be unconstitutional,[111] although it looks like the plant will continue to operate.

Besides the issues raised above, the methodology of the study is a concern. As discussed by ICF, the 2021 study was based off of ICF's 2019 study. The 2019 study had two scenarios, a low-resource and high-resource approach. The 2019 study contained one price curve, for the high-resource scenario. The costs were less in this scenario than the low-resource scenario.

For the 2021 update relied on by NW Natural, ICF eased the constraints on what was available to produce RNG but kept the same cost curves. Thus, the supply increased, at constant costs, which does not seem reasonable. Table 2 below shows the assumptions between the two cases in ICF's 2019 study, along with the updated assumptions in the 2021 study. The latest assumptions are substantially greater than the earlier ones.

Table 2: ICF Study Comparisons

RNG Feedstock	ICF 2019 Study: Low Resource	ICF 2019 Study: High Resource	ICF Updated Study
LFG	50% of EPA's candidate landfills	80% of EPA's candidate landfills	95% of eligible landfills
Animal Manure	30% of technically available animal manure	60% of technically available animal manure	75% of technically available
WRRF	30% of WRRFs with a capacity greater than 7.25 million gallons per day	50% of WRRFs with a capacity greater than 3.3 million gallons per day	95% of facilities w/>3.5MGD
Food Waste	40% of the food waste available at $70/dry ton	70% of the food waste available at $100/dry ton	95% @ $100/ton

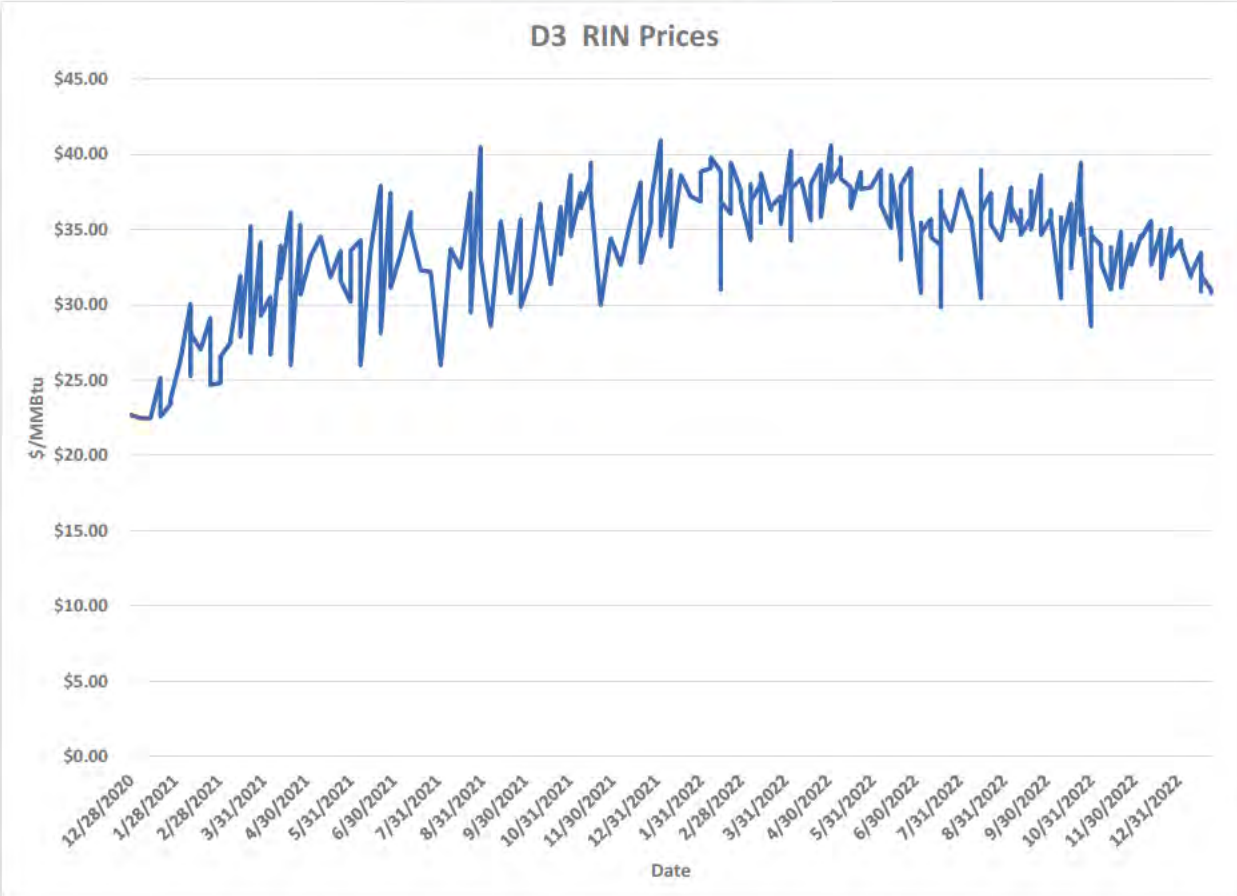
[109] See Wyoming Senate Joint Resolution No. SJ0004, Phasing Out New Electric Vehicle Sales by 2035 (last accessed March 11, 2023).
[110] See Kentucky Senate Bill 4, (adopted March 16,2023).
[111] See Tom Lutey, "Newly-passed Colstrip laws unconstitutional, court rules," Billings Gazette, October 10, 2022.

Agriculture Residue	20% of the agricultural residues available at $50/dry ton	50% of the agricultural residues available at $50/dry ton	80% @ $50/ton
Forestry and forest product residue	30% of the forest and forestry product residues available at $30/dry ton	60% of the forest and forestry product residues available at $60/dry ton	80% @ $50/ton
Energy crops	50% of the energy crops available at $50/dry ton	50% of the energy crops available at $70/dry ton	60% @ $50/ton
Municipal solid waste (MSW)	30% of the non-biogenic fraction of MSW available at $30/dry ton	60% of the non-biogenic fraction of MSW available at $100/dry ton	80% @ $50/ton
P2G	50% capacity factor for dedicated renewables	80% capacity for dedicated renewables	NA

Staff continues to have concerns with the price forecasts for RNG used by the Company. Competition for RNG is high in the renewable fuel market. Transportation RNG, with its environmental attributes represented by D3 Renewable Identification Numbers (RINs), receives premium rates. Figure 6 below highlights the historic prices for D3 RINs as reported by the EPA for 2021 through February 10, 2023. The D3 RIN prices [112] have been higher than NW Natural's current RNG projections for Tranche 2, which is estimated at $19/MMBtu. This means that NW Natural could have difficulty finding large quantities of RNG at prices much below prices of RIN RNG. In a recent filing, NW Natural discusses how the RNG market is driven by the fuels markets, including D3 RINs.[113] The Company points out that while volatile, "the overall value or RNG in these markets remain strong, with a 2-year average of over $33/mmbtu.[114]

[112] Data selected from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information last accessed March 11,2023. Prices are reported at the RIN level, which were converted to $/MMBtu. One MMBtu of RNG is approximately 11.7 RINs.
[113] See UG 462, NW Natural 100, Chittum/Page 25-26, lines 14-1. The current market for D3 RINs, which is the type of RNG the majority of resources we would purchase for RNG Statute and CPP Rule compliance would generate, is quite strong.
[114] See UG 462, NW Natural 100, Chittum/Page 26, lines 3-5.

Figure 6: D3 RIN Prices2021-Feb 10, 2023



Others looking at the RNG market have differing views than those in NW Natural's IRP as well. A recent article by S&P Global[115] addresses the current market for RNG, including the competing markets for RNG, i.e., use in transportation or by utilities:

> Transportation RNG -- which is typically priced around the value of conventional gas, plus D3 RIN credits -- is currently marketable between $30-$35/MMBtu, while RNG sold to utilities, manufacturers and other end users in the voluntary market is marketable between $20-$25/MMBtu, with normal production costs around $15/MMBtu and under, Kinder Morgan's Holsapple told S&P Global.

These estimates conflict with NW Natural's RNG projections. The same S&P Global report notes that producers are expecting prices for RNG around $20/MMBtu for long-term projects:[116]

[115] See https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/121622-rng-industry-expects-us-voluntary-customers-to-spur-demand-after-early-transport-boom last accessed March 11,2023.
[116] Ibid.

> A recent survey of 450 RNG producers by US clean energy consultancy EcoEngineers found that many companies are beginning to draw around $20/MMBtu for RNG sold into voluntary markets on a long-term basis.

Table 3 below compares the historic maximum and minimum EPA values in Figure , the values from S&P, and NW Natural's values for Tranche 1 and 2. Even NW Natural's projections for the higher-cost Tranche 2 are lower than historical and expected costs.

Table 3: RNG Cost Comparison

	Price
Tranche 1 (1/3 of NWN RNG Supply)	Portfolio cost of $14/MMBtu
Tranche 2 (2/3 of NWN RNG Supply)	Portfolio cost of $19/MMBtu
S&P long-term utility purchase of RNG	$20-25/MMBtu
S&P Transportation RNG	$30-35/MMBtu
Historic EPA D3 Cost – minimum (1/4/2021)	$22.46/MMBtu
Historic EPA D3 Cost – maximum (1/3/2022)	$40.95/MMBtu

Request 28 from Staff's opening comments requested further discussion supporting and providing justification for RNG, hydrogen, and synthetic [methane] cost assumptions. In the Company's response, it explains that "larger and larger scale RNG projects are being developed."[117] Further, the Company suggests, "if the utility developed RNG projects become a larger percentage of the utility's RNG portfolio, then costs for NW Natural customers will trend toward production costs."[118]

Staff agrees that utility-developed RNG projects will result in prices that trend toward production costs, as utility projects are generally provided to ratepayers at cost (plus rate-of-return). However, even the Company's Tranche 1 costs are lower that production costs noted by Kinder Morgan. Thus, it does not alleviate Staff's concerns with current long-term RNG price forecasts used in the IRP. Further, in the same section NW Natural cites World Resource Institute, which forecasts project costs from $3 to $30/MMBtu. The $30 is much higher than the Tranche 2 estimates, which top out at under $20/MMBtu. Overall, Staff is not persuaded by the Company's response regarding RNG price assumptions.

Staff understands that the Company provided a scenario with higher RNG costs in the 2022 IRP, however in the next IRP Staff would like to see a sensitivity with costs based on the higher end of recent, relevant publicly available forecasts. Additionally, given the wide range of forecast RNG prices, utilizing more than two tranches may help improve accuracy for costs and availability at different price ranges.

[117] See NW Natural reply comments at 59.
[118] *Ibid*.

Prior to the Company's next IRP technical working groups, Staff plans to explore engaging an independent third party to review the reasonableness of key technology and market assumptions for use in the next IRP.

Recommendation 38: For the next IRP, the Company should provide an analysis that would examine high-cost RNG, hydrogen, and synthetic gas as a sensitivity. The cost estimates should be on the higher end of recent, relevant publicly available forecasts, and the Company should provide the sources used for each cost forecast.

Recommendation 39: For the next IRP, the Company should provide a literature review of RNG price and availability forecasts.

4.9.2 - Hydrogen and Syngas Cost and Availability

Rose Anderson, Senior Economist

As discussed in Staff Opening Comments, NW Natural's estimates for hydrogen costs appear to be on the low end of available forecasts. NW Natural's hydrogen cost trajectory, based on advice from third party consultants, is among the lowest forecasts for hydrogen prices that Staff has reviewed. However, aggressive cost declines for green hydrogen are a real possibility given that renewable energy is ever-more abundant in the region and recent policies have taken aim at significantly reducing the cost of green hydrogen.

In Opening Comments, CUB argues that NW Natural's hydrogen cost estimates are concerning in part because the Company's IRP described hydrogen electrolyzers as dispatching opportunistically based on wholesale market prices. CUB argues that any electric rate paid by NW Natural to an electric utility is not likely to reflect opportunistic wholesale market prices. Staff agrees with this assessment. However, in NW Natural's Reply Comments, the Company explains that IRP hydrogen costs include the cost of a dedicated renewable resource and are not based on opportunistic wholesale market purchases.[119,120]

Staff reviewed the sources provided by the Company for its hydrogen cost estimates and finds that the materials provided offer only minimal support for the Company's estimates. While consultants provided cost estimates for a variety of hydrogen projects, NW Natural provided no clear documentation of its process for translating the third-party studies to a hydrogen price forecast that reflects NW Natural's unique circumstances. Electrolyzer size, capacity factor, and the manner of obtaining renewable energy are all important to the cost of hydrogen, and it is unclear what assumptions were used in this IRP. For example, **[Begin Confidential]** [redacted]

[119] NW Natural Reply Comments. Page 15.
[120] NW Natural Reply to Staff DR 151.

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

Past RG 41 Filings

April 18, 2024

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ■ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

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Is this report associated with a specific docket/case? ☐ No ■ Yes, docket number: RG-41

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Meter Sampling Program Report for 2019, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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February 12th, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2019

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2019 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2019. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2014 and December 31, 2019. The results of this analysis are as follows:

- As of December 31, 2019, we had 728,495 installed meters covered under the Meter Sampling Program. These meters formed 410 meter families. This total does not include meters determined to be non-conforming.
- Over the course of 2019, the company tested 5,271 meters. Over the five-year period of 2014 through 2019, the company had a total of 29,353 meter samples from which to base its results.
- 404 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 706,867 meters, or 97 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 9 new meter families were added in 2019. 3 meter families were removed from service due to small family size, during the normal course of business.
- 34 meter families, consisting of a total of 42,046 meters, are not conforming. Due to the number of meters requiring change-out (5.5% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2023, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 17 meter families, totaling 41,876 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.
    - 15 meter families, totaling 52 meters, will be removed from service due to their small population size and age.
    - 2 meter families, totaling 118 meters will be removed from service due to small family size and sampling requirements exceeding 34% of the total family population.
- Compared to the results above, the Year 2018 report resulted in 11,566 meters being put on the list for removal by the end of 2019.

If you have any questions or comments, please contact me at (503) 226-4211 ext. 5542.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie
Gas Measurement and Station Design Engineering Supervisor

cc: Andy Fortier, Jon Huddleston, Cliff Crawford, Joe Karney, Dave Weber, Kim Heiting

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Appendix A

Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2018	Rockwell	275	0	1	1		
560	0	2018	American	250	0	3	14	1	
487	0	2018	American	800	0	198	4		
505	507	2018	American	1000	0	356	7	1	
562	0	2018	American	250	0	695			
475	0	2018	American	630	0	4744	18	2	
602	0	2018	Itron	250	0	8178	20		
561	0	2018	American	250	0	9707	51	1	
125	0	2017	Rockwell	200	1	1	3		
470	472	2017	American	425	1	1			
520	0	2017	Rockwell	415	1	1			
560	0	2017	American	250	1	1	14		
570	0	2017	Rockwell	275	1	3	3		
562	0	2017	American	250	1	22			
487	0	2017	American	800	1	58	2		
505	507	2017	American	1000	1	203	7		
475	0	2017	American	630	1	1707	25	2	
602	0	2017	Itron	250	1	4603	30		
561	0	2017	American	250	1	11849	91	2	
140	0	2016	Sprague	175	2	1	3		
485	0	2016	American	800	2	1			
590	0	2016	Lancaster	250	2	1	2		
130	0	2016	American	175	2	2	7		
570	0	2016	Rockwell	275	2	2	2		
595	600	2016	Schlumberger	250	2	2			
572	0	2016	Sensus	275	2	3			
505	507	2016	American	1000	2	533	22	1	
475	0	2016	American	630	2	1650	24	1	
602	0	2016	Itron	250	2	4367	30		
561	0	2016	American	250	2	12685	98		
560	0	2015	American	250	3	1	8		
572	0	2015	Sensus	275	3	2	1		
Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
505	507	2015	American	1000	3	365	21		
475	0	2015	American	630	3	1274	55	1	
561	0	2015	American	250	3	17981	171	3	
120	0	2014	Rockwell	175	4	1	2		
572	0	2014	Sensus	275	4	1	1		
570	0	2014	Rockwell	275	4	2	3		
585	0	2014	Sprague	250	4	2			
130	0	2014	American	175	4	3	2		
560	0	2014	American	250	4	5	5		

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
505	507	2014	American	1000	4	447	34		
475	0	2014	American	630	4	1581	64		
561	0	2014	American	250	4	14738	205	1	
120	0	2013	Rockwell	175	5	1			
130	0	2013	American	175	5	1			
450	0	2013	Schlumberger	400	5	1			
510	515	2013	Rockwell	310	5	1			
570	0	2013	Rockwell	275	5	1			
572	0	2013	Sensus	275	5	1	1		
560	0	2013	American	250	5	4			
505	507	2013	American	1000	5	384	34		
475	0	2013	American	630	5	1521	83		
561	0	2013	American	250	5	15370	269	1	2
120	0	2012	Rockwell	175	6	1			
470	472	2012	American	425	6	1			
555	0	2012	American	310	6	1			
595	600	2012	Schlumberger	250	6	1			
570	0	2012	Rockwell	275	6	3	1		
572	0	2012	Sensus	275	6	4			
560	0	2012	American	250	6	6			
471	0	2012	American	425	6	10			
505	507	2012	American	1000	6	407	41	1	
475	0	2012	American	630	6	1465	60	1	
561	0	2012	American	250	6	11993	178	1	
485	0	2011	American	800	7	1			
510	515	2011	Rockwell	310	7	1			
520	0	2011	Rockwell	415	7	1			
570	0	2011	Rockwell	275	7	1			
590	0	2011	Lancaster	250	7	1			
140	0	2011	Sprague	175	7	2			
560	0	2011	American	250	7	3			
572	0	2011	Sensus	275	7	86	3		
471	0	2011	American	425	7	109	10		
505	507	2011	American	1000	7	377	44	1	
475	0	2011	American	630	7	1059	43	1	
561	0	2011	American	250	7	10703	166		
120	0	2010	Rockwell	175	8	1	1		
510	515	2010	Rockwell	310	8	1			
590	0	2010	Lancaster	250	8	1			
470	472	2010	American	425	8	2			
560	0	2010	American	250	8	2			
572	0	2010	Sensus	275	8	16	1		
471	0	2010	American	425	8	101	9		
475	0	2010	American	630	8	667	32		
561	0	2010	American	250	8	10129	199	3	
510	515	2009	Rockwell	310	9	1			
555	0	2009	American	310	9	1			

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140	0	2009	Sprague	175	9	2			
590	0	2009	Lancaster	250	9	2	1		
125	0	2009	Rockwell	200	9	3			
471	0	2009	American	425	9	3	1		
520	0	2009	Rockwell	415	9	3			
470	472	2009	American	425	9	4			
585	0	2009	Sprague	250	9	5			
570	0	2009	Rockwell	275	9	16	1		
130	0	2009	American	175	9	19	1		
505	507	2009	American	1000	9	295	31	4	
572	0	2009	Sensus	275	9	778	19		
561	0	2008	American	250	10	23031	424	49	
560	0	2007	American	250	11	193	25		
470	472	2007	American	425	11	234	28		2
471	0	2007	American	425	11	482	78	8	
561	0	2007	American	250	11	22000	437	42	1
470	472	2006	American	425	12	34	38	1	
560	0	2006	American	250	12	622	47	1	
561	0	2006	American	250	12	21524	359	24	1
450	0	2005	Schlumberger	400	13	8	7		
300	540	2005	Rockwell	800	13	11	11		
570	0	2005	Rockwell	275	13	12	10		
452	0	2005	Actaris	400	13	17	14		
470	472	2005	American	425	13	23	14		
520	0	2005	Rockwell	415	13	48	19		
560	0	2005	American	250	13	78	32	1	1
561	0	2005	American	250	13	1650	88	13	
572	0	2005	Sensus	275	13	24724	390	48	
450	0	2004	Schlumberger	400	14	8	11		
272	0	2004	Actaris	1000	14	15	33	2	
595	600	2004	Schlumberger	250	14	32	16		
585	0	2004	Sprague	250	14	63	28		
470	472	2004	American	425	14	88	22		
520	0	2004	Rockwell	415	14	107	22		
452	0	2004	Actaris	400	14	437	53	2	3
570	0	2004	Rockwell	275	14	3611	56		
572	0	2004	Sensus	275	14	13950	205	17	2
585	0	2003	Sprague	250	15	13	18		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
500	502	2003	American	1000	15	24	21		
450	0	2003	Schlumberger	400	15	29	17		
595	600	2003	Schlumberger	250	15	60	17		1
520	0	2003	Rockwell	415	15	154	74	1	
470	472	2003	American	425	15	209	66	3	
560	0	2003	American	250	15	453	58	1	
570	0	2003	Rockwell	275	15	19865	292	5	2
470	472	2002	American	425	16	434	46	1	
595	600	2002	Schlumberger	250	16	3282	177		2

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560	0	2002	American	250	16	8504	123	5	
570	0	2002	Rockwell	275	16	10821	163	3	
500	502	2001	American	1000	17	11	10	1	1
585	0	2001	Sprague	250	17	49	17		
270	0	2001	Schlumberger	1000	17	53	17		
595	600	2001	Schlumberger	250	17	3815	176	3	1
570	0	2001	Rockwell	275	17	8708	123	3	1
560	0	2001	American	250	17	9423	167	1	1
270	0	2000	Schlumberger	1000	18	18	13		
585	0	2000	Sprague	250	18	36	30	2	
470	472	2000	American	425	18	414	73	3	
595	600	2000	Schlumberger	250	18	3266	297	18	10
570	0	2000	Rockwell	275	18	8497	120	19	1
560	0	2000	American	250	18	11261	236	7	1
125	0	1999	Rockwell	200	19	139	21		
590	0	1999	Lancaster	250	19	151	22		
470	472	1999	American	425	19	250	48	1	
570	0	1999	Rockwell	275	19	10534	190	25	3
560	0	1999	American	250	19	11252	166	3	1
140	0	1998	Sprague	175	20	8	10		
270	0	1998	Schlumberger	1000	20	26	16		
590	0	1998	Lancaster	250	20	28	14		
125	0	1998	Rockwell	200	20	82	27		
500	502	1998	American	1000	20	87	47	7	
470	472	1998	American	425	20	160	65	6	
450	0	1998	Schlumberger	400	20	445	50		
585	0	1998	Sprague	250	20	5414	142		
560	0	1998	American	250	20	14450	258	21	2
485	0	1997	American	800	21	8	7		
510	515	1997	Rockwell	310	21	9	10		
520	0	1997	Rockwell	415	21	58	52	4	
450	0	1997	Schlumberger	400	21	64	18		
140	0	1997	Sprague	175	21	474	56	1	2
590	0	1997	Lancaster	250	21	2123	50		3
570	0	1997	Rockwell	275	21	2363	51	1	
585	0	1997	Sprague	250	21	5932	128	1	2
485	0	1996	American	800	22	8	11		
450	0	1996	Schlumberger	400	22	270	49		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
130	0	1996	American	175	22	1045	48	1	
585	0	1996	Sprague	250	22	4428	118		
570	0	1996	Rockwell	275	22	7687	140	4	
560	0	1996	American	250	22	11115	253	8	1
480	486	1995	American	800	23	18	14		2
130	0	1995	American	175	23	553	66	3	1
585	0	1995	Sprague	250	23	1520	42		
590	0	1995	Lancaster	250	23	4840	151	7	11
570	0	1995	Rockwell	275	23	6500	136	8	2

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560	0	1995	American	250	23	8197	199	12	1
555	0	1994	American	310	24	8	11	1	
510	515	1994	Rockwell	310	24	44	32		3
470	472	1994	American	425	24	225	32		
125	0	1994	Rockwell	200	24	388	80	6	1
120	0	1994	Rockwell	175	24	1375	74	1	2
585	0	1994	Sprague	250	24	1658	51	1	
130	0	1994	American	175	24	2638	118	9	
590	0	1994	Lancaster	250	24	4386	184	9	6
560	0	1994	American	250	24	6174	123	6	
570	0	1993	Rockwell	275	25	61	32	1	
510	515	1993	Rockwell	310	25	98	46	5	2
450	0	1993	Schlumberger	400	25	192	36		
125	0	1993	Rockwell	200	25	483	82	7	1
140	0	1993	Sprague	175	25	653	34		1
120	0	1993	Rockwell	175	25	2664	123	6	3
590	0	1993	Lancaster	250	25	2841	75	1	
130	0	1993	American	175	25	3172	123	13	3
585	0	1993	Sprague	250	25	3842	120		
560	0	1993	American	250	25	4073	123	2	2
470	472	1992	American	425	26	145	28		
140	0	1992	Sprague	175	26	566	35		2
125	0	1992	Rockwell	200	26	617	40	1	
585	0	1992	Sprague	250	26	2107	68		
590	0	1992	Lancaster	250	26	2667	95	1	1
560	0	1992	American	250	26	4806	103		
120	0	1992	Rockwell	175	26	6737	286	9	2
470	472	1991	American	425	27	27	26	2	
480	486	1991	American	800	27	47	36	4	
510	515	1991	Rockwell	310	27	213	24		2
140	0	1991	Sprague	175	27	451	54		3
125	0	1991	Rockwell	200	27	701	39		
590	0	1991	Lancaster	250	27	1724	73		1
120	0	1991	Rockwell	175	27	3858	178	6	5
130	0	1991	American	175	27	4898	138	11	5
560	0	1991	American	250	27	5576	208	4	2
480	486	1990	American	800	28	26	18		
125	0	1990	Rockwell	200	28	294	74	10	
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
140	0	1990	Sprague	175	28	1021	101		6
590	0	1990	Lancaster	250	28	1323	56	1	
130	0	1990	American	175	28	3121	130	18	1
120	0	1990	Rockwell	175	28	3569	145	12	3
570	0	1990	Rockwell	275	28	5397	133	12	3
560	0	1990	American	250	28	6319	195	2	6
555	0	1989	American	310	29	15	28	2	
125	0	1989	Rockwell	200	29	524	74	2	
140	0	1989	Sprague	175	29	760	40		3

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590	0	1989	Lancaster	250	29	1313	72		
130	0	1989	American	175	29	3255	150	10	2
120	0	1989	Rockwell	175	29	3510	147	7	4
560	0	1989	American	250	29	7022	229	4	4
520	0	1988	Rockwell	415	30	49	19		1
585	0	1988	Sprague	250	30	180	22		
140	0	1988	Sprague	175	30	753	59	2	3
120	0	1988	Rockwell	175	30	2189	94	6	2
130	0	1988	American	175	30	3119	137	17	2
560	0	1988	American	250	30	3151	95	1	2
555	0	1987	American	310	31	35	36	3	1
520	0	1987	Rockwell	415	31	43	27	1	2
125	0	1987	Rockwell	200	31	556	81	3	1
120	0	1987	Rockwell	175	31	2220	118	11	2
140	0	1987	Sprague	175	31	2967	125		10
130	0	1987	American	175	31	5904	205	23	2
510	515	1986	Rockwell	310	32	18	13		
555	0	1986	American	310	32	85	34	1	
140	0	1986	Sprague	175	32	964	58	1	1
120	0	1986	Rockwell	175	32	1316	57	2	1
130	0	1986	American	175	32	3992	138	16	2
560	0	1986	American	250	32	6218	194	8	
470	472	1985	American	425	33	24	26	2	
140	0	1985	Sprague	175	33	1147	65	1	7
560	0	1985	American	250	33	1462	42	1	
120	0	1985	Rockwell	175	33	1941	91	13	1
510	515	1984	Rockwell	310	34	15	15	1	1
485	0	1984	American	800	34	72	25		
470	472	1984	American	425	34	109	25		
140	0	1984	Sprague	175	34	708	45		1
125	0	1984	Rockwell	200	34	2109	92	11	1
130	0	1984	American	175	34	4786	182	19	2
470	472	1983	American	425	35	26	16		
140	0	1983	Sprague	175	35	816	93	3	4
125	0	1983	Rockwell	200	35	1763	89	4	1
130	0	1983	American	175	35	3002	127	18	2
470	472	1982	American	425	36	19	11		
520	0	1982	Rockwell	415	36	36	18		
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
510	515	1982	Rockwell	310	36	85	33		2
120	0	1982	Rockwell	175	36	1172	79	12	1
125	0	1982	Rockwell	200	36	3102	113	8	1
505	507	1981	American	1000	37	9	11		2
555	0	1981	American	310	37	27	26	1	1
485	0	1981	American	800	37	31	15		
520	0	1981	Rockwell	415	37	230	36		1
140	0	1981	Sprague	175	37	632	41		1
125	0	1981	Rockwell	200	37	2469	89	11	2

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485	0	1980	American	800	38	19	18	2	1
555	0	1980	American	310	38	63	40	4	
520	0	1980	Rockwell	415	38	75	39	1	
140	0	1980	Sprague	175	38	333	35		3
125	0	1980	Rockwell	200	38	1816	88	12	
130	0	1980	American	175	38	6181	243	17	1
520	0	1979	Rockwell	415	39	74	39	1	2
140	0	1979	Sprague	175	39	132	35	1	2
510	515	1979	Rockwell	310	39	170	49	2	2
120	0	1979	Rockwell	175	39	1617	93	10	4
130	0	1979	American	175	39	6381	203	13	4
520	0	1978	Rockwell	415	40	37	15		
140	0	1978	Sprague	175	40	271	77		4
120	0	1978	Rockwell	175	40	1451	101	6	5
125	0	1978	Rockwell	200	40	1580	94	5	
510	515	1977	Rockwell	310	41	154	39		1
120	0	1977	Rockwell	175	41	1352	89	4	3
130	0	1977	American	175	41	3264	126	3	
510	515	1976	Rockwell	310	42	278	43		1
140	0	1976	Sprague	175	42	1094	64	1	1
130	0	1975	American	175	43	24	14		
140	0	1975	Sprague	175	43	719	94		2
120	0	1975	Rockwell	175	43	1800	98	12	2
140	0	1974	Sprague	175	44	617	39		1
120	0	1974	Rockwell	175	44	2592	158	17	3
120	0	1973	Rockwell	175	45	661	59	2	
130	0	1973	American	175	45	727	83	9	
140	0	1973	Sprague	175	45	2880	143	3	8
140	0	1972	Sprague	175	46	148	37		2
120	0	1972	Rockwell	175	46	846	84	10	1
130	0	1972	American	175	46	2694	95	13	1
140	0	1971	Sprague	175	47	985	59		7
130	0	1971	American	175	47	1067	100	6	1
140	0	1970	Sprague	175	48	346	57		6
140	0	1968	Sprague	175	50	1006	76		16
505	507	2007	American	1000	11	376	71	9	
585	0	1991	Sprague	250	27	746	24		
475	0	2019	American	630	0	467	1		

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
487	0	2019	American	800	0	18			
505	507	2019	American	1000	0	145			
520	0	2018	Rockwell	415	1	1			
561	0	2019	American	250	0	2991	2		
562	0	2019	American	250	0	31	1		
602	0	2019	Itron	250	0	569	1		
570	0	2019	Rockwell	275	0	2	1		
120	0	1981	Rockwell	175	38	684	80	9	1
120	0	1983	Rockwell	175	36	1355	93	10	1

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140	0	1994	Sprague	175	25	591	31	0	3
480	486	2001	American	800	18	13	12	1	0
555	0	1984	American	310	35	214	21	0	1
120	0	1970	Rockwell	175	49	631	85	5	
140	0	1982	Sprague	175	37	581	50	2	3
470	472	1989	American	425	30	33	15	0	0
470	472	1995	American	425	24	87	20	0	0
480	486	1989	American	800	30	25	13	0	0
510	515	1981	Rockwell	310	38	200	62	5	3
520	0	1983	Rockwell	415	36	17	15	1	0
570	0	1994	Rockwell	275	25	5064	107	6	0
570	0	1998	Rockwell	275	21	5447	98	5	1
570	0	2008	Rockwell	275	11	6	1	0	0
120	0	1998	Rockwell	175	21	73	19	0	0
300	540	1996	Rockwell	800	23	29	14	0	1
300	540	2002	Rockwell	800	17	6	1	0	0
450	0	1999	Schlumberger	400	20	99	20	0	0
520	0	1977	Rockwell	415	42	42	15	0	1
520	0	1991	Rockwell	415	28	73	30	1	0
555	0	1997	American	310	22	22	19	2	1
130	0	1978	American	175	41	1553	89	10	1
480	486	1996	American	800	23	7	6	0	0
480	486	2002	American	800	17	22	12	0	0
520	0	1992	Rockwell	415	27	69	18	0	1
570	0	1991	Rockwell	275	28	2883	95	8	0
120	0	1976	Rockwell	175	43	1087	83	7	2
120	0	1980	Rockwell	175	39	1009	87	10	
120	0	1984	Rockwell	175	35	1442	89	11	1
130	0	1985	American	175	34	2087	87	11	3
130	0	1992	American	175	27	1406	92	10	0
452	0	2003	Actaris	400	16	96	31	1	2
505	507	1980	American	1000	39	7	6	0	0
570	0	1989	Rockwell	275	30	751	40	1	0
585	0	1999	Sprague	250	20	243	24	0	0
120	0	1969	Rockwell	175	50	183	66	4	0
125	0	1979	Rockwell	200	40	155	36	1	0
480	486	1992	American	800	27	23	19	1	0
500	502	2002	American	1000	17	36	25	1	1
Perf	**Alt. Perf**	**Year Set**	**Manufacturer**	**Size**	**Age**	**# Meters in Family**	**# OK**	**# Fast**	**# Slow**
480	486	1993	American	800	26	31	28	3	2
120	0	1996	Rockwell	175	23	735	81	4	0
120	0	1997	Rockwell	175	22	164	36	1	0
125	0	1986	Rockwell	200	33	356	65	3	0
510	515	1973	Rockwell	310	46	87	19	0	1
120	0	1995	Rockwell	175	24	327	75	6	0
125	0	1988	Rockwell	200	31	415	39	1	0
125	0	1996	Rockwell	200	23	233	23	0	0
505	507	2008	American	1000	11	300	71	11	0

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510	515	1987	Rockwell	310	32	210	48	2	4
510	515	1992	Rockwell	310	27	118	49	2	5
140	0	1977	Sprague	175	42	313	27	0	2
470	472	1997	American	425	22	286	78	6	0
510	515	1978	Rockwell	310	41	99	47	2	2
510	515	1983	Rockwell	310	36	109	49	2	0
520	0	1996	Rockwell	415	23	97	46	2	1
555	0	1983	American	310	36	90	35	1	0
555	0	1985	American	310	34	109	34	1	0
560	0	1987	American	250	32	430	26	0	0
570	0	1992	Rockwell	275	27	130	55	5	0
572	0	2008	Sensus	275	11	38	28	1	0
470	472	1987	American	425	32	120	52	2	0
510	515	1996	Rockwell	310	23	24	13	0	1
520	0	1995	Rockwell	415	24	287	69	9	2
585	0	2002	Sprague	250	17	44	16	0	0
590	0	1988	Lancaster	250	31	75	19	0	0
590	0	1996	Lancaster	250	23	26	15	0	0
470	472	1993	American	425	26	61	38	6	0
470	472	1996	American	425	23	11	12	1	0
470	472	2001	American	425	18	58	31	1	0
470	472	2008	American	425	11	12	10	0	0
510	515	1990	Rockwell	310	29	204	62	6	3
125	0	1995	Rockwell	200	24	70	45	5	0
130	0	1997	American	175	22	200	47	1	0
470	472	1988	American	425	31	41	36	4	0
471	0	2008	American	425	11	39	34	3	0
510	515	1974	Rockwell	310	45	24	24	0	4
520	0	1994	Rockwell	415	25	91	19	0	1
120	0	1968	Rockwell	175	51	75	31	1	0
470	472	1990	American	425	29	26	13	0	0
510	515	1989	Rockwell	310	30	85	31	1	1
470	472	1986	American	425	33	54	18	0	0
520	0	2000	Rockwell	415	19	84	44	6	0
					Totals	**706867**	**23402**	**1197**	**346**

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
120	0	2018	Rockwell	175	0	1	Determined
130	0	2018	American	175	0	1	Determined
140	0	2018	Sprague	175	0	1	Determined
561	0	2009	American	250	9	13443	Determined
452	0	2008	Actaris	400	10	1	Small Family
510	515	2008	Rockwell	310	10	1	Small Family
555	0	2008	American	310	10	1	Small Family
590	0	2008	Lancaster	250	10	1	Small Family
595	600	2008	Schlumberger	250	10	1	Small Family
140	0	2008	Sprague	175	10	2	Small Family
120	0	2008	Rockwell	175	10	3	Small Family
130	0	2008	American	175	10	3	Small Family
125	0	2008	Rockwell	200	10	5	Small Family
560	0	2008	American	250	10	6	Small Family
572	0	2006	Sensus	275	12	7584	Determined
125	0	2004	Rockwell	200	14	1	Small Family
561	0	2002	American	250	16	1	Small Family
500	502	1999	American	1000	19	11	Determined
560	0	1997	American	250	21	14257	Determined
475	0	1985	American	630	33	1	Small Family
510	515	1980	Rockwell	310	38	115	Determined
485	0	1978	American	800	40	4	Determined
130	0	1974	American	175	44	4583	Determined
120	0	1971	Rockwell	175	47	462	Determined
510	515	1975	Rockwell	310	43	26	Determined
570	0	2008	Rockwell	275	11	5	Small Family
300	540	2002	Rockwell	800	17	20	Determined
480	486	2000	American	800	19	22	Determined
485	0	1982	American	800	37	36	Determined
130	0	1976	American	175	43	1311	Determined
485	0	1987	American	800	32	11	Determined
300	540	1997	Rockwell	800	22	8	Determined
510	515	1988	Rockwell	310	31	102	Sampling Limit
520	0	1993	Rockwell	415	26	16	Sampling Limit
					Total	**42046**	

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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February 16, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2020

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2020 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2020. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2015 and December 31, 2020. The results of this analysis are as follows:

- As of December 31, 2020, 732,541 installed meters are covered under the Meter Sampling Program. These meters formed 383 distinct meter families. This total does not include meters determined to be non-conforming.
- Over the course of 2020, the company tested 8,247 meters. Over the five-year period of 2015 through 2020, the company had a total of 31,269 meter samples from which to base its results.
- 372 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 699,268 meters, or 95 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 11 new meter families were added in 2020. 20 meter families were removed from service due to small family size, during the normal course of business. 7 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.
- 40 meter families, consisting of a total of 27,204 meters, are not conforming. Due to the number of meters requiring change-out (3.7% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2024, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 13 meter families, totaling 27,069 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.

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    - 20 meter families, totaling 45 meters, will be removed from service due to their small population size and age.
    - 7 meter families, totaling 90 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2019 report resulted in 42,046 meters being put on the list for removal by December 2023.
- Regarding the planned 4-year removal of meters determined non-conforming in 2019, 15,084 meters remain of the 42,046 meters determined non-conforming for removal in 2020 to 2023. The remaining meters are planned to be removed by December 2023.

If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie
Gas Measurement and Station Design Engineering Supervisor
Telephone: 503-610-7494
Email: mike.mckenzie@nwnatural.com

cc:

Andy Fortier	Dave Weber
Jon Huddleston	Kim Heiting
Cliff Crawford	Joe Karney

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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
120	0	1970	Rockwell	175	50	622	92	5	0
120	0	1974	Rockwell	175	46	2547	162	18	4
120	0	1975	Rockwell	175	45	1776	98	13	1
120	0	1977	Rockwell	175	43	1334	89	5	3
120	0	1978	Rockwell	175	42	1431	104	5	4
120	0	1979	Rockwell	175	41	1596	96	8	5
120	0	1980	Rockwell	175	40	999	90	9	0
120	0	1981	Rockwell	175	39	672	83	10	1
120	0	1982	Rockwell	175	38	1155	87	14	1
120	0	1984	Rockwell	175	36	1426	92	14	1
120	0	1985	Rockwell	175	35	1916	100	13	1
120	0	1987	Rockwell	175	33	2193	119	12	1
120	0	1988	Rockwell	175	32	2158	100	9	2
120	0	1989	Rockwell	175	31	3481	142	8	3
120	0	1990	Rockwell	175	30	3528	145	12	1
120	0	1991	Rockwell	175	29	3804	187	6	4
120	0	1992	Rockwell	175	28	6669	268	9	3
120	0	1993	Rockwell	175	27	2631	123	5	3
120	0	1994	Rockwell	175	26	1359	63	2	2
120	0	1996	Rockwell	175	24	730	86	4	0
120	0	2012	Rockwell	175	8	1	0	0	0
120	0	2013	Rockwell	175	7	1	0	0	0
120	0	2014	Rockwell	175	6	1	0	0	0
125	0	1978	Rockwell	200	42	1556	98	6	1
125	0	1979	Rockwell	200	41	153	36	1	0
125	0	1980	Rockwell	200	40	1806	88	12	0
125	0	1981	Rockwell	200	39	2452	96	14	1
125	0	1982	Rockwell	200	38	3069	114	8	0
125	0	1983	Rockwell	200	37	1744	94	5	1
125	0	1987	Rockwell	200	33	553	24	0	0
125	0	1989	Rockwell	200	31	522	68	0	0
125	0	1991	Rockwell	200	29	695	40	0	0
125	0	1993	Rockwell	200	27	478	73	7	2
125	0	1994	Rockwell	200	26	384	76	6	1
125	0	1995	Rockwell	200	25	70	45	5	0
125	0	1996	Rockwell	200	24	231	27	0	0
125	0	1998	Rockwell	200	22	82	25	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
125	0	2017	Rockwell	200	3	1	3	0	0
125	0	2019	Rockwell	200	1	1	2	0	0
130	0	1971	American	175	49	1049	104	7	1
130	0	1973	American	175	47	719	82	10	0
130	0	1975	American	175	45	24	13	0	0
130	0	1977	American	175	43	3214	128	7	1
130	0	1979	American	175	41	6308	220	13	3
130	0	1980	American	175	40	6120	243	17	1
130	0	1983	American	175	37	2943	145	21	3
130	0	1984	American	175	36	4720	195	20	4
130	0	1986	American	175	34	3947	143	15	1
130	0	1987	American	175	33	5849	196	23	2
130	0	1988	American	175	32	3084	147	17	1
130	0	1989	American	175	31	3223	147	15	1
130	0	1990	American	175	30	3091	132	18	1
130	0	1991	American	175	29	4854	129	18	5
130	0	1993	American	175	27	3136	119	15	2
130	0	1995	American	175	25	546	66	2	0
130	0	1996	American	175	24	1039	45	1	0
130	0	1997	American	175	23	200	51	1	0
130	0	2013	American	175	7	1	0	0	0
130	0	2014	American	175	6	3	0	0	0
130	0	2016	American	175	4	2	7	0	0
140	0	1968	Sprague	175	52	986	76	0	16
140	0	1970	Sprague	175	50	334	35	0	2
140	0	1971	Sprague	175	49	959	72	0	8
140	0	1972	Sprague	175	48	148	36	0	2
140	0	1973	Sprague	175	47	2844	145	3	8
140	0	1974	Sprague	175	46	609	38	0	2
140	0	1975	Sprague	175	45	702	47	0	2
140	0	1976	Sprague	175	44	1078	63	2	2
140	0	1979	Sprague	175	41	129	36	1	2
140	0	1981	Sprague	175	39	622	38	0	1
140	0	1982	Sprague	175	38	568	49	2	4
140	0	1983	Sprague	175	37	805	52	0	3
140	0	1984	Sprague	175	36	699	34	0	3
140	0	1985	Sprague	175	35	1138	65	1	6
140	0	1986	Sprague	175	34	949	48	1	3
140	0	1987	Sprague	175	33	2931	122	0	13
140	0	1988	Sprague	175	32	738	61	2	2

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
140	0	1989	Sprague	175	31	753	35	0	3
140	0	1990	Sprague	175	30	1010	101	0	4
140	0	1991	Sprague	175	29	438	32	0	3
140	0	1992	Sprague	175	28	562	31	0	2
140	0	1993	Sprague	175	27	646	30	0	1
140	0	1998	Sprague	175	22	8	10	0	0
140	0	2011	Sprague	175	9	2	0	0	0
140	0	2016	Sprague	175	4	1	3	0	0
270	0	1998	Schlumberger	1000	22	25	15	0	0
270	0	2000	Schlumberger	1000	20	18	13	0	0
300	540	2005	Rockwell	800	15	10	11	0	0
450	0	1993	Schlumberger	400	27	188	29	0	0
450	0	1996	Schlumberger	400	24	262	41	0	0
450	0	1998	Schlumberger	400	22	438	45	0	0
450	0	2013	Schlumberger	400	7	1	0	0	0
452	0	2005	Actaris	400	15	17	14	0	0
470	472	1982	American	425	38	18	11	0	0
470	472	1983	American	425	37	26	15	0	0
470	472	1984	American	425	36	105	24	0	0
470	472	1985	American	425	35	23	25	2	0
470	472	1987	American	425	33	112	56	2	0
470	472	1990	American	425	30	25	14	0	0
470	472	1992	American	425	28	141	28	0	0
470	472	1993	American	425	27	61	37	6	0
470	472	1996	American	425	24	11	12	1	0
470	472	1999	American	425	21	248	42	0	0
470	472	2001	American	425	19	57	36	2	0
470	472	2003	American	425	17	203	37	1	0
470	472	2005	American	425	15	22	15	0	0
470	472	2006	American	425	14	34	36	0	0
470	472	2007	American	425	13	231	24	0	2
470	472	2008	American	425	12	12	11	0	0
470	472	2012	American	425	8	1	0	0	0
470	472	2017	American	425	3	1	0	0	0
471	0	2007	American	425	13	471	82	8	0
471	0	2008	American	425	12	38	36	3	0
471	0	2011	American	425	9	109	8	0	0
471	0	2012	American	425	8	10	0	0	0
475	0	2011	American	630	9	1042	57	1	0
475	0	2012	American	630	8	1438	72	1	0

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475	0	2013	American	630	7	1490	90	2	0
475	0	2014	American	630	6	1553	66	0	0
475	0	2015	American	630	5	1250	75	2	0
475	0	2016	American	630	4	1637	35	1	0
475	0	2017	American	630	3	1693	34	2	0
475	0	2018	American	630	2	4705	53	2	1
475	0	2019	American	630	1	3013	21	0	0
480	486	1992	American	800	28	23	17	0	0
480	486	1993	American	800	27	28	30	2	2
480	486	1995	American	800	25	16	13	0	2
480	486	1996	American	800	24	7	6	0	0
480	486	2001	American	800	19	12	12	1	0
485	0	1997	American	800	23	8	7	0	0
485	0	2011	American	800	9	1	0	0	0
485	0	2016	American	800	4	1	0	0	0
487	0	2017	American	800	3	58	2	0	0
487	0	2018	American	800	2	196	6	0	0
487	0	2019	American	800	1	322	6	0	0
500	502	1998	American	1000	22	84	46	7	0
500	502	2001	American	1000	19	11	9	1	1
500	502	2002	American	1000	18	36	27	1	1
505	507	1981	American	1000	39	8	8	0	1
505	507	2008	American	1000	12	297	69	11	0
505	507	2011	American	1000	9	366	43	2	0
505	507	2012	American	1000	8	390	43	2	0
505	507	2013	American	1000	7	379	33	0	0
505	507	2014	American	1000	6	434	38	0	0
505	507	2015	American	1000	5	361	25	0	0
505	507	2016	American	1000	4	522	33	1	0
505	507	2017	American	1000	3	201	9	0	0
505	507	2018	American	1000	2	351	14	1	0
505	507	2019	American	1000	1	312	10	1	0
510	515	1974	Rockwell	310	46	23	24	0	4
510	515	1976	Rockwell	310	44	264	47	2	3
510	515	1978	Rockwell	310	42	96	48	1	3
510	515	1983	Rockwell	310	37	106	36	1	0
510	515	1984	Rockwell	310	36	15	15	1	1
510	515	1987	Rockwell	310	33	206	51	2	4
510	515	1989	Rockwell	310	31	84	31	1	1
510	515	1991	Rockwell	310	29	208	24	0	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1993	Rockwell	310	27	94	46	4	2
510	515	1996	Rockwell	310	24	18	23	0	1
510	515	2011	Rockwell	310	9	1	0	0	0
510	515	2013	Rockwell	310	7	1	0	0	0
520	0	1978	Rockwell	415	42	35	15	0	0
520	0	1979	Rockwell	415	41	72	33	1	1
520	0	1982	Rockwell	415	38	33	16	0	0
520	0	1991	Rockwell	415	29	71	24	0	0
520	0	1996	Rockwell	415	24	95	48	2	1
520	0	2000	Rockwell	415	20	84	43	7	0
520	0	2005	Rockwell	415	15	46	20	0	0
520	0	2011	Rockwell	415	9	1	0	0	0
520	0	2017	Rockwell	415	3	1	0	0	0
520	0	2018	Rockwell	415	2	1	0	0	0
520	0	2019	Rockwell	415	1	1	0	0	0
555	0	1981	American	310	39	27	23	1	1
555	0	1986	American	310	34	84	32	1	0
555	0	1987	American	310	33	31	38	2	1
555	0	1989	American	310	31	14	27	2	0
555	0	2012	American	310	8	1	0	0	0
560	0	1986	American	250	34	6150	211	4	0
560	0	1987	American	250	33	428	25	0	0
560	0	1988	American	250	32	3129	92	1	1
560	0	1989	American	250	31	6952	241	3	5
560	0	1990	American	250	30	6251	202	3	6
560	0	1991	American	250	29	5520	202	4	3
560	0	1992	American	250	28	4777	102	2	2
560	0	1993	American	250	27	4050	106	2	1
560	0	1995	American	250	25	8156	193	10	1
560	0	1996	American	250	24	11041	236	9	3
560	0	1998	American	250	22	14378	235	30	3
560	0	1999	American	250	21	11207	156	9	1
560	0	2000	American	250	20	11207	216	6	1
560	0	2001	American	250	19	9384	160	2	2
560	0	2002	American	250	18	8474	116	5	0
560	0	2003	American	250	17	431	68	1	1
560	0	2005	American	250	15	76	34	1	1
560	0	2006	American	250	14	614	51	1	0
560	0	2007	American	250	13	191	25	0	0
560	0	2011	American	250	9	3	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
560	0	2012	American	250	8	6	0	0	0
560	0	2013	American	250	7	3	0	0	0
560	0	2014	American	250	6	5	2	0	0
560	0	2015	American	250	5	1	8	0	0
560	0	2017	American	250	3	1	14	0	0
560	0	2018	American	250	2	3	14	1	0
561	0	2006	American	250	14	21404	363	38	1
561	0	2007	American	250	13	21896	421	37	1
561	0	2010	American	250	10	10069	212	6	0
561	0	2011	American	250	9	10624	196	3	0
561	0	2012	American	250	8	11926	183	1	0
561	0	2013	American	250	7	15296	247	1	3
561	0	2014	American	250	6	14679	192	1	0
561	0	2015	American	250	5	17928	216	3	0
561	0	2016	American	250	4	12652	120	0	0
561	0	2017	American	250	3	11813	125	2	1
561	0	2018	American	250	2	9754	84	1	0
561	0	2019	American	250	1	14604	44	0	0
561	0	2020	American	250	0	17	0	0	0
562	0	2017	American	250	3	22	0	0	0
562	0	2018	American	250	2	695	0	0	0
562	0	2019	American	250	1	1377	1	0	0
570	0	1989	Rockwell	275	31	744	41	1	0
570	0	1990	Rockwell	275	30	5367	125	11	3
570	0	1993	Rockwell	275	27	61	31	1	0
570	0	1995	Rockwell	275	25	6477	121	8	2
570	0	1996	Rockwell	275	24	7651	142	4	1
570	0	1997	Rockwell	275	23	2355	41	1	0
570	0	1999	Rockwell	275	21	10484	181	27	2
570	0	2000	Rockwell	275	20	8465	115	19	1
570	0	2001	Rockwell	275	19	8670	124	4	1
570	0	2002	Rockwell	275	18	10778	165	3	0
570	0	2003	Rockwell	275	17	19806	269	6	2
570	0	2004	Rockwell	275	16	3592	55	0	0
570	0	2005	Rockwell	275	15	12	10	0	0
570	0	2011	Rockwell	275	9	1	0	0	0
570	0	2012	Rockwell	275	8	3	1	0	0
570	0	2013	Rockwell	275	7	1	0	0	0
570	0	2014	Rockwell	275	6	2	0	0	0
570	0	2016	Rockwell	275	4	2	2	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2017	Rockwell	275	3	3	3	0	0
570	0	2018	Rockwell	275	2	2	2	0	0
572	0	2004	Sensus	275	16	13900	201	16	2
572	0	2005	Sensus	275	15	24631	363	51	0
572	0	2008	Sensus	275	12	38	38	1	0
572	0	2011	Sensus	275	9	86	2	0	0
572	0	2012	Sensus	275	8	4	0	0	0
572	0	2013	Sensus	275	7	1	0	0	0
572	0	2014	Sensus	275	6	1	0	0	0
572	0	2015	Sensus	275	5	2	1	0	0
572	0	2016	Sensus	275	4	3	0	0	0
585	0	1992	Sprague	250	28	2093	64	0	0
585	0	1993	Sprague	250	27	3814	114	1	0
585	0	1994	Sprague	250	26	1645	49	1	1
585	0	1995	Sprague	250	25	1512	38	0	0
585	0	1996	Sprague	250	24	4409	108	1	0
585	0	1997	Sprague	250	23	5901	121	1	1
585	0	1998	Sprague	250	22	5388	139	0	1
585	0	1999	Sprague	250	21	243	23	0	0
585	0	2000	Sprague	250	20	36	29	2	0
585	0	2001	Sprague	250	19	49	17	0	0
585	0	2002	Sprague	250	18	44	16	0	0
585	0	2014	Sprague	250	6	2	0	0	0
590	0	1989	Lancaster	250	31	1300	77	0	0
590	0	1990	Lancaster	250	30	1311	55	0	1
590	0	1991	Lancaster	250	29	1707	73	1	0
590	0	1992	Lancaster	250	28	2651	87	1	1
590	0	1993	Lancaster	250	27	2823	72	1	0
590	0	1994	Lancaster	250	26	4350	172	10	5
590	0	1995	Lancaster	250	25	4802	145	7	11
590	0	1996	Lancaster	250	24	26	21	0	0
590	0	1997	Lancaster	250	23	2112	46	0	3
590	0	1998	Lancaster	250	22	28	14	0	0
590	0	2011	Lancaster	250	9	1	0	0	0
590	0	2016	Lancaster	250	4	1	2	0	0
590	0	2019	Lancaster	250	1	1	1	0	0
595	600	2000	Schlumberger	250	20	3174	316	18	12
595	600	2001	Schlumberger	250	19	3766	180	3	1
595	600	2002	Schlumberger	250	18	3240	180	0	4
595	600	2012	Schlumberger	250	8	1	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
595	600	2016	Schlumberger	250	4	1	1	0	0
602	0	2016	Itron	250	4	4360	35	0	0
602	0	2017	Itron	250	3	4587	42	0	0
602	0	2018	Itron	250	2	8182	52	2	0
602	0	2019	Itron	250	1	11485	30	0	0
602	0	2020	Itron	250	0	20	0	0	0
125	0	1984	Rockwell	200	36	2082	87	12	1
480	486	1989	American	800	31	24	13	0	0
510	515	1992	Rockwell	310	28	116	46	2	5
560	0	1994	American	250	26	6126	121	7	1
300	540	1996	Rockwell	800	24	20	15	0	2
480	486	1990	American	800	30	22	12	0	0
505	507	2007	American	1000	13	339	72	11	0
510	515	1990	Rockwell	310	30	201	61	6	3
561	0	2005	American	250	15	1636	88	13	0
120	0	1983	Rockwell	175	37	1329	92	11	2
125	0	1992	Rockwell	200	28	604	41	1	0
130	0	1992	American	175	28	1388	91	10	0
130	0	1994	American	175	26	2599	89	11	0
140	0	1994	Sprague	175	26	563	46	1	2
270	0	2001	Schlumberger	1000	19	33	28	2	0
272	0	2004	Actaris	1000	16	7	8	0	0
572	0	2009	Sensus	275	11	744	41	0	0
470	472	1986	American	425	34	53	17	0	0
485	0	1984	American	800	36	54	29	1	1
520	0	1987	Rockwell	415	33	38	22	1	2
555	0	1980	American	310	40	58	36	4	0
585	0	1991	Sprague	250	29	736	24	0	0
470	472	1994	American	425	26	215	36	1	1
570	0	1992	Rockwell	275	28	128	55	5	0
570	0	1994	Rockwell	275	26	4979	119	8	0
120	0	1972	Rockwell	175	48	814	78	10	2
125	0	1999	Rockwell	200	21	135	22	0	0
470	472	1997	American	425	23	280	74	5	0
120	0	1976	Rockwell	175	44	1062	83	7	2
120	0	1995	Rockwell	175	25	312	75	5	0
125	0	1986	Rockwell	200	34	335	68	3	0
125	0	1990	Rockwell	200	30	289	70	10	0
140	0	1997	Sprague	175	23	459	25	0	0
570	0	1991	Rockwell	275	29	2829	92	8	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
590	0	1999	Lancaster	250	21	141	23	0	0
595	600	2003	Schlumberger	250	17	51	18	0	0
595	600	2004	Schlumberger	250	16	21	13	0	0
120	0	1969	Rockwell	175	51	168	66	4	0
120	0	1986	Rockwell	175	34	1253	89	5	3
140	0	1977	Sprague	175	43	292	39	0	4
475	0	2010	American	630	10	619	56	2	0
570	0	1998	Rockwell	275	22	5340	115	11	1
585	0	1988	Sprague	250	32	178	22	0	0
585	0	2004	Sprague	250	16	47	18	0	0
120	0	1973	Rockwell	175	47	598	81	10	0
120	0	1997	Rockwell	175	23	157	37	1	0
120	0	1998	Rockwell	175	22	70	19	0	0
130	0	1985	American	175	35	2013	88	11	2
480	486	2002	American	800	18	21	12	0	0
560	0	1985	American	250	35	1397	74	3	1
140	0	1978	Sprague	175	42	242	30	0	3
140	0	1980	Sprague	175	40	273	60	4	7
510	515	1981	Rockwell	310	39	188	21	0	1
510	515	1986	Rockwell	310	34	16	10	0	0
520	0	1981	Rockwell	415	39	220	23	0	1
555	0	1997	American	310	23	21	18	2	1
590	0	1988	Lancaster	250	32	73	19	0	0
120	0	1968	Rockwell	175	52	57	40	2	0
125	0	1988	Rockwell	200	32	343	82	4	0
450	0	2005	Schlumberger	400	15	7	6	0	0
470	472	2000	American	425	20	385	39	1	0
520	0	1988	Rockwell	415	32	42	15	0	1
452	0	2003	Actaris	400	17	77	37	1	1
470	472	1998	American	425	22	136	56	5	0
485	0	1981	American	800	39	19	16	0	3
510	515	1977	Rockwell	310	43	138	35	1	0
520	0	1992	Rockwell	415	28	49	27	1	1
450	0	2003	Schlumberger	400	17	16	10	0	0
470	472	1995	American	425	25	76	23	0	0
470	472	2002	American	425	18	384	76	3	0
470	472	2004	American	425	16	49	32	1	0
471	0	2010	American	425	10	83	22	0	0
510	515	1982	Rockwell	310	38	39	34	1	2
520	0	1980	Rockwell	415	40	55	29	1	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
520	0	1997	Rockwell	415	23	44	16	0	0
555	0	1983	American	310	37	79	41	2	0
555	0	1984	American	310	36	162	61	2	2
452	0	2004	Actaris	400	16	401	73	4	3
450	0	1999	Schlumberger	400	21	91	20	0	0
520	0	2003	Rockwell	415	17	141	21	0	0
555	0	1985	American	310	35	89	32	1	0
450	0	1997	Schlumberger	400	23	54	18	0	0
520	0	1994	Rockwell	415	26	83	19	0	1
510	515	1973	Rockwell	310	47	62	33	1	4
470	472	1989	American	425	31	18	19	2	0
510	515	1979	Rockwell	310	41	118	49	5	7
510	515	1994	Rockwell	310	26	29	14	0	0
520	0	1977	Rockwell	415	43	39	16	0	0
520	0	2004	Rockwell	415	16	60	38	3	0
					Totals	**699,268**	**22,537**	**1,209**	**363**

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
120	0	2010	Rockwell	175	10	1	Small Family
125	0	2009	Rockwell	200	11	3	Small Family
130	0	1972	American	175	48	2661	Determined
130	0	1978	American	175	42	1534	Determined
130	0	2019	American	175	1	1	Small Family
140	0	2009	Sprague	175	11	2	Small Family
470	472	2009	American	425	11	4	Small Family
470	472	2010	American	425	10	2	Small Family
470	472	2019	American	425	1	2	Small Family
471	0	2009	American	425	11	3	Small Family
475	0	2002	American	630	18	1	Small Family
485	0	1980	American	800	40	17	Determined
505	507	1980	American	1000	40	6	Small Family
510	515	2009	Rockwell	310	11	1	Small Family
510	515	2010	Rockwell	310	10	1	Small Family
520	0	2009	Rockwell	415	11	3	Small Family
555	0	2009	American	310	11	1	Small Family
560	0	2010	American	250	10	2	Small Family
560	0	2019	American	250	1	4	Determined
561	0	2008	American	250	12	22887	Determined
570	0	2019	Rockwell	275	1	4	Determined
585	0	2009	Sprague	250	11	5	Small Family
590	0	2009	Lancaster	250	11	2	Small Family
590	0	2010	Lancaster	250	10	1	Small Family
602	0	1982	Itron	250	38	1	Small Family
485	0	1996	American	800	24	6	Small Family
505	507	2009	American	1000	11	270	Determined
480	486	1991	American	800	29	37	Determined
500	502	2003	American	1000	17	14	Determined
130	0	2009	American	175	10	19	Sampling Limit
450	0	2004	Schlumberger	400	15	8	Sampling Limit
510	515	1997	Rockwell	310	22	9	Sampling Limit
520	0	1983	Rockwell	415	36	17	Sampling Limit
570	0	2009	Rockwell	275	10	16	Sampling Limit
572	0	2010	Sensus	275	10	15	Sampling Limit
585	0	2003	Sprague	250	16	12	Sampling Limit

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
555	0	1994	American	310	26	6	Determined
470	472	1988	American	425	32	39	Determined
470	472	1991	American	425	29	15	Determined
520	0	1995	Rockwell	415	25	266	Determined
					Total	**27204**	

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@puc.oregon.gov

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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March 4, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2021

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2021 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2021. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2016 and December 31, 2021. The results of this analysis are as follows:

- As of December 31, 2021, 787,474 meters are installed and covered under the Meter Sampling Program. Of these, 735,372 meters, forming 368 distinct meter families, are conforming. The remaining 52,102 are non-conforming and are scheduled for replacement.
- Over the course of 2021, the company tested 5,790 meters. Over the five-year period of 2016 through 2021, the company had a total of 31,609 meter samples from which to base its results.
- 357 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are so new that they do not yet require minimum sampling. These meter families amount to 719,174 meters, or 91 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 12 new meter families were added in 2021. 14 meter families were removed from service due to small family size, during the normal course of business. 4 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.
- 30 meter families, consisting of a total of 35,677 meters, are not conforming. Due to the number of meters requiring change-out (4.5% of the total population), these meters have been put on the list to be removed over the course of the next 4 years, by December 2025, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
  - 12 meter families, totaling 35,511 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.

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    - 14 meter families, totaling 41 meters, will be removed from service due to their small population size and age.
    - 4 meter families, totaling 125 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2020 report resulted in 27,204 meters being put on the list for removal by December 2024.
- Regarding the planned 4-year removal of meters determined non-conforming in 2019 and 2020, the following meters remain:
    - PCC Year 2020 (for removal 2020 to 2023): 5,906 remain out of 42,046 determined
    - PCC Year 2021 (for removal 2021 to 2024): 14,113 remain out of 27,204 determined
    - PCC Year 2022 (for removal 2022 to 2025): 32,083 remain out of 35,677 determined

If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,
/s/ *Michael J. McKenzie*

Michael J. McKenzie, PE
Gas Measurement and Station Design Engineering Supervisor

cc:

Andy Fortier	Dave Weber
Jon Huddleston	Kim Heiting
Joe Karney	Dan Kizer

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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
120	0	1968	Rockwell	175	53	55	41	2	0
120	0	1969	Rockwell	175	52	166	66	5	0
120	0	1972	Rockwell	175	49	805	83	10	2
120	0	1973	Rockwell	175	48	595	81	10	1
120	0	1974	Rockwell	175	47	2501	176	15	3
120	0	1975	Rockwell	175	46	1726	113	15	1
120	0	1976	Rockwell	175	45	1049	89	7	3
120	0	1978	Rockwell	175	43	1401	103	6	4
120	0	1979	Rockwell	175	42	1561	115	8	4
120	0	1982	Rockwell	175	39	1140	90	14	1
120	0	1983	Rockwell	175	38	1293	108	14	2
120	0	1984	Rockwell	175	37	1410	91	15	1
120	0	1985	Rockwell	175	36	1882	104	12	2
120	0	1987	Rockwell	175	34	2145	139	10	2
120	0	1988	Rockwell	175	33	2101	117	8	5
120	0	1989	Rockwell	175	32	3385	181	11	6
120	0	1990	Rockwell	175	31	3450	156	15	5
120	0	1991	Rockwell	175	30	3716	208	6	8
120	0	1992	Rockwell	175	29	6535	312	10	9
120	0	1993	Rockwell	175	28	2577	131	7	3
120	0	1994	Rockwell	175	27	1329	69	3	4
120	0	1996	Rockwell	175	25	720	86	3	0
120	0	2012	Rockwell	175	9	1	0	0	0
120	0	2013	Rockwell	175	8	1	0	0	0
120	0	2014	Rockwell	175	7	1	0	0	0
125	0	1978	Rockwell	200	43	1527	112	3	1
125	0	1980	Rockwell	200	41	1778	99	12	0
125	0	1981	Rockwell	200	40	2426	105	13	0
125	0	1982	Rockwell	200	39	3020	137	8	0
125	0	1983	Rockwell	200	38	1713	104	5	1
125	0	1984	Rockwell	200	37	2042	108	11	1
125	0	1986	Rockwell	200	35	333	74	3	0
125	0	1988	Rockwell	200	33	342	88	4	0
125	0	1991	Rockwell	200	30	673	49	0	0
125	0	1992	Rockwell	200	29	594	48	1	0
125	0	1993	Rockwell	200	28	469	74	7	2
125	0	1994	Rockwell	200	27	383	78	6	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
125	0	1995	Rockwell	200	26	69	46	5	0
125	0	1996	Rockwell	200	25	227	30	0	0
125	0	1999	Rockwell	200	22	132	23	0	0
125	0	2017	Rockwell	200	4	1	3	0	0
125	0	2019	Rockwell	200	2	1	3	0	0
130	0	1973	American	175	48	710	82	11	1
130	0	1975	American	175	46	23	14	0	0
130	0	1977	American	175	44	3158	141	13	4
130	0	1979	American	175	42	6200	275	13	3
130	0	1980	American	175	41	5995	289	15	3
130	0	1984	American	175	37	4634	224	23	6
130	0	1985	American	175	36	2002	103	10	2
130	0	1986	American	175	35	3875	166	17	2
130	0	1987	American	175	34	5766	208	28	2
130	0	1988	American	175	33	3033	152	18	2
130	0	1989	American	175	32	3162	124	18	4
130	0	1991	American	175	30	4758	166	24	5
130	0	1994	American	175	27	2569	96	13	0
130	0	1996	American	175	25	1031	41	1	1
130	0	1997	American	175	24	197	53	1	1
130	0	2013	American	175	8	1	0	0	0
130	0	2014	American	175	7	3	0	0	0
130	0	2016	American	175	5	2	7	0	0
130	0	2020	American	175	1	1	13	1	0
140	0	1968	Sprague	175	53	957	78	0	14
140	0	1970	Sprague	175	51	329	38	0	3
140	0	1971	Sprague	175	50	935	71	0	7
140	0	1972	Sprague	175	49	145	26	0	2
140	0	1973	Sprague	175	48	2780	172	3	7
140	0	1974	Sprague	175	47	605	34	0	2
140	0	1975	Sprague	175	46	697	44	0	0
140	0	1976	Sprague	175	45	1057	55	2	4
140	0	1977	Sprague	175	44	289	36	0	4
140	0	1978	Sprague	175	43	240	30	0	2
140	0	1979	Sprague	175	42	126	37	1	1
140	0	1980	Sprague	175	41	270	61	4	7
140	0	1981	Sprague	175	40	610	42	0	1
140	0	1982	Sprague	175	39	549	58	2	3
140	0	1983	Sprague	175	38	786	56	0	3
140	0	1985	Sprague	175	36	1102	76	1	5

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
140	0	1986	Sprague	175	35	929	54	1	3
140	0	1987	Sprague	175	34	2870	153	0	13
140	0	1988	Sprague	175	33	718	73	2	3
140	0	1989	Sprague	175	32	743	37	0	4
140	0	1990	Sprague	175	31	995	56	0	1
140	0	1991	Sprague	175	30	431	36	0	3
140	0	1992	Sprague	175	29	549	33	0	1
140	0	1993	Sprague	175	28	624	40	0	4
140	0	1994	Sprague	175	27	554	52	1	2
140	0	1997	Sprague	175	24	454	28	0	0
140	0	1998	Sprague	175	23	8	9	0	0
140	0	2016	Sprague	175	5	1	3	0	0
270	0	2000	Schlumberger	1000	21	17	13	0	0
270	0	2001	Schlumberger	1000	20	25	34	2	0
272	0	2004	Actaris	1000	17	7	9	1	0
450	0	1993	Schlumberger	400	28	180	29	0	0
450	0	1996	Schlumberger	400	25	254	32	0	0
450	0	1998	Schlumberger	400	23	426	45	0	1
450	0	2003	Schlumberger	400	18	16	13	0	0
450	0	2013	Schlumberger	400	8	1	0	0	0
452	0	2003	Actaris	400	18	77	39	1	0
470	472	1982	American	425	39	16	12	0	0
470	472	1984	American	425	37	102	20	0	0
470	472	1985	American	425	36	22	23	2	0
470	472	1986	American	425	35	51	18	0	0
470	472	1987	American	425	34	107	59	2	0
470	472	1989	American	425	32	18	20	2	0
470	472	1992	American	425	29	138	21	0	0
470	472	1995	American	425	26	75	21	0	0
470	472	1996	American	425	25	9	12	1	1
470	472	1997	American	425	24	275	73	5	0
470	472	1998	American	425	23	135	55	6	0
470	472	1999	American	425	22	243	28	0	0
470	472	2000	American	425	21	380	47	1	0
470	472	2004	American	425	17	46	38	4	1
470	472	2006	American	425	15	34	35	0	0
470	472	2008	American	425	13	11	12	0	0
470	472	2012	American	425	9	1	0	0	0
470	472	2017	American	425	4	1	0	0	0
471	0	2007	American	425	14	464	79	8	0

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
471	0	2008	American	425	13	37	37	3	0
471	0	2012	American	425	9	10	0	0	0
475	0	2011	American	630	10	1029	61	1	0
475	0	2012	American	630	9	1419	80	1	0
475	0	2013	American	630	8	1472	90	2	0
475	0	2014	American	630	7	1531	67	0	1
475	0	2015	American	630	6	1244	62	2	0
475	0	2016	American	630	5	1617	51	1	0
475	0	2017	American	630	4	1678	47	2	0
475	0	2018	American	630	3	4664	86	2	1
475	0	2019	American	630	2	2980	59	0	0
475	0	2020	American	630	1	899	9	0	0
480	486	1989	American	800	32	22	13	0	0
480	486	2002	American	800	19	20	12	0	0
485	0	1981	American	800	40	19	17	0	3
485	0	1984	American	800	37	50	30	1	1
485	0	2016	American	800	5	1	0	0	0
487	0	2017	American	800	4	58	2	0	0
487	0	2018	American	800	3	193	9	0	0
487	0	2019	American	800	2	318	8	0	0
487	0	2020	American	800	1	237	5	0	0
487	0	2021	American	800	0	1	0	0	0
505	507	1981	American	1000	40	7	9	0	2
505	507	2008	American	1000	13	286	70	11	0
505	507	2012	American	1000	9	379	43	2	0
505	507	2013	American	1000	8	372	34	0	0
505	507	2014	American	1000	7	428	34	0	0
505	507	2015	American	1000	6	354	26	0	0
505	507	2016	American	1000	5	516	38	1	0
505	507	2017	American	1000	4	199	11	0	0
505	507	2018	American	1000	3	345	19	2	0
505	507	2019	American	1000	2	300	19	1	0
505	507	2020	American	1000	1	15	2	1	0
510	515	1973	Rockwell	310	48	62	30	1	3
510	515	1974	Rockwell	310	47	22	22	0	4
510	515	1976	Rockwell	310	45	241	50	2	4
510	515	1978	Rockwell	310	43	93	46	1	3
510	515	1979	Rockwell	310	42	116	48	5	7
510	515	1982	Rockwell	310	39	37	40	1	3
510	515	1983	Rockwell	310	38	103	36	1	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1984	Rockwell	310	37	15	15	1	1
510	515	1986	Rockwell	310	35	15	11	0	0
510	515	1987	Rockwell	310	34	198	54	2	3
510	515	1991	Rockwell	310	30	202	22	0	1
510	515	1992	Rockwell	310	29	114	39	1	4
510	515	1994	Rockwell	310	27	29	14	0	0
510	515	1996	Rockwell	310	25	18	20	0	1
510	515	2013	Rockwell	310	8	1	0	0	0
520	0	1978	Rockwell	415	43	30	15	0	0
520	0	1980	Rockwell	415	41	54	32	1	0
520	0	1982	Rockwell	415	39	32	16	0	0
520	0	1987	Rockwell	415	34	37	20	0	2
520	0	1988	Rockwell	415	33	42	15	0	1
520	0	1994	Rockwell	415	27	82	19	0	1
520	0	1996	Rockwell	415	25	93	48	2	1
520	0	1997	Rockwell	415	24	43	18	0	0
520	0	2000	Rockwell	415	21	82	43	7	0
520	0	2004	Rockwell	415	17	59	40	4	0
520	0	2017	Rockwell	415	4	1	0	0	0
520	0	2018	Rockwell	415	3	1	0	0	0
520	0	2019	Rockwell	415	2	1	0	0	0
555	0	1980	American	310	41	56	38	4	0
555	0	1981	American	310	40	27	19	1	1
555	0	1984	American	310	37	159	59	2	2
555	0	1987	American	310	34	30	33	2	1
555	0	2012	American	310	9	1	0	0	0
560	0	1985	American	250	36	1390	73	2	1
560	0	1986	American	250	35	6030	251	6	3
560	0	1988	American	250	33	3078	105	2	0
560	0	1989	American	250	32	6813	279	5	5
560	0	1990	American	250	31	6126	236	6	6
560	0	1991	American	250	30	5412	231	4	4
560	0	1992	American	250	29	4722	118	2	3
560	0	1993	American	250	28	3984	124	0	2
560	0	1994	American	250	27	6021	157	8	1
560	0	1995	American	250	26	8019	217	13	4
560	0	1996	American	250	25	10895	297	13	4
560	0	1998	American	250	23	14194	292	38	3
560	0	1999	American	250	22	11081	195	14	1
560	0	2000	American	250	21	11087	247	6	1

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560	0	2001	American	250	20	9293	198	3	2
560	0	2002	American	250	19	8388	147	6	0
560	0	2003	American	250	18	422	61	1	1
560	0	2006	American	250	15	602	56	1	0
560	0	2007	American	250	14	183	26	0	0
560	0	2012	American	250	9	6	0	0	0
560	0	2013	American	250	8	3	0	0	0
560	0	2014	American	250	7	5	0	0	0
560	0	2015	American	250	6	1	1	0	0
560	0	2018	American	250	3	3	14	1	0
561	0	2006	American	250	15	21165	454	59	1
561	0	2007	American	250	14	21587	536	70	2
561	0	2010	American	250	11	9912	310	7	1
561	0	2011	American	250	10	10450	317	4	0
561	0	2012	American	250	9	11754	295	2	2
561	0	2013	American	250	8	15144	335	2	5
561	0	2014	American	250	7	14508	295	3	1
561	0	2015	American	250	6	17781	295	0	0
561	0	2016	American	250	5	12582	186	0	0
561	0	2017	American	250	4	11750	174	2	1
561	0	2018	American	250	3	9707	114	2	1
561	0	2019	American	250	2	14566	104	2	0
561	0	2020	American	250	1	10701	46	9	0
561	0	2021	American	250	0	5	0	0	0
562	0	2017	American	250	4	22	0	0	0
562	0	2018	American	250	3	695	0	0	0
562	0	2020	American	250	1	996	0	0	0
570	0	1990	Rockwell	275	31	5274	174	8	3
570	0	1991	Rockwell	275	30	2825	108	9	0
570	0	1992	Rockwell	275	29	127	56	5	0
570	0	1993	Rockwell	275	28	61	30	1	0
570	0	1994	Rockwell	275	27	4953	137	9	0
570	0	1995	Rockwell	275	26	6370	167	10	4
570	0	1996	Rockwell	275	25	7563	173	3	1
570	0	1997	Rockwell	275	24	2330	51	1	0
570	0	1998	Rockwell	275	23	5327	136	13	1
570	0	1999	Rockwell	275	22	10380	196	26	1
570	0	2000	Rockwell	275	21	8363	161	18	1
570	0	2001	Rockwell	275	20	8593	161	6	0
570	0	2002	Rockwell	275	19	10704	194	3	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
570	0	2003	Rockwell	275	18	19571	408	5	2
570	0	2004	Rockwell	275	17	3551	71	0	0
570	0	2012	Rockwell	275	9	4	1	0	0
570	0	2013	Rockwell	275	8	1	0	0	0
570	0	2014	Rockwell	275	7	2	0	0	0
570	0	2016	Rockwell	275	5	2	2	0	0
570	0	2017	Rockwell	275	4	3	3	0	0
570	0	2018	Rockwell	275	3	2	2	0	0
572	0	2004	Sensus	275	17	13742	258	25	2
572	0	2008	Sensus	275	13	37	38	1	0
572	0	2009	Sensus	275	12	735	50	1	0
572	0	2012	Sensus	275	9	3	1	0	0
572	0	2013	Sensus	275	8	1	0	0	0
572	0	2014	Sensus	275	7	1	0	0	0
572	0	2015	Sensus	275	6	2	0	0	0
572	0	2016	Sensus	275	5	3	0	0	0
572	0	2020	Sensus	275	1	9458	24	2	0
572	0	2021	Sensus	275	0	15	0	0	0
585	0	1992	Sprague	250	29	2049	91	0	1
585	0	1993	Sprague	250	28	3762	135	1	0
585	0	1994	Sprague	250	27	1625	56	0	1
585	0	1996	Sprague	250	25	4358	133	1	0
585	0	1997	Sprague	250	24	5821	163	2	2
585	0	1998	Sprague	250	23	5309	173	0	1
585	0	2001	Sprague	250	20	49	17	0	0
585	0	2002	Sprague	250	19	43	16	0	0
585	0	2004	Sprague	250	17	47	17	0	0
585	0	2014	Sprague	250	7	2	0	0	0
590	0	1989	Lancaster	250	32	1278	78	0	0
590	0	1990	Lancaster	250	31	1290	66	0	1
590	0	1991	Lancaster	250	30	1679	82	1	0
590	0	1992	Lancaster	250	29	2603	114	1	1
590	0	1993	Lancaster	250	28	2788	82	1	0
590	0	1994	Lancaster	250	27	4273	203	11	5
590	0	1995	Lancaster	250	26	4723	168	11	14
590	0	1996	Lancaster	250	25	26	21	0	0
590	0	1997	Lancaster	250	24	2085	60	1	3
590	0	1999	Lancaster	250	22	140	24	0	0
590	0	2016	Lancaster	250	5	1	2	0	0
590	0	2019	Lancaster	250	2	1	1	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
595	600	2000	Schlumberger	250	21	3078	341	16	12
595	600	2001	Schlumberger	250	20	3711	190	4	1
595	600	2002	Schlumberger	250	19	3200	166	0	5
595	600	2003	Schlumberger	250	18	47	20	0	0
595	600	2004	Schlumberger	250	17	21	13	0	0
595	600	2012	Schlumberger	250	9	1	0	0	0
595	600	2016	Schlumberger	250	5	1	1	0	0
595	600	2019	Schlumberger	250	2	1	3	0	0
602	0	2016	Itron	250	5	4339	55	0	0
602	0	2017	Itron	250	4	4561	66	0	1
602	0	2018	Itron	250	3	8145	76	2	0
602	0	2019	Itron	250	2	11507	76	0	0
602	0	2020	Itron	250	1	21437	51	0	0
602	0	2020	Itron	250	1	21437	51	0	0
602	0	2021	Itron	250	0	2	0	0	0
603	0	2020	Itron	400	1	438	2	0	0
555	0	1983	American	310	38	78	40	2	0
120	0	1980	Rockwell	175	41	983	81	8	1
140	0	1984	Sprague	175	37	673	42	0	5
560	0	1987	American	250	34	419	24	0	0
120	0	1986	Rockwell	175	35	1238	97	6	3
125	0	1979	Rockwell	200	42	147	37	1	0
452	0	2004	Actaris	400	17	395	73	4	3
570	0	2005	Rockwell	275	16	7	6	0	0
585	0	1991	Sprague	250	30	701	43	1	0
585	0	2000	Sprague	250	21	32	28	2	0
585	0	1988	Sprague	250	33	174	22	0	0
585	0	1995	Sprague	250	26	1474	54	2	1
120	0	1977	Rockwell	175	44	1295	92	5	3
130	0	1992	American	175	29	1353	92	10	0
450	0	1997	Schlumberger	400	24	53	18	0	0
480	486	1990	American	800	31	20	12	0	0
480	486	2001	American	800	20	11	10	1	0
510	515	1981	Rockwell	310	40	182	21	0	1
570	0	1989	Rockwell	275	32	701	71	3	0
125	0	1989	Rockwell	200	32	503	27	0	2
450	0	1999	Schlumberger	400	22	87	20	0	0
470	472	2001	American	425	20	55	36	2	0
470	472	2002	American	425	19	378	76	4	0
500	502	2002	American	1000	19	33	23	1	1

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow
510	515	1977	Rockwell	310	44	129	36	1	0
520	0	1981	Rockwell	415	40	213	24	0	2
520	0	2003	Rockwell	415	18	139	21	0	0
585	0	1999	Sprague	250	22	240	23	0	0
120	0	1970	Rockwell	175	51	559	79	10	1
120	0	1997	Rockwell	175	24	133	54	5	1
480	486	1995	American	800	26	15	12	0	2
510	515	1993	Rockwell	310	28	88	22	0	2
120	0	1995	Rockwell	175	26	277	70	8	0
270	0	1998	Schlumberger	1000	23	20	12	0	0
520	0	1979	Rockwell	415	42	66	28	1	2
590	0	1988	Lancaster	250	33	70	20	0	0
520	0	1977	Rockwell	415	44	36	15	0	0
130	0	1971	American	175	50	1001	81	9	0
130	0	1995	American	175	26	470	72	8	0
475	0	2010	American	630	11	584	82	8	0
480	486	1992	American	800	29	21	12	0	0
560	0	2005	American	250	16	57	18	0	0
120	0	1981	Rockwell	175	40	640	80	9	1
470	472	1994	American	425	27	182	59	3	1
471	0	2010	American	425	11	74	31	1	0
505	507	2011	American	1000	10	312	75	6	0
510	515	1989	Rockwell	310	32	75	31	1	0
562	0	2019	American	250	2	1371	5	1	0
470	472	1983	American	425	38	21	12	0	0
510	515	1990	Rockwell	310	31	189	63	5	2
120	0	1998	Rockwell	175	23	45	28	1	1
125	0	1987	Rockwell	200	34	496	68	3	0
520	0	1992	Rockwell	415	29	47	27	1	3
470	472	2007	American	425	14	190	50	2	0
471	0	2011	American	425	10	79	33	1	0
590	0	1998	Lancaster	250	23	16	10	0	0
125	0	1998	Rockwell	200	23	39	35	3	0
520	0	1991	Rockwell	415	30	62	17	0	1
125	0	1990	Rockwell	200	31	282	70	10	0
470	472	2003	American	425	18	139	59	3	0
555	0	1985	American	310	36	74	40	2	0
555	0	1989	American	310	32	8	7	0	0
572	0	2011	Sensus	275	10	65	19	0	0
520	0	2005	Rockwell	415	16	19	26	1	0

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	Determination
130	0	1983	American	175	38	2890	Determined
130	0	1990	American	175	31	3041	Determined
130	0	1993	American	175	28	3073	Determined
140	0	2011	Sprague	175	10	2	Small Family
300	540	1996	Rockwell	800	25	18	Determined
470	472	1993	American	425	28	59	Determined
480	486	1993	American	800	28	24	Determined
485	0	2011	American	800	10	1	Small Family
500	502	2001	American	1000	20	10	Determined
505	507	2007	American	1000	14	330	Determined
510	515	2011	Rockwell	310	10	1	Small Family
520	0	2011	Rockwell	415	10	1	Small Family
560	0	2011	American	250	10	3	Small Family
560	0	2020	American	250	1	7	Small Family
561	0	2005	American	250	16	1621	Determined
570	0	2011	Rockwell	275	10	1	Small Family
570	0	2020	Rockwell	275	1	2	Small Family
572	0	2003	Sensus	275	18	1	Small Family
572	0	2005	Sensus	275	16	24364	Determined
590	0	2011	Lancaster	250	10	1	Small Family
480	486	1996	American	800	25	6	Small Family
300	540	2005	Rockwell	800	16	5	Small Family
450	0	2005	Schlumberger	400	16	5	Small Family
485	0	1997	American	800	24	5	Small Family
500	502	1998	American	1000	23	62	Determined
555	0	1986	American	310	35	75	Small Family - Samples > 50%
555	0	1997	American	310	24	19	Determined
470	472	2005	American	425	16	17	Small Family - Samples > 50%
470	472	1990	American	425	31	17	Small Family - Samples > 50%
452	0	2005	Actaris	400	16	16	Small Family - Samples > 50%
					Total	**35677**	

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COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

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February 22, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
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Salem, OR 7308-1088

Re: RG 41: Meter Sampling Program Report for 2022

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2022 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2022. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2017, and December 31, 2022. The results of this analysis are as follows:

- As of December 31, 2022, 791,368 meters are installed and covered under the Meter Sampling Program. Of these, 695,137 meters, forming 369 distinct meter families, are conforming. The remaining 96,231 meters forming 78 distinct meter families are non-conforming and are scheduled for replacement. 60 non-conforming meter families were identified in prior years and 18 new meter families were identified as non-conforming in 2022. The 96,231 non-conforming meters represent 12 percent of the total meter population.
- Over the course of 2022, the company tested 9,577 meters. Over the five-year period of 2017 through 2022, the company had a total of 37,442 meter samples from which to base its results.
- 369 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are new for 2022. These meter families amount to 695,137 meters, or 88 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 1 meter family, Perf #572, the 2005 Sensus R-275, was previously declared PCC for PCC Year 2022. However, after performing and evaluating the results of 5,569 meter tests in 2021 and 2022, specific delivery lots of these meters were determined to be non-conforming, while other lots remained conforming. Due to this, a population of 6,673 meters were removed from the PCC schedule and will remain in the Meter Sampling Program. As of 12/31/2022, 4,424 meters from specific lots of Perf #572, 2005 Sensus R-275 remain listed for removal in the 2022 PCC program.
- 12 new meter families were added in 2022, reflecting new meters placed in service during the normal course of business, as well as meter replacements to replace non-conforming meters. 8 meter families were removed from service, due to small family size, during the normal course of business. 3 meter families were removed from service due to the number of supplementary samples required exceeding 50% of the family size, with a family size less than 100 meters.

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- 18 meter families, consisting of a total of 70,251 meters at the time of declaration, were identified as not conforming in 2022. Due to the number of meters requiring change-out (8.9% of the total population), these meters have been put on the list to be removed over the course of the next four years, by December 2026, per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1. The performance of these families is exhibited in Appendix B.
- A further breakdown of the 18 non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 7 meter families, totaling 70,167 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming. Significant results include:
        - 42,486 meters from the 2006 & 2007 American AC-250 meter families make up the bulk of this lot, reflecting the last American AC-250 meters in service from the 2005-2010 timeframe.
        - 13,495 American AL-175 meters from 1987, 1989, 1991
        - 14,106 American AC-250 meters from 1998
    - 8 meter families, totaling 25 meters, will be removed from service due to their small population size and age.
    - 3 meter families, totaling 59 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50% of the total family population.
- Compared to the results above, the Year 2021 report resulted in 35,677 meters being put on the list for removal by December 2025.
- Regarding the planned four year removal of meters determined non-conforming from 2019-2022, the following meters remain:
    - PCC Year 2020 (for removal 2020 to 2023): 2,583 remain out of 42,046 determined
    - PCC Year 2021 (for removal 2021 to 2024): 9,487 remain out of 27,204 determined
    - PCC Year 2022 (for removal 2022 to 2025): 14,977 remain out of 35,677 determined
    - PCC Year 2023 (for removal 2023 to 2026): 69,184 remain out of 70,251 determined
- Consistent with the NW Natural's tariff, bills for meters that are subject to the four year removal schedule and are later found to not meet the accuracy requirement are deemed subject to refund to customers based on the date when the meter family was determined to require change-out to the date the meter was replaced.

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If you have any questions or comments, please contact me at 503-610-7494.

Sincerely,

/s/ *Michael J. McKenzie*

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Engineering Manager

cc:

Dan Kizer
Jon Huddleston
Joe Karney
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Appendix A
Meter Families in Conformance

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	1968	Rockwell	175	54	53	41	2	0	43
120	0	1969	Rockwell	175	53	157	72	5	0	77
120	0	1970	Rockwell	175	52	529	96	9	1	106
120	0	1972	Rockwell	175	50	759	104	8	1	113
120	0	1973	Rockwell	175	49	562	95	10	1	106
120	0	1974	Rockwell	175	48	2383	236	15	7	258
120	0	1975	Rockwell	175	47	1647	145	18	2	165
120	0	1976	Rockwell	175	46	1003	103	6	4	113
120	0	1977	Rockwell	175	45	1228	114	7	1	122
120	0	1978	Rockwell	175	44	1328	121	8	4	133
120	0	1979	Rockwell	175	43	1491	152	10	4	166
120	0	1980	Rockwell	175	42	951	93	9	1	103
120	0	1981	Rockwell	175	41	617	101	7	2	110
120	0	1982	Rockwell	175	40	1094	111	14	1	126
120	0	1983	Rockwell	175	39	1246	122	16	2	140
120	0	1984	Rockwell	175	38	1359	117	14	1	132
120	0	1985	Rockwell	175	37	1818	134	18	1	153
120	0	1986	Rockwell	175	36	1200	109	8	3	120
120	0	1987	Rockwell	175	35	2084	147	6	3	156
120	0	1988	Rockwell	175	34	2035	155	7	5	167
120	0	1989	Rockwell	175	33	3295	218	12	6	236
120	0	1990	Rockwell	175	32	3317	210	15	6	231
120	0	1991	Rockwell	175	31	3598	262	7	13	282
120	0	1992	Rockwell	175	30	6335	398	11	14	423
120	0	1993	Rockwell	175	29	2502	166	8	4	178
120	0	1994	Rockwell	175	28	1285	96	3	4	103
120	0	1995	Rockwell	175	27	268	79	8	0	87
120	0	1996	Rockwell	175	26	703	89	3	0	92
120	0	1997	Rockwell	175	25	123	58	5	1	64
120	0	1998	Rockwell	175	24	45	29	1	1	31
120	0	2012	Rockwell	175	10	1	0	0	0	0

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	2013	Rockwell	175	9	1	0	0	0	0
120	0	2014	Rockwell	175	8	1	0	0	0	0
120	0	2015	Rockwell	275	7	1	0	0	0	0
120	0	2021	Rockwell	175	1	1	6	0	0	6
125	0	1978	Rockwell	200	44	1454	139	3	1	143
125	0	1979	Rockwell	200	43	142	38	1	0	39
125	0	1980	Rockwell	200	42	1723	126	15	1	142
125	0	1981	Rockwell	200	41	2346	145	10	0	155
125	0	1982	Rockwell	200	40	2923	188	7	0	195
125	0	1983	Rockwell	200	39	1646	141	4	2	147
125	0	1984	Rockwell	200	38	1986	130	14	1	145
125	0	1986	Rockwell	200	36	326	75	3	0	78
125	0	1987	Rockwell	200	35	490	68	3	0	71
125	0	1988	Rockwell	200	34	333	93	4	0	97
125	0	1989	Rockwell	200	33	429	87	5	3	95
125	0	1990	Rockwell	200	32	276	73	10	0	83
125	0	1991	Rockwell	200	31	657	48	0	0	48
125	0	1992	Rockwell	200	30	580	52	2	1	55
125	0	1993	Rockwell	200	29	453	81	6	2	89
125	0	1994	Rockwell	200	28	375	83	6	1	90
125	0	1995	Rockwell	200	27	66	46	5	0	51
125	0	1996	Rockwell	200	26	221	35	0	0	35
125	0	1998	Rockwell	200	24	39	39	3	0	42
125	0	1999	Rockwell	200	23	129	22	0	0	22
125	0	2017	Rockwell	200	5	1	3	0	0	3
125	0	2019	Rockwell	200	3	1	3	0	0	3
130	0	1971	American	175	51	976	92	11	0	103
130	0	1973	American	175	49	686	87	10	2	99
130	0	1975	American	175	47	21	15	0	0	15
130	0	1977	American	175	45	3006	207	24	4	235
130	0	1979	American	175	43	5997	374	20	4	398
130	0	1980	American	175	42	5790	376	24	5	405
130	0	1984	American	175	38	4466	283	40	8	331
130	0	1985	American	175	37	1953	124	13	1	138

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
130	0	1986	American	175	36	3749	201	31	6	238
130	0	1988	American	175	34	2940	184	27	3	214
130	0	1992	American	175	30	1303	93	16	0	109
130	0	1994	American	175	28	2503	119	20	0	139
130	0	1995	American	175	27	459	79	11	0	90
130	0	1996	American	175	26	1010	47	1	2	50
130	0	1997	American	175	25	195	51	1	1	53
130	0	2013	American	175	9	1	0	0	0	0
130	0	2014	American	175	8	3	0	0	0	0
130	0	2016	American	175	6	2	1	0	0	1
130	0	2020	American	175	2	1	13	1	0	14
130	0	2022	American	175	0	1	10	4	1	15
140	0	1968	Sprague	175	54	917	100	0	15	115
140	0	1970	Sprague	175	52	313	47	0	3	50
140	0	1971	Sprague	175	51	884	92	0	11	103
140	0	1972	Sprague	175	50	144	25	0	2	27
140	0	1973	Sprague	175	49	2670	247	3	8	258
140	0	1974	Sprague	175	48	574	51	0	2	53
140	0	1975	Sprague	175	47	664	60	0	3	63
140	0	1976	Sprague	175	46	1009	87	2	5	94
140	0	1977	Sprague	175	45	281	41	0	3	44
140	0	1978	Sprague	175	44	226	39	0	3	42
140	0	1979	Sprague	175	43	121	41	1	1	43
140	0	1980	Sprague	175	42	258	66	5	7	78
140	0	1981	Sprague	175	41	589	47	1	2	50
140	0	1982	Sprague	175	40	514	73	2	3	78
140	0	1983	Sprague	175	39	731	94	3	3	100
140	0	1984	Sprague	175	38	632	66	1	9	76
140	0	1985	Sprague	175	37	1052	105	1	7	113
140	0	1986	Sprague	175	36	908	60	1	3	64
140	0	1987	Sprague	175	35	2754	236	0	13	249
140	0	1988	Sprague	175	34	691	88	3	2	93
140	0	1989	Sprague	175	33	713	51	0	3	54
140	0	1990	Sprague	175	32	960	72	0	2	74

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
140	0	1991	Sprague	175	31	411	42	0	1	43
140	0	1992	Sprague	175	30	528	34	0	3	37
140	0	1993	Sprague	175	29	600	54	0	3	57
140	0	1994	Sprague	175	28	529	61	2	3	66
140	0	1997	Sprague	175	25	449	31	0	0	31
140	0	2016	Sprague	175	6	1	0	0	0	0
270	0	1998	Schlumberger	1000	24	17	11	0	0	11
270	0	2000	Schlumberger	1000	22	17	13	0	0	13
270	0	2001	Schlumberger	1000	21	20	37	2	0	39
450	0	1993	Schlumberger	400	29	166	32	0	0	32
450	0	1996	Schlumberger	400	26	238	38	0	0	38
450	0	1997	Schlumberger	400	25	43	20	0	0	20
450	0	1998	Schlumberger	400	24	397	57	0	1	58
450	0	1999	Schlumberger	400	23	80	21	0	0	21
450	0	2003	Schlumberger	400	19	15	13	0	0	13
450	0	2013	Schlumberger	400	9	1	0	0	0	0
452	0	2003	Actaris	400	19	72	28	0	0	28
452	0	2004	Actaris	400	18	372	86	2	3	91
470	472	1982	American	425	40	16	12	0	0	12
470	472	1983	American	425	39	18	14	0	0	14
470	472	1984	American	425	38	96	22	0	0	22
470	472	1985	American	425	37	21	22	2	0	24
470	472	1986	American	425	36	26	38	1	0	39
470	472	1987	American	425	35	97	60	3	0	63
470	472	1989	American	425	33	17	18	2	0	20
470	472	1992	American	425	30	105	43	2	0	45
470	472	1994	American	425	28	156	69	5	1	75
470	472	1995	American	425	27	73	22	0	0	22
470	472	1996	American	425	26	7	14	1	1	16
470	472	1997	American	425	25	263	78	5	0	83
470	472	1998	American	425	24	128	57	6	0	63
470	472	1999	American	425	23	219	42	2	0	44
470	472	2000	American	425	22	360	55	2	0	57
470	472	2001	American	425	21	49	37	3	0	40

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
470	472	2002	American	425	20	364	80	3	0	83
470	472	2003	American	425	19	137	69	3	0	72
470	472	2004	American	425	18	45	39	4	1	44
470	472	2006	American	425	16	34	35	0	0	35
470	472	2007	American	425	15	184	55	2	0	57
470	472	2008	American	425	14	10	13	0	0	13
470	472	2012	American	425	10	1	0	0	0	0
470	472	2017	American	425	5	1	0	0	0	0
471	0	2007	American	425	15	443	92	8	0	100
471	0	2008	American	425	14	36	35	3	0	38
471	0	2010	American	425	12	73	31	1	0	32
471	0	2011	American	425	11	76	33	1	0	34
471	0	2012	American	425	10	10	0	0	0	0
475	0	1996	American	630	26	1	0	0	0	0
475	0	2010	American	630	12	564	97	11	0	108
475	0	2011	American	630	11	993	82	1	0	83
475	0	2012	American	630	10	1378	100	0	0	100
475	0	2013	American	630	9	1438	94	2	0	96
475	0	2014	American	630	8	1501	83	0	1	84
475	0	2015	American	630	7	1211	73	1	0	74
475	0	2016	American	630	6	1586	67	0	0	67
475	0	2017	American	630	5	1653	70	2	0	72
475	0	2018	American	630	4	4574	165	2	2	169
475	0	2019	American	630	3	2923	111	0	0	111
475	0	2020	American	630	2	891	30	0	0	30
475	0	2021	American	630	1	1139	24	0	0	24
475	0	2022	American	630	0	1422	5	0	0	5
480	486	1989	American	800	33	21	12	0	0	12
480	486	1990	American	800	32	10	18	1	0	19
480	486	1992	American	800	30	18	13	0	0	13
480	486	1995	American	800	27	13	14	1	2	17
480	486	2001	American	800	21	11	10	1	0	11
480	486	2002	American	800	20	16	14	0	0	14
485	0	1981	American	800	41	16	15	0	3	18

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
485	0	1984	American	800	38	44	31	1	1	33
485	0	2016	American	800	6	1	0	0	0	0
487	0	2017	American	800	5	55	5	0	0	5
487	0	2018	American	800	4	187	13	0	0	13
487	0	2019	American	800	3	306	20	0	0	20
487	0	2020	American	800	2	231	12	0	0	12
487	0	2021	American	800	1	339	11	0	0	11
487	0	2022	American	800	0	284	4	0	0	4
500	502	2002	American	1000	20	27	25	2	1	28
505	507	2008	American	1000	14	259	92	11	0	103
505	507	2011	American	1000	11	293	91	7	0	98
505	507	2012	American	1000	10	354	54	2	0	56
505	507	2013	American	1000	9	353	47	0	0	47
505	507	2014	American	1000	8	408	48	0	0	48
505	507	2015	American	1000	7	339	31	0	0	31
505	507	2016	American	1000	6	489	56	0	0	56
505	507	2017	American	1000	5	190	20	0	0	20
505	507	2018	American	1000	4	330	30	2	0	32
505	507	2019	American	1000	3	285	32	1	0	33
505	507	2020	American	1000	2	15	2	1	0	3
505	507	2021	American	1000	1	11	2	1	0	3
505	507	2022	American	1000	0	5	0	0	0	0
510	515	1973	Rockwell	310	49	57	34	1	3	38
510	515	1974	Rockwell	310	48	20	23	0	4	27
510	515	1976	Rockwell	310	46	214	62	3	5	70
510	515	1977	Rockwell	310	45	122	41	1	0	42
510	515	1978	Rockwell	310	44	79	54	1	3	58
510	515	1979	Rockwell	310	43	109	53	5	8	66
510	515	1981	Rockwell	310	41	161	30	0	3	33
510	515	1982	Rockwell	310	40	34	42	1	4	47
510	515	1983	Rockwell	310	39	91	42	1	0	43
510	515	1984	Rockwell	310	38	11	17	1	1	19
510	515	1986	Rockwell	310	36	14	11	0	0	11
510	515	1987	Rockwell	310	35	184	51	1	1	53

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
510	515	1989	Rockwell	310	33	65	34	1	0	35
510	515	1990	Rockwell	310	32	178	68	6	2	76
510	515	1991	Rockwell	310	31	192	26	0	1	27
510	515	1992	Rockwell	310	30	90	50	5	4	59
510	515	1993	Rockwell	310	29	87	19	0	2	21
510	515	1994	Rockwell	310	28	26	16	0	0	16
510	515	1996	Rockwell	310	26	18	20	0	1	21
520	0	1977	Rockwell	415	45	32	16	0	0	16
520	0	1978	Rockwell	415	44	26	17	0	0	17
520	0	1979	Rockwell	415	43	59	33	0	3	36
520	0	1980	Rockwell	415	42	47	37	2	0	39
520	0	1981	Rockwell	415	41	196	30	0	2	32
520	0	1982	Rockwell	415	40	31	16	0	0	16
520	0	1988	Rockwell	415	34	38	16	0	1	17
520	0	1991	Rockwell	415	31	60	17	0	1	18
520	0	1992	Rockwell	415	30	42	29	1	3	33
520	0	1994	Rockwell	415	28	78	21	0	1	22
520	0	1996	Rockwell	415	26	87	49	2	1	52
520	0	1997	Rockwell	415	25	40	17	0	1	18
520	0	2003	Rockwell	415	19	128	31	0	0	31
520	0	2004	Rockwell	415	18	54	43	4	0	47
520	0	2005	Rockwell	415	17	19	27	1	0	28
520	0	2017	Rockwell	415	5	1	0	0	0	0
520	0	2018	Rockwell	415	4	1	0	0	0	0
520	0	2019	Rockwell	415	3	1	0	0	0	0
520	0	2020	Rockwell	415	2	1	1	0	0	1
555	0	1980	American	310	42	47	43	3	0	46
555	0	1981	American	310	41	24	18	0	1	19
555	0	1983	American	310	39	66	51	3	0	54
555	0	1984	American	310	38	148	62	3	1	66
555	0	1985	American	310	37	71	41	2	0	43
555	0	1987	American	310	35	27	33	2	1	36
555	0	1989	American	310	33	7	7	0	0	7
560	0	1985	American	250	37	1358	83	3	1	87

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
560	0	1986	American	250	36	5844	323	7	3	333
560	0	1987	American	250	35	405	31	0	0	31
560	0	1988	American	250	34	3007	136	3	0	139
560	0	1989	American	250	33	6619	374	5	5	384
560	0	1990	American	250	32	5985	288	9	5	302
560	0	1991	American	250	31	5270	279	5	4	288
560	0	1992	American	250	30	4630	155	3	5	163
560	0	1993	American	250	29	3908	156	0	2	158
560	0	1994	American	250	28	5913	186	13	1	200
560	0	1995	American	250	27	7864	270	20	3	293
560	0	1996	American	250	26	10698	375	21	4	400
560	0	1999	American	250	23	10906	273	27	1	301
560	0	2000	American	250	22	10917	319	7	2	328
560	0	2001	American	250	21	9195	217	6	1	224
560	0	2002	American	250	20	8289	187	11	0	198
560	0	2003	American	250	19	394	76	0	2	78
560	0	2005	American	250	17	43	30	1	0	31
560	0	2006	American	250	16	579	67	2	0	69
560	0	2007	American	250	15	179	23	0	0	23
560	0	2012	American	250	10	6	0	0	0	0
560	0	2013	American	250	9	2	0	0	0	0
560	0	2014	American	250	8	5	0	0	0	0
560	0	2015	American	250	7	1	0	0	0	0
560	0	2018	American	250	4	3	14	1	0	15
560	0	2022	American	250	0	1	10	0	0	10
561	0	1984	American	250	38	1	0	0	0	0
561	0	2010	American	250	12	9772	348	8	2	358
561	0	2011	American	250	11	10269	398	5	0	403
561	0	2012	American	250	10	11517	428	3	3	434
561	0	2013	American	250	9	14974	408	4	5	417
561	0	2014	American	250	8	14316	374	4	1	379
561	0	2015	American	250	7	17580	385	1	1	387
561	0	2016	American	250	6	12458	225	0	0	225
561	0	2017	American	250	5	11632	243	2	1	246

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
561	0	2018	American	250	4	9609	172	2	3	177
561	0	2019	American	250	3	14433	197	2	0	199
561	0	2020	American	250	2	10627	109	10	0	119
561	0	2021	American	250	1	6920	70	13	0	83
561	0	2022	American	250	0	6316	32	10	0	42
562	0	2017	American	250	5	22	0	0	0	0
562	0	2018	American	250	4	695	0	0	0	0
562	0	2019	American	250	3	1369	5	1	0	6
562	0	2020	American	250	2	996	0	0	0	0
562	0	2021	American	250	1	1101	2	0	0	2
562	0	2022	American	250	0	567	0	0	0	0
570	0	1989	Rockwell	275	33	682	80	3	0	83
570	0	1990	Rockwell	275	32	5186	200	7	2	209
570	0	1991	Rockwell	275	31	2772	132	7	0	139
570	0	1992	Rockwell	275	30	124	57	5	0	62
570	0	1993	Rockwell	275	29	58	33	1	0	34
570	0	1994	Rockwell	275	28	4881	167	6	0	173
570	0	1995	Rockwell	275	27	6226	240	9	5	254
570	0	1996	Rockwell	275	26	7471	203	3	3	209
570	0	1997	Rockwell	275	25	2298	59	1	0	60
570	0	1998	Rockwell	275	24	5258	166	18	1	185
570	0	1999	Rockwell	275	23	10214	262	35	4	301
570	0	2000	Rockwell	275	22	8251	193	24	3	220
570	0	2001	Rockwell	275	21	8448	218	8	0	226
570	0	2002	Rockwell	275	20	10575	234	2	0	236
570	0	2003	Rockwell	275	19	19336	505	8	1	514
570	0	2004	Rockwell	275	18	3508	91	0	0	91
570	0	2005	Rockwell	275	17	6	7	0	0	7
570	0	2012	Rockwell	275	10	4	1	0	0	1
570	0	2013	Rockwell	275	9	1	0	0	0	0
570	0	2014	Rockwell	275	8	2	0	0	0	0
570	0	2016	Rockwell	275	6	2	0	0	0	0
570	0	2017	Rockwell	275	5	3	3	0	0	3
570	0	2018	Rockwell	275	4	2	2	0	0	2

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
570	0	2022	Rockwell	275	0	1	6	1	0	7
572	0	1999	Sensus	275	23	1	0	0	0	0
572	0	2004	Sensus	275	18	13585	325	22	2	349
572	0	2005	Sensus	275	17	6673	5493	335	7	5835
572	0	2008	Sensus	275	14	34	40	1	0	41
572	0	2009	Sensus	275	13	721	55	1	0	56
572	0	2011	Sensus	275	11	63	20	0	0	20
572	0	2012	Sensus	275	10	3	1	0	0	1
572	0	2013	Sensus	275	9	1	0	0	0	0
572	0	2014	Sensus	275	8	2	0	0	0	0
572	0	2015	Sensus	275	7	2	0	0	0	0
572	0	2016	Sensus	275	6	3	0	0	0	0
572	0	2020	Sensus	275	2	9354	109	3	1	113
572	0	2021	Sensus	275	1	11989	108	0	2	110
572	0	2022	Sensus	275	0	12986	70	2	0	72
585	0	1988	Sprague	250	34	169	22	0	0	22
585	0	1991	Sprague	250	31	681	65	1	0	66
585	0	1992	Sprague	250	30	1989	126	1	1	128
585	0	1993	Sprague	250	29	3673	188	1	0	189
585	0	1994	Sprague	250	28	1598	73	0	1	74
585	0	1995	Sprague	250	27	1442	75	2	1	78
585	0	1996	Sprague	250	26	4262	189	1	1	191
585	0	1997	Sprague	250	25	5721	222	2	2	226
585	0	1998	Sprague	250	24	5200	231	1	1	233
585	0	1999	Sprague	250	23	196	54	1	0	55
585	0	2000	Sprague	250	22	31	29	2	0	31
585	0	2001	Sprague	250	21	47	19	0	0	19
585	0	2002	Sprague	250	20	43	16	0	0	16
585	0	2004	Sprague	250	18	42	20	0	1	21
585	0	2014	Sprague	250	8	2	0	0	0	0
585	0	2021	Sprague	175	1	1	2	0	0	2
590	0	1988	Lancaster	250	34	68	19	0	0	19
590	0	1989	Lancaster	250	33	1237	93	0	0	93
590	0	1990	Lancaster	250	32	1254	79	0	1	80

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
590	0	1991	Lancaster	250	31	1628	107	1	0	108
590	0	1992	Lancaster	250	30	2536	151	2	0	153
590	0	1993	Lancaster	250	29	2740	104	2	0	106
590	0	1994	Lancaster	250	28	4163	232	12	3	247
590	0	1995	Lancaster	250	27	4594	227	13	15	255
590	0	1996	Lancaster	250	26	25	22	0	0	22
590	0	1997	Lancaster	250	25	2042	83	1	2	86
590	0	1998	Lancaster	250	24	15	14	0	0	14
590	0	1999	Lancaster	250	23	96	54	2	0	56
590	0	2016	Lancaster	250	6	1	0	0	0	0
590	0	2019	Lancaster	250	3	1	1	0	0	1
590	0	2021	Lancaster	250	1	1	2	0	0	2
590	0	2022	Lancaster	250	0	1	0	0	0	0
595	600	2000	Schlumberger	250	22	2806	482	22	18	522
595	600	2001	Schlumberger	250	21	3532	324	7	1	332
595	600	2002	Schlumberger	250	20	3098	199	1	8	208
595	600	2003	Schlumberger	250	19	44	18	0	0	18
595	600	2004	Schlumberger	250	18	20	12	0	0	12
595	600	2012	Schlumberger	250	10	1	0	0	0	0
595	600	2016	Schlumberger	250	6	1	1	0	0	1
595	600	2019	Schlumberger	250	3	1	3	0	0	3
602	0	1997	Itron	250	25	1	0	0	0	0
602	0	2016	Itron	250	6	4270	110	0	1	111
602	0	2017	Itron	250	5	4521	98	0	1	99
602	0	2018	Itron	250	4	8079	133	2	0	135
602	0	2019	Itron	250	3	11408	155	0	0	155
602	0	2020	Itron	250	2	21275	211	0	0	211
602	0	2021	Itron	250	1	22427	115	1	0	116
602	0	2022	Itron	250	0	8829	34	0	0	34
603	0	2020	Itron	400	2	421	18	0	0	18
603	0	2021	Itron	400	1	380	7	0	0	7
603	0	2022	Itron	400	0	32	0	0	0	0
					Total	**695,137**				

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Appendix B
Meter Families Not Conforming (To Be Removed Over 4 Years)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	% Not Conforming	PCC Reason
130	0	1987	American	175	35	5684	217	36	1	14.6%	Determined
130	0	1989	American	175	33	3116	135	23	4	16.7%	Determined
130	0	1991	American	175	31	4695	183	29	5	15.7%	Determined
130	0	2021	American	175	1	1	5	1	0	16.7%	Small Family
272	0	2004	Actaris	1000	18	7	7	1	0	12.5%	Small Family
300	540	2005	Rockwell	800	17	4	6	0	1	14.3%	Small Family
505	507	1981	American	1000	41	6	8	0	2	20.0%	Small Family
520	0	2000	Rockwell	415	22	80	41	7	0	14.6%	Determined
560	0	1998	American	250	24	14106	301	47	3	14.2%	Determined
560	0	2021	American	250	1	1	16	6	0	27.3%	Small Family
561	0	2006	American	250	16	21038	448	70	0	13.5%	Determined
561	0	2007	American	250	15	21448	534	82	2	13.6%	Determined
570	0	2021	Rockwell	275	1	4	1	1	0	50.0%	Small Family
602	0	1981	Itron	250	41	1	0	0	0	0%	Small Family
602	0	1993	Itron	250	29	1	0	0	0	0%	Small Family
470	472	2005	American	425	17	17	6	1	0	14.3%	Samples >50%
520	0	1987	Rockwell	415	35	35	6	0	1	14.3%	Samples >50%
140	0	1998	Sprague	175	24	7	1	0	0	0.0%	Samples >50%
					Total	**70,251**					

e-FILING REPORT COVER SHEET

COMPANY NAME: NW Natural

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☐ Yes, report docket number: RG 41

Report is required by: ☐ OAR
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☑ Other At request of Commission Staff
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ☐ Yes, docket number: RG 41

List Key Words for this report. We use these to improve search results.

Meter Sampling for 2020, NW Natural

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@puc.oregon.gov

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

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February 22, 2024

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
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Salem, Oregon 97308-1088

Re: RG 41: Meter Sampling Program Report for 2023

At the request of Commission Staff, Northwest Natural Gas Company, dba NW Natural, submits herewith its 2023 Meter Sampling Program Report.

As required by our Meter Testing Standards and Procedures document, the accuracies of all operating families of diaphragm meters with capacities 1000 ft^3/hr and below have been statistically analyzed for the year 2023. This analysis utilized all relevant meter tests conducted during the five calendar years between January 1, 2018, and December 31, 2023. The results of this analysis are as follows:

- As of December 31, 2023, 803,119 meters are installed and covered under the Meter Sampling Program. Of these, 716,844 meters, forming 362 distinct meter families, are conforming. The remaining 86,275 meters form 83 distinct meter families and are non-conforming and are scheduled for replacement. 59 non-conforming meter families were identified in prior years and 24 new meter families were identified as non-conforming in 2023. The 86,275 non-conforming meters represent 10.7 percent of the total meter population.
- Over the course of 2023, the company tested 7,996 meters. Over the five-year period of 2018 through 2023, the company had a total of 41,217 meter samples from which to base its results.
- 362 meter families either had sufficient meter samples to establish statistical confidence in their accuracy, or are new for 2023. These meter families amount to 716,844 meters, or 89.3 percent of the total meter population. The performances of these families are exhibited in Appendix A.
- 14 new meter families were added in 2023, reflecting new meters placed in service during the normal course of business, as well as meter replacements to replace non-conforming meters. 17 meter families were removed from service due to small family size, during the normal course of business. 4 meter families were removed from service due to the number of supplementary samples required exceeding 50 percent of the family size, with a family size less than 100 meters.
- 25 meter families, consisting of a total of 2,612 meters at the time of declaration, were identified as not conforming in 2023. Per Meter Sampling Program (MSP) guidelines outlined in NW Natural Engineering Procedure Z-1, these will be removed by the end of 2024. The performance of these families is exhibited in Appendix B.
    - The 2023 Meter Sampling Annual Report shows a significant decrease in meters declared non-conforming when compared to the 2022 annual report. In 2022, NW Natural declared 70,251 meters as non-conforming, which consisted predominantly of 42,486 American AC-250 meters

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set in 2006 and 2007, and an additional 14,106 American AC-250 meters set in 1998. These meter families are large, and were predominantly made up of the American meter families that NW Natural has seen fail earlier than expected, which were set from 2005-2009. Those meters from 2005-2009 have now all been declared PCC. For 2023, NW Natural has seen what we would consider a more typical year with only one larger meter family, the 1994 American AL-175 being declared PCC, and we would expect this trend to continue as meters age into the 30-40 year range.

- A further breakdown of the 25 non-conforming meter families and associated meters described above are as follows, the performance of these families is exhibited in Appendix B:
    - 4 meter families, totaling 2,525 meters had sufficient meter tests available to have their accuracy determined statistically and determined non-conforming.
    - 17 meter families, totaling 33 meters, will be removed from service due to their small population size and age.
    - 4 meter families, totaling 54 meters, will be removed from service due to a family size less than 100 meters, and sampling requirements exceeding 50 percent of the total family population.
- Compared to the results above, the Year 2022 report resulted in 70,251 meters being put on the list for removal over five years by December 2026.
- Regarding the planned four-year removal of meters determined non-conforming from 2020-2023, the following meters remain:
    - PCC Year 2020 (for removal 2020 to 2023): 1 remains out of 42,252 determined
        - 1 meter remains for PCC Year 2020 due to access issues.
    - PCC Year 2021 (for removal 2021 to 2024): 6,515 remain out of 27,898 determined.
    - PCC Year 2022 (for removal 2022 to 2025): 9,783 remain out of 35,677 determined.
    - PCC Year 2023 (for removal 2023 to 2026): 67,484 remain out of 70,251 determined.
    - PCC Year 2024 (for removal in 2024): 2,492 remain out of 2,612 determined.

If you have any questions or comments, please contact me at matt.miller@nwnatural.com.

Sincerely,
/s/ *Matt Miller*

Matt Miller
Engineering

Michael J. McKenzie, P.E.
Engineering Manager
cc:

Dan Kizer – Engineering Sr Director
Cari Colton – Utility Technical Services Sr Director
Joe Karney – VP, Engineering & Utility Operations
Dave Weber – VP, Gas Supply & Utility Support Services
Kim Rush – SVP, Chief Operating Officer

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Appendix A
Meter Families in Conformance (Excluding new meters)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
120	0	1969	Rockwell	175	54	157	67	4	0	71
120	0	1970	Rockwell	175	53	533	93	9	1	103
120	0	1972	Rockwell	175	51	762	84	6	1	91
120	0	1973	Rockwell	175	50	564	87	10	1	98
120	0	1974	Rockwell	175	49	2386	188	12	6	206
120	0	1975	Rockwell	175	48	1649	126	12	2	140
120	0	1976	Rockwell	175	47	1010	94	3	4	101
120	0	1977	Rockwell	175	46	1238	104	6	1	111
120	0	1978	Rockwell	175	45	1334	107	5	4	116
120	0	1979	Rockwell	175	44	1495	141	8	4	153
120	0	1981	Rockwell	175	42	619	95	4	2	101
120	0	1983	Rockwell	175	40	1249	115	14	2	131
120	0	1985	Rockwell	175	38	1819	118	13	1	132
120	0	1986	Rockwell	175	37	1201	98	6	2	106
120	0	1987	Rockwell	175	36	2087	129	3	3	135
120	0	1988	Rockwell	175	35	2039	135	5	5	145
120	0	1989	Rockwell	175	34	3301	184	9	5	198
120	0	1990	Rockwell	175	33	3326	194	12	6	212
120	0	1991	Rockwell	175	32	3603	221	6	13	240
120	0	1992	Rockwell	175	31	6347	343	4	13	360
120	0	1993	Rockwell	175	30	2507	151	5	4	160
120	0	1994	Rockwell	175	29	1286	83	3	4	90
120	0	1995	Rockwell	175	28	269	77	8	0	85
120	0	1996	Rockwell	175	27	703	80	2	0	82
120	0	1998	Rockwell	175	25	45	29	1	1	31
120	0	2014	Rockwell	175	9	1	0	0	0	0
120	0	2015	Rockwell	175	8	1	0	0	0	0
120	0	2021	Rockwell	175	2	1	6	0	0	6
125	0	1978	Rockwell	200	45	1459	117	2	1	120
125	0	1980	Rockwell	200	43	1727	93	8	1	102
125	0	1981	Rockwell	200	42	2358	108	6	0	114
125	0	1982	Rockwell	200	41	2928	170	5	0	175
125	0	1983	Rockwell	200	40	1649	135	2	2	139
125	0	1984	Rockwell	200	39	1989	120	10	0	130
125	0	1986	Rockwell	200	37	326	74	2	0	76
125	0	1988	Rockwell	200	35	333	89	3	0	92
125	0	1989	Rockwell	200	34	429	83	5	3	91
125	0	1991	Rockwell	200	32	657	41	0	0	41
125	0	1992	Rockwell	200	31	580	49	1	1	51
125	0	1993	Rockwell	200	30	457	26	0	2	28
125	0	1996	Rockwell	200	27	221	35	0	0	35
125	0	1998	Rockwell	200	25	39	38	3	0	41

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
125	0	2017	Rockwell	200	6	1	0	0	0	0
125	0	2019	Rockwell	200	4	1	3	0	0	3
130	0	1971	American	175	52	979	80	11	0	91
130	0	1973	American	175	50	688	83	10	2	95
130	0	1975	American	175	48	21	15	0	0	15
130	0	1977	American	175	46	3021	177	25	4	206
130	0	1979	American	175	44	6012	333	19	2	354
130	0	1980	American	175	43	5799	343	23	5	371
130	0	1984	American	175	39	4477	246	35	8	289
130	0	1985	American	175	38	1954	110	11	0	121
130	0	1986	American	175	37	3756	176	24	6	206
130	0	1988	American	175	35	2945	134	20	3	157
130	0	1992	American	175	31	1307	89	15	0	104
130	0	1995	American	175	28	461	76	11	0	87
130	0	1997	American	175	26	195	51	1	1	53
130	0	2014	American	175	9	3	0	0	0	0
130	0	2016	American	175	7	2	0	0	0	0
130	0	2020	American	175	3	1	13	1	0	14
140	0	1968	Sprague	175	55	918	87	0	11	98
140	0	1970	Sprague	175	53	314	37	0	2	39
140	0	1971	Sprague	175	52	891	86	0	9	95
140	0	1973	Sprague	175	50	2674	217	3	6	226
140	0	1974	Sprague	175	49	575	44	0	2	46
140	0	1975	Sprague	175	48	667	55	0	3	58
140	0	1976	Sprague	175	47	1013	77	1	5	83
140	0	1977	Sprague	175	46	281	37	0	3	40
140	0	1978	Sprague	175	45	226	39	0	3	42
140	0	1980	Sprague	175	43	259	63	5	7	75
140	0	1981	Sprague	175	42	591	43	1	2	46
140	0	1982	Sprague	175	41	519	68	1	3	72
140	0	1983	Sprague	175	40	733	86	3	1	90
140	0	1985	Sprague	175	38	1056	91	0	6	97
140	0	1986	Sprague	175	37	908	54	0	3	57
140	0	1987	Sprague	175	36	2756	214	0	8	222
140	0	1988	Sprague	175	35	692	81	3	1	85
140	0	1989	Sprague	175	34	715	45	0	2	47
140	0	1990	Sprague	175	33	962	63	0	2	65
140	0	1991	Sprague	175	32	411	37	0	0	37
140	0	1992	Sprague	175	31	531	31	0	2	33
140	0	1993	Sprague	175	30	600	49	0	3	52
140	0	1994	Sprague	175	29	530	54	2	1	57
140	0	1997	Sprague	175	26	449	28	0	0	28
140	0	2016	Sprague	175	7	1	0	0	0	0
270	0	2001	Schlumberger	1000	22	20	35	2	0	37
450	0	1993	Schlumberger	400	30	167	24	0	0	24
450	0	1996	Schlumberger	400	27	240	33	0	0	33

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
450	0	1997	Schlumberger	400	26	43	19	0	0	19
450	0	1998	Schlumberger	400	25	398	52	0	1	53
450	0	1999	Schlumberger	400	24	80	20	0	0	20
450	0	2003	Schlumberger	400	20	15	13	0	0	13
450	0	2022	Schlumberger	400	1	1	0	0	0	0
452	0	2003	Actaris	400	20	72	28	0	0	28
452	0	2004	Actaris	400	19	374	66	2	1	69
470	472	1983	American	425	40	18	11	0	0	11
470	472	1986	American	425	37	27	38	1	0	39
470	472	1987	American	425	36	97	53	3	0	56
470	472	1994	American	425	29	156	65	5	1	71
470	472	1995	American	425	28	73	19	0	0	19
470	472	1996	American	425	27	7	12	0	1	13
470	472	2000	American	425	23	363	49	1	0	50
470	472	2002	American	425	21	364	74	3	0	77
470	472	2003	American	425	20	137	67	3	0	70
470	472	2004	American	425	19	45	39	4	1	44
470	472	2007	American	425	16	184	52	2	0	54
470	472	2008	American	425	15	10	13	0	0	13
470	472	2017	American	425	6	1	0	0	0	0
471	0	2007	American	425	16	444	84	4	0	88
471	0	2008	American	425	15	36	35	2	0	37
471	0	2011	American	425	12	76	31	1	0	32
475	0	2010	American	630	13	564	91	11	0	102
475	0	2011	American	630	12	993	73	1	0	74
475	0	2012	American	630	11	1380	81	0	0	81
475	0	2013	American	630	10	1441	79	2	0	81
475	0	2014	American	630	9	1504	74	0	1	75
475	0	2015	American	630	8	1215	67	1	0	68
475	0	2016	American	630	7	1588	59	0	0	59
475	0	2017	American	630	6	1654	63	1	0	64
475	0	2018	American	630	5	4575	165	2	2	169
475	0	2019	American	630	4	2922	111	0	0	111
475	0	2020	American	630	3	891	30	0	0	30
475	0	2021	American	630	2	1139	24	0	0	24
475	0	2022	American	630	1	1410	5	0	0	5
480	486	1990	American	800	33	10	17	1	0	18
480	486	1995	American	800	28	13	13	1	2	16
480	486	2001	American	800	22	11	8	0	0	8
480	486	2002	American	800	21	16	13	0	0	13
485	0	1981	American	800	42	16	14	0	3	17
485	0	1984	American	800	39	45	25	1	1	27
485	0	2016	American	800	7	1	0	0	0	0
487	0	2017	American	800	6	55	5	0	0	5
487	0	2018	American	800	5	187	12	0	0	12
487	0	2019	American	800	4	307	20	0	0	20

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
487	0	2020	American	800	3	231	12	0	0	12
487	0	2021	American	800	2	340	11	0	0	11
487	0	2022	American	800	1	287	4	0	0	4
500	502	2002	American	1000	21	27	25	2	1	28
505	507	2008	American	1000	15	260	84	10	0	94
505	507	2011	American	1000	12	294	82	7	0	89
505	507	2013	American	1000	10	353	35	0	0	35
505	507	2014	American	1000	9	408	42	0	0	42
505	507	2015	American	1000	8	339	26	0	0	26
505	507	2016	American	1000	7	490	48	0	0	48
505	507	2017	American	1000	6	190	17	0	0	17
505	507	2018	American	1000	5	331	30	2	0	32
505	507	2019	American	1000	4	285	32	1	0	33
505	507	2020	American	1000	3	15	2	1	0	3
505	507	2021	American	1000	2	11	2	1	0	3
505	507	2022	American	1000	1	5	0	0	0	0
510	515	1973	Rockwell	310	50	57	33	1	3	37
510	515	1974	Rockwell	310	49	20	23	0	4	27
510	515	1977	Rockwell	310	46	122	35	1	0	36
510	515	1978	Rockwell	310	45	80	49	1	2	52
510	515	1979	Rockwell	310	44	110	50	5	8	63
510	515	1982	Rockwell	310	41	34	41	1	4	46
510	515	1983	Rockwell	310	40	93	38	0	0	38
510	515	1987	Rockwell	310	36	186	40	1	1	42
510	515	1989	Rockwell	310	34	65	22	0	0	22
510	515	1990	Rockwell	310	33	179	63	6	2	71
510	515	1991	Rockwell	310	32	192	24	0	0	24
510	515	1994	Rockwell	310	29	26	16	0	0	16
510	515	1996	Rockwell	310	27	18	19	0	1	20
520	0	1977	Rockwell	415	46	32	15	0	0	15
520	0	1981	Rockwell	415	42	196	26	0	2	28
520	0	1991	Rockwell	415	32	60	17	0	1	18
520	0	1992	Rockwell	415	31	42	25	1	2	28
520	0	1994	Rockwell	415	29	78	18	0	1	19
520	0	1996	Rockwell	415	27	88	43	2	1	46
520	0	1997	Rockwell	415	26	40	16	0	1	17
520	0	2003	Rockwell	415	20	129	28	0	0	28
520	0	2004	Rockwell	415	19	54	43	4	0	47
520	0	2005	Rockwell	415	18	19	26	1	0	27
520	0	2017	Rockwell	415	6	1	0	0	0	0
520	0	2018	Rockwell	415	5	1	0	0	0	0
520	0	2019	Rockwell	415	4	1	0	0	0	0
520	0	2020	Rockwell	415	3	1	1	0	0	1
555	0	1983	American	310	40	66	48	3	0	51
555	0	1984	American	310	39	148	62	3	1	66
555	0	1985	American	310	38	71	39	2	0	41

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
555	0	1989	American	310	34	7	7	0	0	7
560	0	1985	American	250	38	1361	76	3	1	80
560	0	1986	American	250	37	5853	273	7	3	283
560	0	1987	American	250	36	405	25	0	0	25
560	0	1988	American	250	35	3010	117	2	0	119
560	0	1989	American	250	34	6632	328	5	5	338
560	0	1990	American	250	33	5992	254	9	4	267
560	0	1991	American	250	32	5273	243	5	4	252
560	0	1992	American	250	31	4632	142	3	5	150
560	0	1993	American	250	30	3911	136	0	2	138
560	0	1994	American	250	29	5919	170	10	1	181
560	0	1995	American	250	28	7876	241	17	3	261
560	0	1996	American	250	27	10708	335	21	3	359
560	0	1999	American	250	24	10917	246	25	1	272
560	0	2000	American	250	23	10924	287	5	2	294
560	0	2001	American	250	22	9200	187	6	1	194
560	0	2002	American	250	21	8299	171	8	0	179
560	0	2003	American	250	20	395	48	0	2	50
560	0	2005	American	250	18	44	30	1	0	31
560	0	2006	American	250	17	580	61	2	0	63
560	0	2007	American	250	16	179	23	0	0	23
560	0	2014	American	250	9	5	0	0	0	0
560	0	2015	American	250	8	1	0	0	0	0
560	0	2018	American	250	5	3	14	1	0	15
560	0	2022	American	250	1	1	10	0	0	10
561	0	2010	American	250	13	9777	309	7	2	318
561	0	2011	American	250	12	10282	364	5	0	369
561	0	2012	American	250	11	11527	397	2	3	402
561	0	2013	American	250	10	14981	353	3	4	360
561	0	2014	American	250	9	14324	346	4	1	351
561	0	2015	American	250	8	17597	347	1	1	349
561	0	2016	American	250	7	12472	182	0	0	182
561	0	2017	American	250	6	11644	194	0	1	195
561	0	2018	American	250	5	9615	172	2	3	177
561	0	2019	American	250	4	14438	197	2	0	199
561	0	2020	American	250	3	10632	109	10	0	119
561	0	2023	American	250	0	4	0	0	0	0
562	0	2017	American	250	6	22	0	0	0	0
562	0	2018	American	250	5	695	0	0	0	0
562	0	2019	American	250	4	1369	5	1	0	6
562	0	2020	American	250	3	996	0	0	0	0
562	0	2021	American	250	2	1101	2	0	0	2
562	0	2022	American	250	1	564	0	0	0	0
570	0	1989	Rockwell	275	34	683	75	3	0	78
570	0	1990	Rockwell	275	33	5189	182	5	0	187
570	0	1991	Rockwell	275	32	2774	120	4	0	124

Docket No. UG 490

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
570	0	1994	Rockwell	275	29	4886	154	6	0	160
570	0	1995	Rockwell	275	28	6232	219	7	5	231
570	0	1996	Rockwell	275	27	7475	178	2	3	183
570	0	1997	Rockwell	275	26	2301	46	1	0	47
570	0	1998	Rockwell	275	25	5260	152	18	1	171
570	0	1999	Rockwell	275	24	10222	239	20	4	263
570	0	2000	Rockwell	275	23	8262	174	17	3	194
570	0	2001	Rockwell	275	22	8479	197	7	0	204
570	0	2002	Rockwell	275	21	10583	197	1	0	198
570	0	2003	Rockwell	275	20	19351	452	7	1	460
570	0	2004	Rockwell	275	19	3508	80	0	0	80
570	0	2014	Rockwell	275	9	2	0	0	0	0
570	0	2016	Rockwell	275	7	2	0	0	0	0
570	0	2017	Rockwell	275	6	3	0	0	0	0
570	0	2018	Rockwell	275	5	2	2	0	0	2
572	0	2004	Sensus	275	19	13595	293	20	1	314
572	0	2005	Sensus	275	18	11109	5433	328	7	5768
572	0	2008	Sensus	275	15	34	40	1	0	41
572	0	2009	Sensus	275	14	722	51	1	0	52
572	0	2011	Sensus	275	12	63	18	0	0	18
572	0	2014	Sensus	275	9	2	0	0	0	0
572	0	2015	Sensus	275	8	2	0	0	0	0
572	0	2016	Sensus	275	7	3	0	0	0	0
572	0	2020	Sensus	275	3	9369	109	3	1	113
572	0	2021	Sensus	275	2	11997	108	0	2	110
572	0	2022	Sensus	275	1	12972	70	1	0	71
572	0	2023	Sensus	275	0	2	0	0	0	0
585	0	1991	Sprague	250	32	684	64	1	0	65
585	0	1992	Sprague	250	31	1990	114	1	1	116
585	0	1993	Sprague	250	30	3681	175	1	0	176
585	0	1994	Sprague	250	29	1599	66	0	1	67
585	0	1995	Sprague	250	28	1444	70	2	1	73
585	0	1996	Sprague	250	27	4266	167	1	1	169
585	0	1997	Sprague	250	26	5728	196	1	1	198
585	0	1998	Sprague	250	25	5205	211	1	1	213
585	0	1999	Sprague	250	24	196	52	1	0	53
585	0	2001	Sprague	250	22	47	19	0	0	19
585	0	2002	Sprague	250	21	43	16	0	0	16
585	0	2004	Sprague	250	19	42	20	0	1	21
585	0	2014	Sprague	250	9	2	0	0	0	0
585	0	2021	Sprague	250	2	1	2	0	0	2
590	0	1989	Lancaster	250	34	1242	77	0	0	77
590	0	1990	Lancaster	250	33	1255	70	0	1	71
590	0	1991	Lancaster	250	32	1632	93	1	0	94
590	0	1992	Lancaster	250	31	2541	133	1	0	134
590	0	1993	Lancaster	250	30	2743	93	2	0	95

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
590	0	1994	Lancaster	250	29	4166	195	10	3	208
590	0	1995	Lancaster	250	28	4598	200	11	13	224
590	0	1996	Lancaster	250	27	25	22	0	0	22
590	0	1997	Lancaster	250	26	2042	73	1	1	75
590	0	1998	Lancaster	250	25	15	13	0	0	13
590	0	1999	Lancaster	250	24	96	52	2	0	54
590	0	2016	Lancaster	250	7	1	0	0	0	0
590	0	2019	Lancaster	250	4	1	1	0	0	1
590	0	2021	Lancaster	250	2	1	2	0	0	2
590	0	2022	Lancaster	250	1	1	0	0	0	0
595	600	2000	Schlumberger	250	23	2820	415	16	16	447
595	600	2001	Schlumberger	250	22	3541	291	6	1	298
595	600	2002	Schlumberger	250	21	3112	171	1	8	180
595	600	2003	Schlumberger	250	20	44	17	0	0	17
595	600	2016	Schlumberger	250	7	1	1	0	0	1
595	600	2019	Schlumberger	250	4	1	3	0	0	3
602	0	2016	Itron	250	7	4271	91	0	1	92
602	0	2017	Itron	250	6	4524	85	0	1	86
602	0	2018	Itron	250	5	8086	133	2	0	135
602	0	2019	Itron	250	4	11414	155	0	0	155
602	0	2020	Itron	250	3	21284	211	0	0	211
602	0	2021	Itron	250	2	22430	115	1	0	116
602	0	2022	Itron	250	1	8810	34	0	0	34
602	0	2023	Itron	250	0	2	0	0	0	0
603	0	2020	Itron	400	3	421	18	0	0	18
603	0	2021	Itron	400	2	380	7	0	0	7
603	0	2022	Itron	400	1	32	0	0	0	0
561	0	2021	American	250	2	6918	26	0	0	26
561	0	2022	American	250	1	6237	6	0	0	6
471	0	2010	American	425	13	73	30	1	0	31
510	515	1976	Rockwell	310	47	214	55	3	5	63
595	600	2004	Schlumberger	250	19	20	12	0	0	12
120	0	1980	Rockwell	175	43	951	83	6	1	90
520	0	1978	Rockwell	415	45	26	13	0	0	13
120	0	1997	Rockwell	175	26	123	55	4	1	60
510	515	1981	Rockwell	310	42	161	29	0	3	32
470	472	2001	American	425	22	46	39	3	0	42
120	0	1982	Rockwell	175	41	1088	81	8	1	90
120	0	1984	Rockwell	175	39	1353	93	10	2	105
125	0	1995	Rockwell	200	28	65	46	4	0	50
505	507	2012	American	1000	11	348	52	2	0	54
520	0	1988	Rockwell	415	35	36	15	0	0	15
140	0	1979	Sprague	175	44	118	22	0	0	22
480	486	1992	American	800	31	16	10	0	0	10
120	0	1968	Rockwell	175	55	51	28	1	0	29
140	0	1984	Sprague	175	39	627	69	1	9	79

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Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	# Meter Tests
470	472	1992	American	425	31	103	43	2	0	45
125	0	1999	Rockwell	200	24	127	21	0	0	21
130	0	1996	American	175	27	997	39	1	2	42
125	0	1994	Rockwell	200	29	363	25	0	0	25
480	486	1989	American	800	34	15	10	0	0	10
520	0	1979	Rockwell	415	44	50	24	0	3	27
470	472	1984	American	425	39	95	20	0	0	20
520	0	1980	Rockwell	415	43	39	31	2	0	33
125	0	1987	Rockwell	200	36	476	76	4	0	80
470	472	1982	American	425	41	10	8	0	0	8
470	472	1997	American	425	26	249	65	8	0	73
570	0	1993	Rockwell	275	30	44	15	0	1	16
470	472	2006	American	425	17	21	12	0	0	12
585	0	2000	Sprague	250	23	21	14	0	0	14
470	472	1985	American	425	38	12	9	0	0	9
470	472	1998	American	425	25	124	56	5	0	61
555	0	1980	American	310	43	36	32	2	0	34
555	0	1981	American	310	42	12	9	0	0	9
555	0	1987	American	310	36	21	14	0	0	14
585	0	1988	Sprague	250	35	161	22	0	0	22
520	0	1982	Rockwell	415	41	21	13	0	0	13
590	0	1988	Lancaster	250	35	58	17	0	1	18
125	0	1990	Rockwell	200	33	217	67	6	0	73
470	472	1999	American	425	24	166	67	6	0	73
125	0	1979	Rockwell	200	44	134	22	0	0	22
140	0	1972	Sprague	175	51	128	22	0	0	22
510	515	1986	Rockwell	310	37	9	10	1	1	12
510	515	1992	Rockwell	310	31	68	42	6	3	51
510	515	1993	Rockwell	310	30	65	31	1	2	34
570	0	1992	Rockwell	275	31	109	22	0	0	22

Docket No. UG 490

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Appendix B
Meter Families Not Conforming (To Be Removed Over 1 Year)

Perf	Alt. Perf	Year Set	Manufacturer	Size	Age	# Meters in Family	# OK	# Fast	# Slow	% Not Conforming	PCC Reason
120	0	2012	Rockwell	175	11	1	0	0	0	0	Small Family
120	0	2013	Rockwell	175	10	1	0	0	0	0	Small Family
130	0	1994	American	175	29	2505	106	19	0	125	Determined
130	0	2013	American	175	10	1	0	0	0	0	Small Family
130	0	2022	American	175	1	1	10	4	1	15	Determined
450	0	2013	Schlumberger	400	10	1	0	0	0	0	Small Family
470	472	1989	American	425	34	18	17	2	0	19	Determined
470	472	2012	American	425	11	1	0	0	0	0	Small Family
475	0	1996	American	630	27	1	0	0	0	0	Small Family
560	0	2012	American	250	11	6	0	0	0	0	Small Family
560	0	2013	American	250	10	2	0	0	0	0	Small Family
561	0	1984	American	250	39	1	0	0	0	0	Small Family
570	0	2005	Rockwell	275	18	6	7	0	0	7	Small Family
570	0	2012	Rockwell	275	11	4	1	0	0	1	Small Family
570	0	2013	Rockwell	275	10	1	0	0	0	0	Small Family
570	0	2022	Rockwell	275	1	1	6	1	0	7	Determined
572	0	1999	Sensus	275	24	1	0	0	0	0	Small Family
572	0	2012	Sensus	275	11	3	1	0	0	1	Small Family
572	0	2013	Sensus	275	10	1	0	0	0	0	Small Family
595	600	2012	Schlumberger	250	11	1	0	0	0	0	Small Family
602	0	1997	Itron	250	26	1	0	0	0	0	Small Family
270	0	2000	Schlumberger	1000	23	17	2	0	0	2	Samples >50%
510	515	1984	Rockwell	310	39	12	2	0	0	2	Samples >50%
270	0	1998	Schlumberger	1000	25	16	7	1	0	8	Samples >50%
471	0	2012	American	425	11	9	1	0	0	1	Samples >50%
					Total	**2,612**					

CASE: UG 490
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 907

Confidential Responses to Data Request in Support Of Opening Testimony

April 18, 2024

STAFF EXHIBIT 907 IS CONFIDENTIAL AND SUBJECT

TO PROTECTIVE ORDER NO. 23-480

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

REDACTED
Opening Testimony
IT&S Projects, Cloud-based Software, Administrative and General Expenses

April 18, 2024

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

A. My name is Julie Dyck. I am a Senior Economist/Utility Analyst employed in the Energy Costs Section of the Rates, Safety and Utility Performance (RSUP) Program of the of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. My testimony details the recommendations by Staff regarding IT&S projects, cloud-based software, and administrative and general (non-labor) expenses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1002, comprised of Northwest Natural non-confidential responses to Staff data requests and Exhibit Staff/1003, which includes Northwest Natural confidential responses to data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. IT&S PROJECTS AND CLOUD-BASED SOFTWARE

Q. Please summarize where NW Natural's IT&S Projects can be found.

A. In NWN Natural's Exhibit/700, Company witness Downing provides an overview of 11 separate Information Technology (IT) projects that are expected to be in service by the rate effective date of November 1, 2025. IT&S rate base expenses are found in FERC Accounts 303 (Miscellaneous tangible plant), 391 (Office furniture and equipment), and 397 (Communication equipment); this Testimony focuses mostly on amounts recorded in FERC Accounts 303. Although there are O&M related IT&S expenses that are in additional FERC accounts, they are analyzed by different Staff in their respective testimonies. For example, I analyze Office supplies and expenses (FERC 921) in Issue 3 that contain IT&S related O&M expenses.

Q. Detail how IT&S project costs are split.

A. IT&S project costs are split between capital and O&M. The Company's Capital Asset Policy outlines what is considered capital vs O&M and general guidance is included in the Company's Project Management Handbook.[1] IT Software (on-premises, cloud licensing, and maintenance) and hardware (initial purchase and on-premises maintenance) are typically capital meanwhile project management costs are typically charged to O&M expense accounts.

IT Projects (electronic equipment and computer software/hardware equipment) have continued to be a main driver of NW Natural's capital expenditures. According to NW Natural, "[t]hese costs have experienced an

1 Staff/1002, DR 162 Attachment 1, Project Management Handbook, 22-23.

increase due to cybersecurity threats and other increasing demands and complexity in the IT arena."[2] NW Natural explains that another driver of capital costs is that the cost of first-year maintenance paid as part of the software purchase is capitalized, as are additional costs related to changes in system design and/or system selection during implementation and the development of process manuals and documentation.[3]

Q. Distinguish between the terms cloud-based software and IT&S investments.

A. Cloud-based software and non-cloud-based software fall under the umbrella of IT&S investments.[4] Migration to the cloud is sometimes necessary to avoid transitioning to a new software system or tool, and cloud-based software can be more quickly updated. "Providers like Amazon Web Services (AWS), Microsoft Azure, and Google Cloud Platform have become essential partners for businesses of all sizes."[5] The Company explained five detailed ways that cloud-based and non-cloud-based options differ. Cloud based solutions:

1. Are hosted and managed by third-party providers as opposed to on-premises solutions that have Company owned hardware and equipment.
2. Are more flexible and scalable as there is not a need to usually invest in additional hardware.

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[2] NWN/1400, Davilla/27.
[3] Staff/1002, NWN Response to SDR 80 attachment 1 page 9-10 of 13.
[4] Staff/1002, NWN Response to DR 156 (pdf). See also NWN/700, Downing/8-11 for a detailed discussion of the differences between the two basic IT&S hosting options: cloud-based and on-premises.
[5] Staff/1002, NWN Response to DR 156 Attachment 1 (pdf).

3. Create an incremental O&M increase that escalates through time because businesses only pay for the resources they use on a monthly or yearly basis. Therefore, the programs can be capitalized but the depreciation is approximately five years which often cause a lag in recovery.
4. Tend to be more reliable and secure as the cloud providers invest heavily in security measures and disaster recovery protocols.
5. Typically have automatic upgrades and updates for hardware and security, which reduces IT burden.

Q. Was cloud-based software addressed in previous GRCs?

A. Yes, it was discussed in NW Natural's two most recent rate cases, UG 435[6] (2022) and UG 388 (2020).[7] In UG 435, the Commission adopted a stipulation under which the Horizon 1 cloud-based assets are amortized into rates over a ten-year life.[8] In that stipulation, NW Natural agreed that if the asset was removed from service in less than ten years, the Company would apply the modified blended treasury (MBT) rate to the remaining balance of the asset and defer the difference between the Company's cost of capital and the MBT rate until such time that general rates are changed.[9] In UG 388, while no IT-related issues were in the final settlement, Staff did initially propose the

[6] Staff/1002, NWN Response to DR 156 Attachment 1 (pdf).
[7] See UG 388, NWN/600, Downing/11-14, 16-27, 39, 50; UG 435 NWN/1600, Downing/22.
[8] *See also In the Matter of Northwest Natural Gas Company, Application for Accounting Order for Approval of Depreciation and Amortization of Rates for Investment in Certain Software*, UM 2215, Order No. 23-079 (March 10, 2023) (Accounting order authorizing NWN to use ten-year amortization period for cloud-based asset and implementation costs).
[9] *In the Matter of Northwest Natural Gas Company, Request for a General Rate Revision*, UG 435, Order No. 22-388, Appendix A Page 9 of 37.

reduction of support for Microsoft Office 365 and IT&S staffing. It appears that Staff had no issues with NWN rate basing various amounts from IT projects in UG 435 and UG 388.

Q. Does NW Natural include cloud-based assets in its rate base for this GRC?

A. Yes. Staff is also under the impression that licenses fees and hosting fees are not included in these totals. While implementation costs can be capitalized, license fees can only be capitalized under certain conditions, and hosting fees and maintenance/support are O&M expenses. Staff asks that the Company specify in their Reply Testimony whether there are license or hosting fees included in rate base. If these fees are included, the Company should explain what licensing fees or hosting fees are included as part of rate base and explain the rationale.[10] If Staff's current assumption that there are no such fees is incorrect, Staff will update its recommendation in subsequent testimonies.

Q. Please explain NW Natural's rationale for including cloud-based assets in rate base.

A. The Company explains that whether "Cloud Computing Arrangements" meet the criteria for capitalization is determined under accounting rules. FERC (Regulatory) and GAAP do not differ on the types of costs that can be capitalized or expensed for Cloud Computing Arrangements. NW Natural states that "FERC made a final ruling on ASU 2018-15: Customer's Accounting

[10] This was an issue that was brought up in Robert Young's testimony in Exh 2100 in UE 416, PGE's previous GRC.

for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract to all jurisdictional public utilities and licenses, natural gas companies and centralized service companies. For regulatory accounting, capitalized implementation costs should be recorded as utility plant assets in FERC Account 303 (Misc. intangible plant - computer software) and should be amortized over the term of the associated cloud computing arrangement in FERC Account 403 (Depreciation expense)."[11]

Q. Please describe how the IT&S individual business unit develops their forecast for capital.

A. The Company and each business unit use a bottom-up approach which is typically driven by business needs. Business units coordinate with the Portfolio Management Committee (PMC) to discuss, review, prioritize, and approve funding for projects. Following approval, projects are included into the forecast cycle.

However, the Company's strategy for cloud-based solutions was developed in partnership with Deloitte.[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[13]

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[11] Staff/1002, NWN Response to DR 416 (pdf).

[12] NW Natural/700, Downing/8.

[13] Staff/1003, NWN Response to CONF DR 168 Attachment 1 Page 7 of 21. See also Staff/1002, NWN Response to DR 162 Attachment A (pdf), Page 5 and page 21 are included as an attachment to show the capital planning process in more detail. Page 37 of 50 details that Planview is NW Natural's Project Portfolio Management (PPM) tool. Projects are required to leverage Planview for stage gates, status reporting, schedules, resource management and budgeting, as it serves as the source of truth for much of NWN's rates reporting.

Q. What is the Commission historical treatment of IT capital investment?

A. In previous rate cases, Staff has performed prudence reviews and examined whether the investment satisfies the "used and useful" criteria to determine whether IT investments are includable in rates.[14] Past Staff testimony has focused on a few IT&S projects that were cause for concern. It is also important to acknowledge that there is a knowledge asymmetry that exists between IT&S Staff at the Company and OPUC Staff when it comes to analyzing whether expenses were prudent. This is usually the case with more specialized expense categories but is also mitigated by Staff issuing multiple DRs, reading past testimonies, participating in workshops, and covering the same issue in multiple GRCs.

Q. How did Staff review and analyze the proposed IT projects?

A. Staff initially reviewed Mr. Downing's testimony, noting in particular the Company's statements regarding the current age and cybersecurity vulnerabilities of certain legacy information systems the "IT Projects" will replace. Staff issued a number of data requests to gain a better understanding of the underlying functionality of the proposed projects, why they are needed now, and what steps the Company took to achieve least cost/least risk solutions.[15]

Q. Please detail the IT&S projects that are requested for UG 490 and expected to go into place by the Test Year.

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[14] See *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

[15] Staff issued DRs 156-187 and 408-428 on IT&S related expenses.

A. Rate base IT&S expenditures are found in the "Intangible" and "General" categories of utility plant in service. The Intangible plant is fully comprised of IT&S capital expenditures. IT&S expenditures within the General category are isolated to FERC Accounts 391 for Computers, Computer Horizon, and Computer Bloodhound.[16] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[17] Average rate base balances were calculated using monthly forecast amounts to construct a 10-month AMA for all rate base components.[18] Table 1 shows a list of the plant accounts included. However, Staff's analysis primarily focuses on the IT&S Projects that are listed in Table 2 and described in NWN/700, as these are new projects that are expected to be in place by the Test Year.

TABLE 1: INTANGIBLE SOFTWARE PLANT ACCOUNTS

FERC	Description
303.1	Computer Software
303.2	Customer Information System
303.3	Industrial & Commercial BIL
303.4	CRMS
303.7	Cloud-Based Software
303.11	Computer SW Horizon
303.12	Computer SW Bloodhound
303.71	Cloud-Based SW Horizon

16 Staff/1002, NWN Response to DR 411 (pdf).
17 See CONF workpaper on Rate base and accumulated depreciation in the rate base net plant tab; see also Staff/1002, NWN Response to DR 411 Attachment 1 (excel). While the information included in the response to DR 411 Attachment 1 is non-confidential, Staff labeled this statement as confidential to err on the side of caution since the other workpaper is conf.
18 See NWN/1700, Walker/29.

303.71	Cloud-Based SW Bloodhound

TABLE 2: IT&S PROJECTS THAT GO INTO PLACE BY THE TEST YEAR

Projects	Capital Investment	Incremental O&M[19]	Cloud Based
IQGeo Upgrade Project (Field and Web Mapping)	$1.71M System ($1.5M Oregon Allocated)		Y
MapFrame Replacement Project (General Map viewer)	$5.5M System ($4.8M)		N
Composition 2.0 Project (Customer Bills)	$4.4M System ($3.9M)	$87K ($77K OR Allocated) for hardware and software licensing	N
Genesys Re-platform Project (Call Routing Software)	$2.3M System ($2.0M)	$289K ($254K)	Y
Start-Stop-Transfer Project (Relocate Service)	$2.7M ($2.4M)		N
Clevest Optimization Project (Mobile workforce management software)	$7.5M ($6.6M)		N
Identity Governance and Administration Automation Project (Secure onboarding and offboarding)	$3.0M ($2.6M)	$113K ($99K for software licensing)	Y
Telemetry Refresh Projects (Remote monitoring and control sites)	$6.8M ($6.0M). Of this amount, $4.1M ($3.6M) is associated with the One Pacific Square (OPS) 4-wire sites.[20]		N
Utilities International Planner Re-platform Project (UI Planning System)	$1.8M ($1.6M)	$208K ($183K)	Y
PowerPlan Project (Capital Settlement Process)	$1.7M ($1.5M)		N
SAP Treasury Project	$2.9M ($2.5M)		N
Total	$40.31M ($35.4)	$697K (613K)	

Q. Do any of the projects have prepayments?

19 These amounts are viewable in IT&S forecast tab and show the amounts that are attributable to things other than inflation.

20 The Company's former headquarters.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[21] "For each of the contracts entered into for the IT&S projects included in Exhibit 700, the payment terms were for 30 days after receiving an invoice (i.e., "Net 30")."[22]

Q. Which projects are considered out of service in the Test Year?

A. The Genesys and Utilities International (UI) Planner are two projects that are going out of service and will be re-platformed. The remaining rate base amounts as of October 1, 2023, are -$3,404,683 and -$331,789, respectively. NWN did not include these projects in its forecasted retirements and will therefore update this in its Reply Testimony.[23]

Q. Have these projects been moved into a regulatory asset account?

A. No. "The Company uses the Group Depreciation Method which does not depreciate these assets individually, the total cost of the group is spread out over the useful life of the entire group. Through the depreciation study process the Company reassess the useful life and salvage value of the assets in each group, including retirements, and adjustments to depreciation rates may be made accordingly."[24]

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21 Staff/1003, NWN Response to CONF DR 414 Attachment 1 (excel).
22 Staff/1002, NWN Response to DR 414 (pdf).
23 Staff/1002, NWN Response to DR 415 (pdf).
24 Staff/1002, NWN Response to DR 415 (pdf).

Q. Does Staff have any adjustments before discussing each of the individual IT Projects?

A. Yes. Out of the 11 projects referenced above in Table 2, only eight of those projects have contingency funds. Staff recommends removing the contingency funds of five projects,[25] which results in a total adjustment to NW Natural's proposed rate base of ($1,649,887), Oregon allocated. Of the remaining three projects below, two projects have already used them, one project I am recommending to be removed in its entirety, and it was stated that other projects are not expected to use their contingency funds.[26] Of the eight projects below, one is supposed to be in service 1/24, one is supposed to be in service 6/24, and the other six are supposed to be in service September or October of 2024. Therefore, if the contingency funds have not been used yet, they are unlikely to be used.

TABLE 3: CONTINGENCY FUNDS

Project	Project #	Contingency		Contingency Used
		System Level	Oregon Allocated	
SAP Treasury	I-202722	$ 100,000	$ 87,890	$ 100,000
Comp 2.0	I-202725	$ 262,180	$ 230,430	$ -
Identity Governance & Admin	I-202723	$ 200,000	$ 175,780	$ -
IQGeo Upgrade	I-202804	$ 100,000	$ 87,890	$ 100,000
Clevest	I-202721	$ 645,038	$ 566,924	$ -
TSA	I-202667	$ 430,000	$ 377,927	$ -
MapFrame	I-202862	$ 340,000	$ 298,826	$ -
Genesys	I-202840	$ 200,000	$ 175,780	$ -

25 This excludes SAP Treasury, IQ Geo Upgrade, and Genesys. The reason for the exclusion of Genesys is described later. The other two projects have already used their contingency funds.

26 Staff/1002, NWN Response to DR 185 Attachment 1 (excel) and NWN Response to DR 424 (pdf).

Q. What is IQGeo Software and does Staff have any concerns with including costs of this investment in rate base?

A. IQGeo Software is a web mapping tool. NW Natural states it uses mapping tools to provide field and office personnel with visual online and offline representations of NW Natural facilities and assets, which they use for various business purposes, including inspection compliance programs.[27] NW Natural has upgraded the IQGeo software because it is no longer fully supported, and the project will re-platform the software to a new more cybersecure cloud environment. Staff has reviewed the rationale and costs of the investment and has identified no concerns. NW Natural anticipated that this project will be online in January 2024.

Q. What is MapFrame and does Staff have concerns with including this investment in rate base?

A. MapFrame transitions away from an existing end-of-life software system that has not received a software update from its developer since 2015. Staff reviewed the costs of the project and has not identified costs that should be disallowed. NW Natural anticipates that this project will be online by the end of Summer 2024, so the project should be used and useful before the effective date of rates filed in this case.

Q. Does Staff have any concerns with the Composition 2.0 Project?

A. No. The Composition 2.0 Project modernizes the Company's electronic and printed documents for customers, including bills, notices, letters, welcome

[27] NW Natural/700, Downing/15.

packages, and refund checks. The customer bills (Composition 2.0 project) and Start-Stop-Transfer Project (discussed below) seem important and a good use of funds as there was a big difference in the change of bill formats and being able to automatically transfer account info to online forms. NW Natural anticipates this project will be on-line in September 2024. Staff will monitor the project to make sure it is used and useful prior to the November 1, 2024 effective date for rates in this case.

Q. What is the Genesys Re-platform project?

A. Genesys is the Company's existing on-premises advanced call routing software provider. The Genesys Re-platform Project transitions the Genesys call routing solution to a cloud environment, in response to the impending termination of Genesys' software support for the PureConnect platform by the software provider.[28] Genesys is phasing out the availability of and support for the PureConnect system, first by ceasing to offer new support agreements in January 2024, and then by fully ceasing support and operation of the system on July 31, 2025.[29]

Q. Does Staff have concerns with this project?

A. Staff is concerned that the Genesys re-platform was completed earlier than it needed to be. Full support and operation of the System was guaranteed until July 31, 2025, but the project is underway and is on track to be placed in service by October 2024.

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[28] NW Natural/700, Downing/24.
[29] NW Natural/700, Downing/24-25.

Staff believes this project has been rushed to ensure that it was in place before the rate effective date even though the previous call routing platform would have been fully supported through July 31, 2025. Notably, other software that NW Natural is replacing has been unsupported for years. For example, the IQGeo software has been unsupported since June 2022, MapFrame has not been updated since 2015, and UI Planner is no longer supported as of 2023. Notwithstanding, NW Natural was able to wait until 2024 to transition to a cloud-based solution for these applications. However, it is unclear what the Company means by "fully ceasing support and operation of the system" and whether the System could continue to operate after July 31, 2025.

Staff believes it would have been prudent for NW Natural to wait to implement this change to moderate the cost impact of these significant IT investments in this rate case. Therefore, Staff recommends removing the total Genesys re-platform project from rate base because at the time it was an imprudent expense to make given the longevity of the Genesys call routing software. This is a total adjustment of ($2 million) to rate base, Oregon allocated, and ($254,000) in incremental O&M for software licensing.

Q. What is the Start-Stop-Transfer Project and has Staff identified any concerns with including the costs of this project in rate base?

A. The Start-Stop-Transfer Project provides a new web-based tool that will allow customers to initiate, terminate, or relocate their service with NW Natural using the Company's website.[30] Staff believes this project will be beneficial to ratepayers and has identified no costs that should be disallowed, other than the contingency fund. NW Natural currently anticipates that this project will be on-line in October 2024.[31] As this is right before the effective date of rates from this GRC, Staff will monitor the progress of this project as the case goes on.

Q. What is the Clevest Optimization Project and has Staff identified any issues with the project?

A. Clevest is NW Natural's mobile workforce management software used to schedule, dispatch and complete all work in the field—ranging from emergency response to routine maintenance work. Clevest replaced NW Natural's previous end-of-life application, PragmaCad ("P-CAD"), was developed and implemented as part of the Horizon 1 Project, and has been in service since 2022.[32] The Clevest Optimization Project is an incremental effort to improve the Clevest mobile work management system, including (1) resolving post-deployment issues identified in the product's performance ("stabilization") and (2) adding new functionalities that were initially not included but, following the product's launch, turned out to be critical ("optimization").[33]

Although Staff has no monetary adjustment, Staff has identified a concern. The Company states that since Clevest was fully deployed in 2022 it has had difficulty accommodating the complexity of actual operations, referencing lag

[30] NW Natural/700, Downing/26.
[31] NW Natural/700, Downing/29.
[32] NW Natural/700, Downing/29.
[33] NW Natural/700, Downing/30.

times between 3-5 minutes and up to 30 minutes. The Optimization at issue in this GRC is necessary because the Company initially determined that certain features and functions were not essential and deprioritized. Staff recommends that the Company spend more time in a training environment to prevent situations like this from occurring, which in the end can increase the number of rate impacts for customers and the magnitude of those impacts.

Finally, NW Natural projects that the Clevest Optimization Project will be deployed in October 2024,[34] which is right before the rate effective date for this GRC. Accordingly, Staff will continue to monitor this project to ensure it is used and useful before the investment is placed in rate base.

Q. What is the Identity Governance and Administration (IGA) Automation Project and has Staff identified any concerns?

A. The IGA Automation Project involves implementing a comprehensive new software solution to track and manage the security access and identity management for Company personnel, particularly during onboarding, transfers, and offboarding. The Company testifies that currently, security access and other privileges are handled manually, with no centralized control point. As a result, there is currently no mechanism to certify that an individual's access to security and other functions has been removed following offboarding or other role changes.[35] The Company anticipates the software will be in service by June 2024.[36] Although Staff does not have a particular monetary adjustment to

[34] NW Natural/700, Downing/36.
[35] NW Natural/700, Downing/37.
[36] NW Natural/700, Downing/41.

the project totals, Staff is concerned that the process to acquire the IGA Automation project was convoluted with multiple consultants, including Forrester, with whom they have a subscription, and Integral Partners.[37] For other projects, like Clevest, the Company committed a dedicated business lead and project manager to focus on the work. Staff is generally concerned about the increase from $2.7 million in UG 435 to $9.1 million in UG 490 on consultants.[38] Staff is continuing to investigate this issue. Staff asks that the Company confirm whether this project and supplier and the other projects and suppliers were contracted are a result of an RFP.

Q. What are the Telemetry Refresh Projects and has Staff identified any issues?

A. The Telemetry Refresh Projects replace outdated monitoring and control equipment. The majority of the costs are associated with replacing telemetry equipment (OP 4-Wire sites) that transmitted to the basement of NW Natural's former headquarters, One Pacific Square, in order to avoid the need to renew the OPS basement site lease. NW Natural anticipates the projects will be on-line in October 2024.[39] Staff did not find any issues with these projects at this time but will monitor to ensure the projects are used and useful before they are included in the Company's rate base for this GRC.

Q. What is the Utilities International (UI) Planner Re-platform Project and has Staff identified any issues?

37 Staff/1002, NWN Response to DR 184 (pdf).
38 Staff/1002, NWN Response to DR 159 Attachment 1 (Excel).
39 NW Natural/700, Downing/43-44.

A. The UI Planner is NW Natural's corporate financial and regulatory finance planning system used to perform complex, iterative forecasts and problem-solving.[40] The Company's legacy version of UI Planner was first implemented in 2014 and will no longer be supported by the software provider after 2023.[41] The Company anticipates that the project will be online in August 2024. Staff has not identified issues with the project but will monitor to be sure it is used and useful before it is included in rates.

Q. What is the PowerPlan Project and has Staff identified issues with this project?

A. The PowerPlan Project transitions a key accounting function, known as the capital settlement process, from the Company's existing PowerPlan tool and into the broader SAP ERP system. The capital settlement process tracks costs accumulated under work orders and projects and allocates those costs to various accounts in PowerPlan.[42] The Company states the transition into the broader SAP Enterprise Resource Planning (ERP) System will improve the accuracy of the Company's capital projects tracking and reporting data. Staff has identified no issues with the project. The Company anticipates the project will be complete in October 2024, so Staff will monitor to ensure it is used and useful prior to the rate effective date.

Q. What is the SAP Treasury Project and has Staff identified issues?

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40 NW Natural/700, Downing/44-45.
41 NW Natural/700, Downing/45.
42 NW Natural/700, Downing/45.

A. The SAP Treasury Project implements a software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool replaces previous manual spreadsheet-based processes and according to the Company provides consolidated and comprehensive visibility into the Company's financial risk management using the necessary subset of SAP's "Treasury Track" software functionalities.[43] The SAP Treasury Project was placed in service in October 2023.[44]

Q. Does Staff have comments regarding the IT&S FTE request?

A. Yes. Staff has comments below although the dollar value adjustment is included in Stephanie Yamada's testimony regarding labor, wages and salaries, and FTE.

Q. How many IT&S positions are being requested?

A. NW Natural is requesting eight new IT&S positions aka full-time employees (FTEs). Four of the eight FTEs[45] are essential to support Horizon 2: Vista (H2: Vista). The other four FTEs are needed to support NW Natural's Supervisory Control and Data Acquisition (SCADA) telemetry systems, gas/pipeline control operations, and identity governance administration.[46]

Q. Should the Company be allowed to recover the costs for the H2: Vista related positions in this GRC?

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[43] NW Natural/700, Downing/48.
[44] NW Natural/700, Downing/50.
[45] NW Natural/700, Downing/50-55
[46] NW Natural/700, Downing/53-55.

A. No. H2: Vista will comprehensively update the customer information system (CIS) but no cost recovery for the investment is requested in UG 490 because it will not be online by the rate effective date. The Company states cost recovery for incremental employees is appropriate even though the investment will not be in rates because the Company intends to immediately begin recruiting three of the four positions and expects all four positions to be hired prior to the rate effective date (i.e., November 1, 2024), although the exact dates will depend on finding qualified candidates.

H2: Vista is replacing NW Natural's legacy, 26-year-old CIS.[47] Staff expects that current CIS employees will be cross trained for H2: Vista, as this is replacing the legacy system. Those employees that were working on CIS-related projects before are better equipped to learn a new system. In addition, NW Natural's IT&S FTE count in 2023, when completing the larger Horizon 1 program was 104, whereas their UG 490 request is 116. So even if all eight positions are approved, the Company's total IT&S FTE are likely to be around 112, which is four less than their request, since they are unlikely to fill all positions.

Moreover, H2: Vista is the second phase of a two-phase project. Horizon 1 was approved for recovery in UG 435 and successfully implemented on time and on budget. H2 will comprehensively update the customer information system (CIS) but no cost recovery is requested in UG 490.

[47] Staff/1002, NWN Response to DR 357 (pdf).

In 2023, NW Natural was able to complete the work of Horizon 1 while being “understaffed” from their previous request. Therefore, Staff proposes to remove the dollar value for the four positions. See Table 4 which shows the NW Natural’s FTE count for IT Staff.

TABLE 4: FTE COUNT OF IT STAFF[48]

	2018	2019	2020	2021	UG 435 Request	2023	UG 490 Request
FTE	77	84	92	90	92	104	116

Q. Are the four positions for H2 Vista expected to be included in the deferral that they will file later this year?

A. Yes. “The Company expects to include the costs of these FTEs in the deferral until such time base rates are updated on November 1, 2024, at which point the Company will recover their costs in base rates. The cost of these FTEs is estimated to be incurred prior to the Test Year, during the Test Year and will be ongoing costs.” The Company’s currently plans to file the Horizon 2, or H2: Vista, deferral application in the third quarter of 2024. The Company will update its plans in its Reply Testimony.[49]

Q. Please summarize Staff’s adjustments for IT&S costs.

A. Staff recommends a total adjustment of ($3.7 million) to rate base, which is comprised of ($1.7 million) in contingency funds, ($2 million) of capital costs

48 Staff/1002, NWN Response to DR 160 Attachment 1 (excel).
49 Staff/1002, NWN Response to DR 419 (pdf).

and an adjustment of ($254 thousand) to Test Year O&M costs for the Genesys Re-platform Project. Staff's FTE adjustment is included in Staff Opening Testimony for Stephanie Yamada in Exhibit 2000. My recommendations may change based on further review and as informed by the testimonies offered by other parties.

In addition, Staff intends to follow-up with data requests on the following concerns and asks that the Company address these concerns in their Reply Testimony.

1. Are licensing fees or hosting fees included as part of rate base?
2. Can Genesys continue to operate after July 31, 2025?
3. What is the company's policy for spending time in a training environment for IT projects and are they open to amending the time spent in a training environment?
4. Can the Company confirm IT projects and suppliers were contracted as a result of an RFP?
5. What are their plans for including Genesys and Utilities International (UI) Planner in their forecasted retirements and how will that impact their Test Year request?
6. Is there an update on the planned deferral for Horizon 2 program costs?

ISSUE 2. ADMINISTRATIVE AND GENERAL (NON-LABOR) EXPENSE

Q. Please describe the expenses included in this issue.

A. I review non-labor Administrative &General (A&G) expenses and credits recorded in FERC Accounts 921 (Office Supplies and Expenses, 922 (Administrative Expenses Transferred-Credited), 930.2 Miscellaneous General Expenses) and 931 (Rents). Other Staff review other categories of A&G expense such as 924 (Property Insurance), 925 (Injuries and Damages), and 926 (Employee Pensions and Benefits) and their conclusions and recommendations can be found in Exhibit 700 and 1500.

Q. Does the Commission Staff have a standard for how A&G expenses are treated for ratemaking purposes?

A. Expenses are reviewed for reasonableness and appropriate use. Typically, Staff will evaluate the reasonableness of costs by comparing the Company's forecasted costs to the Base Year actuals, a three-year historical average of actual costs, a review of transactional details, and consideration of any trends or changes that may impact the Company's Test Year expense. The Company uses discrete internal "Cost Element" codes to book a range of administrative and general (A&G) expenses into FERC accounts. Staff elicits information regarding the expenses through Standard Data Requests and Data Requests issued throughout the GRC.

Q. What is NW Natural's Test Year proposal for the A&G expenses?

A. NWN is proposing to increase non-labor administrative and general expenses (in FERC 921, 930, and 931) from $54.8 million in the Base Year to $63.8

million in the Test Year. This represents an increase of $9 million, or 16 percent. This increase in expense outpaces the inflation over the same period and is mostly attributed to FERC 921. The following individual FERC account balances were proposed for the Test Year:

FERC 921 (Office Supplies) - NWN is seeking an increase of $8.1M.[50]

FERC 922 is a credit increase.

FERC 930 (Misc General) - NWN is seeking an increase of $417K.

FERC 931 (Rents) - NWN is seeking an increase of $406K.

Q. How did NWN escalate costs from the Base Year to the Test Year.

A. "The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the West Region Urban CPI as reported in the September 2023 Oregon Economic and Revenue Forecast, published by the OEA. These escalation factors were applied on January 1, 2024, and January 1, 2025 The Company also identified several items where the growth projection was greater or lesser than using CPI and adjusted these items with their specific increase or decrease."[51]

Q. What does Staff recommend for an escalation factor?

A. It is Staff policy to use the Consumer Price Index – All-Urban Consumers for the U.S. (CPI, Urban U.S.) as published by the State of Oregon Office of Economic Analysis for year over year escalation. The escalation factors used in the Company's filing are greater than those used by Staff. Staff proposes an

50 Staff/1002, NWN Response to SDR 58 Attachment 2 (excel).
51 NWN/1400 Davilla/8.

adjustment to use the most recent All-Urban CPI as reported in the March 2024 Oregon Economic and Revenue Forecast (2.7 percent for 2024, 2.0 percent for 2025).[52] In its Opening Testimony, the Company uses 3.6 and 2.9 percent. It is worth noting that even the Western CPI has come down in the March OEA forecast compared to the September values used by the Company in their OT.

Q. Please describe Staff's analysis of NW Natural's proposed Administrative and General expenses?

A. Staff reviewed the corresponding sections of the Company's Application, reviewed the responses to the Standard and Staff DRs[53] pertaining to Admin and General expenses, and analyzed the corresponding transactional data. My analysis focuses on historical A&G expense trends, transactional detail, and NWN's proposed escalation adjustment to non-labor A&G expense. Other Staff reviewed the remaining adjustments, and their conclusions and recommendations regarding their analyses can be found in their testimony.

Q. Describe the Company's proposed Test Year expense for FERC 921 (Office Supplies and Expense). [54]

A. The largest components of this IT&S O&M Expense increase are addressed in NWN/700 and NWN/800 as most are related to IT&S related costs.[55] Figure 2

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52 https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0324.pdf

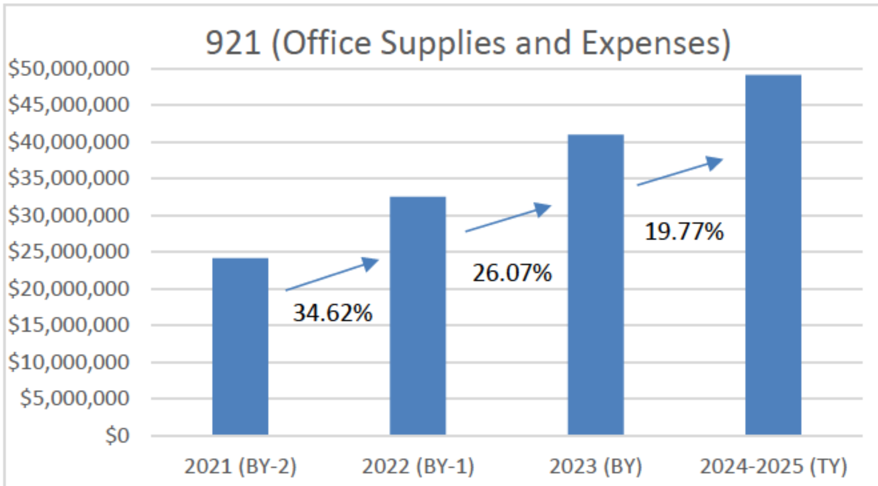
53 Staff DRs 200-202 and 425-428

54 It is worth noting for future Staff to reference that "this adjustment could have been performed more clearly in the workpaper to make reviewing easier." See Staff 1002, NWN Response to DR 408 (pdf) and DR 409 (pdf). For example, "IT&S adjustments were made to increase the total IT&S Test Year amount by $7.7M. How the expenses were allocated to each month in the workpaper was not an emphasis, so the Company spread those expenses equally to each month."

55 Despite the Highly Confidential mention above, all of the material below is non-confidential.

shows the large increase year over year as requested for new expenses such as software and hardware maintenance, legal fees, etc.[56]

FIGURE 1: OR ALLOCATED FERC 921 EXPENSES

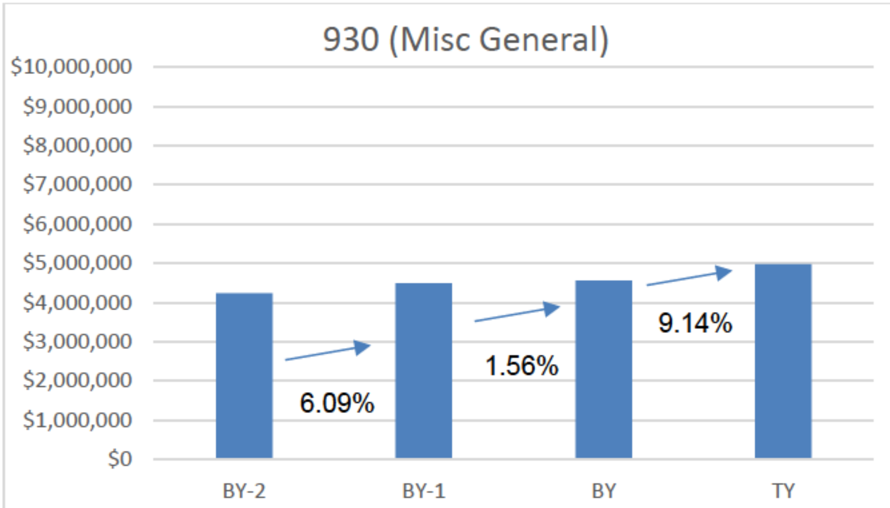


Q. How did the Company arrive at its forecast for general miscellaneous A&G expense recorded in FERC 930?

A. The Company's Test Year FERC 930 expenses are based on escalation; there are no new expenses.

[56] See Exh 1400 OM Model Workpaper_Non-Confidential, tab Dept Non-Payroll Forecast.

FIGURE 2: OR ALLOCATED FERC 930 EXPENSES



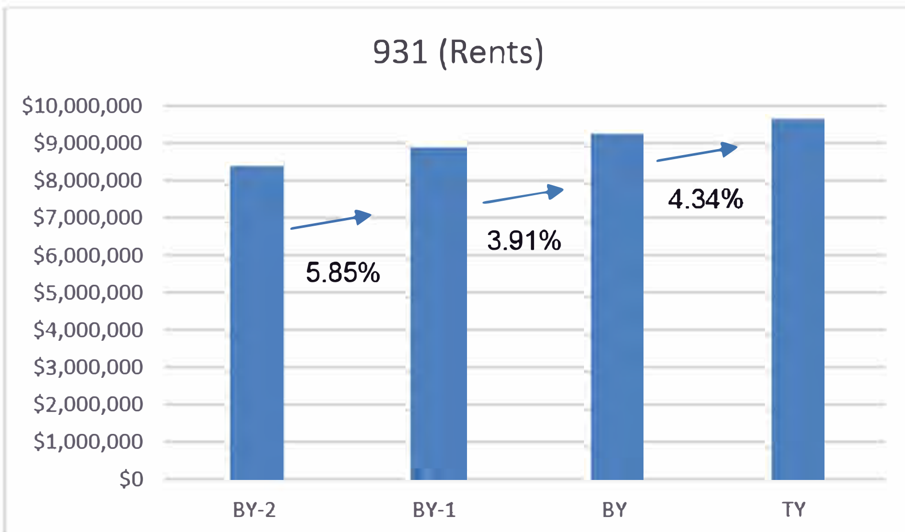
Q. How did the Company forecast its expense for FERC 931 (Rents).

A. The Company states that "An escalation factor should only be relied on where costs are unknown or otherwise fail to be indicative of future costs."[57] One line item in FERC 930 that the Company calls out specifically where this is not the case is for the contracted headquarters lease expense and tenant improvement amortization. As a result, an adjustment was made to reduce what the Test Year expense would have been as a result of inflation values used by the Company. The total expense adjustment decrease in the Test Year is $186 thousand and the OR allocated amount after administrative transfer is $107 thousand as a result of the above line item. Other rents are still expected to increase and therefore, overall FERC 931 costs increased modestly.[58] On the one hand, for the other rent expenses, Staff believes we should not assume that they are increasing at the CPI but given that the

57 NWN/1400, Davilla/9.
58 NWN/1400, Davilla/9.

allowable increase, as mandated by SB 608 (2019) and SB 611 (2023), and as calculated by the Oregon Department of Administrative Services (DAS) for 2024 is 10 percent,[59] Staff does not have an additional adjustment (beyond updated escalation figures) to FERC 931.

FIGURE 3: OR ALLOCATED FERC 931 EXPENSES



Q. Does Staff have adjustments to any of the above accounts?

A. Yes. Staff witness Paul Rossow recommends an adjustment to expenses in FERC accounts 816-930 of ($324,660) to remove fifty percent of expense for items classified as meals and entertainment. Most of this expense is in FERC Account 930. It is also worth noting that there is an additional $36,527 in First Class airfare that is also addressed in Paul Rossow's testimony. I have additional adjustments beyond what Paul Rossow has to FERC Account 930, as shown in Table 5 below.

[59] https://oregoneconomicanalysis.com/2023/09/26/oregon-maximum-rent-increase-2024-10-0/

TABLE 5: FERC 930 EXPENSES TO BE SHARED[60]

Cost Center	Cost Center	GL Account	GL Account	FERC	Test Year Request	Sharing
10768	CORP SECRET-MISC GE	613200	BUSINESS TRAVEL	930	$78,562	$39,281
10768	CORP SECRET-MISC GEN	613100	CONFERENCE TRAVEL	930	$5,051	$2,526
10768	CORP SECRET-MISC GEN	601100	EDUCATION	930	$29,689	$14,845
10768	CORP SECRET-MISC GEN	604800	LAUNDRY	930	$244	$122
10768	CORP SECRET-MISC GEN	601500	MILEAGE REIMBURSE	930	$1,603	$801
10768	CORP SECRET-MISC GEN	603000	OFFICE SUPPLIES	930	$4,612	$2,306
10768	CORP SECRET-MISC GEN	602100	OTHER CONTRACT WORK	930	$1,275	$637
10768	CORP SECRET-MISC GEN	602466	P CARD UNCODED CHARG	930	$39	$20
10768	CORP SECRET-MISC GEN	604700	PARKING	930	$819	$410
10768	CORP SECRET-MISC GEN	606200	PERMITS AND FEES	930	$2,749	$1,374
10768	CORP SECRET-MISC GEN	602800	POSTAGE	930	$77	$39
10768	CORP SECRET-MISC GEN	605100	PROFESSIONAL SERVICE	930	$261,592	$130,796
10768	CORP SECRET-MISC GEN	602700	TELEPHONE	930	$5,454	$2,727
10768	CORP SECRET-MISC GEN	612200	TRAVEL IN TERRITORY	930	$32,736	$16,368
Total Adjustment						**$212,252**

Q. Is there a history of decisions in favor of the 50/50 sharing of costs between shareholders and ratepayers for other expenses?

A. Yes. Staff follows this guidance for the following expenses, Directors and Officers (D&O) liability insurance,[61] meals, entertainment, gifts, airfare, travel, lodging, awards,[62] office refreshments, catering, promotional items,[63] and bonuses and incentives.[64]

[60] These can be found in UG 490 - Exh. 1400 -OM Model Workpaper_Non-Confidential in the Dept. Non-Payroll tab.

[61] In UE 197, the Commission adopted Staff's principal that D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of the expense (Order 09-020 at 19-20).

[62] In UE 197, the Commission adopted Staff's principal that costs for meals and entertainment are discretionary and should be shared equally by ratepayers and shareholders (Order 09-020 at 20-21).

[63] In UE 197, the Commission adopted Staff's principal that these costs are discretionary and should be shared equally by ratepayers and shareholders (Order 09-020 at 20-21).

[64] The Commission's policy is to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses. (Order 99-697 at 44-45; Order 99-033 at 62.)

Q. Summarize Staff adjustments for expense recorded in FERC accounts 921, 922, 930 and 931 as a result of using different escalation figures.

A. This adjustment of ($652,794) in Table 6 was determined by using the sum of the departmental and corporate values for nonpayroll for each of the FERC categories below.[65] This escalation adjustment was made independent of any cost sharing recommended in Table 5 or removals recommended in other testimonies. Therefore, the total recommended adjustment Staff is making in this issue is a combination of the two values, which is ($865,046). In the event there is some other adjustments to expenses in these accounts, the escalation adjustments listed below would also need be updated because there would be new values from which to start the escalation. However, in the Company's O&M model workpaper, their escalation figures are embedded in their Test Year request values in the Dept. Non-Payroll forecast tab, that is why it is difficult to make the cumulative calculations that would be needed to show what updated escalations would be if the requested values had been different or had included the specific adjustments by FERC Account.

[65] See Exh 1400 – OM Model Workpaper, tab O&M TY FERC Allocation Summary and SDR 58 Attachment 2 Non-Labor O&M.

TABLE 6: NON-LABOR ADJUSTMENTS USING UPDATED ESCALATION VALUES

Administrative and General Expense (Non-Labor) FERC Accounts	TY (Company) System	TY (Company) OR	TY (Staff) System	TY (Staff) OR	Adjustments System	Adjustments OR
921: Office Supplies and Expense	$55,691,773	$49,080,025	$54,911,081	$48,392,017	$780,692	**$688,008**
922: Administrative Expenses Transferred - Credit	-$25,374,489	-$22,403,377	-$25,213,617	-$22,261,342	-$160,871	**-$142,035**
930: Miscellaneous General Expense	$5,414,275	$4,977,707	$5,341,904	$4,912,455	$72,371	**$65,252**
931: Rents	$11,024,949	$9,742,139	$10,977,906	$9,700,570	$47,042	**$41,569**
Totals	$46,756,507	$41,396,494	$46,017,273	$40,743,700	$739,234	**$652,794**

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

APRIL 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Dyck

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics. I have completed rate school with NARUC, a data analytics course with Google, and am currently a NABE Frank Schott Scholar working towards becoming a Certified Business Economist.

EXPERIENCE: I was employed as a Junior Utility Analyst by the Oregon Public Utility Commission starting in June 2021 in the Telecommunications and Water division. I transitioned to the ERFA/RSUP Division in July of 2022 as a senior economist. Within this division, I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on Power Cost filings. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Rate case experience include: UG 435, UE 399, UE 416, and UG 461. I was previously employed as an adjunct professor of Econometrics at the Catholic University of America and as an Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on higher education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

April 18, 2024

- Disclosure: Risks scored in red must be disclosed on status reports, including mitigation strategy.
- PM Role: The PM is responsible for communicating and escalating issues and ensuring that all impacted parties understand the possible negative consequences. They are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- SteerCo and Sponsor Role: For red exposure risks the Sponsors and/or Steering Committee are responsible for making critical risk decisions (e.g. approving how are we going to tackle this risk) and accountable for ensuring the mitigation strategy is implemented (e.g. working to identify new resources to support a capacity risk).

Yellow Risk Exposure

- Mitigation Strategy: Yellow exposure risks should likely have a mitigation strategy, although in some cases accepting the risk may be acceptable. If this is the case, all impacted parties, including sponsors and steerco need to be aware and sign off on the impact.
- Disclosure: Risks scored in yellow must be actively discussed and managed in the project leadership team meetings.
- PM Role: The PM is responsible for communicating and escalating risks to the appropriate members in project team; they are accountable for ensuring the risk reaches the appropriate level of response, but are not always accountable for the mitigation itself.
- Sponsor Role: The Sponsor is responsible for acknowledging risk mitigations, and removing barriers for the risk owner to tackle the mitigation.

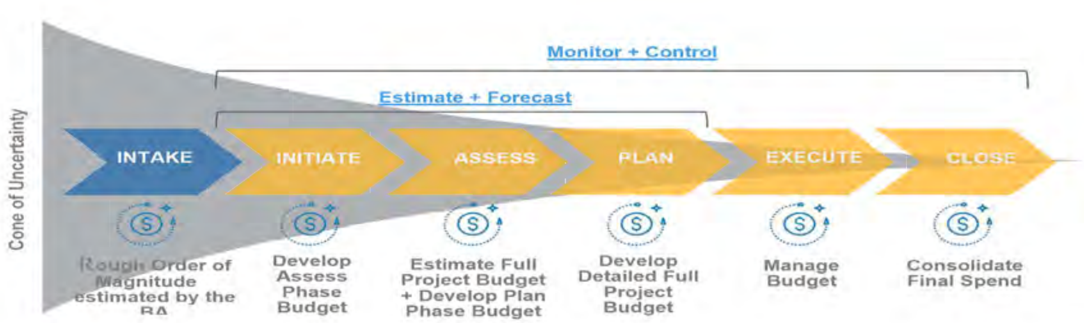
Green Risk Exposure

- Mitigation Strategy: Green exposure risks need to be monitored, but do not necessarily need an active mitigation strategy
- Disclosure: Green risks should be part of the risk register but do not need to be escalated.
- PM Role: The PM is responsible for monitoring the risk and ensuring it does not increase in probability or impact.

As risks occur, the PM moves them into the Planview issues list, which is also monitored to ensure all stakeholders understand the consequences.

Accounting and Budgeting Practices

Project managers are responsible and accountable for maintaining a project's budget – from the estimates generated during the Initiation phase through finalization of the project's actual spends at Project close. The diagram below outlines the high-level Budgeting activities that take place throughout the project's life cycle:



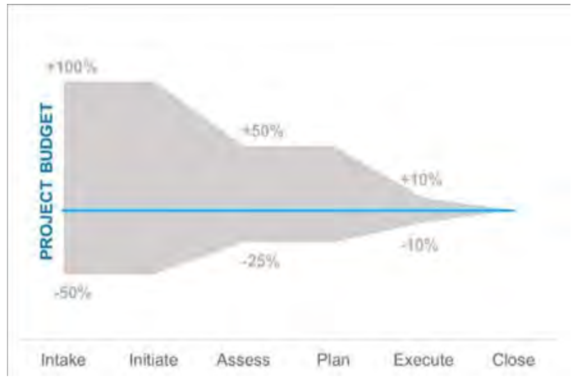
In order to effectively manage budgets, PMs are responsible for tracking and managing internal and external spend and submitting change orders as needed to keep the budget balanced and accurate. Our PMO Cost Accountant closely monitors spending on a month-to month basis to ensure we're providing enough transparency as a public utility.

Forecasting / Estimation

Project Managers will begin their forecasting at Initiation. At this phase of the project, Project Managers should work closely with stakeholders and Accounting to begin outlining high level project costs; these estimates should become more refined as the project progresses.

Cone of Uncertainty

As you develop your budget, the cone of uncertainty provides the acceptable amount of variance at each stage. Communicate thoughtfully to key stakeholders about the cone of uncertainty. Explain that at this phase in a project, the budget is an estimate with a wide potential variance. This will become more defined as the project unfolds. For a typical project, the variance at each phase is usually:



- Intake: When a project is first proposed at Intake, there is a Rough Order of Magnitude (ROM) estimate provided. Given that this estimate is provided before any stakeholders have been engaged or SOWs generated, it is an extremely high-level estimate. At this stage the rough order of magnitude is entered into the Triage form where we expect the variance to fall anywhere from -50% to +100% of the eventual project budget; for those projects that do not have much precedent, variance may be even larger.
- Initiate: As the project enters the "Initiate" phase, you will develop a budget for the Assess phase however you will NOT be required to formally estimate total project costs at this juncture.
- Alternatives Analysis: At the end of the Assess phase when you submit the AA, the project should have the first solid estimate of full project cost. At this point, some variability is still expected: -25% to +50%
- Plan: Finally, as you work through the Planning stages you will be further refining your project forecasts. You should be receiving completed RFPs from prospective vendors. These, along with other refined estimates, will allow you to submit your full project budget, which will constitute your project baseline as you enter Execution. This estimate is expected to fall within +-10% of your actual spends.

Capital vs. O&M

As you begin to estimate project costs, you should speak with Accounting about setting up your project costs. Project Costs are split between Capital and O&M, and both should be included in your budget for all elements (internal labor, external labor, materials, etc.). The capital asset policy outlines what is considered capital vs O&M, but here is a general guideline:

- Interest on mortgages accrued at date of purchase
- Accrued and unpaid taxes at date of purchase
- Other costs incurred in acquiring the land
- Water wells (includes initial cost for drilling, the pump and its casing)
- Right-of-way and easements

CWIP – Construction Work in Progress

Construction Work in Progress consists of construction costs incurred until a capital construction project is put into service; only directly related costs, AFUDC, and Construction Overheard (COH) can be capitalized. Generally, internally developed computer software projects are considered construction projects. Please consult the Accounting Manager if you believe you have a capital internally developed software project to further understand the types of costs that may be capitalized; the accounting guidance related to internally developed software is specific and technical and should not be interpreted without the Accounting Manager's involvement. CWIP project costs are included in FERC account 107 and can include the following

- Direct costs
- Construction Overhead (COH)
- Allowance for Funds Used During Construction (AFUDC)

Completed construction not classified (CCNC) amounts are included in FERC account 106. This account is used to classify capital costs that have not been transferred from work orders to plant retirement units. The transfer from CWIP to CCNC places the asset in service, stops AFUDC, and begins the charging of depreciation expense based on the FERC plant account.

Information Technology Project Capitalization

Information Technology Projects are generally a mix of both O&M Expense and Capital, depending on the nature of the work performed and the time during the Project's lifecycle when the work is performed. At the beginning of an Information Technology Project, the identification and documentation of system requirements, the evaluation and analysis of alternative systems, and the selection analysis is charged to O&M expense. Project management during the system evaluation and selection phase is also charged to O&M expense.

After the software selection has been made, future Project costs are capitalized. Specifically, costs associated with project management, documentation of the "As-is" and the "To-Be" processes, conversion and loading of historical data, and the configuration of the new software is capitalized. The "As-Is" processes are those being followed with either manual or existing software. The "To-Be" processes are those that will be followed in the future using the new software. Further, the cost of "first-year maintenance" paid as part of the software purchase is capitalized and additional costs related to changes in system design and/or system selection during the implementation effort and the development of process manuals and documentation is also capitalized.

Requirements gathering, design and implementation of enhancements to existing systems, and system upgrades may be capitalized if they add significant new functionality to the system; please work with the accounting department to make this determination.

After "Go-Live" follow-on costs relating directly to the project are capitalized. For example, bug fixes and minor enhancements would be capitalized up to the point in time when the system is stable and working as designed. At the end of the Information Technology Project's life cycle, many costs are charged to O&M expense. For example, training for users and training for information technology staff is charged to O&M expenses. Ancillary training expenses, typically meals, travel, and lodging, are also charged to O&M. Costs associated with shelved/abandoned improvements, sunk costs as a result of system reevaluation and re-selection, legal and other administrative costs associated with a contract dispute with a software/system vendor, etc. are charged to O&M expense.

Report development capitalization should be discussed on case by case basis with the assumption that the development of most reports will be classified as O&M expense. Exceptions may include reports being developed as part of a new system implementation project or reports requiring significant data model/structure development for an existing system. Examples of these reports include the following:

- Building new SAP Business Warehouse "cubes" or "extractors" to enable the creation of new reports.
- Reports associated with a Capital Project (e.g., Project Systems reports) regardless of whether they are on an existing system.

System Integrity Costs

Typically, our general rate cases will allow for a system integrity program, allowing the Company to track into rates in the following year the costs of maintaining our distribution and transmission system. Typically, these programs will require the Company to expense of a portion of the costs, for example the current program requires the Company to expense the first $4,500,000 and any balance over this amount is reclassified to Plant Capital Accounts and tracked into rates in the following year through the Purchased Gas Adjustment.

Fleet Charges

Generally, fleet costs are allocated via overhead rate to their respective work orders based on employee work hours. Work orders determine how these charges are allocated to O&M and capital. New vehicle costs, plus the cost to ready it for service are capitalized.

Minor Item Service and Damage Repair Capitalization Considerations

Line repairs requiring 10 feet of pipe or more are capitalized. Repairs are generally expensed but total replacements of retirement units are capitalized. Grading and sewer work on Company land is generally considered capital construction costs. See Table 1 below for specific treatments.

Table 1. Service and Repair Considerations

Work Category	Expense	Capitalize
Service Line Repair / Replacement	Replacement of less than 10 feet or repair to current service line.	Replacement of 10 feet or more of service line
Main line Repair / Replacement	Replacement of less than 10 feet or repair to current main line	Replacement of 10 feet or more of main

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 156
Was cloud-based software addressed in UG 435 or any of the other prior general rate cases (GRCs)?

a. If so, identify which GRCs this issue was addressed in.
b. Are the terms cloud-based software and IT&S investments used interchangeably?
c. Explain how cloud-based solutions are different than their alternatives.
d. Please distinguish projects that are cloud-based and those that are not.
e. Is it typical to have this many IT&S projects up for recovery in a GRC?

Response:

Yes, cloud-based software was addressed in UG 435 and UG 388.

a. UG 435 OPUC DR 482 NWN Response, part b (attached as UG 490 OPUC DR 156 Attachment 1). UG 388, NWN/600, Downing/11-14, 16-27, 39, 50; NWN/1600, Downing/22.
b. No, the terms cloud-based software and IT&S investments are not interchangeable. Cloud-based software falls under the umbrella of IT&S investments. But investments that are not in the cloud are included as well.
c. Please refer to NWN/700, Downing/8-11 for a detailed discussion of the differences between the two basic IT&S hosting options: cloud-based and onpremises. Importantly, many software vendors are transitioning their offerings to be solely cloud-based, meaning that certain products are no longer available as on-premises solutions. For instance, SAP SuccessFactors, which is used for human resources management, is available only via the cloud, while other software vendors such as Genesys have announced terminating support deadlines for on-premises solutions.

   Where both cloud-based and on-premises solutions are available, the two options differ in several ways:

   1. Infrastructure Ownership and Management: With on-premises solutions, businesses own and manage all the necessary hardware, networking equipment, and software licenses themselves. In contrast, cloud-based solutions are hosted and managed by third-party providers. This means

businesses do not need to purchase and maintain physical hardware necessary to host the software service, or expend the same level of resources to develop and implement software updates and patches.

2. Scalability and Flexibility: Cloud-based solutions offer much greater scalability and flexibility compared to on-premises alternatives. Businesses can easily scale their resources up or down based on demand without having to invest in additional hardware. This elasticity ensures that resources are allocated efficiently.

3. Cost Structure: Cloud-based solutions often operate on a subscriptionbased pricing model, where businesses pay only for the resources they use on a monthly or yearly basis, which is creates an incremental O&M increase and generally escalates through time. The implementation of these programs can be capitalized but the depreciation schedule is approximately 5 years, which often causes lag in recovery for a significant portion of the investment. On-premises solutions, on the other hand, require significant upfront capital expenditure but the depreciation schedule is approximately 15 years.

4. Reliability and Security: Cloud providers invest heavily in infrastructure redundancy, security measures, and disaster recovery protocols, often providing higher levels of reliability and security than what can be achieved with on-premises solutions. However, businesses must still carefully evaluate and choose reputable cloud providers and implement best practices to ensure data security and compliance.

5. Maintenance and Updates: Cloud-based solutions typically handle maintenance tasks such as software updates, security patches, and hardware upgrades automatically, reducing the burden on IT staff. Onpremises solutions require businesses to manually manage these tasks, which can be time-consuming and costly.

d. For all cloud based investments, please see submitted workpaper "UG 490 – Exh. 1714 -WP1 – Cloud Based Assets – CONFIDENTIAL".

e. We interpret this question as asking whether the number of IT&S projects included for cost recovery in this rate case is typical of the current state of the industry. Based on that understanding: yes. IT&S modernization is occurring industry-wide as companies are:

a. Required to update or replace non-supported systems.
b. Forced to transition to cloud solutions as vendors have no other options.
c. Managing risk and regulatory requirements by mitigating cybersecurity threats.

NW Natural

Rates & Regulatory Affairs
UG 435
Request for a General Rate Revision
Data Request Response

Request No.: UG 435 OPUC DR 482

482. In reference to NW Natural/600, Downing/page 30, Table 1 at line 6:
a. Please clarify that the total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.
b. If the Horizon Program is primarily a cloud based solution, please provide a detailed response explaining how significant capital costs associated with this project are prudent.
c. Regarding the $8.8 million in "contingency and other costs", have any of the contingent funds been used or are projected to be used? If yes, please provide:
 i. A breakout for each specific project cost overrun necessitating the use of contingency funds.
 ii. A detailed explanation describing why each cost overrun occurred.
 iii. A detailed description of the steps the Company took to manage project costs and adhere to the Company approved project budget.
 iv. If the contingency funds are not needed to complete the project, how will the Company remove these costs from this rate case?

Response:

a. The total Oregon allocated dollar amount for Horizon capital costs of $63.7 million excludes the other IT projects noted in NW Natural/600, Downing/page 2, lines 5-11.

b. The Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2018-15 (ASU 2018-15) specifically to address accounting for cloud-computing software. This update requires companies to capitalize certain costs associated with implementing a cloud arrangement. These costs include implementation to get the hosted service set up, configured, and ready for use. Additionally, new software licenses qualify for capitalization as they fall in the category of Bring Your Own License (BYOL). This means we own the licenses and could pull them from the cloud and install locally if we chose to in the future.

The implementation for cloud or on-premise solutions of these applications will still require design, configuration, development, testing and deployment activities to be successful.

c. Contingent funds have been used and are projected to be used.

i. Please see UG 435 OPUC DR 482 attachment 1, column E – Amount of Change. Total approved contingency use through March 31, 2022, is $4,519,671, Column E Row 23.
Total projected contingency use through March 31, 2022 is $975,000, Column E Row 29. Analysis is still underway for scope and work effort; these are estimates provided by our service integrator.
The Horizon Program is still in process and additional items requiring the use of contingency funds may be required. At this point, the project anticipates a need to use the remainder of the contingency funds by October 31, 2022, but are not currently projected or known. ii. Please see UG 435 OPUC DR 482 attachment 1, column G – Reason for Change.
For the change orders over $1 million dollars, we have attached the change order requests that provide additional details around the explanation of cost overrun.
IQGEO change order for $2 million, see UG 435 OPUC DR 482 attachment 2.
Reporting change order for $1.5 million, see UG 435 OPUC DR 482 attachment 3.
For the projected change orders, analysis is still underway for scope and work effort; these are estimates provided by our service integrator and will follow our change control process for approval.

iii. The Horizon Program is a multi-tier structured and adhered-to governance model with key leadership providing direction and oversight. Please see attachment UG 435 OPUC DR 482 attachment 4.

The Horizon Program has an established Change Control Process that aligns to the governance model. Please see attachment UG 435 OPUC DR 482 attachment 5.
Below is the Horizon Program meeting cadence directly related to project costs:

1. Weekly review of project costs with NWN program Finance and Accounting

2. Weekly review of contractual obligations and service level credits with NWN program team and NWN legal team

3. Weekly review of change control board

4. Monthly Service Level Agreement metrics review with program team and Accenture

5. Monthly invoice review with Accenture and program Finance and Accounting

6. Monthly review of project costs with program Finance, Accounting, Rates and Regulatory, and Program Executives

7. Quarterly review of projects costs with the Senior Executives and IT&S Alignment Team

Following the Horizon Program governance model, change control process, and meeting cadence describes the process that the Horizon Program follows to manage project costs and adhere to the Company approved project budget.

iv. If contingency funds are not needed to complete the project, the Company is willing to adjust the capital in its compliance filing to the actual amount spent for Horizon, when the project goes into service.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 416

Have you estimated the net benefits of any of the capital projects?
If yes, please describe. Explain the rationale for including cloud-based assets in rate base.

Response:

All Information Technology & Services (IT&S) capital projects are expected to have net benefits, as compared to not undertaking the project or undertaking a project alternative analyzed by the Company. These benefits can manifest in various ways, including but not limited to the maintenance of safe and efficient operations, improved customer experience, data protection and privacy, business continuity, network integrity, risk mitigation and enhanced functionality. The benefits and costs of each capital project is set forth in testimony, NW Natural/700. For instance, at NW Natural/700, Downing/4344, the Company explained that the Telemetry Refresh Projects support the Company's prompt and accurate control of the gas distribution system; by undertaking the upgrades and replacing outdated technologies, the Company can not only ensure the safe and reliable provision of service, but avoid the need to maintain a lease at the Company's former headquarters location.
The Accounting rules determine the capitalization treatment of Cloud Computing Arrangements if the criteria are met for capitalization. FERC (Regulatory) and GAAP do not differ on the types of costs that can be capitalized or expensed related to Cloud Computing Arrangements. As it relates to Cloud Computing Arrangements (CCA) that are Service Costs, FERC made a final ruling on ASU 2018-15: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract to all jurisdictional public utilities and licenses, natural gas companies and centralized service companies. For regulatory accounting, capitalized implementation costs should be recorded as utility plant assets in Account 303 (Intangible Plant - Computer Software) and should be amortized over the term of the associated cloud computing arrangement in Account 403 (Depreciation Expense).

NW Natural®

Rates & Regulatory Affairs

UG 490

Request for a General Rate Revision

Data Request Response

Request No.: UG 490 OPUC DR 206

Please provide a narrative description of NWN's capital budgeting process including but not limited to development responsibilities, load study process, annual timing, and approval process.

Response:

The capital forecast is updated multiple times throughout the year. This forecast incorporates the most recent information based on requirements to maintain a safe and reliable system. Each year's budget is based on the forecast created in December, which is presented to and approved by the Board of Directors.

Finance facilitates the process with the five individual business units that provide those forecasts: Engineering, Customer Acquisition, Information Technologies, Facilities, and Transportation & Meter Shop. Review meetings take place with the managers, directors, and officers where the assumptions and forecast are reviewed and determined. Once approved, each group sends their forecast to Finance for inclusion in our overall forecast. The overall forecast is used to inform various groups on progress, adjust our planned spend and include impact the current and long-range forecast. Finance also facilitates a monthly review of current year variances against the approved budget.

Each business unit uses a bottom-up approach, where they determine required and run rate work in addition to identifying other projects that are needed. Detail is provided for applicants and projects.

> Facilities:
>
> Potential projects are identified by the business and/or Facilities department for consideration. The facilities projects steering committee reviews all requests, validates the potential need for the projects and determines if the projects should be added to the facilities 5-year roadmap for further evaluation.
>
> Forecasts for each project are updated quarterly and reviewed by the Facilities Steering Committee, Finance team, and officers.

Transportation and Meters:

Vehicle replacements are evaluated based on a combination of vehicle vintage and mileage. Each year the list of vehicles that meet either the age or mileage limits are evaluated. That list along with department feedback creates the replacement list for the following year. Equipment and Trailers are determined to be replaced based on business need and, on a case-by-case basis. Tools are also requested by departments and are evaluated for business need and included on a list for purchasing the following year. Meter needs are developed based on current meter inventory, customer growth forecasts, meter change outs, PCC changes as well as factoring in vendor lead times.

Customer Acquisition:

Services and Mains capital spend is forecasted based our customer growth forecast or footage of mains multiplied by estimated cost. Housing start projections from the Oregon Department of Economic Analysis are a key assumption when developing new customer projections. Permits are based on previous year actuals plus inflation. Meter installations are based on estimate number of units times cost per unit.

Engineering:

Planned projects are based on need, resource, and supply chain availability. A significant amount of work is driven by jurisdiction and compliance requirements. Planned capital work is typically identified in advance based on long range plans, Facility assessment reports, Equipment studies, safety plans or DIMP & TIMP plans. Prioritization is given to projects based on urgency or feedback from operations personnel. Nearer term planned work can be due to equipment unexpectedly failing or showing near end of life, avoidance of potential pipeline safety impact due to natural forces, and jurisdictional franchise obligations. Larger, discrete projects are individually assigned projects in our project management office and have capital spend budgets and expected in-service dates that are managed through the duration of the project. Those are all individually tracked through our forecasting process. Forecasts for some categories of work are based on historical spend trends.

IT&S:

The collection of projects reflects various business needs. Enterprise Applications projects are driven by new or changes to existing systems to support new or changed compliance requirements, or to support new business needs. Information Security projects follow the cybersecurity strategic plan. The Enterprise Architecture forecast follows the IT&S 5-year strategic plan and are typically new capabilities driven by business needs focusing on building resilient modern platforms, optimizing value of existing platforms and building new

A project's Team site is capabilities as required. Network, Infrastructure and Service delivery typically entail technical refresh cycles. Finally Operational Technology represent engineering projects that require IT&S execution, so this forecast follows the needs and projections of some of the engineering's forecasted capital plan.

The business units where applicable coordinate with the Portfolio Management Committee which meets to discuss, review, prioritize and approve funding for projects and determine if it should be added to the portfolio. Considerations included for discussion are urgency, capital spend and resource constraints. The business units triangulate with the portfolio management committee to ensure that projects are approved and being included in the budget/forecasting process. Following approval, projects are included into the forecast cycle.

Microsoft Teams

Overview: intended for the internal (contractor and FTE) project team to collaborate, discuss and conduct core project activities. Individual workstreams use themed channels chat and document sharing without breaking the thread of discussion. The tool provides continuity of knowledge for project team members joining mid-project and ensures remote access to documents and chat via the Teams Mobile app.

Requesting a Site: When a project is initiated, the PM should request at Team collaboration site by visiting the request form. Instructions on how to complete this form can be found here (use the directions attached to project sites). This will instigate the creation of both a SharePoint site for the project, and an associated Team site configured based on the project's discipline for the PM to adjust to the needs of the team.

Channels and Access: By default, your project Team will be private (invite only). It is the Project manager's responsibility to manage access to the Team and individual channels making sure that the right people have access to each section of the Team. Remember that each channel has its own document storage, and those with access to that channel will be the only ones able to see that documentation. This likely means a contract or procurement channel that is available only to the PM and legal (as needed), and then workstream channels that are available to everyone in the project team for visibility (e.g. Change Management, Project Management, Testing, etc.). Recommended channels will already be set up for the PM to work with but can be adapted to the project need.

Tabs: We recommend that the project manager configure the Tabs (header links) in the Team's channels to provide easy navigation to project resources. The recommended tabs are below, with the associated app to use to add that link (Hint: click on the + symbol at the top of the channel to add new Tabs).

IT	Engineering	Facilities
• Posts (default) • **Project's SharePoint Site** (use SharePoint app) • Files (default) • Planview Site (use website app) • Azure DevOps (use Azure app) • PowerBI (use website ap) • PM Handbook (use website app) • CM Handbook (use website app) • BA COE (use website app) • ITSM (use website app) (coming soon) Project Place	• Posts (default) • SharePoint Site (use SharePoint app) • Files (default) • Planview Site (use website app) • PowerBI (use website ap) • Engineering Site (use website app) • IQGEO (use website app) • R-Drive (use website app) • PM Handbook (use website app)	• Posts (default) • SharePoint Site (use SharePoint app) • Files (default) • Planview Site (use website app) • Smartsheet Schedule (use website app) • PowerBI (use website app) • PM Handbook and/or trainings (use website app)

Training and Resources: A high level overview of how to leverage Teams as a project is available here, and additional tutorials on how to use Teams are available on the M365 initiative page.

Planview

Overview: Planview is NW Natural's Project Portfolio Management (PPM) tool, our home-base for the project process - from idea to closure. Projects are required to leverage Planview for stage gates, status reporting, schedules, resource management and budgeting, as it serves as the source of truth for much of NWN's rates reporting. You can access Planview on your web browser when you're within the NW Natural network and have been granted access to the tool.

Resources: This handbook references Planview for how the tool should be used through each phase (see initial checklists). In addition, guides on how to use the tool can be found on the Hub. We recommend Project Managers watch the full training series listed at the bottom of the PM column as they get started leveraging Planview.

* indicates that the document must be complete and accepted in order to move to the next phase

blue indicates that the document is formally attached or described to the stage gate request

Project Lifecycle at a Glance

	INTAKE	INITIATE	ASSESS	PLAN	EXECUTE	CLOSE
Goal	Understand the root problem and opportunity to inform the selection of the right projects at the right time	Align and approve on business case and the resources needed to assess the project	Develop requirements, assess options, determine alternatives and preferred solution	Fully flesh out the selected solution and define the execution path to achieve the project goals	Track, monitor and control the project as work is completed	Operationalize, adopt and hand over the project deliverables
Project Management (Budget, Schedule, Scope, Resourcing + Project Governance)	*Sponsor: Intake form *PMC: Project review and selection	*PM: Assess Phase Budget *PM: Initial Project Charter *PM: Decision Log, Risk Log, Issues Log *PM: Assess Phase Resource Plan *PM: Monthly Status Reports *PM: Org Chart *PM: RACI and RAPID PM: Teams and SharePoint Site PM: Stakeholder Register PM: Steering Committee + CCB Sponsor: Project oversight + governance *PM: Submit "Move to Assess" Gate	PM: Assess the cost of possible solutions *PM: Design/Plan Phase Budget *PM: Design/Plan Phase Resource Plan *PM: Design/Plan Phase Schedule *PM :Final Project Charter *PM: Decision Log, Risk Log, Issues Log *PM: Monthly Status Reports Sponsor: Project oversight + governance *PM/Sponsor: Alternatives Analysis (if over $1MM w/ COH) *PM: Submit "Move to Plan" Stage Gate	PM: Confirm the costs of the selected solution, forecast costs to plan the project *PM: Execution Budget and forecast *PM: Project Execution Approach / Plan *PM: Execution Phase Resource Plan *PM: Execution Phase Schedule *PM: Monthly Status Reports PM/BA/Tech Lead/Sponsor: Determine final project scope *PM: Decision Log, Risk Log, Issues Log Sponsor: Project oversight + governance PM/Sponsor: Transition to Operations Plan (IT only) *PM: Submit "Move to Execute" Stage Gate	PM: Weekly Status Reports PM: Monitor and control costs, compare to actuals PM: Monitor and control scope delivery, resource capacity, schedule and all other project aspects to ensure project is on track *PM: Decision Log, Risk Log, Issues Log Sponsor: Project oversight + governance PM: Go/No Go Criteria *Sponsor: Go/No Go Approval PM: Move project to "Prepare for Closure"	Sponsor: Project oversight + governance *PM: Lessons Learned *PM: TECO *PM: Project close activities PM/Sponsor: Final Transition to Operations Plan (IT only) *PM: Final budget true-up PM: Submit "Move to Close" Stage Gate
Business Requirements / Design	BA: Triage BA: Context Diagram (as applicable)	BA: Initiation Context Document (BOSCARD) BA: Context Diagram BA: Business Analysis Work Plan	BA: Elicitation + Results *BA: Business Case *BA: Current State Documentation BA: Gap Analysis BA: Requirements + Documentation Biz Owner: SOW summary for RFx	BA: To-be process map and documents *BA: Requirements Documentation BA: Gap Analysis *BA: Functional Specs	BA/QA: User Acceptance Plan BA/QA: Functional Test Plan BA/QA: UAT Results and Approval *BA: Updated Requirements Documentation *BA: Knowledge Base Articles *BA/QA: Requirements Traceability Matrix	BA: Completed Requirements Traceability Reports BA/CM: User Surveys + Interviews
Change Management (if a CM is assigned to the project)	*CM/BA: Stakeholder Register	*CM: Case for Change *CM: Change Artifact List CM: Rough Change Assessment	*CM: Change Impact Assessment *CM: Stakeholder Analysis *CM: Change Strategy CM: Change KPI Development	*CM: Training Needs Assessment, Plan + Materials *CM: Comms Plan + Materials CM: Engagement Plan + Materials CM: Change Portfolio Assessment Form	*CM: Training Materials (including FAQs, QRGs) CM: Training, Communications + Engagement Delivery + Support *CM/Application Owner: Change Artifacts / Operations Handover, Knowledge Transfer Plan CM: Change Readiness Assessment	CM: Training, Communications + Engagement Delivery + Support CM: Adoption Tracking CM: Change Close Survey CM: Knowledge and Tools Transfer, Lessons Learned
Technical Development	EArch: Confirmation that IT&S Alignment Committee Review is complete	Tech Lead: Technical resource plan	EArch: Solution Context Diagram EArch: Solution Options + Design EArch: ARB and TRB are initiated *EArch: Provides RFP scoring criteria against architecture and requirements and/or assessment of alternatives and recommendation of selected option EApps: Software Development Estimate Tech Lead: Technical requirements IT Security: Assess security needs	*EArch: ARB and TRB Approval EArch: IT&S Ticket Request *EArch: Solution Architecture Summary EArch: Data Model and Migration Plan Application Owner: Technical Specs Tech Lead: Source Target Mapping Tech Lead: Business Impact Assessment *Tech Lead: Final Design and Tech Specs Tech Lead: SOX Compliance Plan Tech Lead: ETL/Integration Plan IT SecOps: Vendor Risk Assessment *IT SecOps: Security Design and Review IT SecOps: Incident Response Plan IT SecOps: PCI Assessment Questionnaire of Attestation of Compliance IT SecOps: Security Plan of Action and Milestones Solution Architect: Infrastructure Implementation Plan Solution Architect: Infrastructure Specifications	EApps: Software and Configuration Source Code EApps: Software Build EApps: Deployment EApps: Rollback Scripts EApps: Software Runtime Artifacts EApps: Release Notes *EApps: Run Book Tech Lead: Solution Cutover Plan Tech Lead: Data Conversation / Migration Plan Tech Lead: Solution Test Plan, Scripts, Results, Defect List Tech Lead: Production Release Verification Plan and Results Tech Lead: Information Transfer Agreement Tech Lead: Vendor Security Assessment IT SecOps: Security Testing / Vulnerability Scans, Remediation Plan Disaster Recovery, Tech Lead: Disaster Recovery Testing and Plan Business Continuity: Business Continuity Plan Tech Lead: Change Control Review Board Release Approval IT: Technical Support Plan	IT Security: Security Plan of Action and Milestones
Engineering Requirements and Design	Eng: Triage	Eng/PM: Survey and Assessment Plan	PM: Survey, Assessments Risk + Land: Easements *Eng: Initial (10-30%) Designs *Eng: Permitting Assessment and Plan *Environmental: Enviro Assessment PM: Geotech PM/Sponsors: Resourcing Plan	Eng: Specifications (if externally resourced) *Eng: Traffic Control Plan Eng: Potholing *Eng: 90% Design PM: Geotech Permitting Specialist: Permits Purchasing/Stores: Stock and Non Stock Material Requirements, Material Reservations, Bids including Q&A, Quotes, RFQs RMC: Field Resource Schedules Construction: Resourcing	*PM: Operations + Maintenance Plan, Engineering Procedures PM/Eng: Construction Management Tech Training: Field Training	PM: O&M Manuals *Eng: As-Builts, Management of Change, CDM, Testing and Verification Documentation
Vendor Selection + Procurement	Procurement: Resource planning	Procurement: Procurement strategy / sourcing research + list IT Compliance: TISA for new vendors Procurement: Purchasing Process if a vendor is needed for assessment: Procurement: RFP and vendor selection for any assess-vendors Corp Security: Background checks	Procurement: RFx development, process and responses; sync with Legal Project Manager: Competitive Assessment Memo (CAM) if no RFx Procurement: Scorecard Procurement / Sponsor: Vendor selection IT Compliance: TISA to shortlisted RFx finalists	*Procurement: SOW Procurement: PO Management (for change orders, etc.) Legal/Procurement: Contracting and Negotiation PM: Onboarding PM: ITP checklist (for IT projects)	Procurement: PO Management (for change orders, etc.)	

Risk Identification: Risks are derived from various sources, some of which can be identified before a project starts, and some of which are surprises along the way. Many of these risks or sources are common across projects so the PM may start with NWN's common risks by project type. These tools can be leveraged as a
starting place, but it is the job of the PM to coalesce common and unique risks that the project faces.

Risk identification should be conducted on an ongoing basis, but two points of the project are particularly important:

- During the Assess phase, leverage the assessment team to identify underlying risks with the chosen solution
- During the Planning phase, focus on what challenges might come up during execution; best practice is to hold a workshop with your project team to work through identification, evaluation and response plan

Risk Evaluation: As we document risk, we talk about its probability and its impact; this allows the project team to make thoughtful decisions about potential risks. To make this simple, we can use the following definitions to give a score for both probability and impact:

Probability of Risk Occurring

Level	Probability	Score
High	The risk is likely or certain to occur. Specifically, there is more than 75% chance that the risk occurs	3
Medium	There is some likelihood that the risk will occur. Specifically, there is between a 25% and 75% chance that the risk occurs	2
Low	It is not very likely that the risk will occur. Specifically, there is less than 25% chance that the risk occurs	1

Impact If the Risk Occurs

Level		Cost	Schedule	Scope	Quality	Score
High	If the risk occurs, it will have a severe impact on the ability to achieve the project's critical objectives	Cost increases would be beyond the total authorized spend, causing a change order	Key project event or milestone will be delayed by more than 3 months	Scope decrease would have significant impacts on key deliverables	Performance is degraded to the point that the project would not meet its objectives	3
Medium	If the risk occurs, it will somewhat impact the desired results either crippling a secondary objective or causing a critical outcome to be degraded	Cost increases would dip into contingency funds	Key milestone will be delayed	Scope decrease would impact some core objectives or key deliverables	Performance would be below goal and may have some impacts on project objectives that can be mitigated with work arounds	2
Low	If the risk occurs it will have little or no impact on the project's ability to achieve its objectives	Cost increases could be managed within the approved budget	No key milestones will be impacted	Scope decrease would not impact core objectives or key deliverables	Requires minor performance trades, but will not significantly inhibit project objectives	1

These numbers should then be evaluated to determine overall exposure, which will drive the project team's mitigation response:

Probability		Impact: Low	Impact: Medium	Impact: High
Probability	High	3	6	9
	Medium	2	4	6
	Low	1	2	3

Risk Response and Control

Risk response is perhaps the most important step in risk management; it is important to focus efforts and communications on the most important risks, with targeted and thoughtful mitigation strategies. The risk exposure score will drive how these are tackled.

Red Risk Exposure Mitigation Strategy: The mitigation strategy and execution should be assigned to a risk owner. The project team needs to work together to find outlets to avoid or temper the severity of the risk at hand. If the risk is accepted, it's critical that every stakeholder understand the consequences.

NW Natural®

Rates & Regulatory Affairs
UG 490
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Data Request Response

Request No.: UG 490 OPUC DR 411

What is the rate base total of IT&S expenses for each year from 2019 through the Test Year?

Response:

Rate base IT&S expenditures are found in the "Intangible" and "General" categories of utility plant in service. The Intangible designation is fully comprised of IT&S capital expenditures. IT&S expenditures within the General category are isolated to FERC accounts 391.2 Computers, 391.21 Computer Horizon, and 391.22 Computer Bloodhound.

Please see "UG 490 OPUC DR 411 Attachment 1.xlsx".

Rates & Regulatory Affairs
UG 490
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Data Request Response

Request No.: UG 490 OPUC DR 414

Detail the payment terms for each of the contracts entered into for the IT&S projects included in Exh. 700. Include whether any prepayments were necessary for each project, if so, how much and when, the timeline of payments, and how many years this project is expected to provide benefits to customers and the Company.

Response:

NW Natural understands "payments terms" in this context to mean the condition triggering payment obligations for a contract. For each of the contracts entered into for the IT&S projects included in Exhibit 700, the payment terms were for 30 days after receiving an invoice (i.e., "Net 30").

Please see Confidential UG 490 OPUC DR 414 Attachment 1 for the requested information concerning those projects where prepayments were necessary.

Rates & Regulatory Affairs
UG 490
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Data Request Response

Request No.: UG 490 OPUC DR 415

Which IT&S projects are considered out of service in the Test Year but were previously included as capital projects?

a. Have these projects been moved into a regulatory asset account?

b. What amounts left are undepreciated? In other words, what are the remaining rate base amounts?

Response:

There are two IT&S projects that will be considered out of service at certain points during the Test Year but were previously included as capital projects. Those projects are:

UI Planner
Genesys

These projects are currently part of plant account 303.1-Computer Software.
The remaining rate base amounts as of 10/1/2023 are:

UI Planner - $331,789.40
Genesys - $3,404,683.86

Both IT&S projects are still in service today but are anticipated to be retired before the end of their original depreciable lives before or during the Test Year. Upon review, NW Natural did not include these projects in its forecasted retirements, and will update this in our Reply Testimony. These projects have not been moved into a regulatory asset. The Company uses the Group Depreciation Method which does not depreciate these assets individually, the total cost of the group is spread out over the useful life of the entire group. Through the depreciation study process the Company reassess the useful life and salvage value of the assets in each group, including retirements, and adjustments to depreciation rates may be made accordingly.

Please refer to the Company's response to UG 490 CUB DR 20 (due on March 22, 2024), which will provide more detailed information on the timing and estimated remaining balance on these two projects.

NW Natural

Rates & Regulatory Affairs
UG 490
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Data Request Response

Request No.: UG 490 CUB DR 20

On NW Natural/100/Palfreyman-Kravitz/Page 16, in reference to "update[ing] its IT&S infrastructure, the Company states, "In this proceeding, NW Natural is seeking cost recovery of additional projects to further modernize its IT&S infrastructure and transition to cloud-based IT&S architecture. These upgrades are largely in response to cyber- security advancements, existing software reaching end of life and end of support, and developers exclusively providing cloud-based solutions." For the "existing software reaching end of life" please provide:

a. The in-service date of the software.
b. The useful life of the software when it was purchased and any changes to the useful life since then.
c. Any differences between the useful life and amortization period of the software if these periods ever differed.
d. The amount of money still in rate base for the software.
e. Any proposed changes to "d." in UG 490.
f. The Book Depreciation Reserve value of the software as of 10/1/2023.
g. The Future Accruals value of the software as of 10/1/2023.
h. A narrative explanation of how the software is still being used, if it is still being used, despite the addition/ transition to cloud-based software.

Response:

Please see "UG 490 CUB DR 20 Attachment 1" for subparts a-h. Upon review, NW Natural did not include these projects in its forecasted retirements and will update this in our Reply Testimony.

NW Natural's Response to DR 185 Attachment 1 is available in electronic spreadsheet format only.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 424
Are contingency funds included in rate base or considered O&M expenses? Please point to where these are included in workpapers.

Response:

Contingency amounts may be included in forecasted project costs that are ultimately included in the forecasted rate base. There are no contingency funds included in O&M. The contingency funds, if included at the project level, would be embedded in individual capital project costs that are being closed and allocated to FERC accounts for rate base. There is no single place to point in a workpaper where contingency funds are layered into rate base; it would be embedded into the gross plant additions in UG 490 – Exh. 1713 – WP1 – Gross Plant and Accum Deprec – CONFIDENTIAL workpaper, Additions tab.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 184

Have internal employees assisted in the implementation of any of the projects?

Response:

Yes, our internal employees play key roles in the implementation of all of our IT&S projects. Depending on the size and complexity of the project, internal staff may be involved in various capacities:

1. Subject Matter Experts (SMEs): Internal SMEs provide specialized knowledge and insights related to the project, guiding decisions, and offering expertise in specific areas such as software development, networking, cybersecurity, etc.

2. User Testing and Feedback: Internal employees may participate in user acceptance testing (UAT) to validate that the IT solution meets the organization's requirements and provides a satisfactory user experience.

3. Data Migration and Integration: Internal IT&S staff may assist in migrating data from existing systems to the new IT solution and integrating it with other systems within the organization.

4. Support and Maintenance: After implementation, internal IT&S support teams provide ongoing support and maintenance for the IT solution, addressing any issues that arise and ensuring smooth operation.

5. Documentation and Knowledge Transfer: Internal employees contribute to documenting processes, procedures, and best practices related to the IT project, facilitating knowledge transfer within the organization.

6. Vendor Management: Internal staff may interact with external vendors or consultants involved in the IT project, ensuring alignment with organizational goals, and overseeing contractual agreements.

By leveraging the skills and knowledge of internal employees, we optimize our resources, maintain institutional knowledge, and foster a sense of ownership and accountability throughout the IT project lifecycle.

NW Natural's Response to DR 159 Attachment 1 is available in electronic spreadsheet format only.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 357

The Company describes its need for eight new Information Technology and Services FTEs in NW Natural/700, Downing/50-55. The Company states these positions are needed to adequately staff H2: Vista. While this project will not begin in 2024, the Company states the new positions are needed now for education and integration. When does the Company intend to fill these positions?

Response:

To clarify, only four out of the eight full-time equivalents (FTEs) listed in the NW Natural/700, Downing/50-55 testimony are essential to support Horizon 2: Vista (H2: Vista). The other four FTEs are needed to support NW Natural's SCADA telemetry systems, gas/pipeline control operations, and identity governance administration. (See NW Natural/700, Downing/53-55.)
With respect to the four FTEs necessary to support H2: Vista, the Company intends to immediately begin recruiting three of the four positions, and expects all four positions to be hired prior to the rate effective date (i.e., November 1, 2024), although the exact dates will depend on finding qualified candidates. As explained in NW Natural/700, Downing/51-52, filling these positions in a timely manner is crucial to effectively supporting NW Natural's ongoing CIS needs, while simultaneously allowing existing personnel to develop, test, and implement H2: Vista. NW Natural's legacy, 26-year-old CIS is highly complex, requiring substantial lead times of between 18-24 months for new personnel to be effectively educated and integrated. Robust training is essential to ensure that the legacy CIS continues to support reliable, seamless continuity of service for customers during the H2: Vista development and implementation. Given that NW Natural is already well into the planning stage of H2: Vista, including developing a comprehensive framing study, filling these four FTE positions quickly is imperative to ensure adequate capacity to advance the H2: Vista development and support the legacy CIS.

NW Natural's Response to DR 160 Attachment 1 is available in electronic spreadsheet format only.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 419

Does the Company have an update on the timing of the deferral for the Horizon 2 project?

Response:

The Company's currently plans to file the Horizon 2, or H2: Vista, deferral application in the third quarter of 2024. The Company will update its plans in its Reply Testimony.

NW Natural's Response to SDR 58 Attachment 2 is available in electronic spreadsheet format only.

NW Natural®

Rates & Regulatory Affairs
UG 490
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Data Request Response

Request No.: UG 490 OPUC DR 408

See UG 490 - Exh. 1400 - OM Model Workpaper_Non-Confidential, tab Dept Non-Payroll Forecast, and filtered by Test Year (TY) Adjustments (Highlighted in yellow) for FERC 921.

Cost Center	Cost Center	GL Accou	GL Account	FERC	I/O	Test Year	
10710	INFRASTRUCTURE-OFFIC	608100	TEST YEAR ADJUSTMENT - SUBCRIPTION SERVICES	921		$664,974	$586,028
10710	INFRASTRUCTURE-OFFIC	605600	TEST YEAR ADJUSTMENT - SOFTWARE MAINT	921		$4,846,188	$4,270,847
10710	INFRASTRUCTURE-OFFIC	605900	TEST YEAR ADJUSTMENT - HARDWARE MAINT	921		$214,517	$189,050
10710	INFRASTRUCTURE-OFFIC	606300	TEST YEAR ADJUSTMENT - CELLULAR PHONES	921		$238,493	$210,179
10710	INFRASTRUCTURE-OFFIC	602300	TEST YEAR ADJUSTMENT - RENTS AND LEASES	921		$32,518	$28,657
10818	REGULATORY AFFAIRS-O	605100	TEST YEAR ADJUSTMENT - PROFESSIONAL SERVICE	921		$153,196	$135,009
10831	LEGAL FEES-RATES-OFF	605000	TEST YEAR ADJUSTMENT - LEGAL FEES	921		$908.519	$800.659

a. Why are the TY totals for each month not referencing the IT&S TY Forecast tab, whereas rows for other cost centers reference different respective tabs? In other words, where are the numbers coming from that are in cells AV 2329 through BG 2329?

b. Why are professional services and legal fees included in FERC 921?

c. Were the amounts in (b) above discussed in Exh 1400.

Response:

a. Unlike the other adjustments in the workpaper where one line is adjusted to reflect higher or lower expense, IT&S expected increases from the Base Year to the Test Year are occurring across the entire IT&S organization on many different GL accounts and many different Cost Centers. IT&S forecasts a Test Year increase of $7,729,571 which included escalation. That can be found in the OM workpaper IT&S TY Forecast tab cell I92. The adjustments were hard coded each month in the model to get to the forecasted $7.7M.

This can be confirmed by going to the Dept Non-Payroll Forecast tab and filtering to the IT&S cost centers (10259-10282, 10705-10739 & 11128). The Base Year amounts can be added up using column BL which adds to $28,609,172. The Test Year amounts are in column BH which adds to $36,338,742, an increase of $7,729,571.

In hindsight, this adjustment could have been performed more clearly in the workpaper to make reviewing easier.

b. Professional services and legal fees are included in FERC 921 because they are estimated amounts to be incurred for prosecuting this case, i.e. “rate case expense”.

c. No, they were not discussed in Exh. 1400.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 409

Why are the amounts the same in every month of the test year for the FERC 921 associated IT&S expenses? For example, cells AV 2329 through BG 2329 are $55,415 in each cell.

Response:

While the workpaper/model includes monthly amounts for gross up inflation, the IT&S adjustments were made with the intention to bring the Total 12-month Test Year amount in line with the forecasted increase. IT&S adjustments were made to increase the total IT&S Test Year amount by $7.7M. How the expenses were allocated to each month in the workpaper was not an emphasis, so the Company spread those expenses equally to each month.

NW Natural's Response to DR 411 Attachment 1 is available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

CONFIDENTIAL
Exhibits in Support Of
Opening Testimony

April 18, 2024

[redacted]

NW Natural's Response to CONF DR 414 Attachment 1 is available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Redacted Opening Testimony

April 18, 2024

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

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss long-term hedging policy and Schedule H, Large Volume Non-Residential High Pressure Gas Service Rider for Compressed Natural Gas service.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1101, my witness qualifications statement, and Exhibit Staff/1102, a compilation of responses to data requests referenced in this testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LONG-TERM HEDGING

Q. What is long-term hedging?

A. In this context, hedges are investments that are undertaken to limit risk from high gas prices. Short-term hedges are typically transactions that address the next heating season and medium-term hedges are typically transactions to hedge gas supply costs two and three years out. Long-term hedges are transactions (financial and physical) that hedge gas purchase costs more than three years in the future.[1]

Q. How does the Company recover the costs of long-term hedges?

A. NW Natural recovers costs of long-term hedges through its Purchased Gas Adjustment (PGA) Mechanism. The PGA is an automatic adjustment mechanism that allows NWN a to update rates to capture changes in its purchased gas costs on an annual basis without the need for a general rate review. The PGA includes both a forward-looking and backward-looking component. For the forward-looking component, the Commission allows NWN to reset rates annually with an updated forecast of purchased gas costs. For the backward component, NWN is allowed to defer the variance between forecasted and actual purchased gas costs and given the opportunity to recover that variance in future rates, subject to sharing, a prudence review, and a review of the Company's earnings during the deferral period.[2]

[1] LC 60 NW Natural 2014 IRP, p. 3.39.

[2] *In the Matter of the Public Utility Commission of Oregon Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's three Local Distribution Companies*, UM 1286, Order No. 08-504 (October 21, 2008).

The purpose of the PGA is two-fold: (1) to allow the gas utilities to recover costs associated with the purchase and transportation of natural gas to its systems and (2) to provide an incentive (i.e., the sharing) to minimize the cost of natural gas purchases.

Q. Is long-term hedging specifically addressed in the PGA?

A. In a way. In 2015, the Commission opened an investigation into the long-term hedging policies of Oregon's three natural gas local distribution companies, docketed as UM 1720. Parties to that docket engaged in workshops to determine whether they could agree on guidelines for long-term hedging, but ultimately decided they could not due to the diversity of the available hedging instruments and optionality to the duration and timing of the hedges.[3] Instead, the parties agreed to a process that the gas companies could use to receive feedback from stakeholders regarding long-term hedges.[4] The parties proposed that this process be incorporated into the Commission's Natural Gas Portfolio Development Guidelines that gas utilities must follow in connection with making the Companies' PGA filings. The Commission subsequently adopted the parties' recommendation in Docket No. UM 1286.[5]

Q. Why is long-term hedging an issue in this proceeding?

A. In January 2024, the Company entered the long-term hedging review process as laid out in UM 1286 and the Natural Gas Portfolio Development Guidelines.

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[3] *In the Matter of NW Natural Gas Company, dba NW Natural, Investigation into Long-Term Hedging Policy*, UM 1720, Order No. 18-019, pp. 1-2 (January 18, 2018).
[4] *Id.*
[5] UM 1286(4), supra, Order No. 18-144, App. A (May 1, 2018).

While engaging in this process, Staff identified opportunities to better align benefits of long-term hedges to the Company and to customers. Staff addresses this topic here to propose a change to how the costs of long-term hedges are recovered in NWN's annual PGA.[6]

Q. What is the review process for long-term natural gas hedging strategies for natural gas utilities?

A. If the utility identifies a long-term hedging strategy that it believes is in the interest of customers, the utility requests a meeting with stakeholders, including Staff, the Oregon Citizens' Utility Board, and the Association of Western Energy Consumers (formerly Northwest Industrial Gas Users).[7] In the meeting, the utility shares the proposal. Stakeholders have 30 days to provide a written response on whether they support the utility moving forward or if there are reservations and concerns. If any stakeholder believes the proposal needs further review by the Commission, said stakeholder would utilize the process outlined above to identify the appropriate forum for review.

Q. How often has this hedging review process been implemented by the Company?

A. Northwest Natural engaged this process for the first time in January 2024.

Q. When Staff engaged in this process, what did Staff find?

[6] NWN and the other natural gas companies in Oregon make their annual PGA filings on or around August 1 of each year.
[7] *In the Matter of the Public Utility of Oregon Investigation into the Purchased Gas Adjustment (PGA) Mechanism Used by Oregon's Three Local Distribution Companies*, UG 1286(4), Order No. 18-144, App. A, p. 3.

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The requirements for information shared in this process were vague as written. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What does Staff propose now?

A. Staff does not propose any change to the notice and meeting process utilities should use for proposing long-term hedging proposals adopted in Order No. 18-144. However, Staff proposes 90/10 sharing on costs of long-term hedges that exceed five percent of total gas purchases. Meaning, for any long-term hedge that exceeds the five percent of total gas cost threshold, NWN would only be allowed to include 90 percent of the cost in forecasted rates.

Q. Why is this appropriate?

A. In theory, a gas utility could use hedges to significantly limit the risk of non-recovery of actual purchased gas costs in the PGA. As noted above, the PGA allows the gas utility to recover the variance between its forecasted and actual gas prices, subject to sharing and an earnings and prudence review. If the utility hedges all of its purchased gas, the utility's forecasted costs and actual costs would be the same and there would be no variance. Accordingly, the utility's recovery of its actual costs would not be subject to sharing or an earnings review.

The 90/10 sharing in the PGA is designed to incent the utility to minimize its purchased gas costs. Because the cost of long-term hedges will likely not vary between the forecasted and actual costs, there is no sharing of these costs. Accordingly, requiring the utility to absorb 10 percent of the cost of long-term hedging transactions will help ensure the Company acts in a manner that is in the best interests of both customers and the utility.

Q. Why does Staff only make this recommendation for hedging costs that exceed the five percent of total costs threshold?

A. Staff recommends a five percent of total purchase requirement as a "safe" limit that utilities could "lock in" long term prices as this is a small amount as a reasonable threshold before additional action. Amounts greater than this, however, should include a sharing component. The reason being that reducing price risks benefits both the Company and the customer. The Company benefits as it removes that amount of gas from having price risk ad subject to the PGA sharing. The alignment of incentives helps ensure the Company enters long-term hedging with careful analysis and is in the Company's best interest.

Q. What would be the ratemaking treatment Staff proposes for any long-term hedge the Company enters into for those above the five percent of total retail load?

A. Staff proposes that long-term hedges above five percent of total retail load be presumed reasonable and prudent by evidence of the fact that the Company bears ten percent of the "above market" cost of the contract. The Company would continue to provide notice and hold a meeting with stakeholders.

Q. What do you mean by the "above market" cost of the contract?

A. There is a forward price curve for the natural gas market. To "lock in" those prices, presumably there would need to be a premium to pay. The premium would be deemed the above market cost.

ISSUE 2. SCHEDULE H

Q. What is Schedule H?

A. Scheule H is the Large Volume Non-Residential High Pressure Gas Service Rider for Compressed Natural Gas service. There are currently two (2) customers on Schedule H. There was only one in 2019-2022.[8]

Q. Is Schedule H covered in this GRC?

A. No. Schedule H is removed from the revenue requirement model.[9]

Q. What is the Company proposing for Schedule H in this GRC?

A. The Company is updating Schedule H with new cost of capital components as well as capital investment cost and O&M assumptions for cost of service.[10] This is a standard update consistent with updates in the last GRC.[11]

Q. Where else does Staff review changes to Schedule H?

A. Updates are reviewed through advice filings. ADV 1472/Advice No. 22-23 is the last advice filing with changes to Schedule H. ADV 1472 extended the end date of this service until January 31, 2025.

Q. What did Staff conclude when reviewing Schedule H for ADV 1472?

A. In Staff's memo for the January 24, 2023, Public Meeting, Staff recommended approving the extension of this service. Staff found that the compressed natural gas fuel market has not appreciably changed since 2018. NW Natural is

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8 NWN Response to Staff DR 219.
9 NWN/1700, Walker/17.
10 NWN/1700, Wyman/58.
11 UE 435 NWN/1300, Walker/25.

providing a beneficial service to customers because it may not otherwise be available without the utility's involvement in the market.

Q. Have there been any changes to the market since?

A. Staff requested an update in DR 433. The Company has not seen any appreciable change in the compressed natural gas market since the last update filed in ADV 1472.

Q. Do you have any recommendations?

A. Not at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Anna Kim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Energy Costs Section Manager Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Economics Portland State University, Portland, OR Master of Environmental Studies, The Evergreen State College, Olympia, WA Bachelor of Arts, Environmental Science, University of California, Berkeley, CA
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 in the Energy Resources and Planning Division. My responsibilities include providing advice on energy efficiency policy, pilot and program evaluation, and oversight of energy efficiency programs run through the Energy Trust of Oregon Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UG 490
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 219

Please provide the number of accounts under Schedule H for the Test Year and the last five previous years.

Response:

Schedule H investments are evaluated on a separate cost of service basis relative to core utility assets; costs and revenues associated with this schedule are removed from the Company's revenue requirements models. Therefore, there are zero Schedule H customers included in the Test Year in this rate case proceeding.

There are, however, two customers taking service on Schedule H as of February 1, 2024. The number of customers taking service on Schedule H at December 31 over the past five years are as follow:

2019: 1
2020: 1
2021: 1
2022: 1
2023: 2

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 221

Please describe the Company's understanding of the OPUC's policy and direction regarding the ratemaking treatment of long-term hedging.

a. Please list and discuss past Orders that relate to treatment and direction to parties.

Response:

The Company objects to this data request under OAR 860-001-0500, in that the information requested is not relevant to issues in a rate case. Notwithstanding this objection, the Company is aware of two Commission orders related to long term hedging: Order Nos. 18-019 and 18-144.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 433

Please provide:

a. An update on the compressed natural gas market since the Company's last report in ADV 1472/Advice No. 22-23; and

b. A description of any notable changes to the CNG market, including number of public and private fueling stations.

Response:

For ease of reference, the Company provides its Schedule H – Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider tariff extension request and market report in ADV 1472/Advice No. 22-23, dated December 15, 2022, as UG 490 OPUC DR 433 Attachment 1. The Company also provides Staff's report and recommendation in ADV 1472/Advice No. 22-23, dated January 13, 2023, as UG 490 OPUC DR 433 Attachment 2.

a. The Company finds that the Compressed Natural Gas ("CNG") market has not markedly changed since the Company's tariff extension request was filed and Staff's report was issued on December 15, 2022, and January 13, 2023, respectively. The Company did add one new customer to its Schedule H service in 2023 (City of Wilsonville). Further, the Company continues to engage with potential customers and industry partners that remain interested in moving diesel vehicle fleets to CNG. Diesel prices, while generally trending down after reaching a five-year high in 2022, remained volatile throughout 2023 and early 2024. The Company currently has three open inquiries to explore the feasibility of constructing CNG stations for service under Schedule H.

   The key difficulties potential developers have expressed in building CNG stations are lack of state incentives for a comprehensive network of stations and lack of commitment from fleet owners and operators. Companies with the capital to convert/purchase CNG fueled fleets that would make a CNG station economically viable are hesitant to invest in CNG vehicles because there is a sense of uncertainty about whether CNG will qualify under state clean fuels/carbon reduction programs in the near future. Companies with a nationwide presence are hesitant to convert their Oregon-based fleet to CNG as they prefer to use the same types of vehicles and fuels in every state. Additionally, many smaller companies rent their fleets and even if they would prefer CNG, the fleet owner may not be incentivized or find it economically viable to offer CNG vehicles as an option.

The Company continues to find on-going interest in CNG within its service territory under current market conditions and despite the difficulties cited above. The Company finds that the conclusion from Staff's report is still valid, namely "…that NW Natural is providing a service [through the HPGS] that would not otherwise be available to customers without the utility's involvement in the market. [The] HPGS program provides a benefit to existing customers and a possible scenario can arise where if low CNG prices persist, diesel fleets can have incentives to convert to CNG thus further fueling CNG market development."[1] [2]

b. According to the US Department of Energy's Alternative Fuels Data Center, there are a total of three public and 10 private CNG fueling stations in Oregon as of March 2024. This count does not include the City of Wilsonville CNG fueling station. Additionally, there is one public liquified natural gas ("LNG") fueling station that sells renewable natural gas ("RNG").[3] In total, the Company finds there are 15 CNG and LNG fueling stations in Oregon. Staff's report identified 14 CNG stations as of 2023, which led Staff to conclude that this number indicated that the CNG market "has not changed appreciably" since 2018.[4]

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[1] *See*: UG 490 OPUC DR 433 Attachment 2, page 6.
[2] For the US Department of Energy Alternative Fuel Price Report, see: Alternative Fuels Data Center: Fuel Prices (energy.gov). As of January 1, 2024 CNG averaged $2.95 per gasoline gallon equivalent ("GGE") while diesel averaged $3.51 per GGE.
[3] US Department of Energy Alternative Fuels Data Center, natural gas fueling station locations data can be accessed here: Alternative Fuels Data Center: Natural Gas Fueling Station Locations (energy.gov).
[4] *See*: UG 490 OPUC DR 433 Attachment 2, page 5.

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony
Uncollectible Accounts and
Schedule 330 Residential Bill Discount Program

April 18, 2024

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

A. My name is Charles Lockwood. I am a Utility Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year amount for Uncollectible accounts and the Company's Schedule 330 Residential Bill Discount Program.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/1202, NW Natural Response to DR 296.
- Exhibit Staff/1203, Staff Workpaper on Uncollectible accounts.
- Exhibit Staff/1204, NW Natural's Response to DR 318.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. UNCOLLECTIBLE ACCOUNTS

Q. Please provide a summary of the Commission's historical treatment of uncollectible accounts.

A. It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the Test Year amount for uncollectible accounts for a utility's revenue requirement.[1] Commission Staff also examines other evidence to determine whether this approach results in a reasonable forecasted Test Year result. The amount included in a utility's revenue requirement for uncollectible accounts is revenue sensitive because it depends on the amount of forecasted revenue. That is, the total amount for uncollectible accounts included in the revenue requirement is a function of the Test Year revenue and the uncollectible rate.

Q. Describe the Company's proposal for Test Year uncollectible accounts.

A. The Company's Test Year forecast for uncollectible accounts is $4.49 million, which is approximately $3.8 million higher than the amount recorded in 2021 for uncollectible accounts of $690 thousand. The Company forecasts a Test Year uncollectible rate of 0.491, percent which is approximately five times the

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

Company's uncollectible rate of .097 percent from Northwest Natural's last GRC in Docket No. UG 435 in 2022.

Q. What uncollectible rate is obtained using the three-year average methodology described above?

A. The three-year average methodology produces an uncollectible rate of 0.182 percent.

Q. Does the Company use the three-year average methodology to derive its proposal for the Test Year uncollectible accounts?

A. No. The Company's proposed 2024-2025 amount for uncollectible accounts is calculated using an uncollectible rate that is forecasted using a combination of historical uncollectible rate trends, with adjustments for NW Natural's agreement to stop collecting residential customer deposits, changes to the collections and disconnection process adopted in the Division 21 rules, current macroeconomic factors such as inflation and higher interest rates, and federal regulation changes for collection agencies.[2]

Q. Please explain the Company's process for forecasting the 2024-2025 uncollectible rate.

A. The Company's starting point for the uncollectible rate forecast is the UG 435 approved uncollectible rate which is also the three-year average of the uncollectible rate between 2017-2020 (0.097 percent). The Company utilized this three-year historical average to avoid including months affected by the

[2] NW Natural/1300, Wilson-Sparley/5.

COVID-19 pandemic.[3] The Company then adds six distinct adjustments to the baseline uncollectible rate of 0.097 percent, all of which increase the uncollectible rate. The Company's adjustments are for:

- Weaker Economic Conditions
- Deposits No Longer Collected
- Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day
- Division 21: Customer Notice Chance 15 to 20 Days
- Collection Agency Reduced Recoveries
- Discontinued Arrearage Management Program

Figure 1 provides an overview of the Company's proposed adjustments and the associated calculated adjustment amount to the baseline uncollectible rate.[4]

Figure 1. Proposed Uncollectible Rate Adjustments

Baseline Uncollectible Rate 2017-2019	0.097%
Weaker Economic Conditions	0.100%
Deposits No Longer Collected	0.137%
Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day	0.029%
Division 21: Customer Notice Change 15 to 20 Days	0.007%
Collection Agency Reduced Recoveries	0.071%
Discontinued Arrearage Management Program	0.050%
	0.491%

Q. Please describe the Company's Economic Conditions Adjustment.

[3] NW Natural/1300, Wilson-Sparley/4.
[4] NW Natural/1300, Wilson-Sparley/12.

A. The Company states in testimony that "uncollectible expense typically increases during times of economic downturns."[5] To calculate how NW Natural's presumed current economic condition would impact the uncollectible expense Company averaged the uncollectible rates during previous technical economic recessions to arrive at 0.40 percent. The Company states the 0.40 percent is approximately 0.15 percentage points higher than the average uncollectible rate experienced in non-recessionary periods.[6]

However, given that the economy is weaker according to NW Natural but not in a technical recession today, the Company chose to use a 0.10 percent impact. While this is a decrease from the recession-based calculation of 0.15 percent, this is quite an increase for NW Natural's overall uncollectible rate. This increase alone more than doubles the Company's overall uncollectible rate of 0.097 percent to 0.197 percent.

FIGURE 2. NW NATURAL ECONOMIC CONDITION ANALYSIS

Methodology	Uncollectible Rate	Difference	Change From Currently Approved Rate
Non-Recessionary Periods	.25%	N/A	+0.153%
Technical Recession (2001-2002, 2007-2009)	.40%	+.15%	+0.303%

5 Id.
6 Id.

Adjustment Technical Recession	.35%	**+.10%**	+0.253%

The Company points to several indicators to justify to current macro-economic environment being weaker than in the pre-COVID-19 timeframe of 2017 through early 2020, when the Company last calculated the historical average uncollectible rate used in Docket No. UG 435. These indicators include:

- Interest rates increasing at the fastest rate in thirty-five years;
- The Personal Saving Rate decreasing from 6.4 percent in December 2019 to 3.4 percent in September 2023; and
- Increases in inflation rate, the consumer price index, and national delinquency rate on credit card loans.[7]

Overall, the Company argues that the risk of a recession remains elevated heading into 2024 and these factors create a weaker macroeconomic environment today compared to the Company's baseline period of 2017-2019.

Q. Does Staff agree with the Company's proposed Economic Conditions adjustment?

A. No. Staff believes that the Company fails to adequately justify the estimate of the economy's impact used in the calculation for the Weaker Economic Conditions adjustment. Staff is concerned with the use of the average uncollectible rate between 2001-2002 and 2007-2009 within the Company's

[7] NW Natural/1300, Wilson-Sparley/11, and Federal Reserve Economic Data.

calculations. NW Natural provides little to no substantive justification for their use of these time periods.

Staff believes the time periods selected by NW Natural represent too severe of an economic recession to be used by NW Natural in the calculation for this rate case. For example, the 2008 recession saw U.S. gross domestic product (GDP) decrease by 4.3 percent, making it the deepest recession since World War II.

Further, even if NW Natural can provide additional justification for the usage of these time periods, Staff remains concerned regarding the Company's downward rounding from the 0.15 percent difference in uncollectible rates during these technical economic recessions to calculate the 0.10 percent proposed. Staff feels that the methodology assumes conditions that raise the current uncollectible rate unrealistically, even with the slight downward adjustment. NW Natural notes the economy is weaker but is not in a technical recession today, therefore Staff is unclear if the 0.10 truly represents current economic conditions. Staff also did not find any further explanation from the Company regarding the calculation of the downward adjustment, as the Company's work papers do not provide reasoning.

Even with the Company applying a downward rounding adjustment of 0.05 percent, or one-third of the difference between total uncollectible rates during technical recessions and non-recessionary periods, Staff finds the use of these time periods improper and over states any needed adjustment. Staff requires further information and justification from the Company regarding the overall calculation and downward adjustment made.

Q. Please describe the Company's Deposits No Longer Collected Adjustment.

A. The Company proposes to increase the uncollectible rate by 0.137 percent because the Company permanently stopped collecting deposits from residential customers because of the stipulation adopted in Docket No. UG 436 regarding NW Natural's Schedule R, Residential Arrearage Management Program.[8] The Company represents that the increase of 0.137 is reflective of the $600,000 NW Natural refunded on average in deposits on customers closing bills, given that $600,000 is 0.137 percent of the Company's annual residential gas revenues between 2017 and 2019. The Company states the $600,000 refunded on average assisted the customers and reduced potential write-offs, as when a customer closed their account, any deposit being held by the Company would be credited on the customer's closing bill. Because of this, the Company finds it is reasonable to expect that the lack of collected deposits will increase the uncollectible rate by 0.137 percent.

Q. Does Staff agree with the Company's proposed Deposit Adder adjustment?

A. No. The Company fails to provide any evidence that the end of deposits has led to an increase in uncollectible accounts to date. Staff finds the Company has not clearly articulated the relationship between not collecting deposits and

[8] NW Natural/1300, Wilson-Sparley/13.

an increase to the uncollectible accounts. Staff requests in the Company's Reply Testimony more information clarifying if the customers closing accounts were overdue on payments or if part of the $600,000 was being returned.

Additionally, the Company's deposit adder adjustment calculation assumes that the level of write-offs associated with residential deposits that occurred in 2017-2019 will remain constant and unchanged into the Test Year. The Company's calculation does not allow for any year-over-year variance and fails to consider that the end of deposits coupled with other measures targeted at alleviating residential customers' energy burden will lead to a lower overall level of write-offs for customers.

Q. Please describe the Company's Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day Adjustment.

A. The Company states in testimony that the changes to the OAR Ch. 860, Div. 21 (Division 21) rules regarding shorter time frames for technicians to visit customers and collect payments and the new weather moratoriums will increase the uncollectible rate by 0.029 percent.[9]

Q. Please describe how NW Natural states the Division 21 Rule changes will affect the Company's uncollectible rate.

A. Prior to the Division 21 rule changes, NW Natural technicians would work until 4:00 PM, however, the new rule requires all technicians to stop field credit orders by 2:00 PM. The Company estimates this is a time reduction of

9 NW Natural/1300, Wilson-Sparley/15.

25 percent, which equates to approximately 52 days a year lost as a result of this rule.[10]

In addition, there were two weather moratoriums updated by the Division 21 rule changes. First, the "cold weather moratorium prohibits the Company from disconnecting customers if the weather is or is forecasted to be less than thirty-two degrees or when there is a winter storm warning indicating weather conditions pose a threat to life or property."[11] NW Natural states this results in approximately twenty-eight days a year of inability to completely field credit orders in one or more of the areas within the Company's territory in 2022.

The second weather moratorium updated by the changes to the Division 21 rules prohibits technicians from completing field credit orders if the Air Quality Index (AQI) is 100 or above, resulting in approximately four days of inability to complete field credit orders in 2022.[12]

Overall, the Company is unable to complete credit field orders approximately eighty-four days per year.[13] The Company states "[t]he longer a customer is allowed to continue using gas service without payment, results in a higher bill and eventually leads to a higher uncollectible expense."[14] Therefore, using the 2022 net write-off rate and 2023 budgeted residential revenues, NW Natural found its daily net write-off is $3,723, meaning the total of incremental

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[10] NW Natural/1300, Wilson-Sparley/14.
[11] Id.
[12] NW Natural/1300, Wilson-Sparley/14-15.
[13] Id.
[14] Id.

write-offs for the 84 day reduction would equate to $313 thousand or 0.029 percent of total 2023 budgeted revenues.[15]

Q. Does Staff agree with the Company's Division 21: Temperature/Weather/Wildfire/AQI/Shortened Day Adjustment?

A. No. The Company provides no data to validate the claim that these protections will increase the uncollectible rate. The Company's adjustment calculation broadly assumes that all customers will accrue balances uniformly and that these protections will have no effect on reducing overall disconnections. Staff finds this adjustment to be presumptuous and not backed by any evidence to date. Staff believes that the impacts of the rule change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment. Staff requires further information in the Company's Reply Testimony illustrating how its calculations are "conservative"[16] and if the Company has any updated information on impacts of the rule changes it has seen since the rule changes were adopted.

Q. Please describe the Company's Division 21: Customer Notice Change 15 to 20 Days Adjustment.

A. The Company states in testimony that due to increased notice time for customers facing interruption of service and change in Company practice, NW Natural expects an increase of 0.007 percent in uncollectible expenses.[17]

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[15] Id.
[16] Id.
[17] NW Natural/1300, Wilson-Sparley/16.

To comply with the increased notice time of 15 to 20 days before interruption service in the most effective and efficient manner, the Company needed to remove its three-day call-ahead previously provided to customers.[18]

NW Natural states the Company historically received payment from 20 percent of customers it reached out to with the three-day call ahead. Therefore, to calculate the reduction in payments due to the removal of the three-day call ahead, the Company used the “September 2023 account balance aged 60+ days of $6.8 million and multiplied it by 20 percent to reach $1.4 million of accounts receivable that [the Company] would expect to collect from the three-day call ahead.”[19] The Company then states it typically sees six (6) percent of accounts receivables turn into delinquent accounts that are deemed uncollectible, and therefore, written off, which equates to $81 thousand and represents 0.007 percent of the Company’s 2023 budgeted total revenues.

Q. Does Staff agree with the Company’s Division 21 Notice Division 21: Customer Notice Change 15 to 20 Days Adjustment?

A. No. It remains unclear to Staff why the Company is removing the three-day call-ahead due to the increased customer notice timeframe. Additionally, similarly to the Division 21 rule change adjustment, the Company does not provide any evidence that the updated rules have increased uncollectible expense to date. NW Natural fails to consider that the updated Division 21

[18] NW Natural/1300, Wilson-Sparley/15.
[19] NW Natural/1300, Wilson-Sparley/16.

rules were designed to offer greater protection to customers and ultimately help avoid further disconnections. The increased notice period may allow customers more time to make payments and ultimately avoid disconnection, thereby avoiding becoming uncollectible expense. Staff believes that the impacts of the rules change on the uncollectible rate is yet to be fully understood and therefore disagrees with the proposed adjustment.

Q. Please describe the Company's Collection Agency Reduced Recoveries Adjustment.

A. The Company states it has seen a decline in the number of recoveries received from collection agencies post-pandemic and requests an increase of 0.071 percent to the uncollectible expense.[20]

The Company notes recent changes to Consumer Financial Protection Bureau (CFPB) Regulation F (12 C.F.R. § 1006 and following), as a major factor in the decline of number of recoveries. Consumers now have more control over how collection agencies communicate with them and new restrictions on how agencies collect debts.

Overall, the Company has seen a decrease from recoveries in the years of 2014-2019, averaging 53 percent to 27 percent for 2022 and through October 2023.[21] The Company, therefore, applies the roughly 27 percent reduction in recoveries to its write offs, and proposes to increase the uncollectible rate by 0.071 percent.

[20] NW Natural/1300, Wilson-Sparley/17.
[21] NW Natural/1300, Wilson-Sparley/16-17.

Q. Does Staff agree with the Company's Collection Agency Reduced Recoveries Adjustment?

A. No. The Company's calculation uses just under two years of collection agency recovery rates to arrive at the recommended increase in the uncollectible rate. Staff believes that the focus on 2022 and 2023 recovery rates in this calculation is insufficient to justify the Company's proposed increase. Staff has examined the historic trend of recovery rates provided by the Company in Staff Data Request 296,[22] and while there is a decrease in 2022 and 2023, there is not a long enough time trend from which to infer that the recovery rate will not return to a historic baseline. Staff believes that there has not been adequate data to evaluate whether the new CFPB regulations will impact collection agency recovery rates at the same levels moving forward.

Q. Please describe the Company's adjustment for Discontinued Arrearage Management Program.

A. NW Natural states without the Arrearage Management Program (AMP), the Company projects an increase in the uncollectible rate of 0.05 percent.[23] Of the total write offs of $4.7 million between the months of May 2021 and December 2022, approximately $1.2 million were associated with accounts that had received AMP funds. By applying the post-pandemic collection agency rate of 27 percent, the Company calculates a new write off of $900 thousand, which equates to a 0.05 percent increase in the uncollectible rate.

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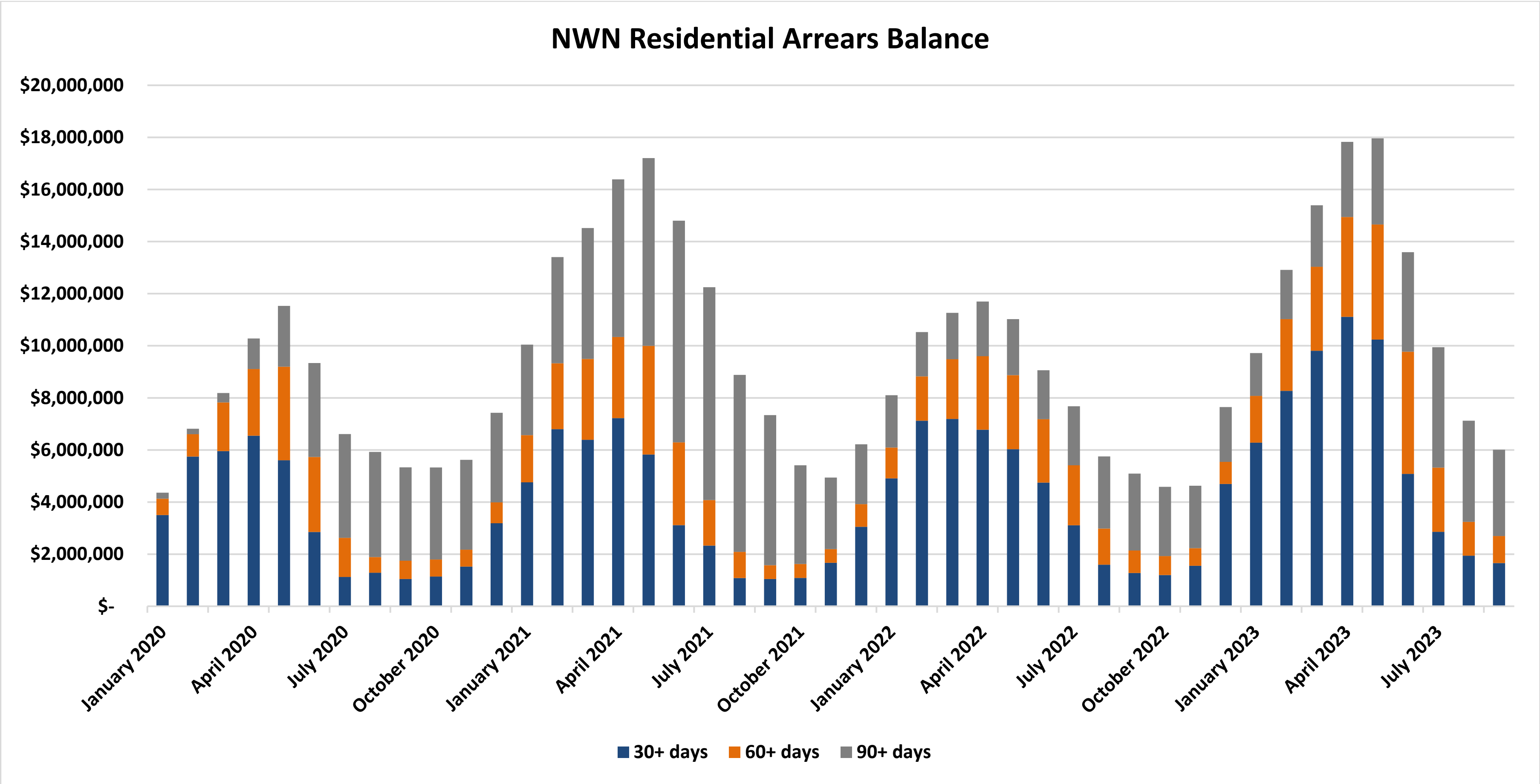
22 Staff/1202, NW Natural Response to DR 296 (electronic spreadsheet).
23 NW Natural/1300, Wilson-Sparley/17.

Q. Does Staff agree with Company's adjustment for Discontinued Arrearage Management Program?

A. No. The Company argues that due to the expiration of the funds provided to customers through the Company's Arrearage Management Program (AMP) the uncollectible rate will increase. The Company's AMP was developed in response to the economic hardship faced by many individuals who lost the ability to pay their utility bills due to the COVID-19 pandemic. The AMP was meant as a temporary stopgap measure to alleviate arrears balances which increased during the pandemic. The expiration of the program does not necessarily indicate that the uncollectible rate will increase. The economic conditions that caused arrears to increase during the pandemic have subsided, and the Company's arrears remained cyclical in nature, shown in Figure 3.[24] Particularly, Figure 3 shows the Company's ninety-day arrears are declining significantly, while only the thirty-day arrears form the majority. Therefore, Staff believes that the Company has not provided sufficient evidence that the expiration of these programs will lead to an increase in uncollectible accounts.

[24] Docket No. RG 94, COVID-19 Monthly Report.

FIGURE 3. NW NATURAL RESIDENTIAL ARREARS BALANCE



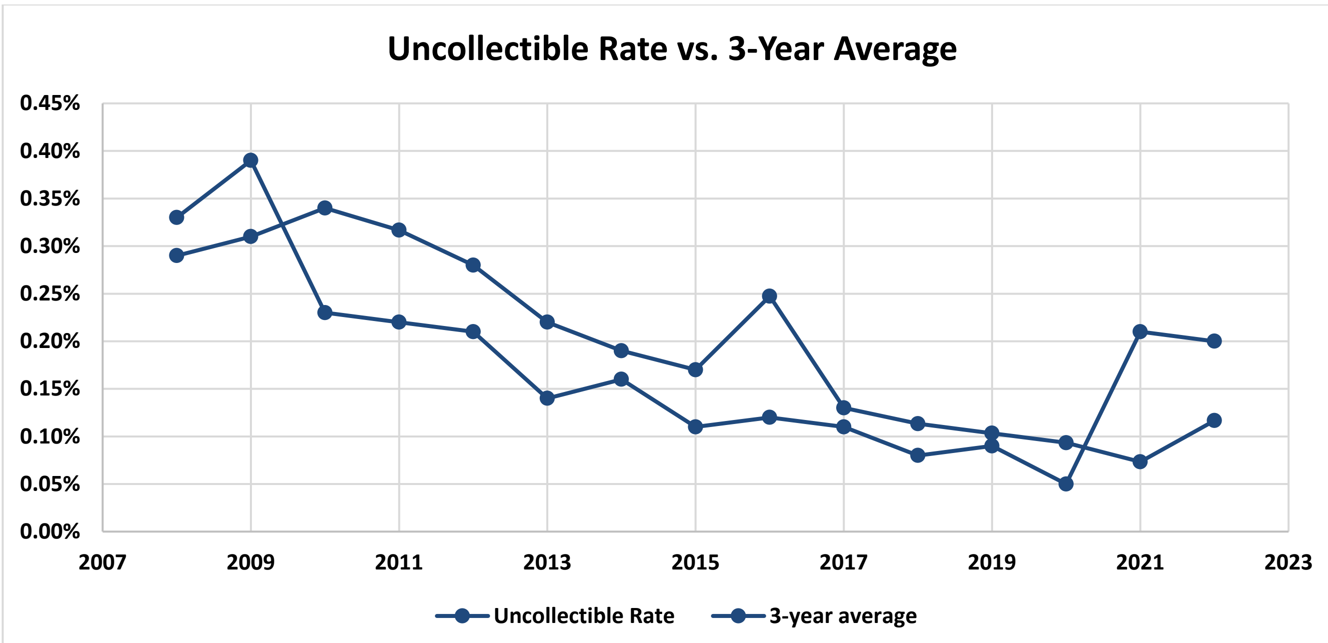
Q. Please summarize NW Natural's application of its Bill Discount Program in the Uncollectible Expense calculations.

A. Staff finds the Company's lack of discussion surrounding the growth of its Bill Discount Program concerning. This concern is magnified by NW Natural's proposal to enhance and enlarge its Bill Discount Program in this docket without reflecting the impact this could have on its Uncollectible Expense. A program that provides relief to the customers that are likely to struggle the most to pay their bills on time could be expected to mitigate some amount of the uncollectible expense. The Company is proposing to recover on the bill discount program, while also receiving an uncollectible rate based on economic conditions, customer protections, and arrearage balance inputs, without discussing how this program may impact its overall uncollectible expense. Therefore, Staff finds the lack of discussion surrounding its impact on uncollectible expenses concerning. Staff requests further information from the Company in its Reply Testimony on its decision to not adjust the uncollectible expense based on increased participation and funding for the Bill Discount Program.

Q. Please summarize Staff's analysis of the overall methodology NW Natural uses to forecast the uncollectible rate.

A. Staff finds that the methodology put forth by the Company to forecast the uncollectible rate using distinct itemized adjustments is not sufficiently robust to justify deviating from the Commission's historic precedent of a three-year average. Historically, the three-year average has tracked the overall trend of the uncollectible rate while smoothing out year-over-year variances. Figure 4 shows the Company's actual uncollectible rate plotted against the average uncollectible rate of the three preceding years.[25]

FIGURE 4. NW NATURAL UNCOLLECTIBLE RATE VS. 3-YEAR AVERAGE



Q. What is Staff's proposed adjustment for the uncollectible rate and uncollectible expense for the Test Year?

A. Staff proposes using the three-year average of the uncollectible rate between 2021 and 2023. NW Natural provided this average, an uncollectible rate of 0.182 percent, in the Company's testimony, as opposed to the .491 percent proposed.[26] Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate level of uncollectible expense to be

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[25] Staff/1203, Staff Workpaper, Uncollectible Rate.
[26] NW Natural/1300, Wilson-Sparley/18.

included in the Test Year. At this time, based on the Company's proposed general revenues in its Exhibit 201, Staff proposes a decrease of approximately $2.6 million to the Company's Test Year expense to account for a reduction to the amount forecasted by NW Natural for uncollectible accounts.

ISSUE 2. BILL DISCOUNT PROGRAM

Q. Please provide background information on investor-owned utility bill discount programs in Oregon.

A. On January 1, 2022, House Bill (HB) 2475, The Energy Affordability Act, became effective. The bill expanded language in ORS 757.230 to include additional factors the Commission may consider when establishing rate classifications, such as the "differential energy burdens on low-income customers and other economic, social equality or environmental justice factors that affect affordability for certain classes of utility customers." The Commission's HB 2475 implementation strategy focused first on interim action to provide near-term relief under the new authority, to be followed by a longer-term investigation into differential rates and programs. Since HB 2475 became effective, Staff has been engaged with each of Oregon's six investor-owned utilities to implement interim bill discount programs that address low-income energy burden. The Commission has approved interim bill discount programs for Oregon investor-owned utilities in the following dockets:

- ADV 1365 – Portland General Electric,
- ADV 1412 – PacifiCorp,
- ADV 1390 – Northwest Natural,
- ADV 1409 – Cascade, and
- ADV 1410 – Avista.

Staff has found that reviewing utility proposals as independent advice filings facilitated a more accessible process, allowed more attention to be given to the elements of the proposal, and provided an open communication venue that facilitated shared agreement and compromise to be reached prior to final approval.

Q. Please summarize the Company's current Residential Bill Discount Program.

A. Designed in 2022, NW Natural's current Residential Bill Discount Program, operational Schedule 330, is an income qualified percentage of bill discount program available to residential customers who were auto enrolled or demonstrate or self-attest that their gross household income, adjusted for household size, is at or below 60 percent of State Median Income (SMI). These customers may access a monthly discount of up to a 40 percent towards applicable charges. The Company currently has a four-tier discount structure with eligibility for each tier determined by household income and size, seen in Figure 6.[27] The four-tier structure was designed through conversations between the Company, Staff, and stakeholders to find a reasonable starting point.

Q. Please summarize the current participation in the Company's Bill Discount Program.

A. The program officially launched on November 1, 2022, with over 11,000 customers who had previously received energy assistance within the prior two years being auto-enrolled.[28] Since the launch, the enrollments have increased

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[27] NW Natural/200, Tanaka/23.
[28] NW Natural/200, Tanaka/16.

to 37,222, representing 5.84 percent of all the Company's residential customers.[29] The estimated cost of the program in 2024 was approximately $8 million, with the largest portions of funding being spent on Tier 0 and Tier 3.[30]

FIGURE 5. NW NATURAL'S 2024 BILL DISCOUNT PROGRAM COSTS

Discount Tiers	Total Cost for 2024 ($)
Tier 0 (40%)	2,074,988
Tier 1 (25%)	1,863,105
Tier 2 (20%)	1,636,610
Tier 3 (15%)	2,356,280
Total:	7,930,984

Q. Please summarize the Company's proposed changes to the Bill Discount Program.

A. Conversations in Docket No. ADV 1390 and guidance from NW Natural's Low-Income Needs Assessment (LINA), has led the Company to propose two major changes to the program.

First, the Company is proposing to target the participant's bill after discount to be a percentage of the customer's income at or near three percent.[31] NW Natural states that a common indicator of energy burden is understood to be when a customer's energy bill is six percent of the customer's income. Therefore, the Company hopes to target three percent after discount

29 Id.
30 Staff/1204, NW Natural's Response to DR 318.
31 NW Natural/200, Tanaka/21.

to minimize energy burden. To calculate necessary levels of discounts, the Company has utilized the mid-point of the income range to determine the bill discount percentage instead of the max of the income range. The Company states that by "[u]sing the mid-point of the income range to determine the bill discount percentage for each tier provides better coverage of reduced energy burden throughout the tier."[32]

Second, the Company proposes to change the Tier 1 discount from 25 percent to 40 percent, and the Tier 0 discount from 40 percent to 80 percent. With the target of three percent energy burden related to natural gas service for customers, the Company chose to update the respective Tier discounts given the proposed rates in this docket and utilizing mid-points of income ranges instead of the max of each income range. The Company does not propose changes to Tier 2 and 3 discounts, which, based on the Company's methodology, were said to achieve the target three percent energy burden or less at their current levels.[33]

FIGURE 6. NW NATURAL'S CURRENT BILL DISCOUNT PROGRAM TIERS

	Adjusted Household Income	**Current** Discount Towards Eligible Charges	**Proposed** Discount Towards Eligible Charges
Tier 0	Up to 15% SMI	40%	80%
Tier 1	>15% up to 30% SMI	25%	40%
Tier 2	>30% up to 45% SMI	20%	20%
Tier 3	>45% up to 60% SMI	15%	15%

32 NW Natural/200, Tanaka/23.
33 Id.

Figure 7. Proposed Bill Discount Program Tiers and Example[34]

Bill Discount Program Impacts, Assuming Household of 4:	SMI 60% Tier 3 - 15%	SMI 45% Tier 2 - 20%	SMI 30% Tier 1 - 40%	SMI 15% Tier 0 - 80%
Income mid-point of tier	$56,246	$40,176	$24,106	$8,035
Average annual bill	$1,124.87	$1,124.87	$1,124.87	$1,124.87
Bill as % income before discount	2.0%	2.8%	4.7%	14.0%
Bill discount	$168.73	$224.97	$449.95	$899.90
Bill after discount	$956.14	$899.90	$674.92	$224.97
Bill as % income after discount	1.7%	2.2%	2.8%	2.8%

Note that this table reflects the rates for Residential Schedule 2 proposed in this case and income eligibility tables for 2023-2024.

Q. Does Staff agree with the proposed change utilizing the mid-point of the income range?

A. Not entirely. Staff appreciates the Company's effort to provide an energy burden targeted design as recommended in the UM 2211 process,[35] however, Staff is concerned that the mid-point of any income bracket does not necessarily correspond to the actual income distribution of enrollments within the Tier. For example, if enrolled customers incomes within a tier have a median below the mid-point of the income bracket, then the mid-point methodology underestimates the level of discount needed to achieve the three percent or below energy burden target.

Second, Staff is interested in providing a higher discount to the Tier 0 customers based on preliminary energy burden data Staff has seen from the

[34] NW Natural/200, Tanaka/24 (NW Natural's calculations).
[35] *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Implementation of House Bill 2475*.

Company and peer utilities. However, rather than accept the mid-point methodology as sound, Staff would prefer to pursue the higher discount as an incremental step that may be refined and adjusted based on additional energy burden assessment information and stakeholder engagement.

Q. Does Staff agree with the proposed changes of the Tier 0 and Tier 1 discounts?

A. Not yet. While Staff appreciates the Company's efforts to move toward a more meaningful discount that endeavors to be informed by a target energy reduction methodology, Staff has two major concerns regarding the proposed change.

First, based on testimony, discussion with the Company, and DR responses received in this docket, Staff remains uncertain with the cost projections of the proposed changes and is specifically concerned with the potential increase in costs due to the increase discounts offered in Tier 0 and Tier 1. NW Natural has currently not completed any cost analysis on the implications of the redesign. Staff recognizes that cost recovery for the Bill Discount Program is not housed within the Company's revenue requirement in this docket and instead is funded through a deferral with a balancing account and an entirely separate amortization filed annually. However, Staff is uncomfortable moving forward with such large changes to the Bill Discount Program without a deeper understanding of the cost impacts of the changes.

Second, Staff's concern with the potential cost increases is exacerbated by what Staff identifies as a pressing need to review the Company's

Schedule 335 cost recovery structure from fixed non-residential charges to a volumetric charge. Staff has and will continue to pursue bill discount cost recovery discussions where we are working to ensure a more equitable distribution of cost recovery that minimizes the cost shifting effects of funding caps when programs grow.

In other words, Staff is not comfortable with moving forward with the changes to the bill discount program without better understanding the cost projections and recovery.

Q. Based on the concerns mentioned above, what does Staff request the Company do?

A. Staff requests that NW Natural perform cost projection analysis with the updated bill discount tiers and propose a change to the Company Schedule 335's cost-recovery in conjunction with this docket that is associated with the higher costs and a more equitable rate spread. Alternatively, Staff recommends the Company withdraw its proposed changes to the Bill Discount Program so that they may be addressed, in conjunction with cost recovery in a separate docket.

Q. Based on the discussion above, what is Staff's current recommendation?

A. Staff currently recommends that the Commission does not accept the proposed program changes until the Company provides further information regarding cost projections and additional information to informing the bill discount structure and cost recovery proposals moving forward. Staff welcomes and encourages the Company to provide additional information in its Reply Testimony. Staff is particularly interested in cost estimates and the Company providing a proposal which updates the cost recovery structure to ensure equitable distribution of costs if and when the project continues to grow.

Staff wants to reiterate its appreciation for the Company's efforts to engage with stakeholders and propose changes to the Bill Discount Program based on its findings in Docket No. ADV 1390 and the LINA. Staff is however unable to recommend approval of the proposed changes to the Bill Discount Program.

SUMMARY. STAFF RECOMMENDATIONS

Q. Please summarize your adjustments.

A. Staff proposes using the three-year average of the uncollectible rate between 2021 and 2023. NW Natural provided this average, an uncollectible rate of 0.182 percent, in the Company's testimony. Staff proposes applying this rate to the final agreed upon general revenues to calculate the appropriate amount for uncollectible accounts to be included in the Test Year. At this time, based on the Company's proposed general revenues in its Exhibit 201, Staff proposes a decrease to the Company's Test Year expense of approximately $2.8 million to eliminate some of the amount the Company forecasted for uncollectible accounts.

Staff recommends that the Commission does not accept the proposed Bill Discount program changes until the Company provides further information regarding cost projections and additional data informing the bill discount structure and cost recovery proposals moving forward. Staff welcomes and encourages the Company to provide additional information in its Reply Testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Charles Lockwood
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	University of Florida Bachelor of Science in Environmental Science, 2019 University of Oregon Juris Doctor, 2022 Concentrations in Green Business Law, Environmental and Natural Resources Law
EXPERIENCE:	Oregon Public Utility Commission Administrative Hearings Division Law Clerk, 2021-2022 Oregon Public Utility Commission Utility Analyst, 2022 - Present

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

April 18, 2024

Staff Workpaper titled UG 490 OT 1202 Workpaper is available in electronic spreadsheet format only

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibits in Support
Of Opening Testimony

April 18, 2024

**Staff Workpaper titled UG 490 OT 1203
Workpaper is available in electronic
spreadsheet format only**

CASE: UG 490
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 318

As it pertains to the Company's proposed bill discount program:

a. Please provide the number of residential customers in the Company's service territory on a monthly basis for 2022-2024.

b. How many customers does NW Natural estimate are able to qualify for each of the programs listed by the Company including OLGA, OLIEE, GAP, and LIHEAP? Please provide a breakdown by discount tier.

c. How many of IPCO's residential customers are currently receiving one of the programs? Additionally, how many customers are receiving two or more of the programs? Which are the most common programs to be combined?

d. Provide an estimate of the number of customers IPCO believes will be enrolled into the Bill Discount Program by the end of the calendar years 2024, 2025 and 2026, by discount tier. Please summarize the methodology used to arrive at these figures.

e. Provide a forecast of the total cost associated with the Bill Discount Program for the calendar years 2024, 2025, and 2026. Please provide a breakdown of cost categories. Please summarize the methodology used to arrive at these figures.

f. Please describe how the Company plans to monitor the kWh usage of Bill Discount Program participants for outliers. If there are no plans to monitor, please explain why.

g. Please provide the monthly average kwh usage for all residential customers for 2022-2024. Please provide a breakdown of average monthly kwh usage for LIHEAP customers for the same time period. Please provide a breakdown by dwelling type.

Response:

a. Oregon residential customer counts are as follows:

Count - 01/2022	629,034

Count - 02/2022	628,983
Count - 03/2022	629,689
Count - 04/2022	630,044
Count - 05/2022	630,161
Count - 06/2022	630,145
Count - 07/2022	629,809
Count - 08/2022	630,381
Count - 09/2022	630,787
Count - 10/2022	631,600
Count - 11/2022	632,897
Count - 12/2022	634,325
Count - 01/2023	635,376
Count - 02/2023	635,303
Count - 03/2023	635,926
Count - 04/2023	635,723
Count - 05/2023	635,653
Count - 06/2023	635,205
Count - 07/2023	634,459
Count - 08/2023	634,194
Count - 09/2023	634,533
Count - 10/2023	635,181
Count - 11/2023	636,072
Count - 12/2023	637,667

b. Please see responses to UG 490 OPUC DR 303a and b.

c. The Company interprets “IPCO” in the question as intended to read “NW Natural.” Please see UG 490 OPUC DR 318 Attachment 1. Based on the data in Attachment 1, it appears that the combination of OLGA and GAP is the most common.

d. The Company interprets “IPCO” in the question as intended to read “NW Natural.” Please see response to UG 490 OPUC DR 303b. Enrollee counts were not estimated by tier.

e. Please see response to UG 490 OPUC DR 303b. The estimated cost of the discounts for the residential bill discount program for 2024 as filed and approved in ADV 1562 was $10,718,994 excluding revenue-sensitive costs. This was comprised of an under-collected balance of $2,248,009.69 from 2023 and a forecast for 2024 of $7,930,984.25. The breakdown of the 2024 forecast by tier is as follows:

	Total cost for 2024 update
Disc tiers	
Level - 40%	2,074,988
Level - 25%	1,863,105
Level - 20%	1,636,610
Level - 15%	2,356,280
	7,930,984

f. The Company interprets "kWh" in the question as intended to read "therm." NW Natural does not currently monitor the therm usage of its residential bill discount program participants. During the Staff and stakeholder process of the Company's program in ADV 1390 during the spring and summer of 2022, stakeholders expressed concern about monitoring participants for increased usage, given the belief that an increase in usage may likely occur because participants could better afford to use more energy (e.g. customers would adjust their thermostats to a more comfortable level instead of at a colder level before the bill discount program). In addition, there may be many various reasons why some customers use more or less than others.

g. The Company interprets "kWh" in the question as intended to read "therm." Please see UG 490 OPUC DR 318 Attachment 2.

CASE: UG 490
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

April 18, 2024

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Northwest Natural's revenue requirements for the following issues: Distribution Operations and Maintenance (O&M) expense; Materials and Supplies; Customer Accounts; Affiliated Interest; and Atmospheric Testing.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1302, consisting of 3 pages, and Confidential Exhibit Staff/1303, consisting of 6 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. DISTRIBUTION O&M EXPENSE

Q. Please describe O&M expense.

A. Distribution O&M refers to those expenses and activities recorded in FERC Accounts 870–894, and include operation, supervision and engineering, distribution load dispatching, compressor station and regulator station expenses, and customer installation expenses.

Q. What is the Company's proposal for distribution O&M expenses in this case?

A. Northwest Natural is proposing to include approximately $73.6 million in distribution O&M expense (FERC Accounts 870–894) in its Test Year expense. This represents an increase of 21 percent over the $60.8 million in the Base Year.[1] The majority of this—approximately $50.77 million—is labor expense. For non-labor expense, the Company proposes an increase in distribution O&M expense from $17.9 million in the Base Year to $22.8 million in the Test Year.[2] This represents an increase of $4.88 million, or more than 27.2 percent over the 2023 Base Year.

My testimony only addresses non-labor expense. Please see Staff Witness Stephanie Yamada's testimony in Staff 2000 addressing the labor portion of distribution O&M.

Q. How does NW Natural explain the increase in non-labor distribution O&M expense?

[1] See NW Natural/1401-1402, Davilla/1.
[2] See Exhibit Staff/1302, Moore/1-2, Company response to Staff DR No. 58.

A. In its opening testimony, the Company points to two specific drivers for increased costs: Contracted locating services expense is projected to increase by $2.9 million and contracted survey services expense is projected to increase by $0.92 million in the Test Year.[3] The Company states that it entered a new agreement with its contract locating company, Health Consultants, which calls for a three percent annual increase in rates. In addition, the Company explains that the number of customers calling to request locating services is projected to increase 1.5 percent annually. The Company also amended its contract with Health Consultants for survey and inspection services, with a rate that is also expected to increase by three percent annually.

Additionally, the Company escalates its general non-labor expense using the West Region Urban CPI.

Q. Please describe your review and analysis of NW Natural's distribution O&M expense.

A. Staff first reviewed the distribution O&M expenses for the historical calendar years of 2021, 2022, and 2023. This review included looking at trends, transactional details, and adjustments proposed by NW Natural.

Staff initially looked at the annual increase in non-labor distribution O&M expenses for the past three years to determine whether the proposed increase in the Test Year is consistent with historical expenses. Staff also reviewed transaction details from the Base Year expense (2023) to ensure expenditures are justifiable for normal utility operations.

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3 See NW Natural/1400, Davilla/11-12.

Staff also reviewed the Company's responses to Staff Data Requests that focused on investigating the Company's new locating and surveying contracts with Health Services.

Q. What does Staff conclude from its review?

A. A trend analysis suggests that the proposed Test Year expenses are out of line with expense trends over previous years. Non-labor Distribution O&M expense has seen significant increases since 2021—a 10.5 percent increase in 2022, and a 14.8 percent increase in 2023 over previous years. The increase in the Test Year expense over CPI inflation is almost entirely a result of the increase in NW Natural's contract locating and survey rates. With the new contract, the cost per locating unit increased 58.4 percent from the Base Year to the Test Year over the previous contract rate. The after-hours locate rate has increased 81.3 percent over the previous contract rate.

Q. Why have NW Natural's locate and survey costs increased so much?

A. NW Natural has used Health Consultants for survey services since at least 2021. NW Natural amended a previous contract for survey services with Health Consultants, and the amended rates for survey services were about 18 to 35 percent higher than the previous contract. As noted above, these rates increased an additional three percent with the most newly executed contract.

The locating contract for most of the Base Year, and several years prior, was with Locating Inc. NW Natural signed a new contract transferring its locating services to Health Consultants effective September 1, 2023.[4]

[4] See Confidential Exhibit NW Natural/1406, Davilla/3.

Q. Did NW Natural conduct a competitive bid process for the survey and locating contracts?

A. Yes. NW Natural conducted a request for procurement (RFP) in late 2022 that sought bids for a single contractor to provide all survey and locating services. In response to a Staff Data Request, NW Natural represents that Health Consultants was selected as the vendor and had the “lowest scaled pricing” and provided excellent quality service…and was the “clear overall winner” for the awarded contract.

Q. Does Staff recommend an adjustment for non-labor distribution O&M?

A. Yes. At this time, Staff does not believe the Company has substantiated the reasonableness of the extreme increase in the cost of survey and locate rates. Therefore, Staff recommends an adjustment that reflects the three-year historical average of non-labor O&M costs, escalated for inflation at inflation rates recommended by Staff in Staff/800, which results in an adjustment of ($6.2 million) to non-labor O&M expense.

ISSUE 2. NON-FUEL MATERIALS AND SUPPLIES

Q. Please summarize NW Natural's proposal for non-fuel materials and supplies.

A. Northwest Natural proposes an average Test Year balance for materials and supplies in rate base of $25,496,000 at a system level. The Oregon-allocated forecast Test Year rate base amount is $21,810,000.[5] This represents a 13.64 percent increase over the 2023 Base Year.

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base.

Q. Please describe Staff's analysis of this issue.

A. Staff reviewed historical balances for the years 2021–2023 and compared the average of monthly average balances for each year with the year-end forecast for 2024. Staff believes that using an average of monthly averages balance for rate-based items provides an accurate picture of yearly rate-based components that earn a rate of return.

Using an average of monthly average balances for 2021, 2022, and 2023, escalated for inflation of 2.7 percent in 2024 and 2.0 for 2025 results in a forecast Test Year balance of $17,783,000.[6]

Q. Does Staff propose an adjustment?

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5 See Staff/1302, Moore/3, Company response to Staff DR No. 84.
6 See Staff/1304, Moore/Workpaper.

A. Yes. Staff believes NW Natural has overestimated the non-fuel material and supplies by $4 million), and therefore recommends a downward adjustment to rate base by this amount.

ISSUE 3. CUSTOMER ACCOUNTS

Q. Please describe Non-labor Customer Accounts expense.

A. Non-labor Customer Accounts expense addressed in my testimony is recorded in FERC Account Nos. 901–903.[7] This includes expense for activities such as supervision, meter reading, and customer records and collection expense.

Q. Please describe NW Natural's proposal regarding non-labor Customer Accounts expense.

A. NW Natural proposes a Test Year forecast of $12.26 million at a system level, and $10.8 million for Oregon-allocated expense. This represents a 20.5 percent increase over the Oregon-allocated Base Year expense of $8.95 million. The majority of the expense, and the increase, is in FERC Account No. 903 – Customer Records and Collection expense.

Q. What reasons does the Company provide to explain the increase?

A. NW Natural explains in its opening testimony it expected an increase in expense due to an expected amendment to its contract with Paymentus, which provides electronic bill payment services. This amendment was in fact executed in late December 2023. NW Natural explains that an increase in costs charged by Paymentus, combined with an increase in the number of customers that prefer to pay their bill by bankcard or other electronic methods, results in a total Oregon-allocated expense increase in the Test Year of $1.29 million over the 2023 Base Year.[8]

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7 Staff Witness Charles Lockwood addresses FERC Account No. 904 – Uncollectible Accounts in Staff/1200.

8 See NW Natural/1400, Davilla/11.

Q. How does Staff view NW Natural's explanation for the increase?

A. Staff is concerned about the escalating cost of offering customers fee-free electronic payment options. The projected increase from the Base year to the Test Year is 42.8 percent from the Base Year to the Test Year; from $3,846,000 in 2023 to $5,490,211 in 2025.[9] In response to a Staff data request, the Company provided the amendment to the Paymentus contract that was made effective in December of 2023.[10] In comparing the fees in the amended contract with the fees outlined in the pre-existing contract, Staff finds **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**.

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[9] See Exhibit Staff/1302, Moore/4-5 – Company response to Staff Data Request No. 404.

[10] See Confidential Exhibit Staff/1303, Moore/1-6 – Confidential response to Staff Data Request No. 404 attachment 1.

In previous cases, Staff has recognized that it is reasonable to make payment options available to customers to ensure customers have convenient methods to pay their bills. Further, given the importance of accessibility to payment options, Staff has supported spreading the costs of these payment options to all customers rather than requiring that the individual customers that use these options pay for them at the time of use. However, this does not mean it is reasonable to spread costs of even the most expensive methods of payment to all customers.

Staff's view is that the Company has a responsibility to communicate to its customers the costs of the various methods of payment, and if customers choose options that are less reasonably priced, the costs should not be spread to other customers. By having all customers absorb the costs of payment processing, without any transparency to what those costs are, and without absorbing—or avoiding—those costs individually, customers are left without any means to mitigate the impact of increasing costs.

Q. How does Staff forecast NW Natural's Test Year expense?

A. In this case, Staff believes it is reasonable to use a three-year historical average and then escalate the average with the expected CPI inflation index to arrive at a forecast Test Year. For customer accounts, the Test Year forecast should be $8.7 million. This forecast methodology accounts for an increase in payment processing costs and incentivizes the Company to encourage lower-cost payment options, while still allowing for more expensive options such as Amazon Pay, PayPal, and Venmo to be available to customers. Staff is not convinced that the more expensive options are a necessary benefit to customers, but are more geared toward Company image enhancement, which benefits shareholders.

Q. Does Staff recommend an adjustment?

A. Yes. Staff recommends the Company's Test Year forecast expense for Customer Accounts be adjusted by ($2.1 million).

ISSUE 4. AFFILIATED INTEREST

Q. Please explain the Commission's historical treatment of cost allocation among affiliates.

A. The Commission's historical treatment of cost allocation among affiliates is pursuant to OAR 860-027-0048 (Allocation of Costs by an Energy Utility), which addresses the allocation of costs between an energy utility and its affiliates, outlining how transactions should be recorded. OAR 860-027-0048 also states that an energy utility must keep a current Cost Allocation Manual (CAM), with detailed methodology on how costs are allocated between affiliates on file with the Commission. The rule also requires that the Allocation Manual shall be "filed yearly as an appendix to the Affiliated Interest Report required under OAR 860-027-0100."

Q. How does NWN generally allocate costs among its affiliates?

A. According to NWN's CAM, "the approach to allocating costs is to directly assign costs when applicable and to allocate costs based on the primary cost driver of the common cost, or relevant proxy, and to ensure that unauthorized subsidization of unregulated activities by regulated activities, and vice versa, does not occur." The CAM also states that "goods or services provided by the utility to an affiliate are provided at the higher of cost or market price," which is in accordance with OAR 860-027-0048. Typical affiliated transactions that occur between NWN and its affiliates include:

- Direct charges of NWN's payroll and administrative expense for affiliate use of NWN's staff;

- Payments between NWN and affiliates for tax expense or benefits;
- Annual allocation of indirect charges per the CAM;
- Direct charges for office space used by NWN's non-regulated affiliates;
- Vendor payments made by NWN on behalf of affiliates; and
- Equity distributions/contributions and dividends between NWN and affiliates.

Q. Please summarize Staff's review of the Company's Affiliate Interest transactions.

A. Staff requested transactional level detail to review cost allocation between the Company and its affiliates and non-regulated entities. Staff reviewed the Company's 2020 affiliated interest report,[43] including its MSA and CAM as well as transactions between NWN and its affiliates. NWN did not propose any changes to its CAM in this filing. Staff's review focused on ensuring allocation factors are calculated and applied correctly and in adherence with cost allocation principles outlined in NARUC's cost allocation manual and referenced above.

Q. Does Staff propose an adjustment related to this issue?

A. No. Staff proposes no adjustment related to this issue.

ISSUE 5. ATMOSPHERIC TESTING

Q. Please describe NW Natural's atmospheric testing program.

A. Atmospheric Testing expenses include the cost of compliance with a federal safety mandate to inspect all portions of natural gas pipelines in contact with air for signs of corrosion. The Company uses a third-party vendor to conduct atmospheric surveys related to leakage and corrosion, and each section of pipe is inspected every three years in compliance with federal regulations.

Q. Please summarize the Company's proposal regarding atmospheric testing.

A. NW Natural proposes to include $2.4 million in Oregon-allocated atmospheric testing activities for the Test Year in FERC Account Nos. 856 (Mains Expense), 874 (Mains and Service Expense), and 892 (Maintenance of Service). This represents a decrease of $2.6 million from the Base Year, in which $4.66 million was spent.

Q. Please describe Staff's review of this issue.

A. Staff reviews the proposed forecast expense for reasonableness, and to assure compliance with federal regulations. Staff issued several data requests to determine the historical spending in this area, as well as compared the Company's historical expense in prior rate cases. The Company's spending varies from year to year, depending on the inspection cycle. The Company's forecast Test Year expense is the lowest it has been since 2019. The Company also represents that it is not proposing any new or different treatment from current or past practice.

Q. What does Staff conclude from its review?

A. Staff concludes the Company's projection is reasonable, and therefore Staff has no adjustment to recommend on this issue.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

April 18, 2024

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. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

April 18, 2024

Data Request 58
FERC O&M Costs - Non Labor Costs
Attachment 2 58(b)
Test Year

	Test Year 11/1/2024 - 10/31/2025						
		Allocations					
	a)	b)	c)	d)	e)	f)	g)
Account	Account Total b+c	Non-Utility	Total Regulated Utility Service	Oregon Alloc. Factor	Oregon Alloc./Share	Oregon Situs	Total included in Filed Rate Case e+f
816	677,828	-	677,828	90%	608,545	-	608,545
818	309,948	-	309,948	89%	275,885	-	275,885
819	42,722	-	42,722	89%	38,027	-	38,027
820	1,338,125	-	1,338,125	89%	1,191,101	-	1,191,101
821	-	-	-	0%	-	-	-
832	791,624	-	791,624	89%	704,625	-	704,625
834	1,667,248	-	1,667,248	89%	1,484,018	-	1,484,018
840	17,001	-	17,001	89%	15,133	-	15,133
844	791,901	-	791,901	89%	704,871	-	704,871
845	(166,352)	-	(166,352)	89%	(148,069)	-	(148,069)
847	736,451	-	736,451	89%	655,515	-	655,515
856	3,471,243	-	3,471,243	99%	3,428,586	-	3,428,586
863	6,235	-	6,235	99%	6,158	-	6,158
870	514,201	-	514,201	92%	474,365	-	474,365
874	16,897,615	-	16,897,615	89%	14,979,916	-	14,979,916
875	129,713	-	129,713	91%	117,893	-	117,893
877	312,319	-	312,319	91%	283,525	-	283,525
878	690,818	-	690,818	88%	607,160	-	607,160
879	3,241,250	-	3,241,250	88%	2,848,719	-	2,848,719
880	146,884	-	146,884	88%	129,755	-	129,755
881	291,272	-	291,272	87%	251,980	-	251,980
885	290,607	-	290,607	92%	266,093	-	266,093
887	1,742,004	-	1,742,004	92%	1,606,235	-	1,606,235
889	597,723	-	597,723	91%	542,832	-	542,832
891	95,853	-	95,853	91%	87,492	-	87,492
892	239,870	-	239,870	88%	210,833	-	210,833
893	488,587	-	488,587	88%	430,681	-	430,681
894	1,869	-	1,869	88%	1,643	-	1,643
901	83,928	-	83,928	88%	73,764	-	73,764
902	42,839	-	42,839	88%	37,652	-	37,652
903	12,132,693	-	12,132,693	88%	10,678,473	-	10,678,473
904	The total for FERC 904 is removed from the O&M balance as it is reported elsewhere for this period.						
907	-	-	-	0%	-	-	-
908	45,169	-	45,169	88%	39,922	-	39,922
909	1,931,093	-	1,931,093	88%	1,697,238	-	1,697,238
910	5,024	-	5,024	88%	4,407	-	4,407
911	6,493	-	6,493	88%	5,706	-	5,706
912	477,137	-	477,137	88%	420,171	-	420,171
913	-	-	-	0%	-	-	-
916	-	-	-	0%	-	-	-
921	55,691,773	-	55,691,773	88%	49,080,025	-	49,080,025
922	(25,374,489)	-	(25,374,489)	88%	(22,403,377)	-	(22,403,377)
924	6,325,360	-	6,325,360	88%	5,589,088	-	5,589,088
925	198,213	-	198,213	88%	175,141	-	175,141
926	15,214,830	-	15,214,830	94%	14,320,189	-	14,320,189
928	-	-	-	0%	-	-	-
930	5,414,275	-	5,414,275	92%	4,977,707	-	4,977,707
931	11,024,949	-	11,024,949	88%	9,742,139	-	9,742,139
932	4,361,563	-	4,361,563	90%	3,924,398	-	3,924,398
TOTAL O&M Expense (Less Acct 904 Uncollectible)	122,945,408	-	122,945,408		110,166,162	-	110,166,162
PLUS $5mm Environmental Recovery Expense	5,000,000	-	5,000,000		5,000,000	-	5,000,000
TOTAL O&M Expense	127,945,408	-	127,945,408		115,166,162	-	115,166,162

Data Request 58
FERC O&M Costs
Attachment 2 58(b)
Base Year

	Base Year Ending December 31, 2023						
	Actuals through 9/30 with 10/1-12/31 Forecast						
		Allocations					
	l)	m)	n)	p)	q)	r)	s)
Account	Account Total m+n	Non-Utility	Total Regulated Utility Service	Oregon Alloc. Factor	Oregon Alloc./Share	Oregon Situs	Total included in Filed Rate Case q+r
816	639,239	-	639,239	90%	573,900	-	573,900
818	292,297	-	292,297	89%	260,174	-	260,174
819	40,618	-	40,618	0%	36,154	-	36,154
820	1,260,118	-	1,260,118	89%	1,121,666	-	1,121,666
821	-	-	-	#DIV/0!	-	-	-
832	156,520	-	156,520	89%	139,318	-	139,318
834	1,571,706	-	1,571,706	89%	1,398,975	-	1,398,975
840	16,022	-	16,022	89%	14,261	-	14,261
844	745,463	-	745,463	89%	663,536	-	663,536
845	(156,047)	-	(156,047)	89%	(138,898)	-	(138,898)
847	692,494	-	692,494	89%	616,389	-	616,389
856	3,270,366	-	3,270,366	99%	3,230,178	-	3,230,178
863	5,849	-	5,849	99%	5,777	-	5,777
870	485,335	-	485,335	92%	447,734	-	447,734
874	11,903,092	-	11,903,092	89%	10,552,218	-	10,552,218
875	122,388	-	122,388	91%	111,235	-	111,235
877	295,121	-	295,121	91%	267,912	-	267,912
878	650,687	-	650,687	88%	571,889	-	571,889
879	3,057,309	-	3,057,309	88%	2,687,055	-	2,687,055
880	139,429	-	139,429	88%	123,169	-	123,169
881	274,341	-	274,341	87%	237,333	-	237,333
885	273,955	-	273,955	92%	250,846	-	250,846
887	1,640,153	-	1,640,153	92%	1,512,322	-	1,512,322
889	563,227	-	563,227	91%	511,504	-	511,504
891	89,537	-	89,537	91%	81,727	-	81,727
892	226,802	-	226,802	88%	199,348	-	199,348
893	461,231	-	461,231	88%	406,567	-	406,567
894	1,755	-	1,755	88%	1,542	-	1,542
901	79,365	-	79,365	88%	69,754	-	69,754
902	40,266	-	40,266	88%	35,390	-	35,390
903	10,053,657	-	10,053,657	88%	8,848,630	-	8,848,630
904	The total for FERC 904 is removed from the O&M balance as it is reported elsewhere for this period.						
907	-	-	-	0%	-	-	-
908	43,437	-	43,437	88%	38,392	-	38,392
909	1,290,342	-	1,290,342	88%	1,134,082	-	1,134,082
910	4,753	-	4,753	88%	4,169	-	4,169
911	6,118	-	6,118	88%	5,377	-	5,377
912	449,737	-	449,737	88%	396,043	-	396,043
913	621,027	-	621,027	88%	545,821	-	545,821
916	-	-	-	0%	-	-	-
921	46,498,211	-	46,498,211	88%	40,977,926	-	40,977,926
922	(23,010,226)	-	(23,010,226)	88%	(20,315,946)	-	(20,315,946)
924	5,104,380	-	5,104,380	88%	4,510,230	-	4,510,230
925	196,151	-	196,151	88%	173,319	-	173,319
926	6,390,917	-	6,390,917	101%	6,472,829	-	6,472,829
928	-	-	-	0%	-	-	-
930	4,963,081	-	4,963,081	92%	4,560,973	-	4,560,973
931	10,565,934	-	10,565,934	88%	9,336,533	-	9,336,533
932	4,110,556	-	4,110,556	90%	3,698,550	-	3,698,550
TOTAL O&M Expense (Less Acct 904 Uncollectible)	96,126,713	-	96,126,713		86,375,906	-	86,375,906
PLUS $5mm Environmental Recovery Expense	5,000,000	-	5,000,000		5,000,000	-	5,000,000
TOTAL O&M Expense	101,126,713	-	101,126,713		91,375,906	-	91,375,906

			MAT & SUPPLIES-GEN	INVEN RESERVE - UTIL	MAT & SUPPLIES-ODORA	INVENTORY-OFFICE SUP	MAT & SUPP-DIESEL AU	MAT & SUPP-UNLEADED	Total	
			NWN/154001		NWN/154040	NWN/154050	NWN/154071	NWN/154073		
		Previous GL	154001	154038	154040	154050	154071	154073		
		New Horizon GL	127220	127235	127245	127250	127255	127260		
January	2023	Actual	22,008,547	-	164,683	-	33,635	14,690	22,221,553	Base Year
February	2023	Actual	21,768,759	-	248,965	-	14,139	(30,759)	22,001,104	Base Year
March	2023	Actual	22,360,396	-	210,118	-	(8,527)	(78,574)	22,483,414	Base Year
April	2023	Actual	22,427,159	-	185,251	-	39,711	74,614	22,726,734	Base Year
May	2023	Actual	22,295,052	-	171,067	-	38,646	53,429	22,558,193	Base Year
June	2023	Actual	22,315,229	-	158,519	-	24,826	126,686	22,625,260	Base Year
July	2023	Actual	22,888,445	-	276,474	-	59,016	156,823	23,380,758	Base Year
August	2023	Actual	23,042,840	-	265,040	-	12,790	116,718	23,437,388	Base Year
September	2023	Actual	23,479,384	-	252,606	-	78,607	153,684	23,964,281	Base Year
October	2023	Forecast	22,261,458		220,424		20,970	48,992	22,551,844	Base Year
November	2023	Forecast	22,425,849		221,252		20,605	47,703	22,715,409	Base Year
December	2023	Forecast	22,590,240		222,081		20,239	46,414	22,878,974	Base Year
January	2024	Forecast	22,754,631		222,910		19,874	45,125	23,042,540	
February	2024	Forecast	22,919,022		223,738		19,509	43,836	23,206,105	
March	2024	Forecast	23,083,413		224,567		19,144	42,547	23,369,671	
April	2024	Forecast	23,247,804		225,396		18,778	41,258	23,533,236	
May	2024	Forecast	23,412,195		226,224		18,413	39,969	23,696,802	
June	2024	Forecast	23,576,587		227,053		18,048	38,680	23,860,367	
July	2024	Forecast	23,740,978		227,882		17,683	37,391	24,023,933	
August	2024	Forecast	23,905,369		228,710		17,317	36,102	24,187,498	
September	2024	Forecast	24,069,760		229,539		16,952	34,813	24,351,064	
October	2024	Forecast	24,234,151		230,368		16,587	33,524	24,514,629	
November	2024	Forecast	24,398,542		231,196		16,221	32,235	24,678,195	Test Year
December	2024	Forecast	24,562,933		232,025		15,856	30,946	24,841,760	Test Year
January	2025	Forecast	24,727,324		232,854		15,491	29,657	25,005,325	Test Year
February	2025	Forecast	24,891,715		233,682		15,126	28,368	25,168,891	Test Year
March	2025	Forecast	25,056,107		234,511		14,760	27,079	25,332,456	Test Year
April	2025	Forecast	25,220,498		235,340		14,395	25,790	25,496,022	Test Year
May	2025	Forecast	25,384,889		236,168		14,030	24,501	25,659,587	Test Year
June	2025	Forecast	25,549,280		236,997		13,664	23,212	25,823,153	Test Year
July	2025	Forecast	25,713,671		237,826		13,299	21,923	25,986,718	Test Year
August	2025	Forecast	25,878,062		238,654		12,934	20,633	26,150,284	Test Year
September	2025	Forecast	26,042,453		239,483		12,569	19,344	26,313,849	Test Year
October	2025	Forecast	26,206,844		240,311		12,203	18,055	26,477,415	Test Year
November	2025	Forecast	26,371,236		241,140		11,838	16,766	26,640,980	
December	2025	Forecast	26,535,627		241,969		11,473	15,477	26,804,546	

Base Year System (000)	22,740
Test Year System (000)	25,496

Rate Base Elements	**Base Year**	**Test Year**
System	**22,740**	**25,496**
Allocation Factor (Distribution Plant)	85.5%	85.5%
Oregon	**19,452**	**21,810**

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 404

Referencing NW Natural/1400, Davilla/pg. 11, Contracted Customer Payment Processing Fees (FERC 903), and NW Natural/1405, Davilla/pgs 1-14:

a. When does the current contract expire?
b. What is the Oregon-allocated total actual expense for this contract for the years 2020-2023?
c. What is the Oregon-allocated total forecast expense for this contract for 2024?
d. What is the Oregon-allocated Test Year forecast for this expense?
e. Please explain and demonstrate the basis for the Oregon-allocated forecast increase to this contract in the Test Year.
f. When (month/year) does the Company expect to have an amended contract in place?
g. What efforts has the Company made to ensure that costs for bankcard services are competitive? Please describe and demonstrate.

Response:

A. The testimony states that the Company "expects to sign a contract amendment and extension in the near term." NW Natural/1400, Davilla/Page 11, Lines 11-12. An extended contract was entered into on December 27, 2023, and is provided as Confidential UG 490 OPUC DR 404 Attachment 1. The current contract expires May 4, 2027.

B. The Oregon-allocated total actual expense for this contract for the years 2020-2023 are as follows:

Period	System Wide	Oregon Allocation
2020 Oct to Dec	$633,000	$557,000
2021	$3,460,000	$3,045,000

2022	$3,930,000	$3,459,000
2023	$4,370,000	$3,846,000

C. The Oregon-allocated total forecast expense for this contract for 2024 is as follows:

Period	System Wide	Oregon Allocation
2024	$5,339,332	$4,699,146

D. The Oregon-allocated Test Year forecast for this expense is $5,490,211 ($6,237,881 System).

E. Please see NW Natural/1400, Davilla/Page 11, Lines 12-16. Primary factors for the Oregon-allocated forecast increase to this contract in the Test Year are:

   a. Customers have expressed a significant preference for bankcard payments.
   b. Migration of customers from 1.) paper payment methods (mailing a check) and 2.) customer specific bank bill pay methods to 3.) autopay methods via ach or bankcard or 4.) one time ach and bankcard payments.
   c. Test Year transactions are expected to grow at a 10 percent compound annual growth rate from the Base Year to the Test Year.

F. Please see the response to subpart A.

G. Before extending the current contract, competitive pricing was received from two other processors that provide bankcard processing services. The pricing of each of those other two processors was greater than our current and selected processor. Vendor A's proposal was approximately 39% more expensive and Vendor B's proposal was approximately 47% more expensive. Please see Confidential UG 490 OPUC DR 404 Attachment 2 for a comparison of those proposals and the Paymentus extended contract.

CASE: UG 490
WITNESS: MITCH MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

CONFIDENTIAL Exhibit in Support
Of Opening Testimony

April 18, 2024

CASE: UG 1400
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

OPENING TESTIMONY

Depreciation Expense, Amortization Expense, Depreciate Reserve, Amortization Reserve, and Allowance for Funds Used During Construction

April 18, 2024

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

A. My name is Ming Peng. I am a Senior Economist employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, and portions of Northwest Natural's (NWN or Company) revenue requirement for this rate case as documented by the Company witnesses, NW Natural/100 Palfreyman-Kravitz, and NW Natural/1600 Spanos. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualifications statement, I prepared Exhibit Staff/1402, NWN Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Please note that I may revise my recommendations based on testimony filed by other participants in this rate case.

1. Depreciation Expenses: I do not yet have a recommendation regarding depreciation expenses because I am waiting for the Oregon PUC to authorize depreciation rates before deciding if the adjustment is needed. In the UG 490 general rate case, NWN used the updated depreciation rates proposed in a new depreciation study the company filed with the Commission in January 2024, docketed as UM 2312. The procedural schedule UM 2312 includes settlement conferences in June 2024 and in the event settlement is not reached, a hearing in July 2024, so a Commission decision on depreciation rates should be issued no later than October 2024. I am currently reviewing the UM 2312 depreciation study. Once the depreciation case is settled and the Commission issues an order to authorize the updated depreciation rates, then Staff can calculate depreciation expenses for the UG 490 revenue requirement.
2. Amortization Expenses: I do not yet have a proposed adjustment because I need to wait to see if NWN's amortization expense calculation complies with Commission-authorized rates in UM 2312. In this depreciation schedule, an amortization expense is the expense for the intangible plants, which include software, cloud-based

software, and the customer information system.

3. Depreciation Reserve (Accumulated depreciation reserve): Staff has proposed no adjustment to depreciation reserves in UG 490, because the depreciation rates are still under review, and if depreciation expense is changed, the depreciation reserve will be changed accordingly.

4. Amortization Reserve (Accumulated amortization reserve): Staff has proposed no adjustment to depreciation reserves in UG 490, because the depreciation/amortization rates are under review, and if amortization expense is changed, the amortization reserve will be changed accordingly.

5. I made an adjustment to the Company's proposed AFUDC by pulling out of rate base the portion of AFUDC that exceeds the authorized rate is of 0.63 and putting it into "Excess AFUDC Regulatory Liability" on the utility's balance sheet. The Company may seek to recover the excess AFUDC through rate adjustments, subject to regulatory approval.

ISSUE 1. DEPRECIATION EXPENSE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

Q. Why is depreciation important in a revenue requirement?

A. NARUC states that:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[2]

1. From a valuation perspective, depreciation is the loss in service value not restored by current maintenance.
2. From an accounting perspective, depreciation is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept.

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[1] NARUC, Public Utility Depreciation Practices, p.318 (1996).
[2] NARUC, Public Utility Depreciation Practices, p.195 (1996).

3. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. the public utility commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. the rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are utility property depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate: (1) the combination of survivor curve[3]-service life (Curve-Life) of utility property, and (2) the net salvage[4] (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. What is the Commission's historical treatment of a depreciation calculation in a revenue requirement?

[3] "Survivor curves" are curves that show the number of units or cost of a given group that is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves."

[4] Net Salvage. The gross salvage of the property retired less the cost of removal. This will be negative if the cost of removal exceeds the gross salvage.

A. A utility should use the Commission-authorized depreciation parameters and rates to calculate the depreciation and amortization expense and reserve. A Company's Depreciation Expense is determined by (OPUC-Authorized Depreciation Rate) x (Oregon net plant in service) x (allocation factor).

Q. Why do we need to use authorized depreciation rate results for the revenue requirement calculation?

A. To compute the revenue requirement (RR), which is measured by cost-of-service, a basic formula is followed:

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

- Depreciation expense is calculated by (Depreciation rate) x (plant in service) x (allocation factor, if any).
- Depreciation expense represents a large percentage of total operating expenses. The deferred income taxes, rate base, and cost of capital are all affected by the depreciation. Therefore, to calculate depreciation expense and reserve, we must use the Commission-authorized depreciation parameters to reflect the true cost in the revenue requirement.

Q. Has NWN explained the key drivers for the increase in the company's revenue requirement?

A. Yes. In UG 490, NWN explains that the results of the depreciation study are one of the key drivers for the increase requested in the Company's revenue requirement. Applying the depreciation rates from the depreciation study to

Test Year plant balances results in an increase to depreciation expense of $62.4 million, and revenue requirement increase of 16.62 percent.

Q. Are there any important issues that we need to consider in the UG 490 GRC and UM 2312 depreciation filings?

A. Yes. In NW Natural/100 Palfreyman-Kravitz/Page 19-23, the witnesses stated, "In the Company's most recently filed depreciation study (UM 2214), the Commission requested that NW Natural address the issue of accelerated depreciation when it files its next depreciation study."

In Order No. 22-322 (at page 3), the Commission stated the following:

> In adopting this stipulation, we are mindful that prior to the company's next depreciation study, to be filed no later than December 31, 2027, NW Natural, Staff, and stakeholders will be engaged in significant work towards the company reducing emissions in response to the Oregon Department of Environmental Quality's Climate Protection Program or other policy and regulatory directives. We anticipate that parties may seek to evaluate accelerated depreciation or other adjustments to asset depreciation schedules as one tool to mitigate uncertainty about decarbonization pathways and manage potential future risks to customers. We ask that the company include in its next depreciation filing testimony addressing its consideration of this approach.

NW Natural/100 Palfreyman-Kravitz/Page 22 further explained:

> For this reason, the Company has updated its depreciation study, which will require a higher revenue requirement. If we can reset these rates to reflect the actual results of our depreciation study, we can then begin to discuss the justifications for, and impacts of, accelerated depreciation. For example, certain investments in our system are relatively short-lived, especially in the cloud-based IT&S environment. This is part of the changing nature of the utility industry, which is driving more frequent rate cases and higher depreciation expense. On the other hand, service and main lines are longer lived assets, have large plant balances, and any policy driven change to these lives

would cause customers' bills to rise.

However, NWN clarified in testimony that is it not proposing accelerated depreciation in this case:

> Given the near-term rate pressure associated with NW Natural's proposal to increase its depreciation expense to reflect the useful life of its assets, we do not believe that further increases to depreciation expense are appropriate to mitigate the potential future risks of certain decarbonization pathways that the Company may pursue.[5]

Q. What is Staff's understanding of accelerated depreciation on gas pipeline assets for decarbonization in this filing?

A. The accelerated depreciation may provide financial benefits for gas pipeline companies; however, it is not a direct way to reduce CO_2 emissions associated with natural gas transportation and consumption. This is because NWN primarily transports and stores natural gas, so using an accelerated depreciation alone would not directly reduce CO_2 emissions from natural gas combustion. Instead, NWN might focus more on operational strategies and investments to improve efficiency, reduce methane emissions, and mitigate environmental impacts, such as optimizing pipeline operations, investing in leak detection and repair programs, implementing best practices for pipeline maintenance and integrity management, and upgrading infrastructure to minimize fugitive emissions.

Q. What is Staff's recommendation for this depreciation issue?

[5] NW Natural/Palfreyman-Kravitz/22.

A. Currently, the UM 2312 depreciation filing is under review. The depreciation rates in NWN's filing have about 200 FERC accounts, sub-accounts, and locations. Evaluating the depreciation parameters of the Survival Curve-Projection Life and Net Salvage Rate are useful measures of a company's depreciation policy. Therefore, in the depreciation study review, I would maintain my analytical integrity based on scientific evidence to identify the industrial assets survival rate and net salvage rate and determine and propose fair and reasonable rates.

ISSUE 2. AMORTIZATION EXPENSE

Q. What is amortization?

A. Amortization is the practice of spreading an intangible asset's cost over that asset's useful life. In contrast, depreciation is the expensing a fixed asset as it is used to reflect its anticipated deterioration. Accounting rules stipulate that physical, tangible assets (with exceptions for non-depreciable assets) are to be depreciated, while intangible assets are amortized.[6]

Q. Have you made an adjustment to Amortization?

A. Not yet. The UM 2312 depreciation study is currently under review. For the same reason, without a Commission-authorized rate, Staff cannot propose an adjustment.

6 Source: Investopedia, Amortization vs. Depreciation.

ISSUE 3. DEPRECIATION RESERVE

Q. What is depreciation reserve?

A. Depreciation Reserve is also called Accumulated Depreciation Reserve. It is the sum of all recorded depreciation on an asset to a specific date.

Q. What is the Commission's historical treatment of depreciation reserve?

A. Accumulated depreciation reserve refers to the life-to-date depreciation that has been recognized that reduces the book value of an asset. The Commission treats this issue by following Generally Accepted Accounting Principles (GAAP) that is as reserve increases, the Rate Base decreases. Please note, rate base is the value of property on which the utility is allowed to earn a specified rate of return, in accordance with rules set by the Commission. In this issue, rate base is the value of property of a utility minus accumulated depreciation of those assets.

Q. Have you adjusted Depreciation Reserve?

A. Not yet. The depreciation reserves are affected by depreciation expenses, asset retirements, sales, transfers, gross salvage, cost of removal, and other adjustments. If depreciation expense is changed, the accumulated depreciation should be changed accordingly. Currently, the depreciation study UM 2312 is under review. If depreciation expense changes, calculated by new depreciation rates after the Commission's authorization, the accumulated depreciation would be changed accordingly.

ISSUE 4. AMORTIZATION RESERVE

Q. Describe Amortization Reserve.

A. Amortization Reserve is accumulated amortization at a point in time, which includes the total amount of recorded amortization, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

Q. What is the Commission's historical treatment of this issue?

A. Amortization Reserve is also called Accumulated Amortization Reserve. In a revenue requirement, as an amortization reserve increases, the Rate Base decreases. Rate Base is the value of property/assets of a utility minus accumulated amortization of those assets.

Q. Have you made any adjustments to Amortization Reserve?

A. Not at this time. The amortization reserves are affected by amortization expenses. If amortization expense is changed, the accumulated amortization should be changed accordingly. I did not make an adjustment to amortization expense. If any adjustments are made by other Staff witnesses, the Company's final amortization reserve would be changed accordingly.

ISSUE 5. AFUDC

Q. What is AFUDC?

A. Electric (Gas) Plant Instruction No. 3(17) provides a formula for computing rates used to capitalize Allowances for Funds Used During Construction (AFUDC).[7] The formula includes a component for the weighted average cost of long-term debt. The entire issue of the use-restricted long-term debt should be included with other long-term debt used in calculating AFUDC rates. Average balances of the trust or other special funds should be included in the computation of the average balance of Construction Work in Progress (CWIP) used in the formula.

AFUDC assigned to the project should be determined by applying AFUDC rates to the eligible project expenditures and also balances in the trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

Q. What is the purpose of the AFUDC review?

A. The purpose of this review is to address whether the Company complied with guidance[8] related to AFUDC and the capitalization of assets based on the regulations of both the Federal Energy Regulatory Commission (FERC) and the Oregon Public Utility Commission (OPUC) in this filing.

Q. Please provide more details regarding AFUDC.

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[7] https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction.

[8] FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

A. AFUDC is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC is the cost of both the debt and equity funds used to finance utility plant additions during the construction period for such additions, determined in accordance with Generally Accepted Accounting Principles (GAAP).

FERC has prescribed two formulas for calculating maximum allowable AFUDC rates:[9]

1. DEBT: This formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.
2. COMMON EQUITY: This formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

FERC has indicated that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the regulatory asset would be the difference between the State AFUDC rate and the FERC AFUDC rate.

The FERC formula and elements for the computation of the allowance for funds used during construction are:[10]

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9 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

10 FERC 18 C.F.R. Part 101 (17) Allowance for funds used during construction (a), (b): https://www.law.cornell.edu/cfr/text/18/part-101

$Ai=s*(S/W)+d*(D/D+P+C)*(1-S/W)$ = Gross allowance for borrowed funds used during construction rate

$Ae=[1-S/W]*[p*(P/D+P+C)+c*(C/D+P+C)]$ = Allowance for other funds used during construction rate

- S=Average short-term debt
- s=Short-term debt interest rate
- D=Long-term debt
- d=Long-term debt interest rate
- P=Preferred stock
- p=Preferred stock cost rate
- C=Common equity
- c=Common equity cost rate
- W= Average balance in construction work in progress, less asset retirement costs related to plant under construction

Q. What is the Regulatory Treatment for AFUDC in Oregon?

A. OPUC allows utilities to include the capitalized AFUDC as part of the rate base. This allows the utility to recover the cost of financing during construction through rates charged to customers. The AFUDC rate is an important component of a utility's rate base, allowing the utility to recover the cost of financing construction expenditures incurred during the development of long-term projects.

Q. Is the AFUDC rate included in the rate base?

A. Yes. AFUDC Rate (%) represents the cost of capital for the utility, including both debt and equity. Including AFUDC in the rate base helps ensure that the utility is able to earn a fair return on its investments while providing customers with reliable service at reasonable rates. Also, please note, the AFUDC rate is related to interest costs; it is not a fixed interest rate but rather a rate used to capitalize interest expenses during the construction period of long-term assets.

Q. Did you make any adjustments after your review?

A. Yes. The AFUDC rate cannot exceed the overall rate of return applied to rate base, to ensure Oregon-jurisdictional rates are just and reasonable. I proposed an adjustment to NWN's 2023 AFUDC rate for the following reasons:

NWN calculated total AFUDC rate in 2023 was 7.47 percent, which exceeded OPUC-authorized Weighted Average Cost of Capital (WACC) rate of 6.84 percent.

UG 490	Calculated AFUDC Rate					rate of return
DR 369	AFUDC	AFUDC	AFUDC	Authorized	Authorized	Authorized
Year	Debt	Equity	Total AFUDC	LT Debt	Common Equity	WACC
	Rate	Rate	Rate	Rate	Rate	Rate
2023	3.05%	4.42%	7.47%	4.48%	9.40%	6.84%

In 2023, NWN's total AFUDC rate is higher than the state-authorized rate of return, the portion of AFUDC that exceeds the authorized rate is 0.63 percent (=7.47 percent - 6.84 percent). When the total AFUDC rate is higher than the state-authorized rate of return, the portion of AFUDC that exceeds the authorized rate is typically recorded as a regulatory liability on the utility's balance sheet. Therefore, I recommend:

1. NWN's AFUDC capitalized should be split between Utility Plant and a Regulatory Asset.
2. NWN should record the exceeded portion as a "Excess AFUDC Regulatory Liability" on the utility's balance sheet. This regulatory liability

represents the amount that the utility is not currently authorized to recover from ratepayers but may be eligible for recovery in the future.

3. Check errors in the capital structure calculation. NWN might need to identify if any data or calculation procedure errors occurred. For example, a short-term and long-term debts in capital structure, because Oregon's capital structure does not include a short-term debt. NWN should also check CWIP eligibility to find the impact on capitalized AFUDC, because the material deviations in excess of 25 basis points could result in significant AFUDC errors.

Ultimately, to be recoverable in rates, amounts in NW Natural's Excess AFUDC Regulatory Liability account would be subject to regulatory review, adjustment, and approval in a rate proceeding.

Q. Did you make any additional adjustments to the AFUDC issue?

A. No. NWN complied with the OPUC policy to exclude CWIP in the rate base, because Oregon does not allow a utility to recover costs of a plant not yet placed in service in retail rates. The Company's AFUDC calculations meet FERC calculation procedures and meet Oregon regulatory requirements.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Accounting and Finance Section of the Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 25 years. My roles have included:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses, including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:
I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 15 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG; Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on January 11, 1999. Historically, my reviews included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, "Market Competition and Economic Policy Survey

Analysis" for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators: I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My mentoring topics focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in the U.S.; "Price-Cap Performance Based Regulation" in UK; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UG 490
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibits in Support
Of Opening Testimony

April 18, 2024

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 372

In Attachment A, tab name "490 AFUDC Calc", please fill out the columns M, N, O, keep the calculation formulas in Excel, and explain in detail whether the Company's calculations of its AFUDC rates comply with the FERC AFUDC rate formulas and accounting requirements.

The explanation should include the following details:

a. Under FERC AFUDC Accounting, the formulas assume that short-term debt is the first source of construction funding. If the balance of "short-term debt exceeds the average balance of CWIP," the total AFUDC rate is comprised of only an allowance for borrowed funds used during construction equal to the short-term debt rate. Were these the assumptions you based the calculations on?

b. If the average balance of "CWIP exceeds the balance of short-term debt", the calculation assumes that the construction funding was not met by short term debt. How did the Company incorporate the different capital sources and cost rates to arrive at the total debt and other funds maximum allowable AFUDC rates? Please explain.

Response:

Please see the Company's response to UG 490 OPUC DR 369.

a. Yes. If the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC consists only of short-term debt.

b. If the average balance of CWIP exceeds the balance of short-term debt, the Company's calculation assumes that the construction funding was not met by short term debt, and the Company then uses the weighted average cost of capital (WACC) to incorporate the Company's other capital sources to arrive at the total debt and equity rates to use for AFUDC.

CASE: UG 490
WITNESS: Nicola Peterson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony
Medical Benefits and Pensions

April 8, 2024

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

A. My name is Nicola Peterson. I am a Senior Telecoms Analyst employed in the Rates Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement, which details my educational background and work experience can be found in Exhibit Staff/1501.

Q. Did you prepare any exhibits?

A. Yes. Exhibit Staff/1501 is my Witness Qualification Statement.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss NW Natural's Test Year Employee Medical Benefit and Pension costs. My testimony is limited to current employee expenses and does not cover post-retirement amounts.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MEDICAL AND HEALTH INSURANCE

Q. Please describe the Company's request regarding medical and health insurance.

A. NW Natural included $19.6 million in medical and dental benefits for the Test Year.[1] The expense includes costs for both bargaining (union) and non-bargaining (non-union) (NBU) employees and is roughly split between the two groups.

NW Natural described the medical benefits provided to its employees and the steps it had taken to mitigate costs. NW Natural also included in its testimony the results of an independent survey that rated the health benefits offered by the NWN in comparison to 34 other Utilities in the PNW. NW Naturals offerings were rated as equal to and substantially at market.[2]

Q. Please discuss Staff's analysis of this issue.

A. Staff analyzed the information provided in NW Natural's testimony and the four-year trend in Figure 1 below. Staff also looked at these costs on a per FTE basis in relation to applicable FTE increases and industry inflation expectations. Staff issued data requests asking for reconciliations for clarification of amounts and explanations of specific increases in costs.

Figure 1 shows the benefits, both medical and pension in the NWN application that Staff has analyzed to date. Staff added the percent increase from Base year to Test Year.

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1 NWN Response to SDR 63.
2 NW Natural/Rogers/14-15.

FIGURE 1: OR ALLOCATED TOTALS FOR MEDICAL BENEFIT COSTS

Utility Oregon	Test Year 2025	Base Year 2023	% BY to TY	Base Year -1 2022	Base year -2 2021
Medical/Dental	$ 19,562,722	$ 16,321,054	20%	$ 15,799,591	$ 16,217,793
401(k)	$ 5,720,041	$ 5,328,286	7%	$ 4,886,964	$ 4,599,304
Group Life Insurance	$ 158,989	$ 139,926	14%	$ 139,070	$ 135,752
Retiree Life Insurance	$ 126,274	$ 121,173	4%	$ 117,634	$ 119,490
LT Disability	$ 721,102	$ 599,584	20%	$ 585,819	$ 564,836
Other	$ 168,421	$ 165,127	2%	$ 147,348	$ 145,753
Total	**$ 26,457,550**	**$ 22,675,150**	**17%**	**$ 21,676,426**	**$ 21,782,928**

According to NW Natural, medical costs increased by 7.1 percent in 2023 and are expected to rise further in 2024 by 9.5 percent.[3]

Figure 2 shows NW Natural' s forecasted employee benefit costs on an FTE basis.

FIGURE 2: TOTAL BENEFITS PER FTE EXPENSES

	Test Year Per FTE 1247	Base year Per FTE 1210	Per FTE % change
Medical/Dental	$18,462	$15,896	16%
401(k)	$5,398	$5,190	4%
Group Life Insurance	$150	$136	10%
Retiree Life Insurance	$119	$118	1%
LT Disability	$681	$584	17%
Other	$159	$161	-1%
Total	**$24,968**	**$22,085**	**13%**

Medical benefit costs per FTE are increasing over the Base Year by 16 percent, however on an FTE basis, total benefit costs are increasing by only 13 percent. From the above table we can see that it is primarily due to the small increase in 401k benefits that is causing this difference.

3 NW Natural/1000, Rogers/15.

Staff compared these increases to other industry projections. PwC Health Research Institute[4] forecasts health care costs to increase by 7 percent in 2024 compared to a 6 percent rise in 2023. The Peterson Center on Healthcare and Kaiser Family Foundation[5] predict health care costs to rise by 5 percent in 2024.

Q. Does Staff agree with the Company's proposal?

A. Staff recognizes that the Company's forecasted costs are higher than what is indicated by the percentage increases forecasted by the Peterson Center, PwC Health Research, and Kaiser Family Foundation noted above. However, assuming the percentage increase for NWN's benefits is as reported in the tables above, Staff does not believe an adjustment to NW Natural's forecast of costs is warranted. However, Staff does have an adjustment to align the Test Year amount for medical benefits with the adjusted number of FTEs that Staff witness Steph Yamada is proposing in Staff/2000. This adjustment is equal to a reduction of 20.96 FTE. Also, as explained below, Staff is waiting for additional information regarding NW Natural's costs for employee benefits before reaching its final conclusion regarding the reasonableness of NW Natural's Test Year forecast for employee benefits.

Q. Please explain why you are waiting for additional information.

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4 https://www.pwc.com/us/en/industries/health-industries/library/behind-the-numbers.html.

5 Health Cost and Affordability Policy Issues and Trends to Watch in 2024 - Peterson-KFF Health System Tracker.

A. Staff based its analysis and proposed adjustment amounts included in the Company’s response to SDR 63, which asks for medical benefit costs for the Test Year, Base Year, and the three years prior to the Base Year. However, according to the Company’s reply to DR 478, the amounts in SDR 63 represent the O&M allocated payroll overheads only. Therefore, at this time, Staff also is only proposing an adjustment to O&M expense based on the Staff-proposed adjustment to FTEs. Further clarification is required prior to recommending an adjustment to capitalized benefits or before Staff can draw conclusions regarding the overall level of costs.

ISSUE 2. CURRENT PENSION COSTS

Q. Please describe the Company's request regarding current pension costs.

A. NW Natural included $10.8 million in retirement benefits for the Test Year. [6] The expense includes costs for both RKSP – Matching Contribution which is open to all employees, and RKSP – Enhanced Contribution, which is open to NBU employees hired after December 31, 2006, and BU employees hired after December 31, 2009. NWN Natural's defined benefits plan, "NW Natural Retirement Plan," is closed to new employees hired after the dates listed above.

RKSP – Matching is a savings plan with employer match based on the percentage saved by the employee, and NW Natural included in their Initial application details of a change in proposed Employer contribution rate. RKSP – Enhanced, includes a fixed Employer contribution rate and requires no employee contribution and therefore should increase in line with salaries and wages.

Q. Please discuss Staff's analysis of this issue.

A. Staff analyzed the information provided in the application and compared it to the information provided in the previous rate case UG 435.[7] See Figure 4 below.

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6 NW Natural/1000, Rogers/20.

7 *NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, UG 435 (filed December 17, 2021).

FIGURE 4: UTILITY RETIREMENT BENEFITS

	Test Year	UG435 Test Yr	% Change
RKSP-Matching Contribution	$ 5,720,000	$ 5,136,300	11.36%
RKSP-Enhanced Contribution	$ 4,588,300	$ 3,851,200	19.14%
WSP-Withdrawal Liability	$ 497,100	$ 506,100	-1.77%
Total	$ 10,805,400	$ 9,493,600	13.81%

Staff found an overall increase of 14 percent over the retirement benefits included in NWN's previous rate case.

Q. Does Staff agree with the Company's proposal?

A. Staff is currently unable to ascertain whether the Company's proposed cost for pensions per FTE is reasonable because Staff is still investigating the capitalized pension costs.

Q. Does Staff have a proposed adjustment at this time?

A. Staff is proposing a combined adjustment of ($523,336), which is based on the fact that both medical and pension Costs are FTE dependent. Staff has calculated a per FTE expense and reduction. This adjustment is based on the amounts included in SDR 63 and an FTE adjustment of (20.96). This adjustment is part of the payroll overhead.

FIGURE 5: ADJUSTMENT CALCULATION

	OR Allocated
Total Medical & Pension Benefit per FTE expense	$24,968
FTE Adj	(20.96)
Total Adjustment	**($523,336)**

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows:

- Forecasted medical and health Insurance. Staff agrees with the Company's cost per FTE and is currently only recommending adjusting these expenses in line with the adjustments Staff is proposing with regard to number of FTE. This is currently an adjustment to O&M only and additional adjustments to Capital maybe forthcoming. That adjustment is included in the figure below.
- Forecasted pension costs. Staff is awaiting responses to data requests and clarity regarding the Company's capitalized pension costs before reaching a decision as to whether the Company's total proposed pension costs is reasonable. Therefore, Staff is currently only recommending adjusting the Company's proposed O&M expense for pensions in line with the adjustments Staff is proposing with regard to number of FTE.

Staff is recommending a combined adjustment to Test year expense of ($523,336).

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: NICOLA PETERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Nicola Peterson

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Telecommunications Analyst
Rates and Telecommunications Section
Rates, Safety and Utility Performance Program

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: BA (Hons) Accounting & Finance
Middlesex University
Associate Chartered Accountant – Institute of Chartered Accountants of England & Wales

EXPERIENCE: I have been employed with the Public Utility Commission of Oregon since 2014. I am a Senior Telecommunications analyst in the Rates and Telecommunications Section of the Safety and Utility Performance Program. My assignments have mainly involved the administration and organization of the Oregon Universal Service Fund (OUSF). I have been the case manager on several OUSF dockets, managing workshops and stakeholder conferences, as well as chairing the OUSF Advisory Board. My other assignments include analysis of tariff filings, rulemakings, eligible telecommunication carrier certification with the FCC and annual reporting and budgeting.

Prior to the OPUC, I began my career in public practice as a Chartered Accountant and Audit Senior and then moved into the telecommunications industry. I have worked for numerous telecommunication companies (NYNEX, British Telecom, Esat Ireland, Digicel Jamaica) in various finance roles, from Financial Analyst to Financial Controller/ Finance Director.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Opening Testimony
Capital Structure

April 18, 2024

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

A. My name is Rose Pileggi. I am a Senior Energy Analyst employed in the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's testimony on Capital Structure.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/1602, responses to Staff Data Requests.

ISSUE 1. CAPITAL STRUCTURE

Q. When did the Commission last consider this issue?

A. The Commission entered Order No. 22-388 in Docket No. UG 435 adopting a partial stipulation in which the parties agreed to a capital structure of 50 percent equity and 50 percent long-term debt.[1] This is the same capital structure proposed by NW Natural (NWN or Company) in its initial filing in Docket No. UG 435.

Q. What capital structure did the Company propose in its opening testimony?

A. NW Natural has proposed a capital structure in its current General Rate Case (GRC) of 50 percent equity and 50 percent long-term debt.[2]

Q. Does the Company always maintain a precise 50/50 capital structure?

A. No. NW Natural's capital structure fluctuates over time. The fluctuations are expected as issuances, redemptions, and maturations on financial instruments are not in perfect sync nor is it always beneficial for the company to maintain a perfectly uniform capital structure. NW Natural provided the previous 5 years of data on capital structure in response to Staff Data Request No. 286.[3]

Q. Did NW Natural maintain a capital structure near its 50/50 capital structure over the past 5 years?

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[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* UG 435, Order No. 22-388 (October 24, 2022).
[2] NW Natural/300, Wilson/1, line 16.
[3] See Staff/1602, Pileggi/1.

A. Yes. The Company experienced swings in capital structure in which the equity percentage ranged from a low of 47.9 percent to a high of 51.4 percent. The average equity percentage over this period was 49.0 percent.

Q. How has the Commission treated capital structure for NW Natural's peers in recent years?

A. In UG 461, the Commission approved a stipulation for a 50 percent equity and 50 percent long-term debt capital structure for Avista. In UG 390, the Commission approved a stipulation for a 50 percent equity and 50 percent long-term debt capital structure for Cascade Natural Gas.

Q. What does Staff recommend for the capital structure of NW Natural?

A. Staff recommends a notional capital structure of 50 percent equity and 50 percent long-term debt. The notional capital structure acknowledges that the Company knows what timing of debt and equity issuances works best for the Company and centers around the typical 50/50 split that NW Natural and its peers already utilize. While rates charged to customers are based on a 50/50 capital structure, the Company may operate on the financing authorizations granted by the Oregon PUC and capital structures it chooses consistent with those authorizations. This is no different than any other cost or expense item projected in the test year. Those decisions by the Commission do not constrain the Company to incur those exact expense level decisions by the Commission.

Q. Could Staff's position change on this issue?

A. Staff will closely monitor the Company's and intervenors' testimony and analysis, which will be considered in Staff analysis and rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Rose T. Pileggi

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Costs Section

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: In 2013, I received a Bachelor of Science in Business Administration from Thomas Edison State University. In 2017, I received a Master of Science in Finance from the University of Portland.

EXPERIENCE: I have been employed by the Commission since July of 2022 analyzing finance, power cost, rate case and affiliated interest dockets.

From July 2021 through June 2022, I worked as an Analyst for the Oregon Judicial Department. Duties included data analysis, ensuring compliance with pertinent statutes and rules to ensure that data was being handled in accordance with requirements and recommending process improvements.

From 2017 to 2021, I worked as an Investment Analyst, Portfolio Manager, and Systems Manager for Northwest Capital Management. My work included analysis of the markets and investments, the management and rebalancing of portfolios, creating reports as required by the SEC, as well as managing software integrations for operational and reporting purposes.

CASE: UG 490
WITNESS: ROSE PILEGGI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support
Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 286

Please provide the Company's actual capital structure over the last 5 historical years and through the Company's test year. For the calculation of capital structure, please average all 12 monthly capital structures for the calendar year. The response should fill the provided tables.

Response:

Please see the filled in tables. NOTE: The Year Average figures provided above are the result of a 13-month AMA calculation, consistent with the methodology used in the Earnings Test and in UG 490. The calculation includes December of the previous year; and both the previous December and current December are given ½ weight.

Year	Year-End		Year Average	
	Equity %	Long-Term Debt %	Equity %	Long-Term Debt %
2019	49.18%	50.82%	49.07%	50.93%
2020	47.46%	52.54%	48.00%	52.00%
2021	49.58%	50.42%	48.62%	51.38%
2022	50.61%	49.39%	51.43%	48.57%
2023	47.48%	52.52%	47.87%	52.13%
[redacted]				

*Forecasted value

Equity in Dollars

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019	741,401,550	747,701,219	747,442,410	753,082,952	737,424,483	830,176,987	823,886,959	804,638,974	798,975,925	801,855,436	803,841,451	822,396,768
2020	844,992,113	849,218,800	857,858,011	861,339,855	845,245,992	839,437,550	830,907,305	810,200,544	805,543,627	805,585,192	809,612,267	835,214,333
2021	860,915,951	870,861,026	881,606,789	887,765,096	873,445,101	868,449,970	861,071,058	841,747,599	835,817,950	848,312,512	942,003,840	978,170,501
2022	978,807,635	979,020,556	978,731,720	1,118,572,108	1,118,740,189	1,143,839,440	1,147,255,337	1,158,012,151	1,157,882,907	1,158,037,966	1,158,464,201	1,162,670,812
2023	1,224,556,337	1,235,045,607	1,250,553,362	1,235,511,724	1,217,204,595	1,210,601,010	1,201,962,749	1,176,032,058	1,202,386,561	1,205,224,034	1,206,091,745	1,233,641,559

Long-Term Debt in Dollars

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019	739,700,000	739,700,000	739,700,000	739,700,000	739,700,000	879,700,000	879,700,000	879,700,000	869,700,000	869,700,000	869,700,000	849,700,000
2020	849,700,000	774,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000

2021	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	924,700,000	914,700,000	864,700,000	864,700,000	994,700,000	994,700,000
2022	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	994,700,000	1,134,700,000	1,134,700,000	1,134,700,000	1,134,700,000
2023	1,225,727,836	1,225,715,409	1,324,422,457	1,324,468,682	1,324,508,417	1,324,559,042	1,324,608,342	1,404,475,530	1,404,552,884	1,404,619,144	1,364,673,440	1,364,731,949

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

Opening Testimony
Political Activities, Advertising,
Memberships, Dues, and Donations
Meals and Entertainment, Awards, Gifts, Airfare,
Lodging, and Travel

April 18, 2024

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

A. My name is Paul Rossow. I am a Utility Analyst employed in the Accounting and Finance Section of the Rates, Safety and Utility Performance Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1701.

Q. What is the purpose of your testimony?

A. I discuss my review of several topics of NW Natural's (NWN or Company) Test Year Operations and Maintenance (O&M) non-payroll expenses, including expenses for political activities, advertising expenses, memberships, dues and donations, meals and entertainment, awards, gifts, airfare, lodging, and travel.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following support exhibits:

Exhibit Staff/1701. Witness Qualification Statement
Exhibit Staff/1702. Responses to Data Requests (Non-Confidential)
Exhibit Staff/1703. Membership Work Paper (Non-Confidential)
Exhibit Staff/1704. Meals and Entertainment Work Paper (Non-Confidential)

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony addresses issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. POLITICAL ACTIVITIES

Q. Please explain the Commission's historical treatment of political activities.

A. The Commission has not allowed regulated utilities to recover political activity or lobbying expenses through rates charged for regulated services. Political activity along with lobbying are discretionary and are not required to provide safe and adequate service to customers.[1]

Political activities and lobbying expenses can occur by:

- Directly communicating with officials,
- Providing transportation for elected officials,
- Attending government conferences and expressing special interest views,
- Drafting special interest legislation and presenting it to a legislator for consideration,
- Providing support for elected officials on trade missions, by providing in kind services to special interest groups,
- Hosting receptions for congressional delegations, and
- Attempting to influence legislators and other public officials to introduce or support measures that favor some special interest.

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[1] *In re Pacific Northwest Bell Telephone Company,* UT 43, Order No. 87-406 (March 31, 1987) (1987 WL 257178), p. 43: "The Commissioner views lobbying and similar political activities as essentially the same issue presented by community activities. Ratepayers should not be required to contribute to the advancement of political positions in which they may not believe. *See Pacific Power & Light Company* [*PacifiCorp*], UF 3074, Order 74-658 at 13."

Q. Does NW Natural seek recovery of expense for political activities or lobbying in this rate case?

A. The Company testifies it is not seeking recovery for these expenses in the 2025 Test Year.[2]

Q. Please describe your analysis for the political activities and lobbying expenses.

A. Staff reviewed NWN's Direct Testimony, issued Data Request Nos. 341 – 351, and analyzed NW Natural's transactional data in its response to Standard Data Request No. 57. Staff noted 104 lobbying transactions recorded to cost element titled "Meals and Entertainment" that Staff recommends expenses excluding 100 percent, which revealed $12,535 recorded to the total Company's Base Year under FERC Account 921. This equates to an Oregon Base Year allocated amount of $11,047.

Next, Staff applied All-Urban CPI inflation factors of 2.7 percent and 2.0 percent in 2024 and 2025, respectively, resulting in an Oregon escalated Test Year adjustment to Lobby expenses of ($11,572).

Q. What are Staff's findings regarding political activities and lobby expenses?

A. Staff finds that an adjustment of ($11,572) is needed for the Test Year.

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[2] NW Natural/1200, Williams/2-7.

ISSUE 2. ADVERTISING

Q. Does the Commission have a standard means of determining how advertising expenses are treated?

A. Yes. OAR 860-026-0022 specifies how advertising expenses are treated in a utility rate case. The rule describes five categories (A-E), each with a different standard for inclusion in rates.

Category “A” includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[3] Category A advertising expenses no greater than twelve and one-half hundredths of one percent (0.125 percent) of the gross retail operating revenues determined in that proceeding are presumed just and reasonable for rate making purposes, though the presumption is rebuttable.[4] The utility bears the burden to prove that any Category A expense that exceeds the threshold is just and reasonable for ratemaking purposes.

Category “B” includes legally mandated advertising expenses, which are assumed to be reasonable for rate making purposes.[5]

Category "C” includes institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category “A”, “B”, or “D”.[6] Utilities must demonstrate these expenses are just

3 OAR 860-026-0022(2)(a).
4 OAR 860-026-0022(3)(a).
5 OAR 860-026-0022(2)(b).
6 OAR 860-026-0022(2)(c).

and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category.

Category “D” includes political advertising expenses and non-utility advertising expenses, which are presumed to be not just and reasonable for ratemaking purposes.[7]

Lastly, Category “E” includes energy efficiency or conservation advertising expenses that relate to a Commission approved program. Utilities must show these expenses are reasonable and recoverable in rates. With Commission approval, advertising expenses in Category “E” may be capitalized.[8]

Q. Please describe the Company’s Oregon Test Year expense for advertising.

A. The Company proposes to include $1,378,465 in Category A and $975,000 in its Category B advertising in the 2025 Test Year as illustrated in Figure 1. The Company reports it has not included any expense for Categories C, D, or E advertising in the 2025 Test Year.

FIGURE 1. TOTAL ADVERTISING IN THE TEST YEAR

Category	Included in Rates?	2025 Expenses $
A	Yes	$1,378,465
B	Yes	$975,163
C	No	$0
D	No	$0
E	No	$0
Total		$2,353,628

[7] OAR 860-026-0022(2)(d).
[8] OAR 860-026-0022(2)(e).

Q. Please describe your analysis of NW Natural's proposed advertising expenses for Category A.

A. Staff analyzed NW Natural's advertising data in its response to Standard Data Request Nos. 57, 104, 335 -340, and 454, which inquired about NW Natural's advertising expenditures. Staff confirmed that advertisements were related to energy efficiency, safety, and conservation.

Q. How does the Company's Oregon Test Year advertising expenses compare to historical spending?

A. NW Natural's Oregon Test Year request of $1,378,465 for Category A expenses is a 20 percent increase from what was allowed in UG 435 Test Year expense for Category A of $1,148,090.[9]

The Company's Oregon Test Year request of $975,163 for Category B expense is an 18 percent increase from what was allowed in UG 435 Test Year expense for Category B of $827,027.[10]

Q. Please describe how the Category A Test Year expenses are calculated for Oregon ratepayers.

A. Staff's review found that NW Natural is proposing Category A advertising expense of $1.95 per customer, which is $0.03 higher than the amount that is presumed reasonable under OAR 860-026-0022(3)(a).

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[9] Staff/1702, NWN Response to DR 338.
[10] Ibid.

FIGURE 2. 2025 TEST YEAR CATEGORY A ADVERTISING CALCULATION

Category A Expense:

NW Natural Oregon Proposed Operating Revenue:	$1,083,624,393
*Factor per OAR:	0.125%
Calculation = $1,083,624,393 x .00125 =	$1,354,530

Test Year Number of Customers:	707,022
Per Customer Calculation = $1,354,530/707,022 =	$1.92

Proposed Category A Expense:

NW Natural Oregon Proposed Operating Revenue:	$1,083,624,393
*Factor per OAR:	0.125%
Proposed Test Year Budget:	$1,378,465

Test Year Number of Customers:	707,022
Per Customer Caluclation = $1,378,465/707,022 =	$1.95

Difference between Company and Staff:	$23,935

*OAR 860-026-0022 Rule = 1/8 of 1% of sales is presumed reasonable

Q. What is your recommendation regarding Category A Advertising expense?

A. Staff proposes to limit the Company's recovery of Category A expense to the amount that is presumed reasonable under OAR 860-026-0022(3)(a), which is $1,354,530 or $1.92 per customer for the Oregon Test Year.

Q. Why do you propose to disallow expense that exceeds the threshold for the rebuttable presumption?

A. As discussed elsewhere in Staff testimony, utility customers are facing significant pressure from escalating costs, including utility costs. NW Natural has not shown that it is appropriate for customers to bear costs for advertising above the administratively set threshold for presumed reasonableness. Staff expects the utility to be diligent in cost cutting and minimizing given that it has had rate three general rate increases in the last six years.

Q. Please describe your analysis of the Company's proposed advertising expenses for Category B.

A. Category "B" includes legally mandated advertising expenses, which are presumed to be just and reasonable for rate-making purposes, though the presumption is rebuttable.

Q. Please explain your proposed Category B advertising expense.

A. Staff analyzed NW Natural's Category B advertising expense data in its responses as referenced above for Category A advertising expense. Staff confirmed that advertisements were related to safety-related communications. NW Natural plans to expand their website to offer multi-language content and deploy broader multi-language media for the Test Year.

Staff recognizes that the Company's proposed Category B expense is presumed reasonable but believes that the presumption is overcome in this case. For the reasons discussed above, there is no justification for rate recovery of a 22 percent increase in expense from 2023 actuals or an 18 percent increase from the expense allowed in the last GRC.

Given the presumption of reasonableness is rebutted due to the steep increase proposed by NW Natural, Staff recommends determining the Test Year expense for Category B advertising by averaging in the expense for the years before and after the Base Year to smooth out the increase in the Test

Year. This modification results in a Test Year expense of $836,078, Staff recommends an adjustment of ($139,085) to NW Natural's proposed Test Year Category B advertising expense of $975,163.

FIGURE 3. 2025 TEST YEAR CATEGORY B ADVERTISING CALCULATION

Category B Expense	
Year	Oregon Allocated
2022 Actual:	$911,928
2023 Actual:	$802,055
2024 Budget:	$794,250
Average:	$836,078
2025 Test Year:	$975,163
Difference between Company and Staff Proposal:	($139,085)

Q. What is the total adjustment to advertising?

A. Staff proposes adjusting overall advertising expense on an Oregon allocated Test Year by ($163,020).

ISSUE 3. MEMBERSHIPS, DUES, AND DONATIONS

Q. Please explain the Commission's historical treatment of memberships, dues, and donations.

A. The Commission has determined that some expense associated with memberships, dues, and donations to some organizations is not appropriately included in a utility's revenue requirement, primarily because some or all the organizational activities are:[11]

- Not necessary for utility service,
- Primarily to promote the company within the community,
- Not to benefit ratepayers, or
- Not recoverable in rates if done by the utility itself.

Additionally, Commission policy does not require ratepayers to pay for causes that they do not necessarily support. [12]

To limit the amount of ratepayer funding of activities that fall within the categories listed above, Commission practice is to exclude membership expenses related to economic development and civic organizations and to exclude a certain percentage of membership costs for trade organizations. With respect to other organizations, Staff follows Commission precedent by disallowing all memberships or dues unless the utility can present a convincing argument that the membership is necessary for utility service or otherwise to benefit ratepayers.

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[11] See Order No. 87-406.
[12] See OPUC Order No. 87-406 at 40-41, Order No. 91-186 at 16, and Order No. 09-020 at 20-21.

Q. Did NW Natural propose an adjustment to its Test Year to remove memberships, dues, and donations?

A. No.

Q. Please explain your analysis for the memberships, dues, and donations adjustment.

A. Staff analysis included the review of NWN's memberships and dues expenses listed in Standard Data Request 90.

Q. What was the result of Staff's analysis for memberships, dues, and donations?

A. Staff's adjustment utilizes a list of memberships from NW Natural's response to Data Request No. 90. Staff identified $57,120 expense for memberships related to economic development and civic organizations in NWN's Oregon allocated Base Year. Next, Staff applied All-Urban CPI inflation factors of 2.7 percent and 2.0 percent in 2024 and 2025, respectively, resulting in an Oregon escalated Test Year adjustment to memberships of ($59,835).

Staff also identified $1,611,788 expense for memberships related to national and regional industry trade organizations in NWN's Base Year. Staff removed 25 percent of the expense to the Base Year in the amount of $402,947. Staff applied All-Urban CPI inflation factors mentioned above, resulting in an Oregon escalated Test Year adjustment to memberships of ($422,103).

Q. What is Staff's total adjustment to memberships, dues, and donations?

A. Staff’s analysis results in an escalated Oregon allocated Test Year adjustment to memberships of ($481,938).

ISSUE 4. MEALS AND ENTERTAINMENT, AWARDS, GIFTS, AIRFARE, LODGING, AND TRAVEL

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary expenses.

A. O&M non-labor discretionary expenses include expenses for items such as awards, food, gifts, meals, and entertainment. In Docket No. UE 197, the Commission clarified its policy that expenses for meals and entertainment, office refreshments, catering, gifts, and awards are discretionary and should be shared equally by customers and shareholders.[13] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, Staff recommends disallowance of O&M non-payroll expenses that are imprudent or excessive or do not benefit Oregon regulated utility operations at a transactional level.

Q. Did the Company propose an adjustment to its Test Year to remove meals and entertainment and awards expenses?

A. No.

Q. Please describe your analysis for the meals and entertainment O&M non-payroll expenses.

A. Staff reviewed NW Natural's Direct Testimony, NWN's Standard Data Response No. 57, NWN's response to Data Request Nos. 442 – 455, and NWN response Data Request No. 201 Attachment 3, which includes meals

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[13] *See In the* Matter *of Portland General Electric Company Request for a Rate Revision*, Docket No. UE 197, Order No. 09-020, p. 16 (January 22, 2009).

and entertainment, awards, gifts, refreshments, airfare, lodging and travel type of expenses, to identify any O&M non-payroll discretionary expenses that appear to be excessive or not related to the provision of safe and reliable energy to customers. In the Company's response to Data Request No. 201 Attachment 3, the Company provided O&M non-payroll transactional expenses in Excel format. The accounting data includes category fields, account number, cost element numbers, FERC accounts, transaction descriptions, source descriptions, and currency amount.

From this workbook, Staff searched through the data to aid in Staff's analysis of O&M non-payroll discretionary expenses. Staff filtered the data by transaction description and account number name. Some of the selected expenditure types were meals and entertainment, awards, gifts, refreshments, airfare, lodging, and travel.

Staff reviewed the selected expenditure types mentioned above to determine whether they benefit customers or are discretionary and should be shared between customers and shareholders according to Commission policy. Items Staff found to have no benefit to customers, Staff excludes at 100 percent. Those expenses Staff believed benefitted both customers and shareholders, Staff disallowed at 50 percent. Once Staff determined the disallowance based on 2023 dollars, Staff adopted the All-Urban CPI inflation factors. The inflation factors reflect assumed inflation of 2.7 percent and 2.0 percent in 2024 and 2025, respectively.

Q. Would you please explain your adjustment?

A. Yes. For example, within the selected expenditure types, Staff noted transactions related to expenses described as: meals and entertainment, awards, gifts, refreshments, and retreat at Skamania Lodge that Staff recommends excluding 50 percent.

Q. What was the result of Staff's review for these expense types?

A. After reviewing O&M non-payroll expenses, Staff identified 2023 total Company Base Year expense of $691,631 with an associated Oregon allocated Base Year amount of $597,759. After removing 50 percent of the allocated Base Year results in an amount of $298,880. Next Staff applied the All-Urban inflation factors mentioned above, resulting in an adjustment to the Oregon Test Year allocated amount of ($313,088).

Q. Is there an issue relating to airfare?

A. Yes. In the Company's response to Staff data request No. 447, it was revealed that NW Natural inadvertently included first class airfare totaling a Base Year amount of $36,257. Staff applied All-Urban CPI inflation factors mentioned above, resulting in an Oregon escalated Test Year adjustment to airfare of $37,981. The Company will correct the revenue requirement in their reply testimony to exclude the total of these transactions.

Q. What is Staff's total meals and entertainment adjustment?

A. Staff's total adjustment is an adjustment of ($351,069) to O&M non-labor discretionary expenses.

SUMMARY FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's recommendations are as follows:

- Issue 1 (Political Activities) – a total adjustment of ($11,572) to the Oregon allocated Test Year expense for FERC Account 921;
- Issue 2 (Advertising) – a total adjustment of ($163,020) to the Oregon allocated Test Year for FERC Account 909;
- Issue 3 (Memberships, Dues, and Donations) – a total adjustment of ($481,938) to the Oregon allocated total Test Year expense for FERC Accounts 832-932; and
- Issue 4 (Meals and Entertainment, Awards, Gifts, refreshments, Airfare, Lodging, and Travel) – a total adjustment of ($351,069) to the Oregon allocated total expense for FERC Accounts 816-936. Additionally, the Company will update its revenue requirement in its reply testimony relating to first class airfare for a total Oregon Test Year amount of $37,981.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE Suite 100 Salem OR 97302-1166
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UE 374, UE 394, UE 399, UE 435, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, UG 390, and UG 435. I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Non-Confidential Data Responses in Support Of Opening Testimony

April 18, 2024

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 341

Please discuss the Company's current expenses for political activities/public affairs. Does the Company propose any approaches or budgeting that is new or different from the last two general rate cases.

Response:

NW Natural, like other utilities in Oregon, engages in public affairs matters on behalf of our customers and are included in the revenue requirement for UG 490. This includes working with a local jurisdiction on obtaining permits for utility construction projects, language updating franchise agreements or right of way ordinances, and safety and security efforts within our jurisdictions.

Political expenses are not requested for recovery. This includes incidental expenses, like mileage, associated with any political activities.

In our prior rate case, the allocations for political activities for the Government and Community Affairs team were based on historical allocations used by the Company. In the current case, the Government and Community Affairs team have recorded exception time for political activities in the base year, and the Company is not seeking recovery of those costs in the Test Year. The Company included information about timekeeping and accounting to differentiate time spent on political activities versus general utility activities such as safety and security efforts within our jurisdictions in NW Natural/1200, Williams.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 342

Are these activities included in the revenue requirement for UG 490? If yes, please identify FERC Accounts that contain these expenditures.

Response:

The heading for this Staff data request is: **RE: Political Activities/Public Affairs**

Please see the Company's response to UG 490 OPUC DR 341.The public affairs activities described in UG 490 OPUC DR 341 are included in the revenue requirement for UG 490 and are included in FERC 921, as such activities include "informational engagement and education for local governments for which ratepayer support is appropriate." UG 435, Order No. 22-388 (entered October 24, 2022), page 24.

As it relates to NW Natural/1200, Williams, the described political lobbying activities or activities intended to influence that are tracked through exception reporting are not included in the revenue requirement for UG 490. As described in NW Natural/1200, Williams these activities are charged to FERC 426.4 – Expenditures for certain civic, political, and related activities. FERC 426.4 is not included in the revenue requirement and is considered "below the line".

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1703

Non-Confidential Memberships, Dues, and Donations Work Paper
(Filed In Electronic Format)

April 18, 2024

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1704

Non-Confidential Data Response in Support Of Opening Testimony

April 18, 2024

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 447

If NW Natural is seeking rate recovery for first class airline tickets in docket UG 490, please provide:

a. the amount of each transaction on a system and Oregon allocated basis,
b. justification for purchasing first class airline tickets,
c. the FERC account number, and
d. Oregon allocation factor.

Response:

The policy of the Company is not to request cost recovery for expenses related to the incremental difference between the cost of first/business class airline tickets and base-fare airline tickets.

Through our review of the airfare transactions in development of this response, it appears that there are certain transactions that were not coded correctly and the incremental cost between base fare and first-class fare was inadvertently included in Base Year. Refer to Confidential UG 490 OPUC DR 447 Attachment 1 for a summary. The Company will correct the revenue requirement in our reply testimony to exclude the total of these transactions in the Base Year of $36,257 on an Oregon-allocated basis.

Please also see the Company's response to UG 490 Coalition DR 446.

CASE: UG 490
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1704

Non-Confidential Meals and Entertainment Work Paper
(Filed In Electronic Format)

April 18, 2024

CASE: UG 490
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Opening Testimony
Marginal Cost, Rate Spread and Rate Design

April 18, 2024

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

A. My name is Eric Shierman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1801.

Q. What is the purpose of your testimony?

A. This testimony reviews NWN's proposals on marginal cost, rate spread, and rate design and offers Staff's recommendations.

Q. Did you prepare any exhibits for this docket?

A. Yes, Exhibit Staff/1801 is my witness qualification statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MARGINAL COST

Q. What is the Long Run Incremental Cost (LRIC) Study and what is its goal?

A. Estimates of the NWN LRIC is developed through a study and identifies the different costs to serve each rate schedule. Utilities do not keep granular accounting records of costs by customer type. As such, the LRIC uses the replacement costs (by assuming all inputs are variable) of the entire system to attribute costs to particular rate schedules. The costs are functionalized by dividing them into several cost categories and then attributed to different customer classes by how the customer class uses the facilities.

For example, distribution mains are large pipes utilized by all customer classes to deliver gas for use. These can be broken down into “system mains” and “main extensions” based on their size and position in the distribution system. Since a major cost driver of these large-diameter mains is meeting peak demand, a customer class’s burden to pay for these system mains should correlate to each customer schedule’s own peak day load. The higher the peak day load for a schedule, the more that schedule is requiring the Company to invest in system mains to meet peak demand.

Once each cost category is broken down and each customer class’s cost causation has been identified, ratios are used to allocate the revenue requirement for each designated functional category.[1] Ultimately, the study compares what portion of costs each customer class is currently paying to what

[1] See UG 490 - Exh. 1801 - WP6 - Long-Run Incremental Cost Study (LRIC) Model.

they should be paying based on the above noted allocation method. This can be used as the basis for cost-based rates, the theory being you should pay for the costs you are causing to the system.

Costs that can be easily divided up are calculated by taking the per-customer average and multiplying by the number of customers in that schedule. The remaining costs are allocated by identifying cost types within each cost category and customer class. Many other considerations often can and do go into rate spread and rate design, but usually the LRIC is a large driving force behind the rates a customer pays.

Q. Has the Company's LRIC methodology changed since the last rate case?

A. Yes. The Company made two changes based on Staff's feedback in UG 435.[2] The Company modified the Maximum Daily Demand Value (MDDV) calculation for design day load factor development, which accounts for changing incremental customer counts across time, in response to Staff's feedback that nonresidential customers going in and out of business gave the false appearance of lower use per customer. Second, the Company modified its system core main allocation to calculate weighted peak day deliveries for all rate schedules as a basis for core main cost assignment by allocating interruptible customers a 50 percent credit for system core main allocation, down from 100 percent.[3] In UG 435, Staff noted that these customers do use

[2] NW Natural/1800, Wyman/32-33.
[3] Id.

system capacity, so weighting them with no marginal system core main cost underestimates their marginal cost.[4]

Q. Do you believe that the Company implemented Staff's feedback effectively?

A. Based on Staff's inspection of the Company's LRIC workpapers, it appears to Staff that this feedback was implemented effectively. Staff has no additional feedback regarding the Company's LRIC at this time but looks forward to reading other parties' testimony and perhaps updating its position.

Q. What did the Company's new LRIC show?

A. The LRIC shows nearly half of customers classes, including residential customers, are paying closer to parity than was the case in UG 435. [5] The customers paying below parity are RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out. Table 1 displays the parity ratios at present rates.[6]

Table 1. LRIC Study Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Parity Ratio	0.96	0.95	1.21	0.82	1.66	1.95	1.63	2.34
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	1.61	1.91	2.22	1.65	1.30	1.46	2.64	1.25

[4] NW Natural/1800, Wyman/43-44.
[5] NW Natural/1800, Wyman/57-58.
[6] Table from UG 490 NW Natural/1800, Wyman/57. Rate Schedule 2 (Residential), Schedule 3 (Commercial), 27 (Residential Heating Dry-Out Service), Schedule 31 (Non-Residential Firm Sales and Firm Transportation Service), Schedule 32 (Large Volume Non-Residential Sales and Transportation Service).

A parity ratio of one is equal parity between total LRIC for a class of customers and total revenues for that class given revenue from rates charged to that class of customers. A ratio under one means the customer class is paying less than its LRIC and a ratio greater than one means the customer class is paying more than its LRIC.

Q. Does Staff have adjustments to NWN's assessment of marginal cost?

A. Staff has no adjustments at this time but may after reviewing other parties' testimony.

ISSUE 2. RATE SPREAD

Q. Please describe rate spread.

A. Rate spread is the practice of allocating a company's revenue requirement to its various customer classes. Doing so effectively should balance concerns of economic efficiency, equity and energy justice concerns, and rate shock.

Q. How does one properly balance these potentially conflicting concerns?

A. In general, rate spread allocations begin by conducting a LRIC study to determine the optimal way to allocate costs between the Company's various customer classes. As described in this testimony, the LRIC provides valuable insight into the costs to serve each of the Company's customer subgroups, which can be compared to the revenues generated by each subgroup. While there is often disagreement in methodology that an LRIC employs, one goal of rate spread is to align the revenue earned from each customer class with the costs to serve each customer class according to the LRIC. This is often referred to as "moving towards parity."

If the LRIC does show a need to move towards parity from current rates, it is best practice to make the move towards parity deliberate enough that customers can properly adapt to these new different rates and to signal that they are still operating under a regulatorily stable environment. This is often referred to as avoiding rate shock or inequitable results from a policy perspective—an example of which may be significantly increasing the rates of one customer class so that other customer classes may have a rate decrease.

Finally, the Commission has been statutorily authorized to consider equity and environmental justice concerns as factors in rate spread. A move towards parity may put costs on environmental justice or underserved groups in a way that may not be optimal from a socio-economic perspective. Further, to the extent that current modeling approaches employed with the LRIC look only at costs to the system, disparities in the system benefits received by different customer groups remain unaccounted for.

These various concerns of lack of modeling clarity, rate shock, and awareness of environmental justice concerns make it so every rate spread methodology has tradeoffs and selecting an optimal rate spread methodology must balance all these concerns.

Q. How does the Company's proposal align with parity considering what the LRIC shows with respect to cost causation?

A. NWN's proposal brings each rate class to the parity ratios that are closer to 1 than they would otherwise be with no change to the current rate spread. Table 2 below shows the current parity ratios of the classes discussed above and the parity rations that would result from the Company's proposal.

Table 2: NWN's Proposed Change in Parity Ratios

Schedule	Current Parity Ratio	Proposed Parity Ratio	Change
02R	0.96	0.97	0.01
03C	0.95	0.96	0.01
03I	1.21	1.13	(0.08)
27R	0.82	0.86	0.04
31CSF	1.66	1.54	(0.12)
31CTF	1.95	1.73	(0.22)
31ISF	1.63	1.51	0.12)
31ITF	2.34	2.07	(0.27)
32CSF	1.61	1.50	(0.11)
32ISF	1.91	1.70	(0.21)
32CTF	2.22	1.97	(0.25)
32ITF	1.65	1.47	(0.18)
32CSI	1.3	1.21	(0.09)
32ISI	1.46	1.36	(0.10)
32CTI	2.64	2.34	(0.30)
32ITI	2.64	1.11	(1.53)

Q. Does Staff agree with the use of LRIC as a basis for the Company's rate spread?

A. Staff supports the use of LRIC as a baseline resource for rate spread proposals. As a general matter, pricing and customer cost allocations should reflect long-run-incremental cost-causation as much as possible.

A strict LRIC-based target allocation of marginal costs to the various customer schedules would be the outcome of allocating shares of embedded cost categories to customer schedules strictly in proportion to their respective shares of LRIC costs for the respective categories. However, as the Company testifies, relying entirely on parity may result in very large rate increases for many customers and perhaps inadvertently signal rate volatility.[7] Staff agrees with the Company's position that rate spread must balance the interests of rate equity and rate volatility with the results of an LRIC. However, at times these priorities can be at odds with each other.

Evolutions to the rate spread cost allocation from the LRIC can avoid the burden of imposing an increase to a particular customer schedule that is unacceptably out of line with the overall increase and avoid allowing some schedules to receive a rate decrease in the context of a significant increase being imposed on most of the other customer schedules. This "deviation" appears particularly appropriate in the context of the Company's UG 490 proposal, such that the results of the LRIC results would implement an increase relative to total revenues of 21.0 percent for Schedule 2 Residential, 19.5 percent for Schedule 3 Commercial, and 32.1 percent for Schedule 27 Dry-Out rate classes while the large commercial, industrial, and transportation rate classes would receive overall rate decreases.[8] As a percentage of marginal revenues, the disparity appears even more dramatic. Table 3 presents the percentage change of marginal revenues to bring each rate class to parity according to the Company's LRIC.

[7] NW Natural/1800, Wyman/81.
[8] NWN/1800, Wyman/82.

Table 3: Percent of Margin Increase for Each Customer Class

Rate Schedule	Average	02R	03CSF	03ISF	27R	31CSF	31CTF	31ISF	31ITF
Target Increase (LRIC)	29.30%	34.2%	35.8%	6.5%	57.0%	-22.0%	-33.7%	-20.5%	-44.7%
Rate Schedule	**32CSF**	**32ISF**	**32CTF**	**32ITF**	**32CSI**	**32ISI**	**32CTI**	**32ITI**	**33T**
Target Increase (LRIC)	-19.7%	-32.4%	-41.8%	-21.8%	-0.7%	-11.3%	-51.1%	3.5%	0.0%

While such a spread would result in rate parity across the classes, the impact to customers in terms of price signals, affordability, and reasonableness would be substantial. Further, as highlighted by the Company, the Commission has provided some precedent on how it may regard mismatches between rates derived from the LRIC and proposed rate changes, stating, as noted earlier, that it is not inclined to raise some rates while lowering others without compelling evidence that immediate action is warranted. [9]

Q. How has the Company proposed to balance the concerns of moving towards parity, mitigating rate shock, and ensuring no customer receives a rate decrease while others receive a rate increase?

A. The Company proposes to balance these concerns by first applying a cap to the proposed increases relative to margin according to the LRIC to Schedule 2, Schedule 3, and Schedule 27. The Company chose to cap the rate increase to each of these customer classes to no more than a multiplier value tied to the

[9] Id.

average increase of 29.3 percent presented in Table 3. The multipliers were 1.04, 1.05, and 1.22 for Schedules, 2, 3, and 27, respectively.[10]

For the remainder of the revenue requirement increase, the Company applies a rate increase floor that allocates half of the increase in margin revenues to all customers whose parity ratio is over 1.75 percent. The remainder of costs are spread to all remaining customer classes on an equal percent of margin basis.[11]

Q. What is the effect on total revenue requirement of the Company's rate spread proposal?

A. Table 4 presents the total revenue requirement increase per schedule and the ratio of the percentage increase per schedule relative to the average increase.

[10] NW Natural/1802.
[11] NW Natural/1800, Wyman/84-85.

Table 4: Total Proposed Rate Increase by Schedule

Schedule	Rev. Req. Increase	% Increase	Ratio of Increase
02R	$ 109,872,388	18.8%	1.13
03C	$ 34,870,187	16.8%	1.01
03I	$ 488,805	9.6%	0.58
27R	$ 212,003	20.2%	1.21
31CSF	$ 2,041,479	9.0%	0.54
31CTF	$ 167,028	14.7%	0.88
31ISF	$ 704,711	7.3%	0.44
31ITF	$ 22,982	14.7%	0.88
32CSF	$ 2,848,675	7.2%	0.43
32ISF	$ 537,107	3.6%	0.22
32CTF	$ 145,599	14.7%	0.88
32ITF	$ 983,401	14.7%	0.89
32CSI	$ 521,566	3.9%	0.23
32ISI	$ 607,749	3.6%	0.22
32CTI	$ 75,413	14.7%	0.88
32ITI	$ 810,559	14.7%	0.88
33T	$ -	0.0%	0.00
Total	$ 154,909,651	16.7%	1.00

Q. Why does Staff believe that it is important to present the rate increase for each customer class as a ratio to the percent of the total rate increase – including gas costs?

A. Staff and other parties are proposing adjustments to the Company's proposed revenue requirement. As an example, Staff in its opening testimony recommends adjustments to the Company's revenue requirement totaling between ($36 million) and ($42 million) depending on the Return on Equity (ROE) assumptions used.[12] Discussing rate spread proposals on a total dollar or a percentage increase basis becomes difficult as agreements or Commission orders may change the overall size of the revenue requirement

[12] See Staff/200.

pie that must be split among the rate classes. Therefore, Staff believes it to be easier and more appropriate to instead present its rate spread recommendations as a ratio to the average percentage increase and a set of guidelines to fairly allocate rate spread as the case evolves.

Q. Does Staff find the Company's proposed rate spread to be fair?

A. No. While the Company does move towards parity and the ratio of cost increases relative to the average is relatively small, Staff does not believe that concerns about the relatively large rate increases are properly addressed by the proposed spread of incremental revenue requirement. As can be seen above, various industrial schedules have received as little as 22 percent of the average increase while other customer schedules receive up to 121 percent of the average increase. Given the overall size of the company's proposed increase to revenue requirement, Staff believes it would be preferable to slow the move towards parity and spread rates more evenly across customer classes.

Q. How does Staff propose moving towards parity while more evenly spreading the rate increase across customer classes?

A. Staff proposes to use the Company's current rate spread as a starting point and implement a floor of 75 percent of the average percentage increase when determining the lowest possible rate spread allocation to each schedule. In effect, this raises the allocated revenue requirement for Schedule 31 and Schedule 32 customers. Any revenue requirement added to these schedules will then be taken away from the three schedules that were given a cap in the Company's initial rate spread methodology.

This means that the incremental revenue requirement to Schedule 2 and Schedule 27 customers is lowered, but still remains above the average percentage increase. Staff has expressed concerns about relying solely on the LRIC for determining parity, and Staff believes that this more optimally balances the pursuit of parity based on the LRIC with concerns about customers experiencing relatively large rate increases.

Q. Please explain Staff's rationale for this proposal.

A. Staff has long argued that in the face of exceptional overall rate increases a narrower rate spread should be adopted.[13] While the LRIC is informative for determining rate spread, Staff argues that a scenario in which some rate schedules experience nearly a 19 percent rate increase, while others see only a 4 percent increase,

is inequitable.

Q. What is the effect of Staff's adjustment to the Company's proposed rate spread model?

A. The rate spread under Staff's proposed method is contained below in Table 5. For ease of presentation, Staff presents this proposal using the Company's filed proposed revenue requirement rather than Staff's proposed revenue requirement presented in the testimony of Staff Witness Luz Mondragon in Staff Exhibit 200. For scale, Staff proposes a total of ($36 million) to

[13] For a recent example of this see UE 426 Staff/1500, Stevens/37.

($42 million) in adjustments to the Company's requested revenue requirement.[14]

Table 5. Staff's Proposed Rate Spread

Schedule	Rev. Req. Increase	% Increase	Ratio of Increase
02R	$ 102,416,260	17.52%	1.05
03C	$ 34,874,898	16.80%	1.01
03I	$ 635,517	12.49%	0.75
27R	$ 184,159	17.52%	1.05
31CSF	$ 2,817,832	12.49%	0.75
31CTF	$ 167,028	14.74%	0.88
31ISF	$ 1,203,584	12.49%	0.75
31ITF	$ 22,982	14.74%	0.88
32CSF	$ 4,955,681	12.49%	0.75
32ISF	$ 1,848,231	12.49%	0.75
32CTF	$ 145,599	14.73%	0.88
32ITF	$ 983,401	14.74%	0.89
32CSI	$ 1,673,401	12.49%	0.75
32ISI	$ 2,095,108	12.49%	0.75
32CTI	$ 75,413	14.74%	0.88
32ITI	$ 810,559	14.73%	0.88
33T	$ 0	0.00%	0.00
Total	$ 154,909,651	16.70%	1.00

[14] See Staff/200.

ISSUE 3. RATE DESIGN

Q. Please summarize the Company's rate design proposals?

A. NWN proposes three changes to the monthly charge:

- Increase the basic charge for residential single-family customer from $8 to $10.[15]
- Implement a bifurcated basic charge that keeps the multi-family basic charge at $8.[16]
- Create a new monthly charge premium of $16.25 for all new customers to the Company's system that would be added onto the Company's basic charge proposal.[17]

Q. Why is a monthly charge generally included in a residential rate design?

A. The monthly charge is the price a customer pays in a month regardless of the amount of energy consumed. If one were to set rates purely on short-run cost causation, the basic charge would be used to recoup the Company's fixed costs that do not vary with a customer's natural gas usage.

However, Staff notes that setting a basic charge purely on the merits of assumed Company fixed costs comes with some notable shortcomings. First, studies of the fixed per-customer costs can vary dramatically depending on the assumptions used by the modeler. Staff has discussed these general concerns about the LRIC in this testimony as well as many other proceedings and notes that LRIC is long run where all inputs are variable while short-run

[15] NW Natural/1800, Wyman/60.
[16] NW Natural/1800, Wyman/73.
[17] NW Natural/1800, Wyman/77.

allows for fixed costs. In the short run, main and distribution pipes costs are fixed and no reinforcements are needed, while in the long-run all of the Company's facilities are variable. Second, a high basic charge has the potential to exacerbate existing energy equity and affordability issues for certain communities by improperly saddling low-income and low-usage customers with higher overall bills than they would otherwise have. While it is difficult to make this determination absent better data on how natural gas usage varies with income, Staff believes that a key consideration to changes to rate design is the disproportionate impacts the changes may have to environmental justice communities. Staff discusses these and other energy justice concerns associated with the Company's basic charge proposal further in Staff/300.

Q. How do the Company's proposed monthly charges align with the customer and fixed costs that the Company modeled?

A. The Company's LRIC Study in this rate case models the per-customer single family fixed cost of service at approximately $37 per month.[18] Based on the Company's study on multi-family cost of service, the Company expects the multi-family fixed cost of service to be between $9 and $15, depending on the capital cost payback assumptions used.[19]

[18] NW Natural/1800, Wyman/60.
[19] See Workpaper 3 to NW Natural Exhibit 1800.

Q. Based on this analysis, does Staff agree with the Company's proposal to bifurcate the basic charge into a single-family and multi-family charge?

A. Yes. Staff appreciates the Company carrying out the thorough analysis following our recommendation in UG 435.[20] NWN has studied the cost differences and confirmed the two-dollar credit for multifamily residential customers is justified by cost savings from operational efficiencies.[21] While the proper methodology to study the fixed cost of service is sensitive to the assumptions made in the study, Staff is convinced that the Company's modeling is adequate to justify a bifurcated basic charge even if one were to view it through a cost causation lens. Staff further notes that it expects a bifurcated basic charge to have positive equity impacts, as low-income Oregonians within NW Natural's service territory are generally more likely to live in multi-family dwellings.

Q. Does Staff agree with the Company's proposal to raise the monthly charge for single-family residential customers from $8 to $10?

A. Staff takes no issue with the increase to the basic charge at this time. Staff notes that NWN has among the lowest monthly charge among peer utilities.[22] That being said, looming affordability concerns across many utility customers gives reason to consider this proposed increase directly through the lens of

[20] See Docket No. UG 435, OPUC Staff, Opening Comments, April 22, 2022, Staff/1300 Scala/48.
[21] NWN/1800, Wyman/72.
[22] NWN/1800, Wyman/60.

customer impacts. As such, Staff may update its views following the Energy Justice Issues Public Workshop and its review of intervenors' testimonies.

Q. What is the Company's proposal for new residential customers?

A. NWN proposes to charge new premise residential customers a $16.25 premium over existing customers in the monthly basic charge. In effect, this will raise the monthly charge to $26.25 for single family customers and to $24.25 for multi-family customers who join NW Natural's Oregon gas system as a new premise customer on or after November 1, 2024. As a result, residential customers would have four different monthly charges under NWN's proposal. These four proposed monthly charges can be seen in Table 6.

Table 6. NWN's Proposed Residential Monthly Charges

Density	Old Customer	New Premise Customer
Single Family	$10	$26.25
Multi-Family	$8	$24.25

Q. What is the Company's stated reason for this higher basic charge for new premise residential customers?

A. NWN's load forecast finds new premise customers have, on average, a use per customer (UPC) roughly 210.8 therms lower than existing customers.[23] The Company states that it wants to collect a more equitable amount of revenue from new premise customers as compared to revenue collected from existing customers as part of its "responsible growth strategy". With lower margins from new premise customers, the Company seeks to raise revenue from new

[23] NW Natural/1800, Wyman/77.

premise customers in the fixed monthly charge to recoup lost revenue from lower volumetric sales.

Q. Does Staff support the NWN proposal?

A. No. Staff believes that issues related to new customers are more appropriately addressed by the Company's line extension allowance (LEA) policy and NWN's decoupling mechanism. Staff Witness Dr. Curtis Dlouhy discusses Staff's issues with the Company's LEA proposal in Staff Exhibit 900, which are not just limited to the Company's new premise basic charge. Further, issues with variances in volumetric sales are best solved by the Company's decoupling mechanism rather than a blanket charge that applies to all new customers. Proposals to modify the decoupling mechanism are addressed in Staff Witness Dr. Bret Stevens' testimony in Staff Exhibit 1900.

Q. Does Staff believe that a new premise basic charge is equitable?

A. Neither Staff nor the Company have a strong grasp of the demographics that would be subject to a new premise basic charge. Absent this knowledge, it is impossible for Staff or stakeholders to understand whether the financial impacts and cost shifting that result from this proposal would ultimately benefit or harm marginalized communities. Our concerns about LEA policy and decoupling aside, Staff believes that components justified as part of the Company's larger business or "responsible growth strategy" should be explored in a comprehensive planning setting such as an IRP where stakeholders can review the Company's intended trajectory more holistically and have an opportunity to express concerns or share their expertise before such a sweeping change is proposed in a general rate case.

Q. Does Staff believe that it is fair and just rate design to distinguish residential customers by their status as a new customer or existing customer?

A. No. Staff prefers this to be handled through the decoupling mechanism which has different revenue per customer targets based on whether the customer is "new" or existing. The decoupling mechanism is designed to recover the Company's fixed cost regardless of variable consumption. This mechanism decreases the risk that the Company under-recovers these costs. NWN is proposing to differentiate between existing and new customers in its decoupling mechanism calculation, however Staff sees the rationale for this proposal as sufficiently different from the rationale for the new premise basic charge.

The decoupling mechanism proposal is meant to address an issue that is dependent on the customer connection date. In particular, Staff's decoupling mechanism proposal is accounting for the fact that new premise customers tend to consume less than existing customers *and* that their lower consumption is not taken into account when NWN calculates its decoupling revenues between rate cases. Staff argues that it is the combination of these issues that makes the decoupling proposal appropriate.

Q. Does Staff believe that the Company's LEA proposal and new premise basic charge send a fair signal to new customers?

A. No. Staff notes that in spite of the Commission's decision to incrementally decrease the LEA each year in UG 435 to under $1000, the Company has proposed an allowance as high as $3700 for the lowest usage new customers.[24] Taken in a vacuum, a new customer may choose to build natural gas into their home based on the financial incentives from the generous allowance. However, the Company's proposal to recover a higher fixed charge from new customers would reduce the financial benefit from the LEA.

Staff is concerned a new customer will be more likely to see a generous LEA than to notice the additional basic charge for new premises customers in the Company's tariffs for residential customers. Therefore, Staff believes that this structure of a large LEA and new premise fixed charge could be somewhat deceptive. In effect, this higher up-front allowance and higher monthly fixed charge acts like a loan to connect to the Company's natural gas system, but there is no guarantee the customer is aware they are paying for the benefit of the loan with a higher fixed charge than existing customers.

Q. Does this conclude your testimony?

A. Yes.

[24] NW Natural/2000, Kravitz – Therrien/23.

CASE: UG 490
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Eric Shierman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	MS Economics; Portland State University; Portland, Oregon BA Political Economy; Hillsdale College; Hillsdale, Michigan
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since June 2019. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UG 490
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Opening Testimony
Load Forecast, Decoupling, and Rate Base

April 18, 2024

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

A. My name is Bret Stevens. I am a Senior Economist employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program (RSUP) of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/1901.

Q. What is the purpose of your testimony?

A. I discuss and review several issues in Northwest Natural's (NWN) general rate case. This includes NWN's Test Year load forecast, decoupling, and the calculation of rate base for purposes of establishing the return component of NWN's revenue requirement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. LOAD FORECASTING

Q. Please describe the results of Northwest Natural's (NWN) Test Year load forecast.

A. NWN forecasts an Oregon load of 1,050 million therms in the Test Year. Roughly 40.6 percent, 17.5 percent, and 41.9 percent of this total load is attributable to the residential, small commercial, and industrial & transportation customers respectively.[1]

Q. Please describe NWN's methodology for this forecast.

A. NWN forecasts Test Year load in three steps. First, NWN forecasts usage per customer (UPC) in the Test Year by using an ARIMA model on historical usage, weather, and economic data. This Test Year load is forecasted assuming normal weather in the Test Year based on 25-year climate normals.[2] Second, NWN forecasts Test Year customer counts. This forecast is based on historical regional business and employment growth trends, housing start forecasts, and other economic factors.[3] Lastly, the UPC forecast and customer count forecast are multiplied to create the schedule-wide load forecast.

Q. Does Staff have any major concerns regarding the fundamentals of NWN's load forecast methodology?

A. No, Staff has no major concerns with NWN overall load forecast methodology. In general, Northwest Natural uses industry standard methodologies and is

1 NWN/1801, Wyman/1.
2 NWN/1800, Wyman/6.
3 NWN/1800, Wyman/7.

receptive to feedback regarding model improvements. That said, nearly all econometric models have room for improvement across various metrics.

Q. Does Staff have any proposed changes to NWN's load forecast methodology?

A. Yes. Staff is recommending changes to the load forecast with the intention of improving transparency and model flexibility. Staff is recommending a unique set of changes for each rate class UPC forecast. Staff's recommendations can be categorized as the following:

1. Algorithmically parameterize ARIMA models as baseline with any deviations justified in testimony.
2. Attempt to use non-linear weather terms when applicable and discuss rationale for excluding these terms.
3. Use monthly dummies as opposed to the natural logarithm of the number of weekend and holiday days in each month.
4. Drop variables with very small effects.

Q. Has Staff performed these changes to the forecast?

A. Partially. Staff has estimated regression results for various schedules but has not yet evaluated the impact of these proposed changes on the Company's proposed revenue requirement or rates. Staff is working with the Company to implement these changes and understand the full effect of Staff's recommendation on rates. Staff does not anticipate that these changes will have a large impact on the proposed rates in this case but contends that these changes will improve the accuracy of NWN's load forecast.

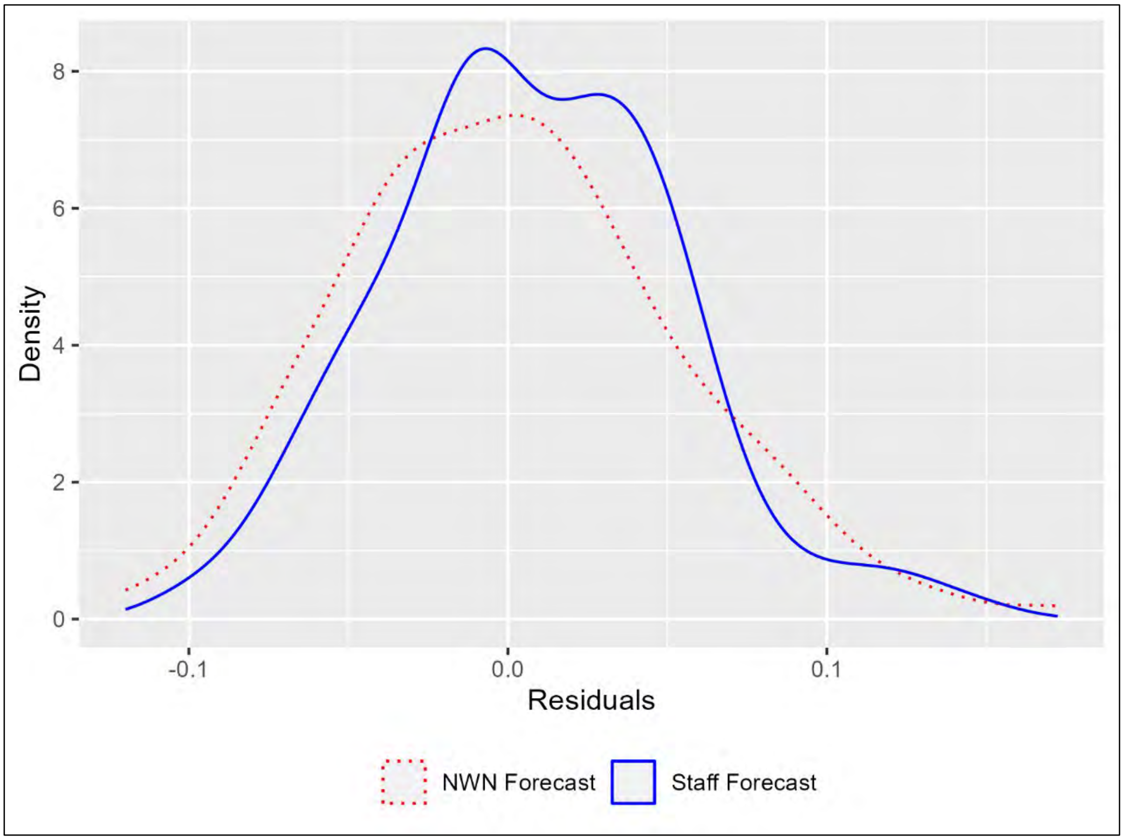
Q. Please describe Staff's proposed changes to the residential forecast.

A. Staff is proposing several changes to the residential forecast. First, Staff supports using a (1,1,1) ARIMA model as opposed to NWN's proposed (1,0,0)(0,0,1)[2] ARIMA model. This parameterization was automatically selected using the Hyndman-Khandakar algorithm. Staff also recommends modifying the covariate matrix to include monthly fixed effects to control for seasonality, a squared HDD term to control for non-linear effects of weather, and the exclusion of various weather terms that did not produce meaningful coefficients.

Q. How do Staff's proposed changes affect the residential load forecast?

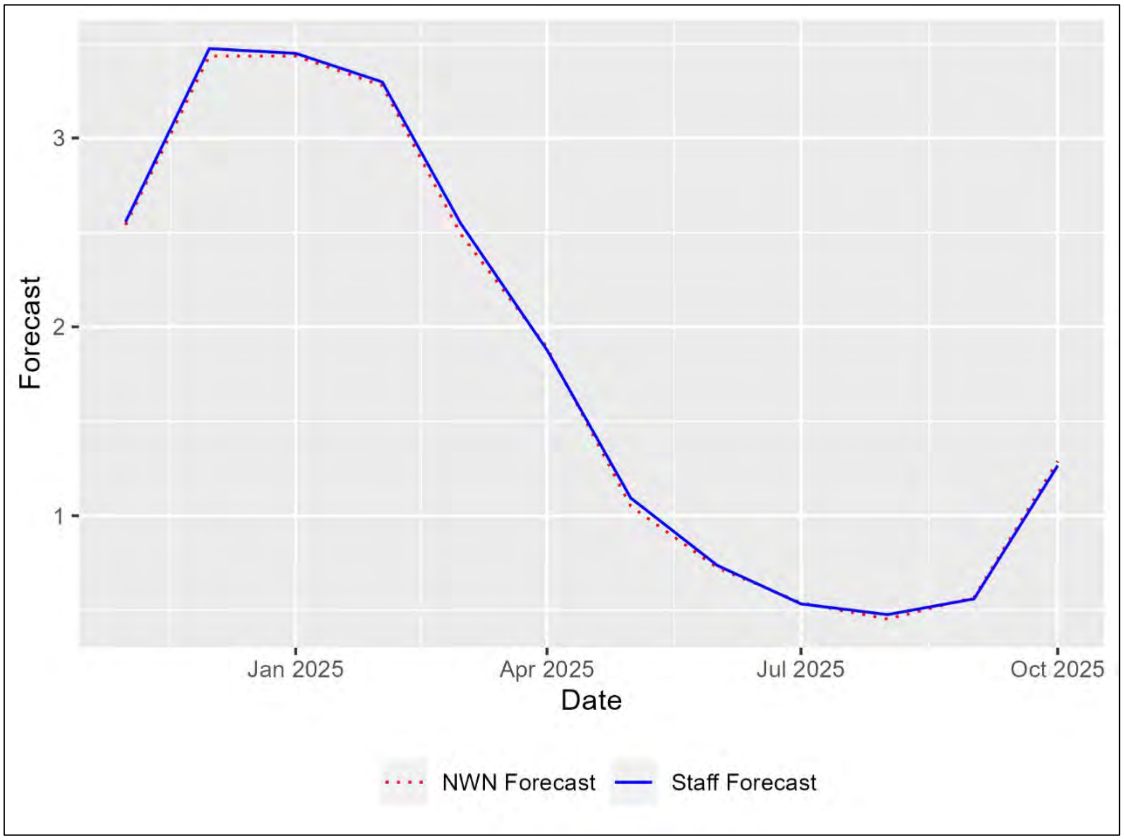
A. These modifications to the load forecast are largely to help the model be more flexible and help improve interpretability. Staff's changes do improve the fit of the model as measured by the Akaike information criterion (AIC) and Bayesian information criterion (BIC). The distribution of residuals between Staff and NWN's proposed models can be seen below in Figure 1.

Figure 1. Comparison of Residential Model Residuals



Staff's changes do not greatly affect the residential load forecast. The difference between Staff's and NWN's monthly residential load forecasts can be seen in Figure 2 below.

Figure 2. Residential Test Year Load Forecast Comparison



Q. Please describe Staff's proposed changes to the commercial load forecast.

A. Staff is proposing several changes to the commercial forecast. First, Staff notes that NWN uses two models to forecast commercial usage. One model forecasts usage for all commercial customers, while the other only forecasts usage for small commercial customers. For the model forecasting all commercial customers, Staff supports using a (1,0,0)(1,1,1)[12] ARIMA model as opposed to NWN's proposed (1,0,0)(0,0,1)[2] ARIMA model. Staff also recommends that all monthly fixed effects be removed from this model.

Instead, the seasonal differencing will account for the seasonal variation in usage.

Staff notes that this parameterization was not chosen by algorithm but was instead manually chosen by Staff. Staff chose to override the model as the algorithmically parameterized model forecasted summer months much higher than the historical norms. A comparison of the forecasts produced by each of these models can be seen in Figure 3. Staff also included a squared HDD term in its model and removed weather variables with negligible impact on the model. Overall, Staff's model has a comparable fit to the automatically parametrized model with monthly fixed effects. The comparison of residuals of each of these models can be seen in Figure 4.

1 **Figure 3. Comparisons of Commercial Forecasts**

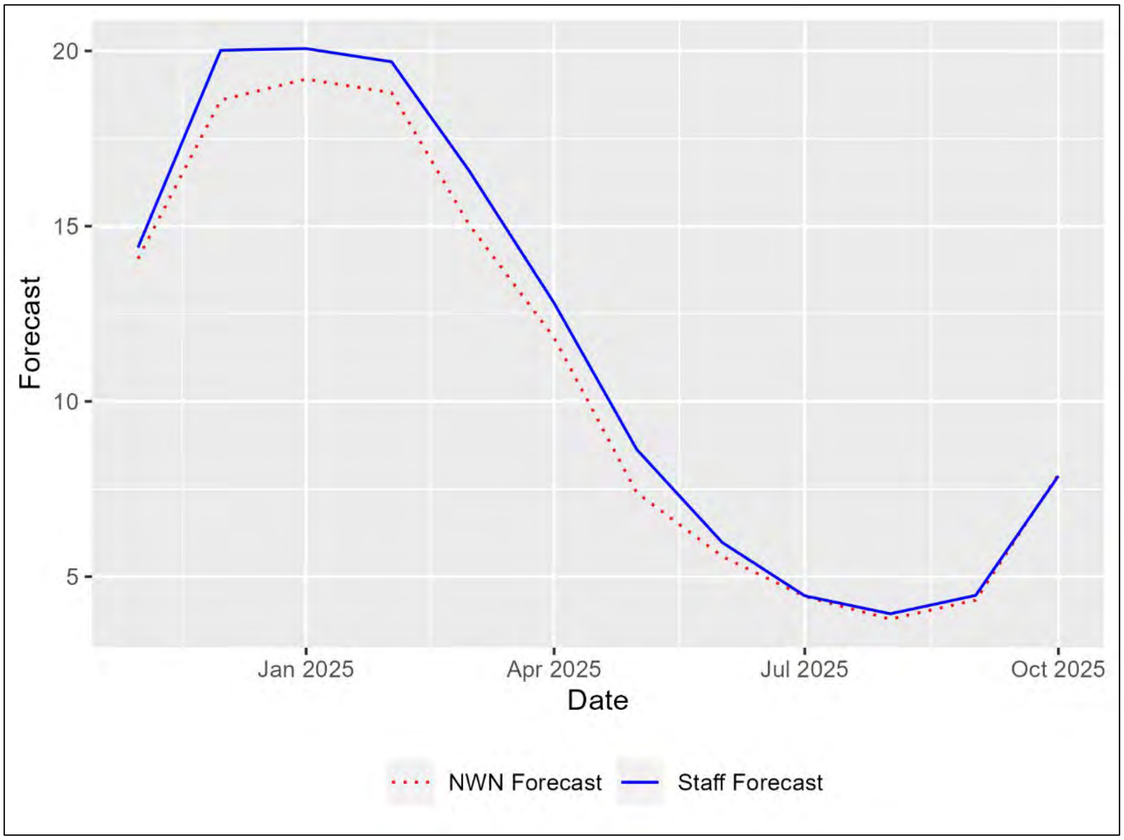
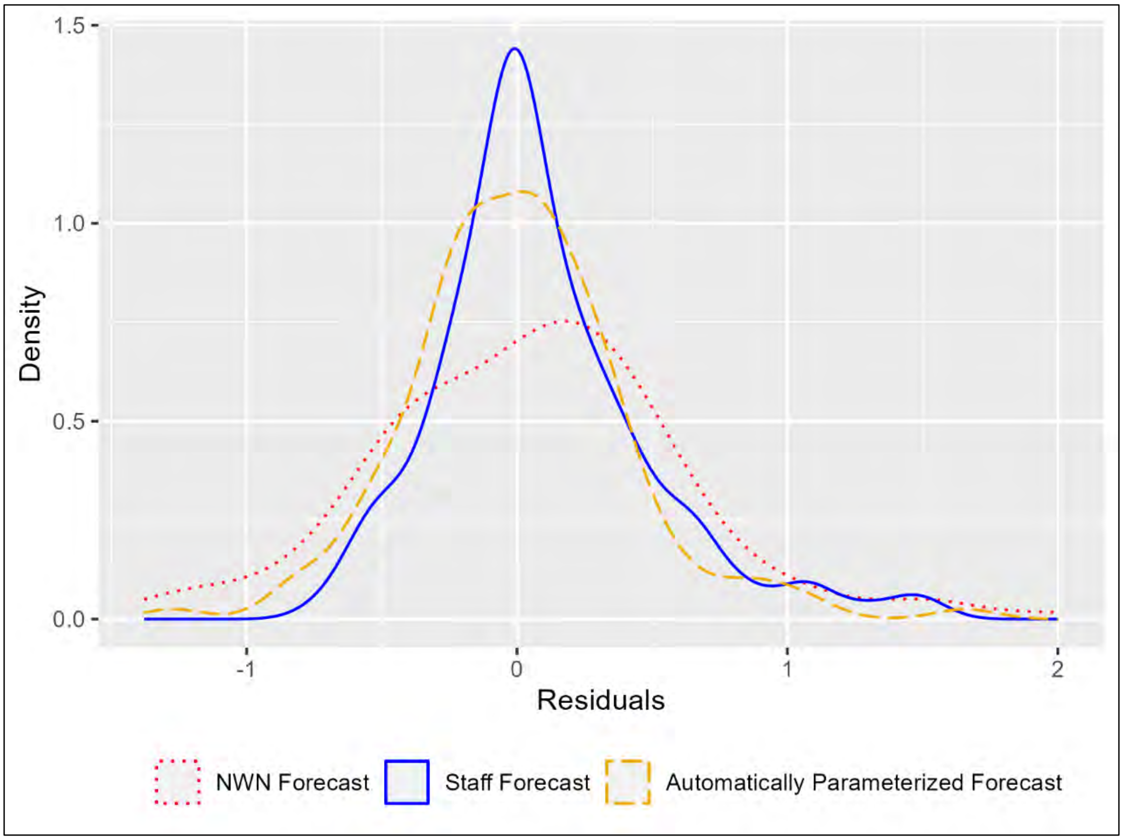


Figure 4. Comparison of Commercial Model Residuals



For the small commercial model, Staff similarly recommends removing monthly fixed effects from the model and instead relying on seasonal differencing. Staff recommends using a (0,1,1)(1,2,1)[12] ARIMA model as opposed to NWN's (1,0,0)(0,0,1)[2] ARIMA model. Again, the model produced via Staff's preferred parameterization algorithm produced unrealistic summer usage estimates. Staff also included a squared HDD term and removed weather variables with negligible impacts on the model. A comparison of the forecasts and model fit can be seen in Figure 5 and Figure 6 respectively.

1 **Figure 5. Comparisons of Small Commercial Forecasts**

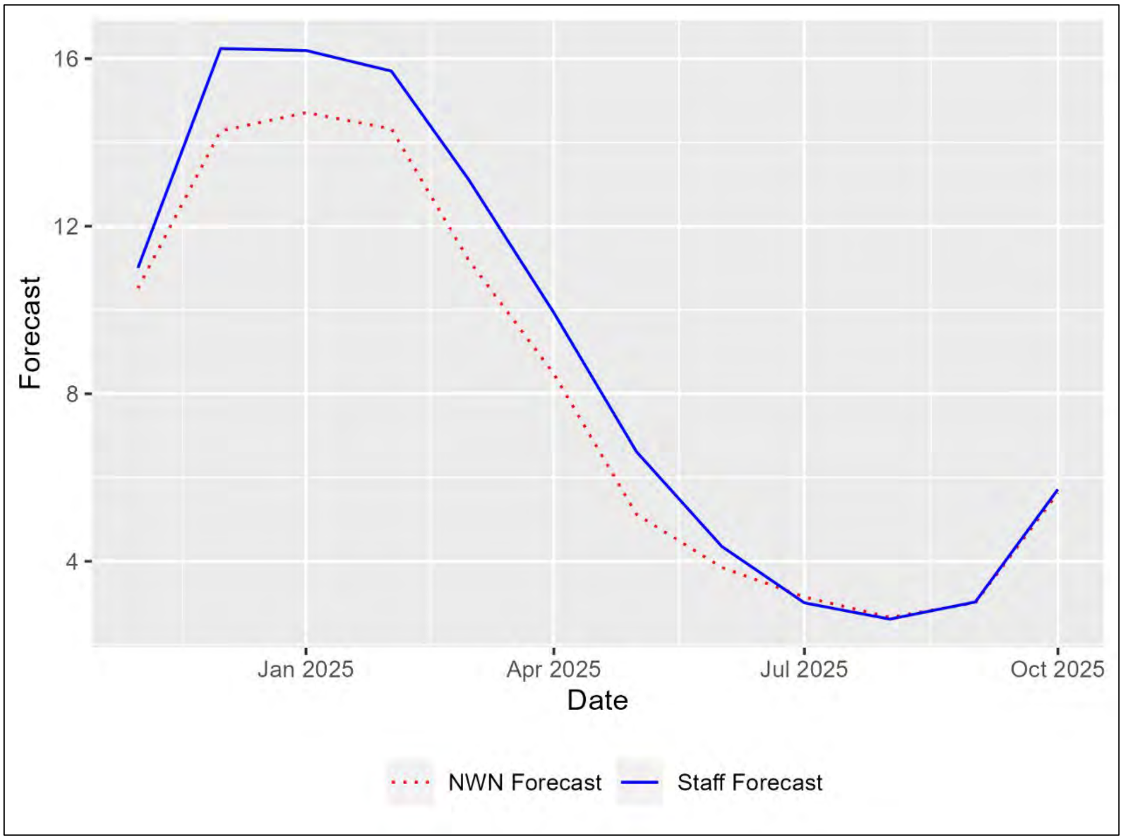
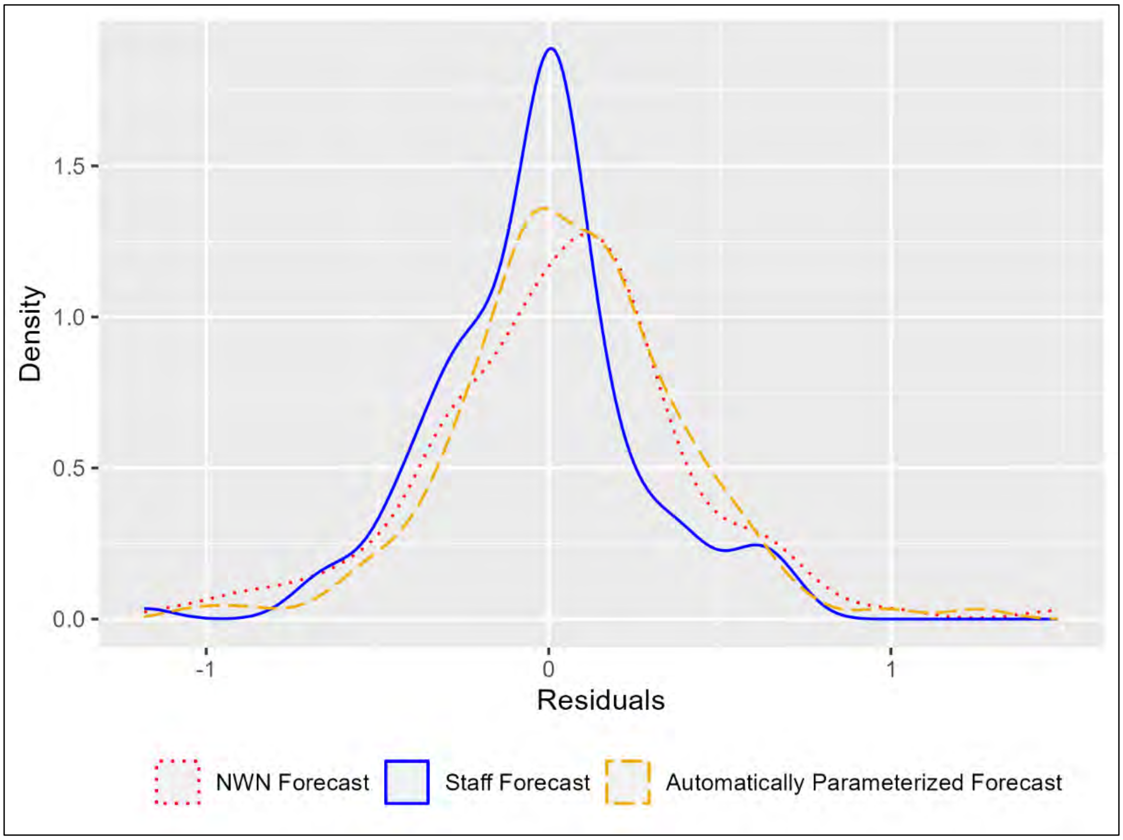


Figure 6. Comparison of Small Commercial Model Residuals



Q. How do Staff's proposed changes affect the commercial load forecast?

A. Staff's proposed modifications to the load forecast are to enhance the model's flexibility and improve its interpretability. Staff's changes do improve the fit of the model as measured by the AIC and BIC. Staff's forecast slightly increases the Test Year load forecast for commercial customers, primarily through a higher forecasted peak consumption in winter months.

Q. Please describe Staff's proposed changes to the Schedule 27 (Residential Dry-Out) forecast.

A. Staff is proposing several minor modifications to the Schedule 27 model. First, Staff proposes using a (1,0,0) ARIMA model as opposed to NWN's proposed

(1,0,1) ARIMA model. Staff's proposed parameterization was automatically selected using the Hyndman-Khandakar algorithm. Further, Staff recommends using monthly fixed effects and removing weather variables with a negligible effect on the model.

Q. How do Staff's proposed changes affect the Schedule 27 load forecast?

A. Staff's recommended modifications have a very small impact on the Schedule 27 load forecast. The difference between Staff's and the Company's forecasts can be seen below in Figure 7. These modifications to the load forecast are largely to help the model be more flexible and help improve interpretability. Staff's changes do improve the fit of the model as measured by the AIC and BIC. The comparison of Staff and the Company's proposed models can be seen in Figure 8 below.

Figure 7. Comparison of Schedule 27 Forecasts

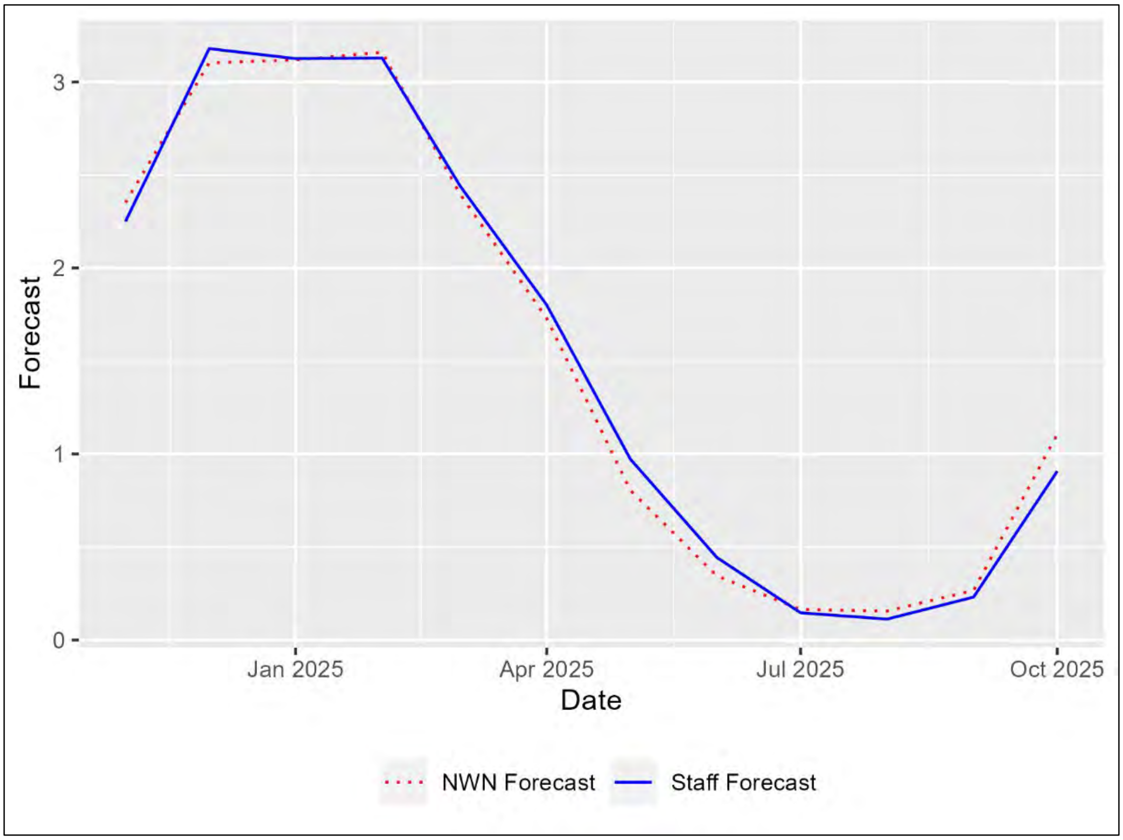
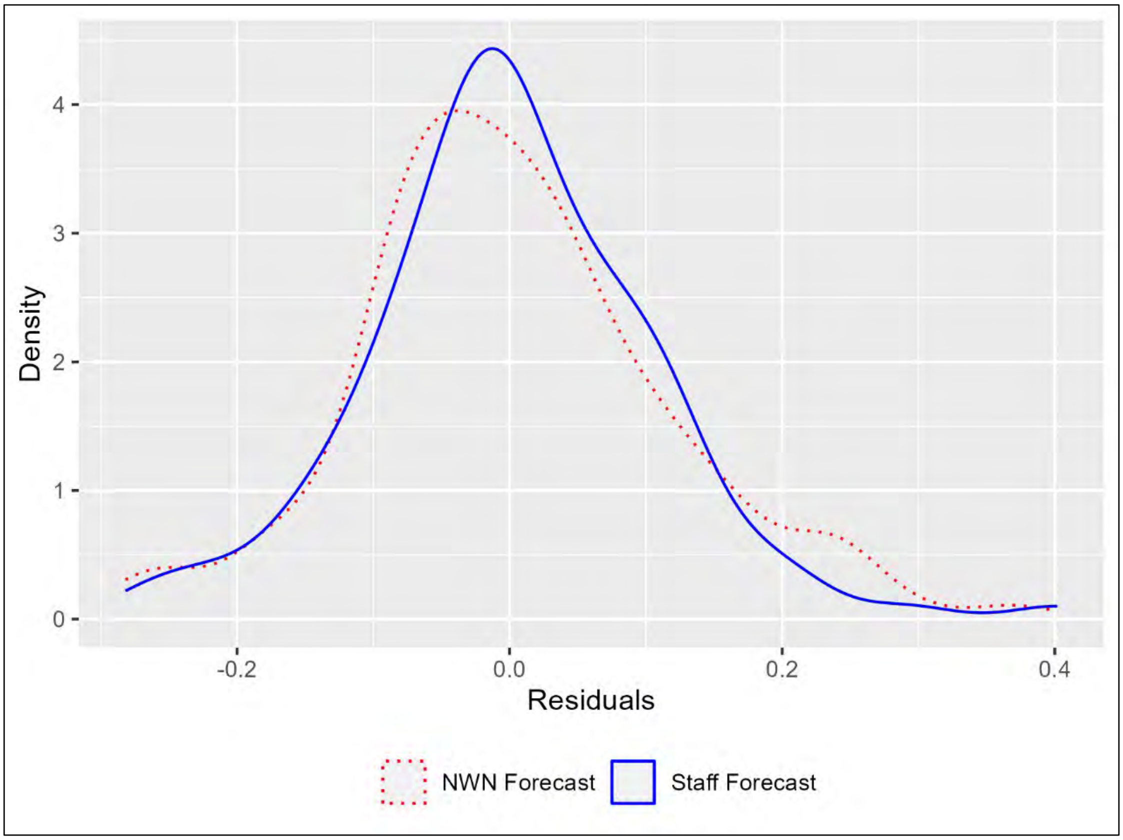


Figure 8. Comparison of Schedule 27 Model Residuals



Q. Please describe Staff's proposed changes to the Schedule 31 (Non-Residential Firm Sales and Firm Transportation Service) forecast.

A. For NWN's Schedule 31 forecast, Staff is recommending the same changes be made as recommended for the Schedule 27 forecast. Namely, Staff recommends that a (1,0,0) ARIMA model be used as opposed to a (1,0,1) ARIMA model, monthly fixed effects be used, and weather variables with a negligible impact on the model be omitted.

Q. How do Staff's proposed changes affect the Schedule 31 load forecast?

A. Again, the effects of Staff's recommended changes have a relatively small impact on the overall forecast for Schedule 31 and are largely to help the model be more flexible and help improve interpretability. The Staff and Company forecasts can be seen below in Figure 9. Staff's changes do improve the fit of the model as measured by the AIC and BIC. The comparison of Staff and the Company proposed models can be seen in Figure 10 below.

Figure 9. Comparison of Schedule 31 Forecast

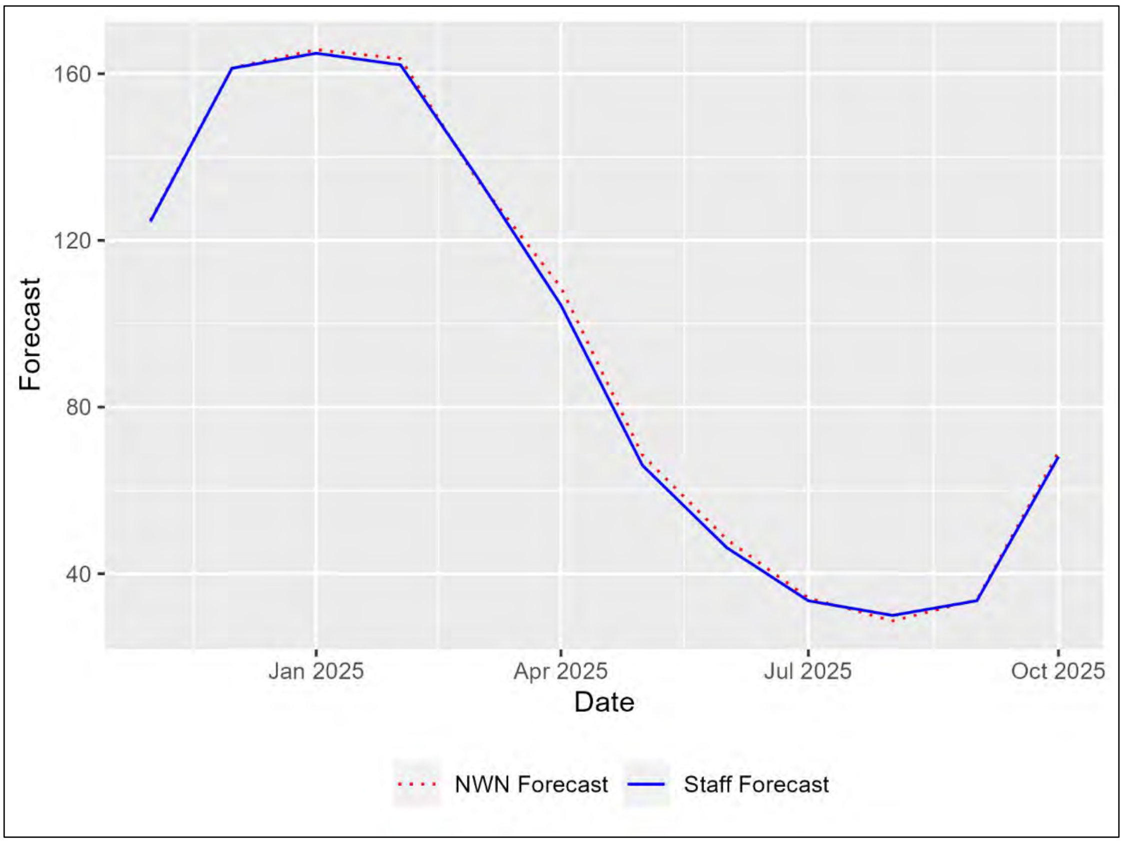
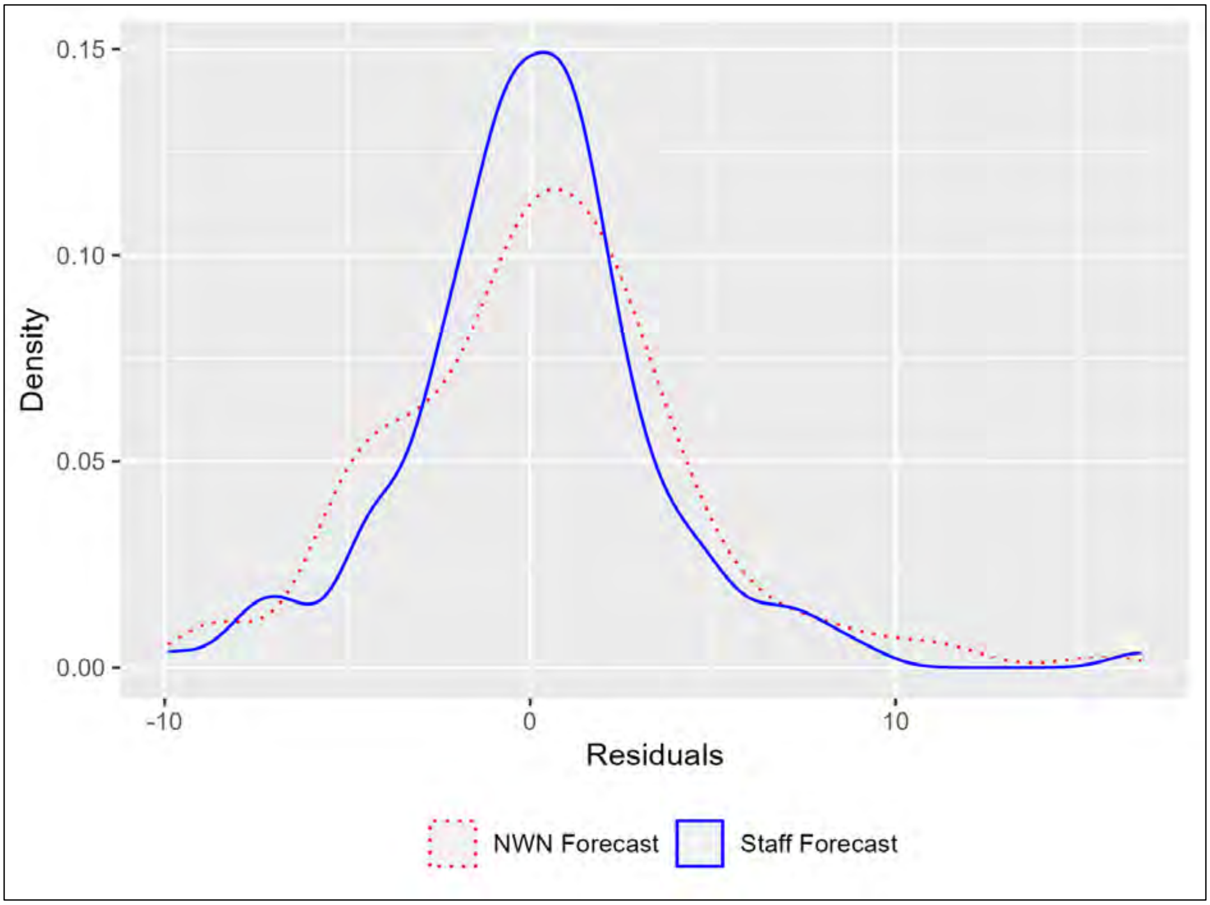


Figure 10. Comparison of Schedule 31 Residuals



Q. Please describe Staff's proposed changes to the Schedule 32 (Large Volume Non-Residential Sales and Transportation Service) forecast.

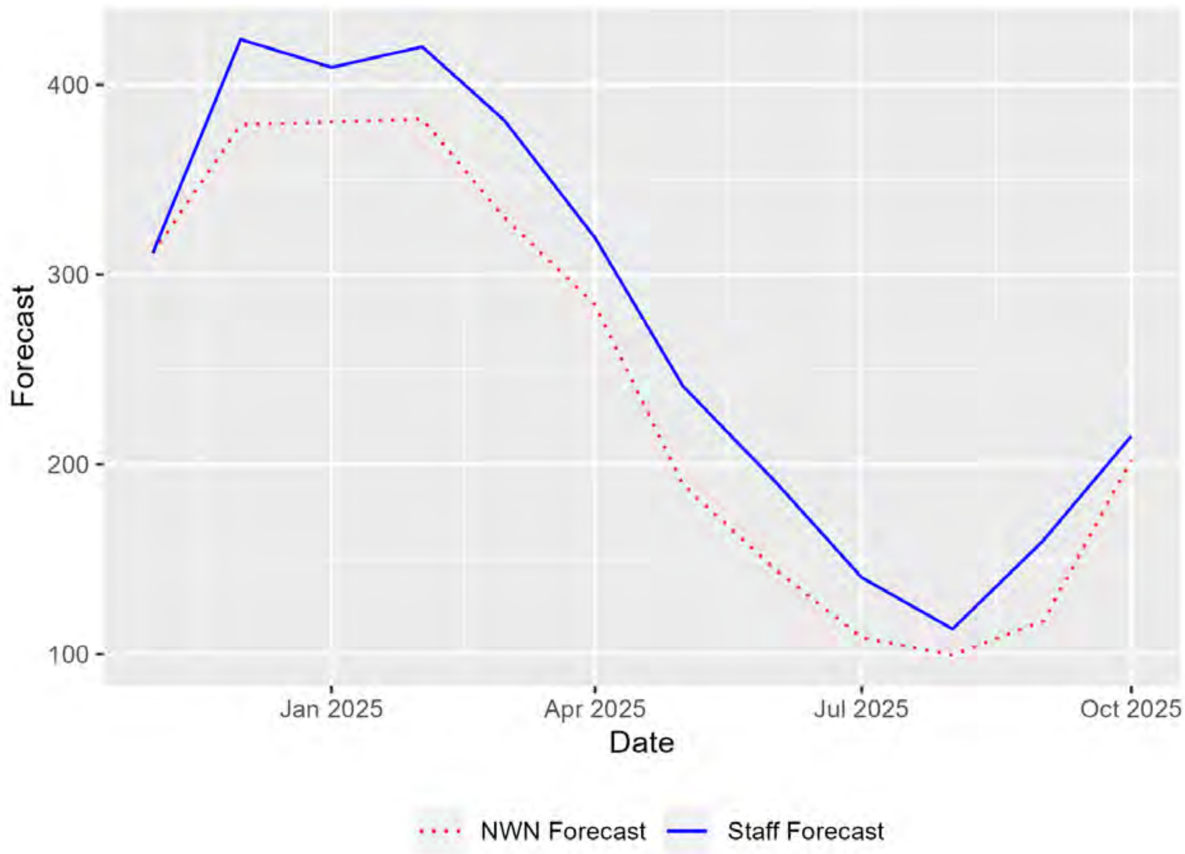
A. For NWN's Schedule 31 forecast, Staff is recommending more substantive changes. Staff recommends that a (1,0,0)(1,2,1)[12] ARIMA model be used as opposed to a (1,0,0) ARIMA model. As with the commercial models discussed above, Staff is recommending that no monthly fixed effects be included in the model and that seasonal differencing instead be used to control for seasonal variation. Staff is also recommending that weather variables that have a negligible effect on the forecast be removed.

Staff notes that this parameterization was not chosen algorithmically but was manually selected by Staff. Similar to the commercial models, the algorithmically parameterized model with monthly fixed effects produced a summer season forecast that was much higher than any historical consumption. Staff's parameterization is meant to produce a summer forecast that is more in line with historical consumption, while still improving fit and adequately controlling for seasonality.

Q. How do Staff's proposed changes affect the Schedule 32 load forecast?

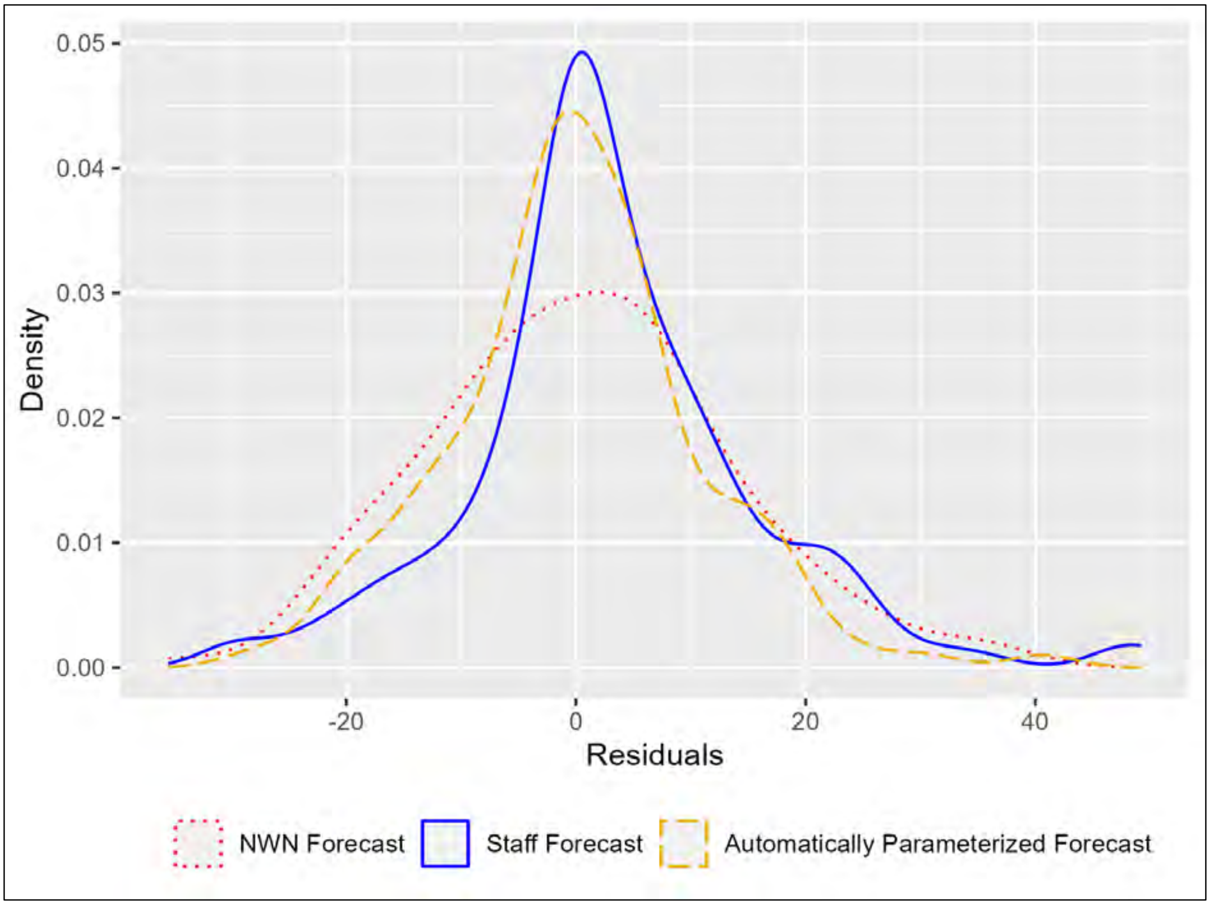
A. Staff's recommended changes increase the Schedule 32 slightly. This increase is uniform in each month but is most pronounced in the peak period. The difference between Staff's recommended model, NWN's model, and the algorithmically parameterized models can be seen below in Figure 11.

Figure 11. Comparison of Schedule 32 Forecast



Both Staff's model and the algorithmically parameterized model provide improvement to the fit as measured by the AIC and BIC. Each model's distribution of residuals can be seen below in Figure 12.

Figure 12. Comparison of Schedule 32 Residuals



ISSUE 2. DECOUPLING

Q. Please summarize NWN's proposal regarding its decoupling mechanism.

A. NWN is proposing to bifurcate the residential Decoupling calculation between established customers and new customers that join the system after each rate case. This change would modify the decoupling revenue calculation by comparing new premise residential customer usage to a lower baseline level. NWN's proposal is based on Staff's recommendation in UG 435. This proposal is meant to account for the fact that customers joining the system will not have the same baseline consumption distribution as established customers on the system. If the system-wide baseline consumption, calculated in the most recent rate case, is applied to all customers joining the system between rate cases, the Company may over collect via its decoupling mechanism as new customers consume significantly less than the system-wide average.

NWN proposes using customer usage data from 2018-2022 to estimate the baseline consumption of new customers connecting between rate cases. NWN also proposes beginning the bifurcation of the Decoupling mechanism after the difference between normal and actual heating degree days is calculated.

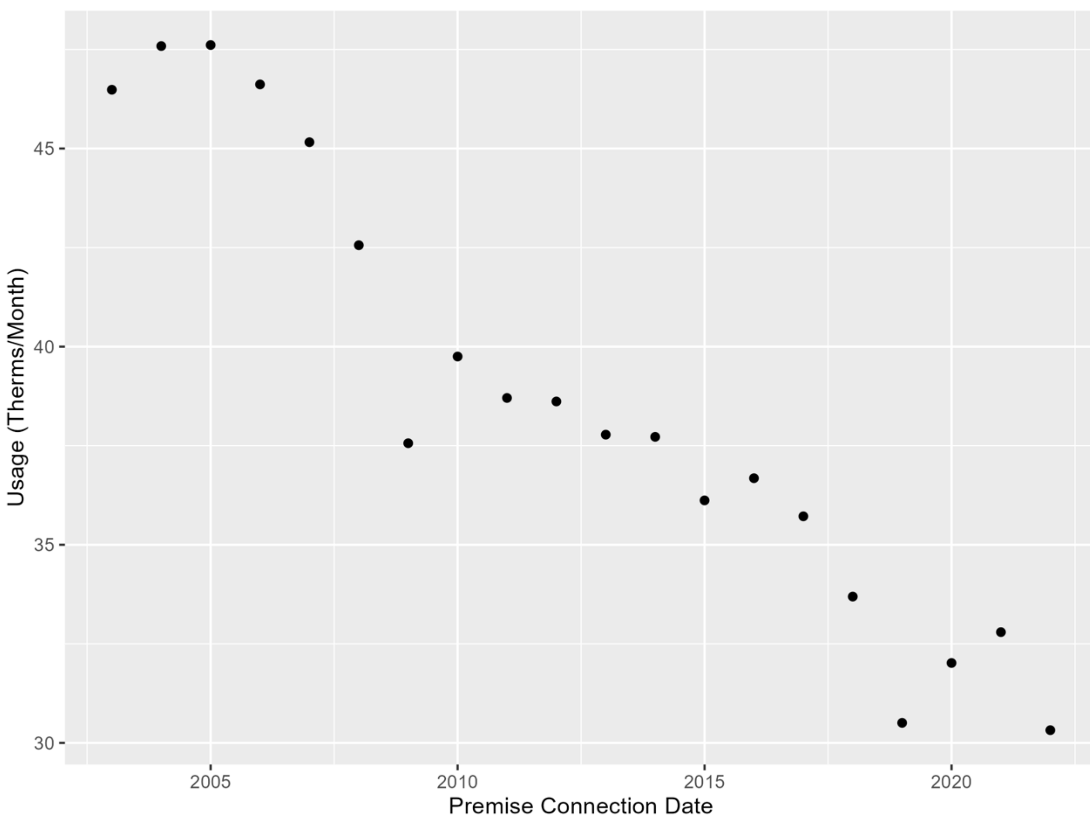
Q. How has usage changed for newer customers?

A. Figure 13 shows the average monthly usage for premises connected from 2003-2022.[4] This shows that the average yearly consumption of a premise

[4] Figure 13 was created using data obtained in Staff DR 390.

connecting to NWN’s system has consumed nearly one less therm per month than a premise that was connected in the prior year. This decrease in average usage is stark and represents many technological and economic changes in NWN’s service territory.

Figure 13. Average Monthly Usage by Premise Connection Year



Q. Does Staff agree that the bifurcation should only be applied to customers being added between rate cases?

A. No. After further review of the data, Staff is recommending that the residential class, for the purposes of the Decoupling mechanism, be fully bifurcated between “new” and “existing” customers on a permanent basis.

That is, “new” customers would not be folded into the “existing” customer category during rate cases and would remain separate going forward.

Q. What is Staff’s rationale for this recommendation?

A. Staff’s concern is largely around customer attrition. Staff’s initial decoupling recommendation in UG 435 was made to solve the issue presented by new customers being systematically different than existing customers. However, in this updated recommendation Staff is aiming to also address the fact that customers leaving the system are likely different than customers who have recently joined the system.

NWN’s decoupling mechanism accounts for differences both in usage per customer and customer count compared to the load forecast. If the baseline for “existing” customers includes all customers connected at the time of the rate case, then the system-wide baseline usage and heating coefficient will be the weighted averages of older and newer customers. However, customers who leave the system are likely not customers who have only connected to the system recently. As such, the usage distribution of customers leaving the system is likely shifted to right of the usage distribution for the entire system. This would then lead to a mechanism that compares customers remaining on the system to a baseline usage that is skewed upward. Permanently bifurcating the decoupling mechanism between “existing” and “new” customers would help mitigate the impact of this phenomenon.

Q. What year should be used to designate "new" customers for the decoupling mechanism going forward?

A. "New" customers, for the purpose of the decoupling bifurcation, should be considered as any customer who connected to the system beginning in 2018. Staff chose this year for several reasons. First, NWN implicitly acknowledges in its testimony that customers who joined the system after this date have significantly different consumption compared to existing customers as they used this group to calculate their indicative baseline for new customers. Second, all houses built on and after 2018 would be subject to the updated residential building codes set in 2017. Lastly, Figure 13 shows that average usage of customers that connected to the system between 2018-2022 has remained fairly constant. This indicates that the rate of change in UPC may be stabilizing, or at least slowing down. As such, this cohort of customers will likely be more similar to each other than customers who connected to the system before 2018.

Staff does recognize that the exact year of delineation is somewhat subjective. One could easily argue that 2017 or 2019 may be better or equally as good as 2018 for separating these groups and as such, no delineation should be made. However, Staff argues that it is still worthwhile to establish a partition between these groups even if no delineation will be perfect.

Q. Does Staff believe that the definition of this bifurcation group should remain unchanged in all future rate cases?

A. No. If customer usage patterns sufficiently change in future years, it may be prudent to redefine the delineation between older and new customers.

Q. Does Staff agree that the bifurcation should take place after the difference between the normal and actual heating degree days is calculated?

A. No. Staff recommends that the Company calculate separate heating coefficients separately for both customers who connected before and after 2018. Staff recognizes that this recommendation runs counter to Staff's proposal in UG 435.[5] However upon further review, Staff has altered its recommendation. This change is meant to reflect the fact that new customers to the system will likely both have lower baseline usage and reactions to weather fluctuations. This phenomenon is due to newly connected premises having newer and more efficient heating systems and homes that were built to modern residential building codes. If the weather normalized usage for these customers is not updated to reflect this, then the decoupling mechanism will be set assuming a higher level of usage for new customers than should be anticipated.

[5] Staff/1300, Scala/27.

ISSUE 3. RATE BASE CALCULATION

Q. From a high level, please describe how Northwest Natural calculates rate base in this case.

A. NWN is proposing to use a 13-month Average-of-Monthly-Averages (AMA) approach to calculate rate base in this case. In this calculation, they do include growth-related capital additions in the Test Year, however, but do not include major capital additions.

Q. Does this methodology indicate a significant break from how rate base was calculated in the past?

A. No. Staff reviewed testimony from UG 435, and the high-level rate base calculation has remained the same.

Q. Does Staff agree with this calculation?

A. Yes. This is Staff's preferred methodology for calculating rate base. Staff is still in the process of reviewing the exact capital additions included in the calculation, but at this time has no issues with NWN's methodology. Staff may recommend that certain capital additions be excluded in future testimony if any inappropriate costs are found.

SUMMARY

Q. Please summarize your recommendations.

A. Staff is proposing relatively minor changes to NWN's load forecast. These changes are meant to improve transparency and flexibility of NWN's econometric load forecasting models. In general, these recommendations involve automatically parameterizing ARIMA models as a baseline, using non-linear weather variables, using seasonal ARIMA terms when applicable, and removing weather variables with small effects. Staff is proposing that NWN bifurcate its proposed decoupling mechanism before the difference between normal and actual heating degree days is calculated. This necessitates that a heating coefficient is separately calculated for new customers. Lastly, Staff does not have any recommendation regarding NWN's overall rate base calculation methodology at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: BRET STEVENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1901

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME: Bret Stevens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Safety, and Utility Performance

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Salem, OR. 97301

EDUCATION: Ph.D., Agricultural & Resource Economics (2023)
University of California, Davis

M.S., Agricultural & Resource Economics (2017)
University of California, Davis

B.A., Economics/Environmental Studies (2016)
Western Washington University

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2022. My primary responsibilities revolve around providing research and analysis on rate spread and rate design. I have been a staff witness in UE 407, UE 410, UE 412, UE 414, UE 416, UE 421, UE 426 and UG 461. Prior to working for the Commission, I was employed by the University of California, Davis as a graduate student researcher, associate instructor, and teaching assistant. I taught courses on econometrics, finance, and microeconomics.

CASE: UG 490
WITNESS: Steph Yamada

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

REDACTED
OPENING TESTIMONY
Highly Confidential Information is Subject to Modified Protective Order No. 23-480

April 18, 2024

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

A. My name is Steph Yamada. I am a Senior Utility Analyst employed in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide background, analysis, and recommendations regarding the Company's Test Year inclusions for wages, salary, incentives, and full-time equivalents (FTE).

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualifications statement provided in Exhibit Staff/2001, I prepared the following supporting exhibits: Exhibit Staff/2002 (NW Natural's Non-Confidential DR Responses), Exhibit Staff/2003 (NW Natural's Highly Confidential DR Responses), and Exhibit Staff/2004 (Staff's Highly Confidential Workpapers).

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. SALARIES & WAGES

Q. Please summarize the Company's proposal for salaries and wages in this case.

A. The Company proposes to include salaries, wages, and overtime totaling **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in Oregon in the Test Year,[1] as summarized in Figure 1.

FIGURE 1: TEST YEAR SALARIES, WAGES, OVERTIME

[BEGIN HIGHLY CONFIDENTIAL]

Category	Base Salaries & Wages	Overtime
Officers	$4,982,411	$0
Exempt	$65,175,815	$0
Nonexempt	$748,875	$5,242
Union	[redacted]	[redacted]
Total	[redacted]	[redacted]

[END HIGHLY CONFIDENTIAL]

For non-union employees and officers, the base wage amounts shown in Figure 1 were determined by escalating calendar year 2023 costs by 5.30 percent in 2024 and 4.85 percent in 2025.[2] The base wages for union employees were calculated **[BEGIN HIGHLY CONFIDENTIAL]** [redacted][3] [redacted]

[1] Staff/2003, NW Natural's Response to Staff's SDR 92, HIGHLY CONFIDENTIAL Attachment 1 (Viewable only in Huddle).
[2] NW Natural/1000, Rogers/6.
[3] NW Natural/1000, Rogers/7, lines 11-13 and 17-20, HIGHLY CONFIDENTIAL.

[redacted] **[END HIGHLY CONFIDENTIAL]**[4]

Q. How does the Company determine employee compensation?

A. For non-union employees, NW Natural uses survey data to align its base pay with the median of the market for comparable jobs with other companies.[5] Union employees' total compensation is determined through a negotiated process that incorporates selected market survey data and union contracts.[6] For officers, the Company uses competitive compensation data, which are collected and analyzed by an independent compensation consultant, Pay Governance, to determine appropriate compensation levels.[7]

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for salaries and wages, including overtime.

A. The Commission generally determines the appropriate level of wages and salaries for employees in the Test Year using Staff's three-year Wage and Salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[8,9] The model calculates an appropriate level of Test Year expense

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4 NW Natural/1000, Rogers/5, lines 7-9, HIGHLY CONFIDENTIAL.
5 NW Natural/1000, Rogers/4, lines 3-6.
6 NW Natural/1000, Rogers/4, lines 14-22.
7 NW Natural/1000, Rogers/5, lines 16-23.
8 *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999), *In the Matter of PacifiCorp*, Docket No. UE 374, Order No. 20-473 at 102 (December 18, 2020).
9 *See Pacific Power & Light*, UE 116, Order No. 01-787 at 40; *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All Urban CPI (for non-union labor) or negotiated increases (for union labor). For the purposes of this analysis, the base year is three years prior to the Test Year. The model then applies a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility. The Commission has previously declined to apply the sharing mechanism to union wages, instead basing the Test Year inclusion on the contracted increases in applicable union agreements.[10]

Q. Why has the Commission used the W&S model to determine the Test Year inclusion for non-union wages and salaries?

A. The Commission has explained its rationale in previous orders. For example, in an order issued in 1999, the Commission explained:

> The [Three Year] model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staff's use of the All-Urban CPI index to adjust historic wages and salaries. Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs. Contrary to the assertions by NW Natural, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey. Moreover, Staff's method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[11]

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[10] *In the Matter of PacifiCorp*, Docket No. UE 374, Order No. 20-473 at 100 (December 18, 2020).
[11] *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999).

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for base wage and salary levels for the Test Year.

A. Consistent with the W&S model, Staff began with actual wage information from three years prior to the Test Year.[12] With a Test Year of November 1, 2024, to October 31, 2025, Staff began with 2022 wage information and escalated it to 2025 using All-Urban CPI rates, which are 4.1 percent for 2023, 2.7 percent for 2024, and 2.0 percent for 2025.[13] Staff then applied the sharing principle to Staff's and the Company's projected 2024 Test Year amounts for non-union labor. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, results in a ($672,170) adjustment to Staff's projection for officer wages and a ($801,812) adjustment to exempt employee wages at the Oregon level.[14] Finally, these adjustments are allocated 64.9 percent to O&M and 35.1 percent to capital.[15] Staff did not make any adjustments to union labor.

Q. What is Staff's recommended adjustment for base salaries and wages?

A. Staff recommends a total adjustment of ($1,473,983) attributable to the Company's base salaries and wages for Oregon, excluding union labor. This amount is allocated ($956,615) to O&M and ($517,368) to capital.

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[12] Staff/2003, NW Natural's Response to Staff's SDR 92, HIGHLY CONFIDENTIAL Attachment 1 (Viewable only in Huddle).

[13] Oregon Economic & Revenue Forecast - March 2024 - Volume XLIV, No. 1, Table A.4, page 43.

[14] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year W&S" Tab.

[15] Staff/2002, NW Natural's Response to Staff's SDR 93.

Q. Does Staff recommend further adjustments to union employee wages?

A. Yes. Staff recommends that union wages be updated to reflect actual negotiated union wage increases for the Test Year once those amounts are known. Staff's recommended totals reflect the Company's current estimate for union compensation, which was developed as discussed previously. The current contract for union employees is set to expire on May 31, 2024, and NW Natural is currently in negotiations with the bargaining unit for a new contract.[16] The Company **[BEGIN HIGHLY CONFIDENTIAL]** [redacted][17] [redacted] **[END HIGHLY CONFIDENTIAL]**.[18]

Q. Please explain how Staff used the Three-Year W&S model to arrive at Staff's overtime recommendation for the Test Year.

A. Staff's overtime analysis follows the same methodology as that used for base salaries and wages, which was discussed previously. The results of this analysis are shown in Staff's workpapers.[19]

Q. What is Staff's recommended adjustment for overtime?

A. Staff recommends an adjustment of ($4,935) attributable to the Company's non-exempt employee overtime for Oregon. This amount is allocated ($3,203) to O&M and ($1,732) to capital.

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[16] NW Natural/1000, Rogers/5, lines 1-3.
[17] NW Natural/1000, Rogers/5, lines 4-5.
[18] NW Natural/1000, Rogers/5, lines 11-12.
[19] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year OT" Tab.

ISSUE 2. INCENTIVES

Q. Please summarize the Company's proposal for incentives in this case.

A. The Company is seeking recovery of incentives totaling $9,340,431 in Oregon.[20] This amount is allocated from a system total of $10,528,091.[21] The breakdown of the Oregon amount is summarized in Figure 2, as follows.[22]

FIGURE 2: COMPANY PROPOSED INCENTIVES

Incentive	Exempt	Non-Exempt	Total
Annual Incentive (Short-Term)	$8,065,357	$52,562	$8,117,919
Long Term Incentive Pay (O&M)	$130,315	$0	$130,315
Stock Expense (RSU) (O&M)	$895,024	$0	$895,024
Employee Stock Purchase Plan	$197,173	$0	$197,173
Total	**$9,287,869**	**$52,562**	**$9,340,431**

The Company has excluded all executive incentive compensation from the Test Year.[23,24] Union employees are not eligible for pay-at-risk.[25] The Employee Stock Purchase Plan (ESPP) is not identified by employee type,[26] and is included in the Exempt column in Figure 2.

Q. Does NW Natural argue that incentives should be fully includable in rates?

A. Yes. NW Natural proposes to include the full amount of non-officer incentives as shown in Figure 2. The Company argues that pay-at-risk "represents an

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20 NW Natural/1000, Rogers/13, line 6.
21 Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
22 Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
23 NW Natural/1400, Davilla/14.
24 Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.
25 NW Natural/1000, Rogers/10.
26 Staff/2002, NW Natural's Response to Staff's DR 142, Attachment 1.

essential part of competitive total compensation," and "is necessary for NW Natural to compete in the job market."[27] Regarding Restricted Stock Units (RSUs), the Company asserts that RSUs, which vest over four years, are "eligible for full cost recovery,"[28] stating that such incentives "are not awarded to incentivize financial performance."[29] While the Company has excluded officer incentives from its request "[g]iven the sizeable increase to revenues requested in this rate case,"[30] it maintains that such costs are prudently incurred, and that its "position [has not] changed regarding the ability to recover the costs of pay-at-risk pay for officers of the Company."[31] The Company further argues that the "Commission should treat the question of cost recovery for pay-at-risk on a case-by-case basis."[32]

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for incentives.

A. To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[33] It is also Commission policy to disallow 75 percent of performance-based bonuses because they are generally

27 NW Natural/1000, Rogers/8, lines 6-7.
28 NW Natural/1000, Rogers/12, lines 18-21.
29 NW Natural/1000, Rogers/12, lines 21-22.
30 NW Natural/1000, Rogers/9, line 5.
31 NW Natural/1000, Rogers/9, lines 8-17.
32 NW Natural/1000, Rogers/13, lines 10-11.
33 See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket No. UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

focused on increased earnings and therefore bring more benefit to shareholders.[34] The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers.[35] Union bonuses are treated in the same manner as non-union bonuses.[36] In this case, the issue of union bonuses is not relevant because union employees are not eligible for such compensation.

Q. Please describe Staff's analysis with regard to incentives.

A. As discussed previously, the Company proposes to include incentives totaling $9,340,431 in the Test Year. Since the Annual Incentives are calculated as a percentage of payroll and Staff made downward payroll adjustments as described previously, Staff first made a corresponding adjustment to the Company's proposal for Annual Incentives. Since the Company's proposed Annual Incentive inclusion is limited to exempt and nonexempt employees, Staff based its corresponding adjustment on Staff's base salary & wage adjustment in those employee categories. Staff allocated the reduction to exempt and nonexempt employees in the same proportions reflected in the Company's Test Year proposal. This adjustment is summarized in Figure 3 as follows.

[34] See Order No. 20-473 at 104.
[35] See Order No. 20-473 at 104.
[36] See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.

FIGURE 3: STAFF'S ANNUAL INCENTIVES ADJUSTMENT – OREGON

Staff's Initial Short-Term Incentives Adjustment	
Company Proposed Annual Incentive	$8,117,919
Staff's Exempt & Nonexempt Salary Adjustment	-5.30%
Staff's Corresponding Annual Incentive Adjustment	$(430,136)
Staff Adjusted Annual Incentive	**$7,687,783**

Next, Staff adjusted the Company's Long-Term Incentive Pay, Stock Expense, and ESPP in accordance with Staff's proposed FTE adjustment. Staff's proposal for exempt and nonexempt FTEs (discussed elsewhere in this testimony) represents a 4.14 percent reduction from the Company's proposed level. Consequently, Staff reduced Long Term Incentive Pay, Stock Expense, and the ESPP by 4.14 percent, or a total of ($50,597) in those categories.

Staff categorized the incentives as merit-based. Consequently, Staff reduced its adjusted incentives figures by 50 percent, in line with standard Commission practice. Staff's adjustment was allocated between O&M and capital in the same manner as described previously for salaries and wages. As described previously, the Company has already excluded 100 percent of officer incentives, in line with standard Commission practice.

Q. Has NW Natural demonstrated that the Commission should deviate from its longstanding practices regarding incentives and include the full amount of the Company's proposal?

A. No, NW Natural has not made a persuasive demonstration for why the Commission should deviate from its longstanding practices. The Company has primarily argued that pay-at-risk "represents an essential part of competitive total compensation," and "is necessary for NW Natural to compete in the job market[.]"[37] The Company has made similar arguments in previous cases. For example, in Docket No. UG 132, the Company initially proposed "that 100 percent of the non-officers' bonuses be included in utility expense," and argued that "the bonuses are designed to make the company's total compensation package for these employees competitive with comparable jobs in the regional labor market."[38] In that case, the Commission concluded that Staff's recommendation to exclude 75 percent of performance-based bonuses and 50 percent of merit-based bonuses was "consistent with past ratemaking treatment of bonuses in prior electric and natural gas cases," stating that "NW Natural has not persuaded us that a change in policy is warranted."[39]

Q. The Company specifically argues that RSUs are eligible for full cost recovery. Why did Staff include RSUs in the amount that was reduced by 50 percent in its adjustment?

A. As discussed previously, the Commission typically excludes 50 percent of non-officer, non-performance-based incentives. Staff applied this reduction to its adjusted figure for RSUs, in accordance with Standard Commission practice.

Q. What is Staff's recommended adjustment for incentives?

37 NW Natural/1000, Rogers/8, lines 6-7.
38 See Order No. 99-697 at 44.
39 See Order No. 99-697 at 45.

A. Staff recommends a total Oregon-allocated adjustment of ($4,910,582) attributable to the Company's employee incentives.[40] This amount is allocated ($3,186,968) to O&M and ($1,723,614) to capital.

[40] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC 3-year Incentives" Tab.

ISSUE 3. FTE

Q. Please summarize the Company's proposal for FTE in this case.

A. NW Natural proposes to include 1,183 employees in the Test Year at the system level.[41,42] This includes 1,170 FTEs existing at the end of the 2023 base year plus 13 additional employees that NW Natural expects to hire in the first half of 2024.[43] The Company removed 64.3 vacant FTEs and 63.7 non-regulated FTEs to arrive at the 1,183 total.[44] The system-wide and Oregon allocations are summarized in Figure 4 as follows.

FIGURE 4: COMPANY PROPOSED FTE

Type	System FTEs	Oregon FTEs
Officers	12.4	10.9
Exempt	560.4	497.1
Nonexempt	10.5	9.3
Union	599.6	531.9
Total	**1,183.0**	**1,049.2**

Q. Why does NW Natural propose to add 13 additional employees in 2024?

A. Eight of the proposed new FTEs relate to Information Technology & Services (IT&S) functions. These include four new Customer Information System (CIS) positions related to H2: Vista, three new operational technology positions, and

41 NW Natural/1000, Rogers/22.
42 Staff/2002, NW Natural's response to Staff's SDR 92, Attachment 1 (Non-Confidential portion).
43 NW Natural/1000, Rogers/21.
44 NW Natural/1400, Davilla/5.

one new security position.[45] The other five proposed new FTEs relate to decarbonization and compliance with the Climate Protection Program (CPP).[46]

Q. How has the Commission previously determined the appropriate FTE level for inclusion in rates?

A. Specific methodologies may vary somewhat on a case-by-case basis. However, the Commission has previously adopted Staff's principle that A&G non-union workforce should be limited to levels forecasted as a function of customers per FTE.[47]

Q. Please describe Staff's analysis with regard to FTEs.

A. For exempt and nonexempt employees, Staff first analyzed FTEs as a function of customers served per FTE. Staff's analysis indicated that between 2021 and 2023, the Company served an average of 1,469.9 customers per FTE at the Oregon level.[48,49] The Test Year proposal reflects 1,396.2 customers served per FTE in Oregon, representing a decrease of 73.7 customers per FTE, or five percent. Based on the total projected Oregon customer count of 707,022 at the end of the Test Year,[50] the three-year historical average of customers served per FTE would require a total of 481 exempt and nonexempt FTEs attributable to Oregon. The Company proposes to include 506.4, which is 25.4 higher than Staff's calculation. Staff proposes to remove these 25.4

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45 NW Natural/700, Downing/51.
46 NW Natural/1500, Kravitz-Chittum/20.
47 See Order No. 99-033 at 63.
48 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
49 Staff/2002, NW Natural's Response to Staff's DR 153, Attachment 1.
50 Staff/2002, NW Natural's Response to Staff's DR 153, Attachment 1.

higher-than-average FTEs. This adjustment is applied to the exempt and nonexempt employee categories in the same proportions as reflected in the Company's Test Year proposal.

Staff also proposes to add back certain FTEs related to the new positions proposed by the Company. As discussed previously, the Company proposes to add 13 new employees in the Test Year—five related to the CPP, and eight related to IT&S functions. Staff proposes to exclude four of the eight proposed new IT&S FTEs and four of the five proposed new CPP FTEs. The resulting net increase of five FTEs is allocated 88.7 percent to Oregon,[51] and added to the exempt employee category. Together with Staff's 25.4 FTE reduction that was discussed previously, Staff's proposal represents a net reduction of 20.96 at the Oregon level compared to the Company's Test Year proposal. Staff's proposed FTE totals are summarized in Figure 5, following.

FIGURE 5: STAFF PROPOSED FTE

Type	Company (System)	OR Alloc.	Company (OR)	Staff Adjustment	Staff (OR)
Officers	12.42	88.1%	10.94		10.94
Exempt	560.39	88.7%	497.06	(20.49)	476.57
Nonexempt	10.52	88.7%	9.33	(0.47)	8.86
Union	599.63	88.7%	531.88		531.88
Total	**1,182.96**		**1,049.22**	**(20.96)**	**1,028.26**

Q. Did Staff make any adjustments to officer or union FTEs?

[51] Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).

A. No. While the Company's system-level officer FTE count has increased from 11.4 in 2020 to 12.4 in the Test Year,[52] this does not appear to be a departure from historical levels.[53] Union FTEs have increased by only 1.2 percent since 2020.[54]

Q. Please explain why Staff recommends the exclusion of four FTEs related to the CPP.

A. As explained in the testimony of Staff witness Curtis Dlouhy (Exhibit Staff/900), Staff believes that there is not enough work to warrant full time positions for at least two of the requested five new FTEs nor would it be proper to allow cost recovery for four of the five requested FTEs now that the CPP rules have been invalidated by the Oregon Court of Appeals Two of the roles were meant to perform duties directly related to CPP compliance prior to its invalidation, and the Company has not adequately convinced Staff that there is enough work for these roles to do absent the CPP.

Further, NW Natural and other litigants asked the Court to invalidate the CPP rules on both procedural and substantive grounds and the Court's opinion invalidating the rules only addressed the procedural concerns.[55] Staff anticipates that if the DEQ implements new CPP rules, the rules will be challenged once again. Staff believes that it is not in customers' best interest to

52 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
53 Staff/2002, NW Natural's Response to Staff's DR 148.
54 Staff/2002, NW Natural's Response to Staff's SDR 92 (Non-Confidential portion).
55 *Northwest Natural Gas Company, et al. v. Environmental Quality Commission,* 329 Or. App. 648, 652 (2023) ("Petitioners raise numerous assignments of error, contending the CPP Rules are invalid. In this opinion, we address only one of those assignments because it is dispositive regarding the validity of the CPP Rules.").

allow the cost recovery of four out of the five positions to implement the CPP while the future of the CPP is still in doubt. Staff supports the inclusion of costs associated with the Peak Load Management Analyst because Staff believes that this position can provide value to customers even without the CPP.

Q. Please explain why Staff recommends the exclusion of four FTEs related to IT&S.

A. As explained in the testimony of Staff witness Julie Dyck (Exhibit Staff/1000), Staff expects that current CIS employees and the other remaining four new IT&S positions will be cross trained as this is replacing a legacy system. Those employees that were working on CIS-related projects before are better equipped to learn a new system. In addition, their IT&S FTE count in 2023, when completing the larger Horizon 1 program was 104, whereas their UG 490 request is 116. So even if all 8 positions are approved, their total IT&S FTE are likely to be around 112, which is four less than their request, since they are unlikely to fill all positions. Lastly, the costs of these FTEs are expected to be included in a Company requested deferral of costs to implement H2 along with the costs of the program itself. The Company plans to update their plans for deferral in their Reply Testimony.

Q. What is Staff's recommended adjustment for FTEs?

A. Staff's adjustment for FTEs at the Oregon level is summarized in Figure 6 as follows.

FIGURE 6: STAFF'S EXEMPT & NONEXEMPT FTE ADJUSTMENT - OREGON

Description	**Exempt**	**Nonexempt**	**Total**
Test Period Base Wages & Salaries	$65,175,815	$748,875	$65,924,691
Staff Adjustment to Test Period Payroll	($801,812)	$0	($801,812)
Adjusted Payroll	$64,374,003	$748,875	$65,122,878
Ave. # of Employees (Test Year FTE)	497.06	9.33	506.40
Adjusted Average Salary	129,508	80,255	$209,763
Staff Proposed FTE	476.57	8.86	485.44
Staff Proposed Proforma Payroll	$61,720,286	$711,323	$62,431,609
Net Payroll Adjustment	**($2,653,716)**	**($37,553)**	**$2,691,269**

This adjustment is allocated between capital and O&M in the same manner as salaries & wages, as discussed previously. Staff's resulting recommended adjustment totals ($2,691,269) for Oregon, which is allocated ($1,746,634) to O&M and ($944,636) to capital.[56]

[56] See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC FTE" Tab.

ISSUE 4. OTHER RELATED ADJUSTMENTS

Q. Do Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs, as discussed previously in this testimony, result in other related adjustments to the Test Year?

A. Yes. Staff's adjustments in these areas also result in associated reductions to depreciation expense and payroll tax.

Q. Please explain Staff's adjustment to depreciation expense.

A. Staff's recommended adjustments to base salaries and wages, overtime, incentives, and FTEs result in a total capital adjustment of ($3,187,350) related to Oregon. The removal of this amount from rate base requires a corresponding reduction to depreciation expense. The Company's filing reflects depreciation expense representing 4.15 percent of gross plant;[57] Staff applied that percentage to its proposed capital reduction, resulting in a $(132,130) adjustment to O&M.[58]

Q. Please explain Staff's adjustment to payroll tax.

A. Staff's payroll adjustments reflect a 3.24 percent reduction compared to the Company's proposed amounts. Staff made a corresponding adjustment to the Company's proposed inclusion for payroll taxes.[59] The resulting adjustment attributable to Oregon is ($367,505).[60]

Q. Please summarize the adjustments described in your testimony.

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57 NW Natural/1713, Walker/1, lines 1 and 22.
58 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC Depreciation" Tab.
59 Staff/2002, NW Natural's Response to Staff's DR 155, Attachment 1.
60 See Staff/2004, Staff's HIGHLY CONFIDENTIAL Workpapers, "PUC Payroll Taxes" Tab.

A. The Oregon-allocated adjustments reflected in my testimony are summarized in Figure 7, as follows.

FIGURE 7: SUMMARY OF STAFF'S ADJUSTMENTS – OREGON

Description	O&M	Capital
Wages & Salaries	($956,615)	($517,368)
FTE Adjustment	($1,746,634)	($944,636)
Incentives	($3,186,968)	($1,723,614)
Overtime	($3,203)	($1,732)
Payroll Taxes	($403,183)	$0
Depreciation Expense	($132,130)	$0
Total	**($6,428,731)**	**($3,187,350)**

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2001

Witness Qualifications Statement

April 18, 2024

WITNESS QUALIFICATIONS STATEMENT

NAME:	Steph Yamada
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Rates and Telecommunications Section Rates, Safety and Utility Performance Program
ADDRESS:	201 High St SE, Suite 100, Salem, OR, 97301
EDUCATION:	Master of Business Administration Western Governors University Bachelor of Science in Accounting University of Oregon
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon since 2013. I am currently a Senior Utility Analyst in the Rates and Telecommunications Section of the Rates, Safety and Utility Performance Program. My responsibilities include leading research and providing technical support on a wide range of technical and policy issues for water and telecommunications companies. I have analyzed and addressed numerous telecommunications issues including special contracts, promotional concessions, tariff changes, price listings, numbering issues, service abandonment, property sales, and price plans, and provided testimony in UM 1895. With regard to water, I have analyzed and addressed numerous issues including tariff changes, property sales, affiliated interest transactions, financing requests, revenue requirement calculations, cost of service, rate spread, and rate design. I have also served as case manager and provided testimony in UW 163, UW 166, UW 173, UP 384, UW 176, UW 181, UW 189, UW 191, UW 192, UW 195, UW 196, and UW 197. With regard to energy, I have provided testimony in UE 426.

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2002

NW Natural's
Non-Confidential
DR Responses

April 18, 2024

NW Natural

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 93

For the Test Year, please provide the breakout between O and M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

Test Year labor expenses expressed as percentages:

O&M	64.9%
Capital	35.1%

Oregon Test Year labor expense represents 88.7% of Total Company labor expense.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 142

NW Natural/1000, Rogers/13 states, “The Company is proposing to recover $9,340,431 in total at-risk pay for NBU employees in this rate case.”

a. Please provide the underlying data for this information. Please provide all data in electronic workbook format with all cell formulae and references intact.

b. Please reconcile this figure with the Oregon-specific test year figure for incentives shown in the Company’s highly confidential response to SDR 92.

c. Please provide the Company’s proposed incentives separated by incentive type and employee type (exempt, nonexempt, etc.). Please also provide the total Company vs. Oregon amounts.

d. Does the Company’s proposed incentives total of $9,340,431 include the stock purchase plan and incentive plan expenses described in NW Natural/1400, Davilla/17, lines 7-13? Please separately state the amount attributable to each.

Response:

a) See UG 490 OPUC DR 142 Attachment 1 for calculations and references for the $9,340,431 identified as at-risk pay. Please note that the $197,173 of expense for Non-Officer Employee Stock Purchase Plan (ESPP) was inadvertently categorized as at-risk pay when in fact employees have the option to opt out at any time. The total at-risk pay in this case is $9,143,258 which, when added to the $197,173 of expense for Non-Officer ESPP, equals the $9,340,431 for which the Company is seeking recovery in this rate case.

b) UG 490 OPUC DR 142 Attachment 1 identifies the items and amounts included in SDR 92.

c) UG 490 OPUC DR 142 Attachment 1 breaks out between exempt and non-exempt. Exempt excludes Officers as no incentive compensation for Officers is included in this case. Non-Officer ESPP is not identified as either exempt, non-exempt or union. In Attachment 1 the full amount of Non-Officer ESPP is shown in the exempt column.

d) Yes, the difference between SDR 92 amount and the $9,340,431 in testimony is due to the stock purchase plan, ESPP and long-term incentive compensation amounts. Those are identified separately in Attachment 1.

**NW Natural’s Attachment 1
provided in response to Staff’s DR 142
is available in electronic spreadsheet format only.**

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 92

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year.
Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response:

Please see Highly Confidential UG 490 SDR 92 Attachment 1. This attachment was previously filed as non-confidential, however due to on-going labor negotiations the union wage information for 2024-2025 has been protected and refiled as Highly Confidential.

O&M MODEL - UTILITY ONLY

Test Year: 11/01/2024 - 10/31/2025 (UTILITY)						
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	12.4	$ 5,653,610	$ -		$ 5,653,610	88.1%
Exempt	560.4	$ 73,478,935	$ -	$ 9,092,849	$ 82,571,783	88.7%
Nonexempt	10.5	$ 844,279	$ 5,910	$ 59,258	$ 909,447	88.7%
Union	599.6	$ [redacted]				88.7%
Total	1,183.0	$ [redacted]				

1st Year prior to Test Year: 01/01/2023 - 12/31/2023 (9 months actual + 3 months projected)						
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	11.9	$ 4,661,662	$ -	$ 2,839,198	$ 7,500,859	88.1%
Exempt	520.3	$ 66,132,497	$ -	$ 9,671,964	$ 75,804,461	88.7%
Nonexempt	10.2	$ 789,820	$ 1,400	$ 65,926	$ 857,145	88.7%
Union	556.1	$ 48,599,118	$ 6,821,568	$ -	$ 55,420,685	88.7%
Total	1,098.5	$ 120,183,096	$ 6,822,967	$ 12,577,087	$ 139,583,150	

2nd Year prior to Test Year: 01/01/2022 - 12/31/2022						
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	Oregon
Officers	11.6	$ 3,980,558	$ -	$ 2,569,892	$ 6,550,450	90.2%
Exempt	524.1	$ 61,462,624	$ -	$ 9,392,463	$ 70,855,087	90.2%
Nonexempt	11.8	$ 991,749	$ 358	$ 81,258	$ 1,073,364	90.2%
Union	549.6	$ 45,071,630	$ 6,459,647	$ -	$ 51,531,277	90.2%
Total	1,097.0	$ 111,506,560	$ 6,460,005	$ 12,043,613	$ 130,010,178	

3rd Year prior to Test Year: 01/01/2021 - 12/31/2021						
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total	
Officers	10.5	$ 3,412,676	$ -	$ 1,995,806	$ 5,408,482	89.7%
Exempt	507.3	$ 57,634,964	$ -	$ 7,639,029	$ 65,273,993	89.7%
Nonexempt	16.1	$ 1,200,650	$ 3,098	$ 82,928	$ 1,286,676	89.7%
Union	592.3	$ 46,634,119	$ 6,495,661	$ -	$ 53,129,779	89.7%
Total	1,126.1	$ 108,882,409	$ 6,498,759	$ 9,717,763	$ 125,098,931	

4th Year prior to Test Year: 01/01/20120 - 12/31/2020					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	11.4	$ 3,881,418	$ -	$ 2,243,206	$ 6,124,624
Exempt	485.6	$ 53,216,452	$ -	$ 7,700,559	$ 60,917,011
Nonexempt	15.3	$ 1,109,173	$ 13,489	$ 97,987	$ 1,220,649
Union	592.4	$ 46,104,869	$ 5,589,269	$ 1,118,278	$ 52,812,417
Total	1,104.7	$ 104,311,912	$ 5,602,758	$ 11,160,030	$ 121,074,701

(1)

O&M MODEL - OREGON UTILITY ONLY

Test Year: 11/01/2024 - 10/31/2025 (UTILITY-OREGON)					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.9	$ 4,982,411	$ -	$ - (1)	$ 4,982,411
Exempt	497.1	$ 65,175,815	$ -	$ 8,065,357	$ 73,241,172
Nonexempt	9.3	$ 748,875	$ 5,242	$ 52,562	$ 806,680
Union	531.9	$ [redacted]			
Total	1,049.2	$ [redacted]			

1st Year prior to Test Year: 01/01/2023 - 12/31/2023 (9 months actual + 3 months projected)					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.5	$ 4,108,227	$ -	$ 2,502,127	$ 6,610,354
Exempt	461.5	$ 58,659,525	$ -	$ 8,579,032	$ 67,238,557
Nonexempt	9.1	$ 700,570	$ 1,242	$ 58,476	$ 760,288
Union	493.3	$ 43,107,418	$ 6,050,730	$ -	$ 49,158,148
Total	974.3	$ 106,575,740	$ 6,051,972	$ 11,139,635	$ 123,767,347
Numbers above exclude 6.4 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.4 Exempt FTEs, 0.0 Nonexempt FTEs, and 6.1 Union FTEs.					

2nd Year prior to Test Year: 01/01/2022 - 12/31/2022					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	10.4	$ 3,591,522	$ -	$ 2,318,726	$ 5,910,248
Exempt	472.8	$ 55,455,635	$ -	$ 8,474,500	$ 63,930,136
Nonexempt	10.7	$ 894,821	$ 323	$ 73,316	$ 968,460
Union	495.9	$ 40,666,600	$ 5,828,320	$ -	$ 46,494,920
Total	989.8	$ 100,608,578	$ 5,828,643	$ 10,866,543	$ 117,303,763
Numbers above exclude 6.6 FTEs on Leave Without Pay (military, work comp, etc.) they include 1.0 Exempt FTEs, 0.1 Nonexempt FTEs, and 5.5 Union FTEs.					

3rd Year prior to Test Year: 01/01/2021 - 12/31/2021					
	Total Company FTEs	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	9.4	$ 3,059,693	$ -	$ 1,789,374	$ 4,849,067
Exempt	454.8	$ 51,673,607	$ -	$ 6,848,901	$ 58,522,508
Nonexempt	14.4	$ 1,076,463	$ 2,778	$ 74,350	$ 1,153,591
Union	531.0	$ 41,810,612	$ 5,823,795	$ -	$ 47,634,407
Total	1,009.6	$ 97,620,375	$ 5,826,573	$ 8,712,625	$ 112,159,573
Numbers above exclude 9.1 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.2 Exempt FTEs, 0.1 Nonexempt FTEs, and 8.8 Union FTEs.					

4th Year prior to Test Year: 01/01/20120 - 12/31/2020					
	Total Company FTEs	**Base Wages or Salaries**	**Overtime**	**Incentive or Bonus**	**Total**
Officers	10.2	$ 3,464,166	$ -	$ 2,002,061	$ 5,466,227
Exempt	435.2	$ 47,697,906	$ -	$ 6,902,011	$ 54,599,917
Nonexempt	13.7	$ 994,152	$ 12,090	$ 87,826	$ 1,094,067
Union	531.0	$ 41,323,794	$ 5,009,662	$ 1,002,313	$ 47,335,769
Total	990.1	$ 93,480,018	$ 5,021,752	$ 9,994,211	$ 108,495,981

Numbers above exclude 11.3 FTEs on Leave Without Pay (military, work comp, etc.) they include 0.9 Exempt FTEs, 0.1 Nonexempt FTEs, and 10.4 Union FTEs.

Officer incentive amount included in this Standard Data Request response represents all annual incentive compensation expected but all Officer incentive amounts were excluded in our test year request.

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
<u>Data Request Response</u>

<u>Request No.</u>: UG 490 OPUC DR 153

Please provide in table format the Company's customer count by class, for each month, and each year for fiscal years 2020 through 2025, and identify which values are projected values. Please show figures for the total Company vs. Oregon specifically.

<u>Response:</u>

See "UG 490 OPUC DR 153 Attachment 1.xlsx" for Oregon and the total Company monthly customer counts from 2020 through 2025.

**NW Natural's Attachment 1
provided in response to Staff's DR 153
is available in electronic spreadsheet format only.**

NW Natural®

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 148
Non-confidential data provided in response to SDR 92 shows the following FTEs attributable to officers:

2020	2021	2022	2023	Test Year
11.4	10.5	11.6	11.9	12.4

Please explain why it is necessary to increase officer FTEs from the 2020-2023 average of 11.3 to 12.4 in the Test Year.

Response:

The number of officers can fluctuate from year to year if we have officers resign or retire, and it can take time to find replacements for those positions. Additionally, in late 2022, we did move our Sr Director of Rates and Regulatory to the VP of Rates and Regulatory officer position. This is a position that was an officer position in the past but had been vacant since Spring of 2016.

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 OPUC DR 155

Regarding payroll taxes,

a. How much does the Company propose to include in this case? Please provide the total Company and Oregon specific amounts.

b. Please explain how they are calculated. Please include the underlying data and calculations in electronic workbook format with all cell formulae and references intact.

c. Where are they included in the Company's rate request?

Response:

a. Projected Total Company payroll expense is $13,982,300 during the Test Year. This is allocated to O&M, Capital, and Non-Utility. The Capital allocated system amount is $4,692,277. The capital is included in project spend in this case and is allocated to many different FERC accounts with varying allocations to OR. The O&M allocated system amount is $8,718,527, and OR allocation is $7,758,059. This is moved out of O&M and to Other Taxes in the Revenue Requirement. The Non-Utility allocated amount is not included in this case.

b. See UG 490 OPUC DR 155 Attachment 1. The calculation for individual pieces of payroll taxes is taken by multiplying payroll dollars applicable to the tax times the tax rate.

c. Capital is included in project spend. The OR allocated expense can be found included in Other Taxes in the Revenue Requirement calculation. See Workpaper UG 490 – Exh. 1700 – WP1 – Revenue Requirements Model, tab Exhibit 1712 – Other Taxes, cell G24.

**NW Natural's Attachment 1
provided in response to Staff's DR 155
is available in electronic spreadsheet format only.**

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2003

NW Natural's
HIGHLY CONFIDENTIAL
DR Responses

April 18, 2024

Rates & Regulatory Affairs
UG 490
2024 Oregon General Rate Revision
Data Request Response

Request No.: UG 490 SDR 92

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year.
Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (Unadjusted) Paid Cash Compensation			
Category	Total Company FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Response:

Please see Highly Confidential UG 490 SDR 92 Attachment 1. This attachment was previously filed as non-confidential, however due to on-going labor negotiations the union wage information for 2024-2025 has been protected and refiled as Highly Confidential.

**NW Natural's HIGHLY CONFIDENTIAL
Attachment 1 provided in response to
Staff's SDR 92 is viewable only in Huddle,
subject to Modified Protective Order No. 23-480.**

**A redacted version is included
in Exhibit Staff/2002.**

CASE: UG 490
WITNESS: STEPH YAMADA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2004

HIGHLY CONFIDENTIAL
Staff Workpapers

April 18, 2024

Staff's HIGHLY CONFIDENTIAL workpapers are available in electronic spreadsheet format only.

CASE: UG 490
WITNESS: KEVIN HENNESSY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Opening Testimony
Safety Projects

April 18, 2024

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

A. My name is Kevin Hennessy. I am the Natural Gas Engineering and Safety Manager employed in the Utility Safety, Reliability, and Security Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/2101.

Q. What is the purpose of your testimony?

A. I review Daniel Kizer's testimony regarding investments being made by Northwest Natural Gas Company (NW Natural, NWN or Company) for safety-related programs.

Q. Did you prepare any other exhibits for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Could there be changes or updates to Staff's position and recommendations?

A. Yes. My testimony represents issues identified to date. My recommendations and issues may change when informed by new data and after reviewing testimony and analysis by other parties.

ISSUE 1. NW NATURAL SAFETY AND INSPECTION PROGRAMS

Q. Did you review Daniel Kizer's testimony regarding investments being made by Northwest Natural for safety-related programs?

A. Yes. I did.

Q. Did you have any concerns regarding the approach being taken with these programs.

A. Not generally, however certain programs warrant further mention.

Q. Are these programs consistent with the annual Safety Project Plan (SPP) filed by the Company in UM 1900?

A. Yes. Staff appreciates that the Company has created alignment between this portion of the rate case and the Safety Project Plan[1] to provide early indications of future actions and spending.

Q. Which program do you highlight?

A. First, I have concerns regarding the "ILI," Inline Inspection Program.

Q. What is your primary concern?

A. The Company is currently converting transmission lines to ensure the Company can conduct integrity assessments with inline inspections. Mr. Kizer testified the Company incurred significant costs for one of the ILI conversion projects completed in 2022, the P31/P75 McMinnville Trans ILI Project, after it went into service. Specifically, the Company spent an additional $1.4 million to

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Annual Natural Gas Safety Project Plan*, UM 1900, NW Natural's 2024 Oregon Safety Project Plan (September 27, 2023).

address and remediate three sites on the pipeline where the Company could not perform the inline assessment.[2]

Q. What recommendation to you have for the Commission to better control these cost escalations?

A. I suggest the Commission require NW Natural keep additional records and perform research in advance of construction to mitigate such construction overruns or surprises. Since this program just starting, incorporating learning developed in the McMinnville project makes sense.

Q. What other programs do you want to address?

A. Next, I discuss the underground storage-well integrity program, which will be ongoing for the foreseeable future.

Q. What recommendation to you have for the Commission regarding the Company's underground storage and integrity program?

A. I recommend the Commission require that NW Natural develop clear cost estimates "for the life of the facility" and that the Company include these cost estimates in the Company's annual Oregon Safety Project Plan filed in Docket UM 1900.

Q. Do you wish to discuss any other projects?

A. Yes. The last topic I address is the NW Natural's non-hazardous leakage projects.

Q. What is your concern in this regard?

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2 NW Natural/500, Kizer/44-45.

A. It is important to reduce or eliminate such leakage. In both the Safety Project Plan and in NW Natural's testimony it's not clear to me how many facilities have such leaks.

Q. What recommendation to you have for the Commission regarding non-hazardous leakage?

A. I recommend the Commission require that NW Natural capture and provide more detail in the Safety Project Plan, showing starting or prior counts and severity of leaks, the reduction in the count and severity, the estimated methane reduction, and the costs for the year.

Q. Does this conclude your testimony?

A. Yes.