NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

December 30, 2024 NWN OPUC Advice No. 24-26 / UG 520

VIA ELECTRONIC FILING AND HAND DELIVERY

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UG 520 – Application of NW Natural for a General Rate Revision

In accordance with OAR 860-022-0019, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith its Application for a General Rate Revision ("Application"). One physical copy of the non-confidential, redacted Executive Summary, Direct Testimonies, and Exhibits will be delivered to the Commission the week of January 6, 2025. A petition for waiver of OAR 860-001-0170(2) is being filed concurrently. In compliance with OAR 860-022-0019(2)(a), responses to the Standard Data Requests are being provided on the Commission's Huddle site and work papers are being provided to puc.workpapers@puc.oregon.gov. Notices will be published in accordance with the requirements of OAR 860-022-0017.

Please note, the filing contains some confidential information that represents business-sensitive, non-public information. Confidential and Highly Confidential or Sensitive Security Information will be provided subject to General Protective Order No. 23-132 and Modified Protective Order No. 24-456, respectively.

Included with this filing are revisions to Tariff, P.U.C. Or. 25 (as Exhibit NW Natural/1515, Walker), stated to become effective with service on and after **November 1, 2025**. A list of all proposed tariff sheets can be found in the attached Table of Tariff Sheets Revisions.

The Company waives paper service in this proceeding.

Please address correspondence on this matter to me with copies to the following:

Eric Nelsen
NW Natural
Senior Regulatory Attorney
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7618
eric.nelsen@nwnatural.com
OSB #192566

eFiling
NW Natural
Rates and Regulatory Affairs
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
eFiling@nwnatural.com

Jocelyn Pease
McDowell Rackner & Gibson PC
419 SW 11th Ave, Ste. 400
Portland, OR 97205
Telephone: (503) 595-3620
dockets@mrg-law.com
OSB #102065

Sincerely,

NW NATURAL

/s/ Zachary Kravitz

Zachary Kravitz
Vice President, Rates & Regulatory Affairs

Enclosures

NW Natural
TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE NOVEMBER 1, 2025
OPUC Advice No. 24-26

Schedule Title	Proposed Sheet
Schedule H – Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider	Seventh Revision of Sheet H-5
Rate Schedule 2 - Residential Sales Service	Seventeenth Revision of Sheet 2-1
Rate Schedule 3 - Basic Firm Sales Service – Non-Residential	Sixteenth Revision of Sheet 3-4
Rate Schedule 4 - Residential Multi-Family Service	Fifth Revision of Sheet 4-1
Rate Schedule 15 - Charges for Special Metering Equipment, Rental Meters, and Metering Services (Optional)	Sixth Revision of Sheet 15-1
Rate Schedule 15 - Charges for Special Metering Equipment, Rental Meters, and Metering Services (Optional)	Sixth Revision of Sheet 15-2
Rate Schedule 27 - Residential Heating Dry-Out Service	Fourteenth Revision of Sheet 27-1
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Sixteenth Revision of Sheet 31-11
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Fourteenth Revision of Sheet 31-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Fourteenth Revision of Sheet 32-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Sixteenth Revision of Sheet 32-13
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Fourteenth Revision of Sheet 32-14
Schedule 100 – Summary of Temporary Adjustments	Twelfth Revision of Sheet 100-1
Schedule 100 – Summary of Temporary Adjustments	Eleventh Revision of Sheet 100-2
Schedule 100 – Summary of Temporary Adjustments	Twelfth Revision of Sheet 100-3
Schedule 100 – Summary of Temporary Adjustments	Eleventh Revision of Sheet 100-4
Schedule 151 – Meter Modernization Program Amortization	Original of Sheet 151-1
Schedule 151 – Meter Modernization Program Amortization	Original of Sheet 151-2
Schedule 167 - General Adjustments to Rates	Sixth Revision of Sheet 167-1
Schedule 175 - Amortization of Horizon 1 Start-Up Cost Deferral	Second Revision of Sheet 175-1
Schedule 182 - Rate Adjustment for Environmental Cost Recovery	Fourth Revision of Sheet 182-1

Schedule 187 – Special Rate Adjustment for Mist Capacity Recall	Fifth Revision of Sheet 187-1
Schedule 190 - Partial Decoupling Mechanism	Seventeenth Revision of Sheet 190-1
Schedule 190 - Partial Decoupling Mechanism	Fourteenth Revision of Sheet 190-2
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Sixth Revision of Sheet 195-3
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Tenth Revision of Sheet 195-4
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Fourteenth Revision of Sheet 195-5
Schedule 196 - Adjustment for Certain Excess Deferred Income Taxes Related to the 2017 Federal Tax Cuts and Jobs Act	Fourth Revision of Sheet 196-1
Schedule 196 - Adjustment for Certain Excess Deferred Income Taxes Related to the 2017 Federal Tax Cuts and Jobs Act	Sixth Revision of Sheet 196-2
Schedule 197 - Amortization of Pension Balancing Account	Fourth Revision of Sheet 197-2

NW Natural

UG 520

**NOTICE OF APPLICATION FOR
GENERAL RATE REVISION**

December 30, 2024

<u>To All Parties Who Participated in UG 490:</u>
Please be advised that on December 30, 2024, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), has filed for a GENERAL RATE REVISION. A copy of the Company's non-confidential, redacted UG 520 OPUC ADVICE NO. 24-26 containing the EXECUTIVE SUMMARY, DIRECT TESTIMONIES, and EXHIBITS are available for inspection at its main office or at the Public Utility Commission of Oregon's ("Commission") eDocket website. An electronic courtesy copy is also attached.

The purpose of this Notice is to inform parties who participated in the Company's last general rate case, UG 490, that a General Rate Revision has been filed.

Parties who desire more information or who wish to obtain a copy of the filing, or notice of the time and place of any hearing, if scheduled, should contact the Company or the Commission as follows:

NW Natural
Attn: Zach Kravitz
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7617

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, Oregon 97308-1088
Telephone: (503) 378-6678

Any person may submit to the Commission written comments on this General Rate Revision within 25 days of service of this notice or seek to intervene in the proceeding. The granting of this General Rate Revision will authorize a change in rates.

* * * * *

CERTIFICATE OF SERVICE

UG 520

I hereby certify that on December 30, 2024, I have served by electronic delivery non-confidential, redacted copies of UG 520 OPUC ADVICE NO. 24-26, EXECUTIVE SUMMARY, DIRECT TESTIMONIES AND EXHIBITS OF NW NATURAL'S GENERAL RATE REVISION upon all parties of record for the Company's last general rate case, UG 490.

UG 490

JOHN GARRETT
OREGON CITIZENS' UTILITY BOARD
john@oregoncub.org

CLAIRE VALENTINE-FOSSUM
OREGON CITIZENS' UTILITY BOARD
claire@oregoncub.org

OREGON CITIZENS' UTILITY BOARD
dockets@oregoncub.org

CHAD M. STOKES
CABLE HUSTON LLP
cstokes@cablehuston.com

BRADLEY MULLINS
MW ANALYTICS, ENERGY & UTILITIES
brmullins@mwanalytics.com

STEPHANIE ANDRUS
OREGON DEPT. OF JUSTICE
stephanie.andrus@doj.state.or.us

MARLI KLASS
OREGON DEPT. OF JUSTICE
marli.klass@doj.state.or.us

MATTHEW MULDOON
PUBLIC UTILITY COMMISSION
matt.muldoon@puc.oregon.gov

JAIMINI PAREKH
EARTHJUSTICE
jparekh@earthjustice.org

NOORULANNE JAN
EARTHJUSTICE
njan@earthjustice.org

MICHAEL MAYER
EARTHJUSTICE
mmayer@earthjustice.org

ADAM HINZ
EARTHJUSTICE
ahinz@earthjustice.org

KRISTEN BOYLES
EARTHJUSTICE
kboyles@earthjustice.org

CARRA SAHLER
LEWIS & CLARK LAW SCHOOL
sahler@lclark.edu

ERIC NELSEN
NW NATURAL
eric.nelsen@nwnatural.com

JOCELYN PEASE
MCDOWELL RACKNER & GIBSON PC
jocelyn@mrg-law.com
dockets@mrg-law.com

NW NATURAL
efiling@nwnatural.com

DATED December 30, 2024, Portland, Oregon.

/s/ Erica Lee-Pella

Erica Lee-Pella
Rates & Regulatory Affairs
NW NATURAL
250 SW Taylor Street
Portland, Oregon 97204
(503) 610-7330
erica.lee-pella@nwnatural.com

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG 520

In the Matter of NORTHWEST NATURAL GAS COMPANY dba NW Natural Application for a General Rate Revision.	**NW NATURAL'S EXECUTIVE SUMMARY**

I. INTRODUCTION

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), is filing a general rate revision with the Public Utility Commission of Oregon ("Commission"), in accordance with ORS 757.205, 757.215 and 757.220, to revise its schedules of rates and charges for natural gas service in Oregon to become effective with service provided on and after November 1, 2025. With this filing, the Company requests a revision to customer base rates that will increase the Company's annual Oregon jurisdictional revenues by $59.4 million, or an approximate 5.79 percent increase over current customer rates.

The revised rates produce revenues necessary to sustain the provision of safe, reliable, and low-cost natural gas service to customers in Oregon, while preserving the Company's ability to attract capital for future investments. The Company files this Executive Summary in accordance with OAR 860-022-0019(1). Exhibit A to the Executive Summary provides the required information in accordance with OAR 860-022-0019(1)(a)-(h).

II. BACKGROUND

NW Natural is an Oregon corporation whose principal place of business is 250 SW Taylor Street, Portland, Oregon, 97204. NW Natural is a public utility providing natural gas service in Oregon within the meaning of ORS 757.005, and is subject to the jurisdiction of this Commission. NW Natural has over 700 thousand customer accounts in Oregon, consisting of approximately 639 thousand residential, 62 thousand commercial, and 822 industrial customers. Approximately 88 percent of NW Natural's customers are located in Oregon.

Communications regarding this filing, including data requests issued to the Company, should be addressed to:

eFiling
NW Natural
Rates and Regulatory Affairs
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7330
Fax: (503) 220-2579
Email: eFiling@nwnatural.com

Jocelyn Pease
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, Oregon 97205
Telephone: (503) 595-3620
Fax: (503) 595-3928
Email: dockets@mrg-law.com
OSB#: 102065

Eric Nelsen
NW Natural
Senior Regulatory Attorney
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7618
Fax: (503) 220-2579
Email: eric.nelsen@nwnatural.com
OSB #: 192566

Zachary Kravitz
NW Natural
Vice President, Rates & Regulatory
250 SW Taylor Street
Portland, Oregon 97204
Telephone: (503) 610-7617
Fax: (503) 220-2579
Email: zachary.kravitz@nwnatural.com

III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the 12-months ending October 31, 2026 ("Test Year"). NW Natural provides information for a historical base year of the 12- months ending December 31, 2024 ("Base Year") and makes adjustments to that information to reflect the forecasted Test Year. In order to meet the legal requirement that rates be fair, just, reasonable, and sufficient, the Company has selected the Test Year to closely reflect the investment and expense levels that will exist during the time that the rates adopted in this case are expected to be in effect. The new rates are filed with a requested effective date of November 1, 2025. This assumes the addition of the full 9-month statutory suspension period to the 30-day effective date normally applicable to tariff revisions.

B. Rate of Return

The Company's request is based on a capital structure of 52 percent common sequity and 48 percent long-term debt, a requested 10.40 percent return on equity ("ROE"), and a resulting overall rate of return ("ROR") on rate base of 7.658 percent. The Company's current authorized ROE is 9.40 percent. As described in the testimony of Jennifer E. Nelson, a reasonable ROE range for NW Natural is 9.90 percent to 11.00 percent using a combination of models and alternative input assumptions. Based on the results of the methods analyzed, Ms. Nelson recommends that 10.40 percent ROE is a reasonable, if not conservative, estimate of the Company's cost of equity.

C. Factors Driving Rate Adjustment

The need to increase rates is driven by increasing operating costs due to inflation and higher interest rates, as well as the costs of our long-planned investments to continue to support our utility service to customers. NW Natural has completed, or is in the process of completing, several long-planned investments in the safety and reliability of its operations for which the Company is seeking timely cost recovery. The key drivers for the Company's proposed rate increase include:

- **Replacing End-of-Life Mist Compressors:** NW Natural is replacing two end-of-life compressors at our Mist storage facility. Mist is a significant portion of our firm resource stack and operating compression is critical to meeting both our existing and anticipated winter demand. Both existing compressors have exceeded their useful lives and replacements are necessary to ensure Mist's continued reliability. The Company will replace the oldest compressor unit first in October 2025. NW Natural will use the other compressor unit to support injection operations during the replacement period. NW Natural is scheduled to replace the remaining compressor unit in October 2026.
- **Modernizing IT&S Systems:** NW Natural continues to make investments to replace end-of-life information technology and services ("IT&S") systems. In this case, NW Natural is seeking cost recovery of essential projects that are necessary to ensure the continued functionality of its IT&S infrastructure. These projects include: 1) continuing the multi-year program to phase out end-of-life field and web mapping software and transitioning to a consolidated set of modern software solutions; 2) ongoing work to improve its Identity Governance and Administration (IGA), which is the process of granting, updating, reviewing and revoking access to technology systems for NW Natural employees and contractors, based on job changes or other Company needs; and 3) NW Natural's ongoing Telemetry

Refresh Projects to replace decades-old supervisory control and data acquisition (SCADA) technologies with modern equipment to comply with new security and safety standards. NW Natural is also making other upgrades largely in response to cyber-security advancements and directives from the United States Department of Homeland Security's Transportation Security Administration ("TSA"), existing software reaching end-of-life and end-of-support, and developers exclusively providing cloud-based solutions. Because many of these new investments are cloud-based services and depreciate over a very short period of time (typically five years), NW Natural must seek cost recovery on a timely basis. Otherwise, the Company would not be able to recover a substantial portion of these investments (i.e., a delay of a year would result in NW Natural not recovering approximately 20 percent of its cloud-based IT&S investments).

- **Seismically Secure Regional Resource Centers and Physical Security Enhancements:** NW Natural has continued to execute on its long-term facilities strategy, which is driven by the Company's priority to provide continuity of operations during unplanned events. The Company methodically evaluates its facilities, including our resource centers across its service territory, to mitigate the risk that a seismic or other unplanned event could make our facilities inoperable. NW Natural is on the final stretch of its 10-year facilities roadmap. The Company has undertaken a long-planned approach to modernize its aging facilities. In this proceeding, the Company is seeking recovery for investments in The Dalles Resource Center. As the Company's only facility in the Columbia River Gorge, it is critical that The Dalles Resource Center have the necessary functionality for the

Company to respond to emergencies, including major seismic events. To help ensure this functionality, NW Natural will install a fueling station that will be available for Company use during emergencies that could impact retail fueling stations. The existing site and buildings are too small to accommodate the required operations functionality, hampering efficiency and employee safety. In this rate proceeding, NW Natural is also seeking to recover the costs of continuing physical security enhancements. These enhancements are made at the direction from the TSA and are necessary in response to increasing threats to facilities and the nature of those threats.

- **Distribution System & Storage Investments:** NW Natural is continuing to make improvements to our distribution system and storage facilities in order to keep our system safe, reliable, and economical. In addition to the end-of-life replacement of compressors at the Mist storage facility, NW Natural is seeking recovery of several major distribution and storage projects. These include Phase B of the North Coast Feeder Uprate Project, which is a system reinforcement in the areas of Astoria, Warrenton and Cannon Beach, and several other projects to ensure the continued safe and reliable operation of our system. NW Natural is also expanding its use of non-pipeline alternative ("NPA") solutions that can address system constraints in certain circumstances. Specifically, the Company is exploring solutions such as Geographically Targeted Energy Efficiency ("GeoTEE") and Geographically Targeted Demand Response ("GeoDR"), as well as a system-wide demand response program, that may mitigate the need to upgrade pipelines in certain areas of its system. In addition, NW Natural has hired an outside consultant to prepare a compressed natural gas ("CNG") or liquefied natural gas ("LNG") trucking study to help determine the viability of CNG or LNG gas supply alternatives in lieu of pipeline solutions for a peak weather event. NW Natural is currently conducting these NPA analyses and expects them to be available for alternatives planning purposes in the next Integrated Resource Plan ("IRP") to be filed in August 2025.

- **Meter Modernization Program:** As the Company described in docket UG 490, NW Natural is proceeding with a multi-year process to replace metering infrastructure nearing end-of-life. The meter modernization program ("MMP") will replace end-of-life Encoder Receiver Transmitter ("ERT") devices, which electronically record and transmit metered gas consumption data to the Company. Additionally, the MMP will maximize cost-efficiency by simultaneously replacing meters that do not meet our testing standards. As part of its MMP, NW Natural is installing replacement devices on a daily basis and the Company is seeking timely recovery of these costs to limit the magnitude of future rate increases.
- **Depreciation Rates:** NW Natural is proposing updated depreciation rates with this general rate case. The Company is filing an updated depreciation study performed by Gannett Fleming, which builds off the settlement in the Company's previous depreciation study that the Commission approved in Order No. 24-302.

NW Natural's goal is to provide safe and reliable service at affordable rates for its customers. NW Natural continues to manage its costs through careful planning and budgeting, with an ongoing focus on controlling costs. However, the long-planned investments that the Company is currently making to ensure it can provide high-quality and reliable natural gas service require the Company to file a rate case at this time.

D. Rate Mitigation

With this rate change, our average residential customer's bill is still less expensive than it was two decades ago after adjusting for inflation. Moreover, as shown in Figure 1 below, the bill discount program ("BDP") for income-eligible customers with incomes at or below 60 percent of the state median income ("SMI") has dramatically lowered participating customers' bills before taking into account any other bill assistance programs. In the Company's last rate case, NW Natural worked with intervenors to increase the discounts available to income-eligible customers, which is more tailored to address energy burden than the prior discounts available. For comparison, beginning on November 1, 2005, the average monthly residential bill was $82.49 for all residential customers. With our updated tiers to our BDP, the average monthly residential bill for participating customers beginning on November 1, 2025 is lower than what that customer would have paid twenty years ago *without adjusting for inflation*, highlighting both the stability of our rates over that time and the value of the BDP. Please see Figure 1 below.

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Figure 1

Comparison of Average 2025 BDP Bill to Average 2005 Residential Bill ($82.49)

BDP Tier Level	BDP Discount of Total Bill	Average 2025 Monthly Bill Under BDP	2025 BDP Monthly Bill Compared to Average 2005 Bill
Tier 0 0-15% SMI	85%	$13.13	-84.1%
Tier 1 16-30% SMI	50%	$43.77	-46.9%
Tier 2 31-45% SMI	30%	$61.28	-25.7%
Tier 3 46-60% SMI	15%	$74.41	-9.8%

NW Natural's most recent Energy Burden Assessment ("EBA") found that in only the second full year of offering the BDP, we now have 78 percent of our income-eligible customers enrolled in the program. While NW Natural strives to reach all of our income-eligible customers, the Company is pleased with the participation rates for such a new program.

With respect to the considerations for this rate case, NW Natural carefully considered the input from stakeholders and the Commission in the last rate case, and sought to limit the size of the increase in this case. Although the Commission declined to adopt CUB's proposal for a 10 percent rate cap—and NW Natural opposed that proposal based on legal concerns and the resulting safety and reliability risks that an artificial rate cap would create—NW Natural nonetheless supports the underlying concept of avoiding rate volatility wherever possible. To that end, NW Natural is filing a smaller and simpler rate case in this proceeding to further this shared goal with the understanding that certain events outside the Company’s control, such as purchased gas and climate regulation compliance costs, could contribute to rate volatility despite more frequent general rate cases.

NW Natural continues to carefully scrutinize its potential investments and operating costs to minimize costs to customers. For example, the Company has decided to delay implementing a replacement of its customer information system (“CIS”) until approximately 2030, after conducting a six-month study with Ernst & Young providing support as a third-party consultant, thereby delaying a major capital investment. The Company is also continuing to take a very disciplined approach to renewable natural gas (“RNG”) investments while maintaining progress in acquiring greater amounts of RNG through prudent purchases. We have decided to not move forward with certain RNG investments that exceeded our initial cost expectations due to inflation and uncertain interconnection costs, among other reasons. That said, we will, of course, make any necessary investments to comply with applicable climate regulations, including investments in RNG. However, we are nonetheless conscious of the cost pressures that our customers are facing and are committed to addressing it without compromising safe and reliable service or compliance with state regulations.

Additionally, although NW Natural had hoped to establish the framework for a multi-year rate plan in docket UG 490, that did not occur and the Commission instead directed a Staff-led process to investigate the potential use of a multi-year rate plan. Therefore, NW Natural has proposed only a traditional single-year plan in this case. The

Company looks forward to continuing the dialogue regarding the potential contours for a multi-year approach in the Staff-led process.

IV. TESTIMONY SUMMARY

The Company's direct case consists of the following testimony and witnesses:

- In NW Natural/100, **Justin B. Palfreyman**, NW Natural's President, and **Zachary D. Kravitz**, Vice President of Rates and Regulatory Affairs, describe the value that NW Natural provides to the customers we serve and the entire Pacific Northwest. In addition, they provide a high-level overview of the Company's application for a general rate revision, including explaining the cost and business drivers that led to NW Natural making this request. They also provide an update on several important equity initiatives, including implementing an expanded BDP and finalizing our second EBA.
- In NW Natural/200, **Cecelia J. Tanaka**, Community Partnerships Manager, describes the Company's initiatives and priorities regarding equity and inclusion, including details on the Company's EBA and low-income assistance offerings.
- In NW Natural/300, **Brody J. Wilson**, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony explains the Company's financing strategy of maintaining a balance of long-term debt and equity financing. Mr. Wilson explains why the Company is targeting a capital structure of 52 percent common equity and 48 percent long-term debt, resulting in an ROR on rate base of 7.658 percent, which will maintain financial health and benefit customers.

- In NW Natural/400, **Jennifer E. Nelson**, Assistant Vice President, of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, provide testimony about the Company's cost of equity, or in other words, the return that investors in NW Natural should reasonably expect to have the opportunity to earn in order to attract capital. Her testimony supports a reasonable range for the Company's cost of equity between 9.90 percent and 11.00 percent. Ms. Nelson recommends that NW Natural be allowed an opportunity to earn a 10.40 percent return on equity in the revenue requirement authorized in this proceeding.
- In NW Natural/500, **Daniel B. Kizer**, Engineering Senior Director, and **Scott S. Johnson**, Director of Gas Supply, provide testimony about aspects of the Company's long-term system planning and the Company's recent improvements to its system modeling, as well as the improvements to our distribution system and storage facilities that the Company has undertaken in order to keep our system safe, reliable, and economical.
- In NW Natural/600, **Wayne K. Pipes**, Director of Facilities, Security and Emergency Management, describes the Company's execution on its long-term facilities strategy, including acquiring land for the new resource center at The Dalles and continuing physical security enhancements.
- In NW Natural/700, **Brian E. Fellon**, Vice President and Chief Information Officer, describes NW Natural's ongoing IT&S strategic approach and details the Company's cost-recovery requests with respect to major projects and crucial hiring needs. **Mr. Fellon** also sponsors separate testimony describing the Company's

response to the emergency mandatory federal regulatory requirements in TSA Security Directive Pipeline-2021-02. NW Natural/800 (Sensitive Security Information).

- In NW Natural/900, **Joe S. Karney**, Vice President of Engineering and Utility Operations, provides an update on the Company's Meter Modernization Program.
- In NW Natural/1000, **Melinda B. Rogers**, Vice President, Chief Human Resources and Diversity Officer, provides testimony on our labor costs, and describes the Company's practices related to compensation, which ensure that all employees receive compensation at market-median rates. Additionally, Ms. Rogers describes our overall employee count and sets forth the Company's request to include these costs in the Company's revenue requirement.
- In NW Natural/1100, **Cory A. Beck**, Director of Customer Experience Services, provides testimony about the Company's communications to customers on matters of safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and opportunities to conserve and be educated about the products that they purchase from us.
- In NW Natural/1200, **Kathryn M. Williams**, Vice President, Chief Public Affairs and Sustainability Officer, provides an update on the Company's time-tracking for lobbying expenses and provides the basis for recovery for NW Natural's government affairs team.
- In NW Natural/1300, **Tobin F. Davilla**, Senior Manager of Financial Planning and Budget, provides testimony about the operations and maintenance expense levels

that the Company has incurred and expects to incur in the Test Year, as well as overall capital spending, for which it requests recovery in this application.

- In NW Natural/1400, **John J. Spanos**, President of Gannett Fleming Valuation and Rate Consultants, LLC, presents the depreciation study that is used to calculate the Company's depreciation rates. The depreciation study will also be filed in a separate docket.
- In NW Natural/1500, **Kyle T. Walker**, Senior Manager of Rates and Regulatory Affairs, provides the calculation of the Company's revenue requirement, which represents the annual dollars needed to recover prudently incurred costs of operating the utility business, and presentation of Tariffs.
- In NW Natural/1600, **Robert J. Wyman**, Rates and Regulatory Economist, provides the Company's use-per-customer forecast, long run incremental cost study, and the proposed spread across rates of the revenue requirement increase requested.

V. CONCLUSION

For the reasons described in this application, and further by the testimony and exhibits of the witnesses offered in this proceeding, the Company requests that the Commission issue an order approving the proposed rate changes and tariff sheets.

DATED: December 30, 2024

NORTHWEST NATURAL GAS COMPANY

/s/Eric W. Nelsen

Eric W. Nelsen (OSB# 192566)

MCDOWELL RACKNER & GIBSON PC

/s/Jocelyn Pease

Jocelyn C. Pease (OSB# 102065)

Attorneys for Northwest Natural Gas Company

Exhibit A to NW Natural's Executive Summary
Summary of Requested General Rate Increase
Filed December 30, 2024

Total Revenues Collected Under Proposed Rates:	$1,063,677,975
Revenue Change Requested:	$62,064,430
Revenues Net of any Credits from Federal Agencies:	$1,063,677,975
Percentage Change in Revenue Requested:	5.9 %
Percentage Change in Revenues	
Net of any Credits from Federal Agencies:	5.9 %

Test Period: November 1, 2025 to October 31, 2026

Requested Over Rate of Return	7.658%
Requested Rate of Return on Equity:	10.40%
Proposed Rate Base:	$2,293,722,494
Results of Operation	
Before Proposed Rate Change	
Utility Operating Income:	$133,797,368
Average Rate Base:	$2,293,722,494
Rate of Return on Capital:	5.833%
Rate of Return on Equity:	6.89%
After Proposed Rate Change	
Utility Operating Income:	$175,653,269
Average Rate Base:	$2,293,722,494
Rate of Return on Capital:	7.658%
Rate of Return on Equity:	10.4%

The $59.4 million of revenue requirement which includes $4.5 million of Plant EDIT amortization are as follows:

Rate Schedules	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
Schedule 2 – Single Family	$81.79	$87.11	$5.32	6.5%
Schedule 2 – Multi Family	$79.79	$85.11	$5.32	6.7%
Schedule 3 – Commercial	$339.18	$359.48	$20.30	6.0%
Schedule 3 – Industrial	$1,383.94	$1,430.34	$46.40	3.4%
Schedule 27 - Dry Out	$60.20	$64.85	$4.65	7.7%
Schedule 31 - Firm Sales - Commercial	$2,541.08	$2,624.73	$83.65	3.3%
Schedule 31 - Firm Transportation - Commercial	$1,653.21	$1,752.10	$98.89	6.0%
Schedule 31 - Firm Sales - Industrial	$3,980.09	$4,081.00	$100.91	2.5%
Schedule 31 - Firm Transportation - Industrial	$1,382.15	$1,479.28	$97.13	7.0%
Schedule 32 - Firm Sales - Commercial	$5,706.48	$5,857.52	$151.04	2.6%
Schedule 32 - Firm Sales - Industrial	$13,561.76	$13,841.96	$280.20	2.1%
Schedule 32 - Firm Transportation - Commercial	$3,265.79	$3,486.10	$220.31	6.7%
Schedule 32 - Firm Transportation - Industrial	$7,207.79	$7,807.76	$599.97	8.3%
Schedule 32 - Interruptible Sales - Commercial	$22,529.18	$22,990.36	$461.18	2.0%
Schedule 32 - Interruptible Sales - Industrial	$34,889.67	$35,422.34	$532.67	1.5%
Schedule 32 - Interruptible Transportation - Commercial	$11,577.98	$12,266.42	$688.44	5.9%
Schedule 32 - Interruptible Transportation - Industrial	$11,470.59	$12,335.91	$865.32	7.5%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	$0.00	0.0%
Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those schedules.				

The revenue requirement plus additional temporary impacts to customers are as follows:

Rate Schedules	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
Schedule 2 – Multi Family	$81.79	$87.34	$5.55	6.8%
Schedule 2 – New Premise	$79.79	$85.34	$5.55	7.0%
Schedule 3 – Commercial	$339.18	$360.39	$21.21	6.3%
Schedule 3 – Industrial	$1,383.94	$1,433.10	$49.16	3.6%
Schedule 27 - Dry Out	$60.20	$65.02	$4.82	8.0%
Schedule 31 - Firm Sales - Commercial	$2,541.08	$2,630.47	$89.39	3.5%
Schedule 31 - Firm Transportation - Commercial	$1,653.21	$1,758.88	$105.67	6.4%
Schedule 31 - Firm Sales - Industrial	$3,980.09	$4,087.90	$107.81	2.7%
Schedule 31 - Firm Transportation - Industrial	$1,382.15	$1,485.06	$102.91	7.4%
Schedule 32 - Firm Sales - Commercial	$5,706.48	$5,867.84	$161.36	2.8%
Schedule 32 - Firm Sales - Industrial	$13,561.76	$13,861.10	$299.34	2.2%
Schedule 32 - Firm Transportation - Commercial	$3,265.79	$3,501.15	$235.36	7.2%
Schedule 32 - Firm Transportation - Industrial	$7,207.79	$7,843.34	$635.55	8.8%
Schedule 32 - Interruptible Sales - Commercial	$22,529.18	$23,017.79	$488.61	2.2%
Schedule 32 - Interruptible Sales - Industrial	$34,889.67	$35,453.97	$564.30	1.6%
Schedule 32 - Interruptible Transportation - Commercial	$11,577.98	$12,313.88	$735.90	6.4%
Schedule 32 - Interruptible Transportation - Industrial	$11,470.59	$12,387.77	$917.18	8.0%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	$0.00	0.0%
Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those schedules.				

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Justin B. Palfreyman and Zachary D. Kravitz

POLICY EXHIBIT 100

December 30, 2024

EXHIBIT 100 - DIRECT TESTIMONY - POLICY

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your names, positions with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company") and summarize your educational background and business experience.

A. My name is Justin B. Palfreyman. I am the President of NW Natural. I joined NW Natural as Vice President of Strategy and Business Development in 2016 and have previously served as President of NW Natural's affiliate, NW Natural Water Company, LLC. I have over 20 years of professional experience in general management, strategy, finance and corporate development functions. Prior to joining NW Natural, I worked as a Director in Lazard's Power, Energy and Infrastructure Group in New York, where I provided strategic and financial advice to utilities, corporations, financial investors and government clients. My advisory assignments related to general strategic advice; mergers, acquisitions and divestitures; raising capital; restructurings; corporate preparedness/takeover defense; and capital structure optimization. Prior to Lazard, I worked in the Infrastructure Investment Banking Group at Goldman Sachs in New York. I also previously held various positions in finance, strategy and business development at both Apex Learning and Accenture in Seattle, Washington. I hold a Master of Business Administration from the University of Chicago Booth School of Business, a Master of Public Policy from The University of Chicago Irving B. Harris School of Public Policy, and a Bachelor of Business Administration from Pacific Lutheran University.

My name is Zachary D. Kravitz. I am the Vice President of Rates and Regulatory Affairs for NW Natural. I joined NW Natural's Legal Department in 2014 as Associate Regulatory Counsel. In 2018, I joined the Rates and Regulatory Affairs Department in the position of Director of Rates & Regulatory Affairs, and later Senior Director. Prior to joining NW Natural, I worked in the energy and utility practice at the law firms of Chester, Wilcox & Saxbe, LLC and Taft, Stettinius & Hollister, LLP in Columbus, Ohio. Before that, I worked at the Ohio Attorney General's Office in the Labor Relations Division. I received a Bachelor of Arts degree in English and Government from the University of Texas at Austin and a Juris Doctor degree from the University of Florida.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide a high-level overview of the Company's application for a general rate revision and explain the cost and business drivers that led to NW Natural making this request.

Q. Please summarize your testimony.

A. First, we discuss the value that NW Natural provides to its customers and to the Pacific Northwest. Specifically, we discuss the importance of NW Natural's pipeline and storage system to the overall energy system, why the capacity that we provide is increasingly crucial to the reliability of both the power and gas systems due to increasing energy demands, and why we must continue to maintain and invest in a safe system.

Second, we describe the key drivers of our request for a general rate revision, such as making critical investments at our Mist storage facility to ensure that NW Natural can maintain adequate capacity to continue meeting our customers' energy demand during the coldest winter days as the region's power and gas systems grow more and more constrained with each passing year. By recovering these costs, NW Natural can maintain its strong financial health and stable credit ratings, thereby securing access to capital markets, and ultimately providing low-cost, safe, and reliable utility service to our customers.

Third, we provide an update on several important equity initiatives, including implementing an expanded bill discount program and finalizing our second Energy Burden Assessment ("EBA"). We are proud of the continued progress we have made, as evidenced by the fact that 78 percent of eligible residential customers are participating in an expanded bill discount program that offers up to 85 percent off a customer's bill, and we are eager to share additional details of our work in this area.

Finally, we introduce the Company's witnesses and provide a high-level description of their testimony.

II. THE VALUE OF NW NATURAL

Q. Please describe the value that NW Natural provides to its customers.

A. NW Natural provides value to its customers through the delivery of safe, reliable and affordable utility services. NW Natural delivers natural gas to its customers through more than 14,000 miles of transmission and distribution pipelines. In addition, it has over 20 billion cubic feet of natural gas storage at our three storage operations, which allows us to reliably and affordably provide energy to our customers on the coldest of winter days. As the largest standalone gas utility in the Pacific Northwest, NW Natural serves more than 2 million people in Oregon and southwest Washington. Our employee base of approximately 1,300 dedicated employees provides service to over 700 thousand Oregon customer accounts in 126 cities in 15 different counties, representing approximately 88 percent of our total gas system customer base.

We are proud of the fact that we continue to affordably provide safe and reliable service to our customers. Our average residential customer's bill is also less expensive than it was two decades ago after adjusting for inflation. Moreover, as shown in Figure 1 below, the bill discount program ("BDP") for income-eligible customers with incomes at or below 60 percent of the state median income ("SMI") has dramatically lowered participating customers' bills before taking into account any other bill assistance programs. Beginning on November 1, 2005, the average monthly residential bill was $82.49 for all residential customers. With our updated tiers to our BDP, the average monthly residential bill for participating customers beginning on November 1, 2025 is lower than what that customer would have paid twenty years ago *without adjusting for inflation*, highlighting both the stability of our rates over that time and the value of the BDP. Please see Figure 1 below.

Figure 1

Comparison of Average 2025 BDP Bill to Average 2005 Residential Bill ($82.49)

BDP Tier Level	BDP Discount of Total Bill	Average 2025 Monthly Bill Under BDP	2025 BDP Monthly Bill Compared to Average 2005 Bill
Tier 0 0-15% SMI	85%	$13.13	-84.1%
Tier 1 16-30% SMI	50%	$43.77	-46.9%
Tier 2 31-45% SMI	30%	$61.28	-25.7%
Tier 3 46-60% SMI	15%	$74.41	-9.8%

Q. Please describe the value that NW Natural provides to the Pacific Northwest as a whole.

A. NW Natural plays a vital role in the overall energy system of the Pacific Northwest. In Oregon, the gas and electric systems have a concurrent peak in winter. During the recent January 2024 winter storm event, NW Natural delivered 55 percent more energy than Oregon's two largest electric utilities combined on the peak hour.

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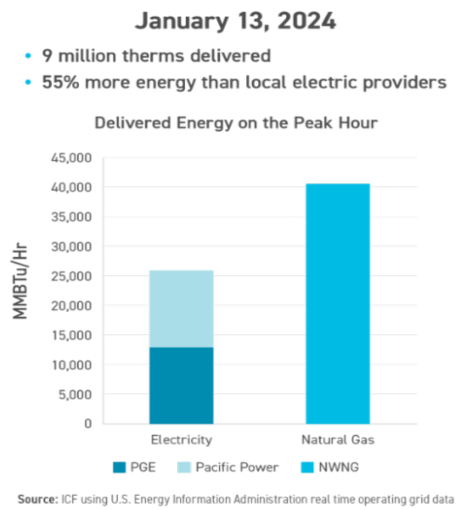
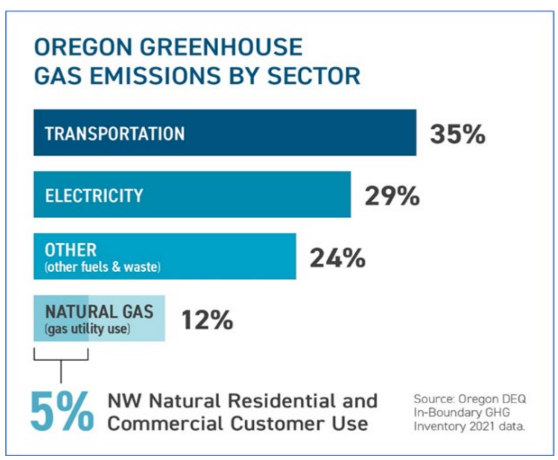
Figure 2



NW Natural provides this value, even though its customers' use of natural gas only accounts for a small share of the State's overall emissions. For example, NW Natural's residential and commercial customers' use accounts for about 5 percent of the State's overall emissions.

Figure 3 [1]



[1] Department of Environmental Quality, Oregon Greenhouse Gas Sector-Based Inventory Data (last visited Dec. 16, 2024) (available at: https://www.oregon.gov/deq/FilterDocs/ghg-sectordata.xlsx).

Q. Please provide more detail on the capacity value that NW Natural's system provides to Oregon.

A. The capacity provided by NW Natural is critical to ensuring that Oregon's overall energy system remains reliable, resilient, and affordable. On the coldest winter days, NW Natural's system meets 90 percent of the energy needs for its residential space and water heat customers. This amount of capacity would be extremely difficult to replace with electric solutions given the limitations already facing the Pacific Northwest's power system. According to the Pacific Northwest Utilities Conference Committee ("PNUCC"), the region already has a winter peak deficit of approximately 2,500 MW in 2025 and that deficit will grow to approximately 13,700 MW in 2034.[2] In addition, NW Natural serves commercial and industrial customers whose use of natural gas simply cannot be electrified at any price given current technology.

Q. Have recent winter weather events provided real-life examples of the importance of NW Natural's capacity?

A. Yes. In mid-January 2024, NW Natural's service territory experienced severe winter weather, which demonstrated the capacity, resiliency, and reliability values of the natural gas system. On January 13, 2024, as temperatures dropped to 15°F in the Portland area, NW Natural delivered 9 million therms of natural gas to homes and businesses, virtually matching our previous record for a single gas day, and

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[2] PNUCC, *2024 Northwest Regional Forecast* at 21 (May 1, 2024) (available at https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf).

approximately doubling our average daily winter send out. NW Natural delivered approximately 8 million therms of natural gas for each of the following three days. In addition to matching a single gas day delivery record and sustaining high volumes of natural gas delivery to our customers, NW Natural also broke previous Mist storage facility send out records for five days during this period and delivered over 4.5 million therms of stored natural gas on January 13, 2024.

Approximately one year prior, on December 22, 2022, NW Natural's system experienced another extremely cold day where temperatures dropped to 17 degrees resulting in record throughput on our system that would only be matched by the January 2024 weather event discussed above. Both of these recent winter weather events demonstrate the capacity value of NW Natural's system during the coldest winter weather.

Q. Given record throughput during severe weather events in the last two winters, is it fair to say that Oregon's reliance on NW Natural's capacity is increasing?

A. Yes. The last two winters illustrate how important NW Natural's system is to Oregon. During the severe weather events in both winters, NW Natural reliably met its customers' needs to heat their homes and their businesses despite record setting demand. Moreover, in addition to the winter peak deficit identified by PNUCC and cited above, a recent *The Oregonian* article (NW Natural/101, Palfreyman-Kravitz) states that the power demands of data centers are "soaring" and that "[i]f the Northwest fails to add enough generation and transmission to meet the growing energy needs . . . periodic blackouts are inevitable at times power demand is at its greatest." The Northwest Power and Conservation Council projects that the region will need between 4,000 aMW and 6,500 aMW of additional generation by 2030, which is enough to power 3 million and 5 million homes.[3] For context, there are only about 1.88 million housing units in the entire state of Oregon, according to the U.S. Census Bureau.[4] An industry expert believes that the additional generation needed will be at the higher end of that scale.[5]

Q. Are natural gas utilities also facing their own capacity challenges?

A. Yes. Capacity constraints across the region's overall energy system are starting to present challenges to both natural gas and electric utilities. These challenges highlight the value that NW Natural's system provides to both its customers and the entire Pacific Northwest through its existing storage facilities and pipeline network. For natural gas utilities specifically, such challenges are two-fold. First, electric utilities are increasingly relying on natural gas power generation. The increased use of natural gas for power generation impacts the broader market for natural gas. Figure 4 below shows the increasing use of natural gas for power generation in Oregon while the direct use of natural gas has remained relatively flat since the turn of the century.

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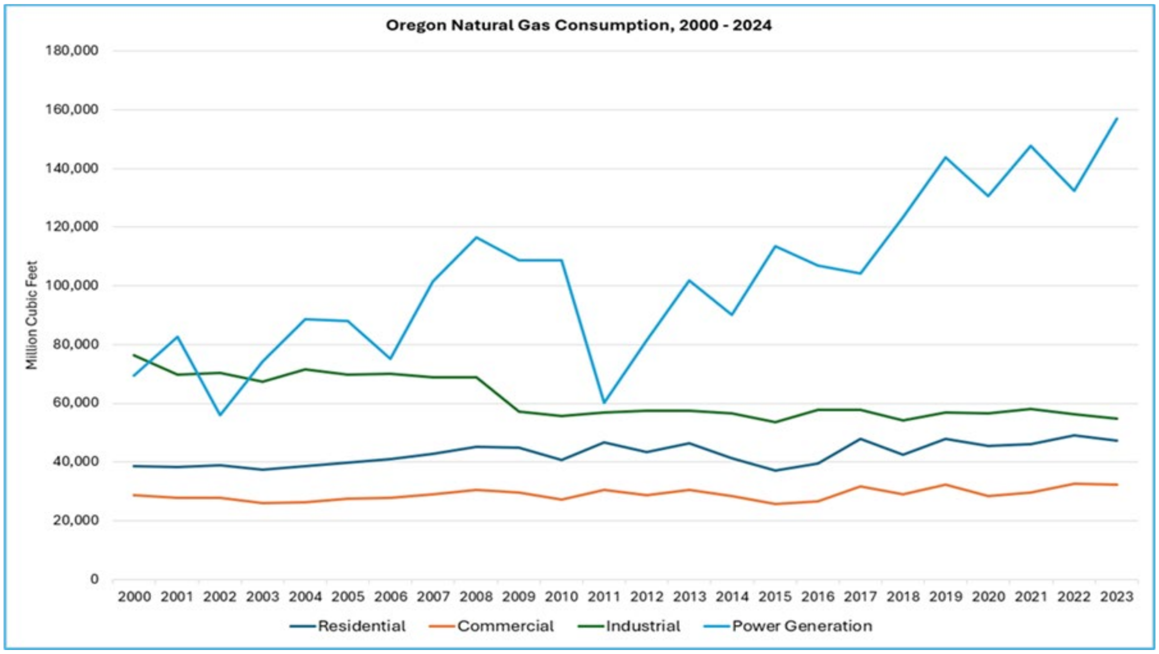
[3] NW Natural/101, Palfreyman-Kravitz.

[4] U.S. Census Bureau, Quick Facts, Oregon, available at: https://www.census.gov/quickfacts/fact/table/OR/BZA210222

[5] NW Natural/101, Palfreyman-Kravitz.

Figure 4



This increased use of natural gas for power generation puts further stress on the interstate pipeline system, especially during periods of inclement weather where renewable power generation is diminished due to a lack of sun and wind. These challenges may become more pronounced in the future in order to address the winter peak deficit identified by PNUCC that is projected to grow to 13,700 MW by 2034, as well as increased data center demand.[6]

Second, a liquefied natural gas ("LNG") export terminal, Woodfibre, is currently under construction in southern British Columbia and is scheduled to commence operation in 2027. When Woodfibre comes online, it will effectively

[6] PNUCC, *2024 Northwest Regional Forecast* at 21 (May 1, 2024) (available at https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf).

remove approximately 16 percent of the supply from the Sumas market. The Sumas market is where natural gas is imported from British Columbia, a key supply source for the Pacific Northwest. Removing supply from the Sumas natural gas market will further tighten natural gas supplies in the region, further contributing to the capacity challenges the region is facing. This will have a direct impact on NW Natural and will require additional capacity to serve our existing customer base.

Q. What is NW Natural doing to address these challenges?

A. NW Natural is relying on its ownership of and access to regional natural gas storage facilities to meet these challenges. Specifically, NW Natural owns underground storage facilities at Mist and two LNG storage facilities at Portland and Newport. In addition, NW Natural contracts for storage service at Jackson Prairie, which is located about 80 miles north of Portland near Centralia, Washington. At these storage facilities, natural gas can be stored indefinitely and dispatched over the entire winter season including sustained multi-day cold stretches. NW Natural's access to these storage facilities gives NW Natural the ability to store natural gas for use during the coldest days of the year irrespective of increased demand during this time of year.

Furthermore, NW Natural has also already developed additional capacity at Mist in advance of utility customer need. This capacity currently serves the interstate/intrastate storage market but can be recalled for service to NW Natural's utility customers at its depreciated value, providing real-time access to incremental capacity at a low cost. Mist is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. Due to its location, Mist is particularly well suited to meet load requirements in the Portland area, which can then free up other capacity resources to meet incremental system requirements. NW Natural has recalled an incremental 20,000 Dth/day of Mist deliverability to meet this demand beginning November 1, 2024, and expects additional recalls to meet demand in the future. The ability to recall Mist storage capacity for utility customer use plays a major role in addressing demand uncertainty created by an increased reliance on natural gas for power generation and competing demands for natural gas supply from the Woodfibre LNG facility in British Columbia.

Q. Do NW Natural's storage facilities also help maintain power system reliability?

A. Yes. NW Natural's North Mist storage facility is exclusively used by Portland General Electric Company ("PGE") to store approximately 1.2 billion cubic feet of natural gas for power production. In its recent general rate case, PGE stated that it appreciates the flexibility of North Mist, which allows it to "withdraw gas . . . on a 'no-notice' basis, which provides a high degree of intra-day and intra-hour flexibility that aligns with PGE's need for a flexible and dynamic fuel supply."[7] Moreover, PGE states that "holding fuel reserves *directly insures customers* from both

[7] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 435, Surrebuttal Testimony of Greg Batzler and Stephanie Meeks, PGE/2400 at 31-32 (Oct. 1, 2024).

runaway prices *and* supply disruptions."[8] Therefore, it helps prepare PGE "for the worst-case scenario that the next marginal unit of gas or electricity may be unavailable at any price," since "[t]he energy market does not have infinite depth and liquidity."[9]

NW Natural appreciates the value that PGE finds in the North Mist storage facility. It is an example of joint power-gas coordination that helps ensure the reliability, resiliency, and affordability of the overall energy system. In the coming years, NW Natural is eager to pursue opportunities to further leverage the capacity of its system, including the enormous amount of flexibility provided by Mist, to complement the region's continued expansion of intermittent renewable power generation. Hybrid heating, which combines a natural gas furnace with an electric heat pump, is a logical next step that promotes decarbonization without sacrificing reliability, resiliency or affordability. Additionally, alternative heating and cooling technologies, like thermal energy networks, use a shared network of pipes transferring heat in and out of buildings that, when properly designed, leads to increased energy optimization.

Q. Given its importance, is NW Natural making investments to ensure the reliability of its Mist storage facility?

A. Yes. As explained in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (NW Natural/500, Kizer-Johnson), NW Natural is replacing two end-of-life

[8] *Id.* at 33 (emphasis in original).

[9] *Id.* at 34.

compressors at Mist. As described above, Mist is a significant portion of our firm resource stack and without operating compression, NW Natural cannot meet its existing or anticipated winter demand. Specifically, the GC500 compressor and GC600 compressor, installed in 1998 and 2001-2002, respectively, perform the bulk of the compression work for withdrawal and injection activities at Mist. Both compressors have exceeded their expected useful life with over 45,000 hours operation and require ongoing "break-fix" repairs that routinely disrupt the operations at Mist. The Company will replace the GC500 unit first, in October 2025, because it is the oldest unit. NW Natural will use the GC600 unit to support injection operations during the replacement period. NW Natural is scheduled to replace the GC600 turbine compressor in October 2026. Replacing these compressors is vital to ensure the future reliability of Mist in the face of increasing constraints on both the power and gas systems.

III. NW NATURAL'S APPLICATION FOR GENERAL RATE REVISION

Q. Please summarize the Company's requested rate increase.

A. NW Natural is seeking to increase revenues from base rates by $59.4 million, which would be a 5.79 percent increase in overall revenues. The requested increase in base rates includes a capital structure of 52 percent common equity and 48 percent long-term debt, and a requested 10.4 percent return on equity ("ROE"), resulting in an overall rate of return ("ROR") on rate base of 7.658 percent.

We determined that NW Natural would need to file this rate request with the Commission to recover the costs of investments to continue to support our utility service to customers, such as the new compressors at Mist, as well as recover increasing operating costs. To meet the operational requirements necessary to serve our customers, the Company cannot compromise the safety and reliability of our system by under-investing or avoiding necessary investments. The consequences of any such under-investment go far beyond the financial considerations faced by most companies. In our case, failing to invest in the safety and reliability of our system can lead to customers or members of the general public suffering serious injury or even death. Our public safety responsibility is paramount, and we must continue to prudently invest in our system to ensure the safe and reliable delivery of energy to homes and businesses in Oregon. Ultimately, we must recover the costs of those investments to maintain the financial health of the Company.

Q. Without this request for rate relief, what is the financial impact to NW Natural?

A. Without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall ROR to be 5.83 percent, with a corresponding ROE of 6.9 percent, well below the proposed ROR and ROE in this case of 7.7 percent and 10.4 percent, respectively. The Company, therefore, needs to increase its rates in order to maintain an ability to recover our costs and earn a reasonable return that will allow it to attract the capital that is required to safely and reliably run its utility system for the benefit of our customers.

Q. You stated that the Company is seeking to change its current 50-50 capital structure to a capital structure of 52 percent common equity and 48 percent long-term debt. Why is NW Natural seeking this change?

A. As further explained in the Direct Testimony of Brody J. Wilson (NW Natural/300, Wilson), NW Natural is seeking to support its creditworthiness by increasing its capital structure equity percentage from 50 percent to 52 percent, thereby improving its credit metrics with rating agencies. We are seeking this change to reflect our actual forecasted capital structure in 2025 and through the Test Year. By reducing NW Natural's long-term debt ratio, NW Natural can improve its performance for key credit metrics, which measure operating cashflow to debt obligations. In the last five years, NW Natural has been below the rating agencies' downgrade thresholds for these metrics. By taking actions to protect against a credit downgrade, we can benefit our customers by continuing to access capital markets at the most favorable terms possible and through all types of economic conditions.

Moreover, even with this change to our capital structure, NW Natural would still have a debt ratio that is higher than its gas utility peers. This group has an average debt ratio of approximately 44.72 percent over the last three years.[10] This shows that NW Natural's proposed capital structure is still more leveraged than its peer utilities, but is nonetheless much more in-line with the rest of the industry than our current 50-50 capital structure.

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[10] *See* NW Natural/400, Nelson/71, line 18.

Q. In filing this general rate revision, did NW Natural consider the fact that residential customer rates increased approximately 4.7 percent starting on November 1, 2024?

A. Yes. NW Natural considered the previous rate increase it received on November 1, 2024, due to the combined effects of its last general rate case (UG 490) and its Purchased Gas Adjustment ("PGA"). In recent years, NW Natural has sought to change its base rates every other year through general rate case filings, while the PGA is an annual filing to update rates for our commodity costs. When base rates are not changed annually, particularly in inflationary environments, the costs that the utility needs to recover begin to compound and create larger rate increases for our customers. By filing our rate case today, NW Natural is seeking to recover increasing costs while attempting to avoid rate volatility.

Q. In NW Natural's last general rate case, the Company discussed filing a multiyear rate plan in its next rate case. Why has the Company not chosen to do that in this filing?

A. In NW Natural's last general rate case, the Company signaled that it intended to file a multi-year rate plan as part of its next rate case and sought engagement from rate case parties on this issue. The Oregon Citizens' Utility Board ("CUB") responded that NW Natural should not file a multi-year rate plan and that the Commission should open an investigation instead.[11] AWEC and Staff also raised

[11] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 48 (Oct. 25, 2024).

concerns with NW Natural's proposal to file a multi-year rate plan in its next general rate case.[12] Although the Commission ultimately did not preclude NW Natural from filing such a case, it did direct Staff to conduct at least one workshop on the issue and "submit and present a report at a public meeting in 2025 that addresses the types of multi-year rate plans available, how other jurisdictions have implemented multi-year rate plans, the likely resource commitment and timeline required to effectively implement multi-year rate plans, and any concerns raised by stakeholders."[13]

NW Natural has considered rate case parties' feedback and wants to support the Staff-led report into multi-year rate plans. The Company trusts that this report will be robust and mindful that multi-year rate plans are not a novel concept. Several states, including Washington and California, use them today to set utility rates. NW Natural continues to believe that multi-year rate plans have the potential to limit rate volatility, result in smaller albeit more frequent rate changes, and increase administrative efficiency, so long as they are implemented fairly for the customers and the Company. While the Company had hoped to establish the contours of multi-year rate plans in its last general rate proceeding, this did not occur. To streamline this case and avoid unduly stressing parties' resources responding to a new multi-year rate plan so soon after its last case, the

[12] *Id.*

[13] *Id.* at 50.

Company has decided to continue the status quo of filing a rate case based on a single forward Test Year.

Q. Is this rate case smaller and simpler than NW Natural's recent general rate cases?

A. Yes. This case is considerably smaller in size than our prior rate case and limited to only issues of cost recovery for the utility's revenue requirement. Unlike previous general rate cases, NW Natural is not raising substantive policy issues, which is intended to simplify the proceeding, assuming that other parties also follow the same course. In making this change, we note that we are listening to feedback from our stakeholders, including CUB's statements in our previous general rate case that, "[r]ate cases do not have to be large and onerous," and "[a] utility can keep it simple."[14] Given the evolving regulatory and policy environment, NW Natural cannot, of course, guarantee that it will never seek policy changes in a future general rate case. However, we have sought to simplify matters as much as practicable in this general rate case.

[14] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bob Jenks, CUB/100 at 16 (Apr. 18, 2024).

Q. In the Company's last general rate case, CUB proposed a cap on rate increases at the lower of 10 percent per year or 7 percent plus the annual increase in the Consumer Price Index.[15] How is the Company considering this proposal from its last general rate case?

A. Although the Commission declined to adopt CUB's proposal and NW Natural opposed it based on legal concerns and the resulting safety and reliability risks that an artificial rate cap would create, NW Natural nonetheless supports the underlying concept of avoiding rate volatility wherever possible. We believe that smaller and simpler rate cases can help achieve this shared goal with the understanding that certain events outside the Company's control could contribute to rate volatility despite more frequent general rate cases.

Q. What events outside the Company's control could contribute to rate volatility, despite more frequent general rate cases?

A. The cost of natural gas is a factor that is outside NW Natural's control and can lead to volatility in rates, depending on the external factors in the broader natural gas market. Although NW Natural's ownership of and access to storage facilities may be able to mitigate this volatility to a certain extent, it cannot eliminate it, especially if unforeseen events occur that lead to large increases or decreases in the price of natural gas.

Additionally, a new Climate Protection Program ("CPP") will go into effect on January 1, 2025, which adopts a declining limit, or cap, on covered emissions,

[15] *Id.* at 7-8.

including those emissions that result from its sales customers' and transport customers' use of natural gas. However, unlike California's and Washington's programs, the CPP is not a "cap and trade" program that utilizes an allowance-based auction framework and an established market to trade compliance instruments. Moreover, since NW Natural's CPP compliance obligation will not be weather-normalized, CPP compliance costs may lead to volatility in rates in the future, depending on the compliance options available to NW Natural and the winter weather during compliance periods.

Q. What has the Company done to mitigate the impacts of this rate case?

A. NW Natural has increased the discounts available under our BDP and will begin offering an arrearage management program for our customers most in need. NW Natural's BDP provides immediate relief to our income-eligible customers with incomes at or below 60 percent of the state median income. The development of the BDP was a collaborative effort with many stakeholders, and we are continuously improving upon the initial BDP. Additionally, in our last general rate case, NW Natural worked with intervenors to increase the discounts available to income-eligible customers, which is more tailored to address energy burden than the prior discounts available. In only the second full year of offering the BDP, we now have 78 percent of our income-eligible customers enrolled in the program. While we strive to reach all of our income-eligible customers, we are pleased with the participation rates for such a new program.

NW Natural is currently developing the arrearage management program, in addition to pre-existing time payment arrangements, which will provide arrearage relief for our customers in the 0-15 percent of state median income. We anticipate this program will be implemented on or before April 1, 2025.

Q. Has NW Natural taken steps to limit the size of rate increases?

A. Yes. NW Natural continues to scrutinize its potential investments and operating costs to minimize costs to customers. For example, as explained in the Direct Testimony of Brian E. Fellon (NW Natural/700, Fellon), the Company has decided to delay implementing a replacement of its customer information system ("CIS") until approximately 2030, after conducting a six-month study with Ernst & Young providing support as a third-party consultant, thereby delaying a major capital investment.

We are also continuing to take a very disciplined approach to renewable natural gas ("RNG") investments while maintaining progress in acquiring greater amounts of RNG through prudent purchases. We have decided to not move forward with certain RNG investments that exceeded our initial cost expectations due to inflation and uncertain interconnection costs, among other reasons. That said, we will, of course, make any necessary investments to comply with applicable climate regulations, including investments in RNG. However, we are nonetheless conscious of the cost pressures that our customers are facing and are committed to addressing it without compromising safe and reliable service or compliance with state regulations.

Q. Please describe the significant factors that are driving the need to file this rate case.

A. Although this rate request is more modest compared to recent rate cases, there are five significant factors that are driving the need to file this rate case.

- NW Natural continues to make investments to replace end-of-life information technology and services ("IT&S") systems. Many of these new investments are cloud-based services and depreciate over a very short period of time (typically five years). Given this short period, NW Natural must seek cost recovery on a timely basis. Otherwise, the Company would not be able to recover a substantial portion of these investments (i.e., a delay of a year would result in NW Natural not recovering approximately 20 percent of its cloud-based IT&S investments).
- NW Natural continues to make investments to ensure safe and reliable operations, including modernizing its facilities infrastructure and making investments at our Mist storage facility to replace end-of-life assets.
- As part of its Meter Modernization Program, NW Natural is installing replacement devices on a daily basis and the Company is seeking timely recovery of these costs to limit the magnitude of future rate increases.
- We are proposing shorter depreciable lives for service lines and meter installations that are in-line with the industry and guidance by the Commission to continue to evaluate the depreciable lives of our assets.

- NW Natural's operating costs continue to escalate, both due to inflation and higher interest rates.

Q. Please discuss the Company's plans to update its IT&S infrastructure.

A. In this proceeding, NW Natural is seeking cost recovery of essential projects that are necessary to ensure the continued functionality of its IT&S infrastructure. These projects include: 1) continuing the multi-year program to phase out end-of-life field and web mapping software and transitioning to a consolidated set of modern software solutions; 2) ongoing work to improve its Identity Governance and Administration (IGA), which is the process of granting, updating, reviewing and revoking access to technology systems for NW Natural employees and contractors, based on job changes or other Company needs; and 3) NW Natural's ongoing Telemetry Refresh Projects to replace decades-old supervisory control and data acquisition (SCADA) technologies with modern equipment to comply with new security and safety standards. NW Natural is also making other upgrades largely in response to cyber-security advancements, existing software reaching end-of-life and end-of-support, and developers exclusively providing cloud-based solutions.

The Direct Testimony of Brian E. Fellon (NW Natural/700, Fellon), the Company's Vice President and Chief Information Officer, provides a comprehensive explanation of the Company's IT&S projects, including those mentioned above.

Q. Please describe NW Natural's approach to modernizing its facilities infrastructure.

A. NW Natural has continued to execute on its long-term facilities strategy, which is driven by our priority to provide continuity of operations during unplanned events. In this rate proceeding, NW Natural is seeking to recover the costs of continuing physical security enhancements. These enhancements are made at the direction from the United States Department of Homeland Security's Transportation Security Administration ("TSA") and are necessary in response to increasing threats to facilities and the nature of those threats.

NW Natural is on the final stretch of its 10-year facilities roadmap. The Company has undertaken a long-planned approach to modernize its aging facilities. As the Company's only facility in the Columbia River Gorge, The Dalles Resource Center must have the necessary functionality for the Company to respond to emergencies, including major seismic events. To help ensure this functionality, NW Natural will install a fueling station that will be available for Company use during emergencies that could impact retail fueling stations. The existing site and buildings are too small to accommodate the required operations functionality, hampering efficiency and employee safety.

The Direct Testimony of Wayne K. Pipes (NW Natural/600, Pipes), Director of Facilities, Security and Emergency Management, further explains these projects.

Q. Please provide a brief update on the Company's Meter Modernization Program.

A. As thoroughly discussed in the Company's last general rate case, the Meter Modernization Program is an ongoing Company initiative that focuses on the replacement of a large portion of NW Natural's metering assets due to aging batteries inside the communication devices (encoder receiver transmitters or "ERTs") attached to our meters. Additionally, the Meter Modernization Program will maximize cost-efficiency by simultaneously replacing meters that do not meet our testing standards. NW Natural's contract vendor began its deployment of ERT change-outs in March 2024 and the program is currently within its original budget spend. The Direct Testimony of Joe S. Karney (NW Natural/900, Karney) provides a complete update on the Meter Modernization Program.

In addition to seeking recovery of its capital investments in the program, NW Natural is also seeking to amortize approximately $2.6 million of its Meter Modernization Program deferral balance, as explained in the Direct Testimony of Kyle T. Walker (NW Natural/1500, Walker). These deferral costs are one-time operations and maintenance ("O&M") expense incurred for the limited duration of the program, including the cost of recycling end-of-life metering equipment and additional labor costs. The one-year amortization of this deferral, taken together with the requested increase in base rates, would result in approximately a 5.93 percent increase to revenues collected from customers for the Test Year.

Q. Please summarize the changes to distribution system planning that the Company has made, as well as the significant distribution system and storage facility projects that are included in this case.

A. Historically, NW Natural has conducted distribution system planning on a just-in-time basis. In other words, traditional pipeline solutions were not developed until areas of the system became constrained. Although this approach made sense in the past, it limits the effectiveness of long-lead time non-pipeline alternative ("NPA") solutions that can also address system constraints in certain circumstances. NW Natural is in the process of expanding its suite of NPA solutions such as Geographically Targeted Energy Efficiency (GeoTEE) and Geographically Targeted Demand Response (GeoDR), as well as a system-wide demand response program, that may mitigate the need to upgrade pipelines in certain areas of its system. In addition, NW Natural has hired an outside consultant to prepare a compressed natural gas ("CNG") or LNG trucking study to help determine if and when CNG or LNG gas supplies may be a viable alternative to a pipeline solution for a peak weather event. NW Natural is currently conducting these NPA analyses and expects them to be available for alternatives planning purposes in the next Integrated Resource Plan ("IRP") to be filed in August 2025.

Despite the potential of NPAs, we nonetheless must continue to make improvements to our distribution system and storage facilities in order to keep our system safe, reliable, and economical. In addition to the end-of-life replacement of compressors at the Mist storage facility discussed above, NW Natural is seeking recovery of several major distribution and storage projects. These include Phase B of the North Coast Feeder Uprate Project, which is a system reinforcement in the areas of Astoria, Warrenton and Cannon Beach, as well as several other projects to ensure the continued safe and reliable operation of our system.

The Direct Testimony of Daniel B. Kizer, Senior Director of Engineering, and Scott S. Johnson, Senior Director of Gas Supply, (NW Natural/500, Kizer-Johnson) explains NW Natural's distribution system planning changes and describes the Company's distribution system and storage facilities projects in detail.

Q. What are the key factors driving the Company's ROE request?

A. NW Natural's ROE request is based on analysis from our outside consultant, which shows that long-term interest rates have increased substantially since the historical lows of 2020 and are expected to remain elevated despite the anticipated reduction in short-term interest rates from the Federal Reserve. This rise in interest rates have led to higher yields on longer-term treasury bonds, which provide investors a more attractive risk-free alternative to utility stocks. In addition, the environmental policy focus in the Pacific Northwest for gas utilities has increased the perceived risk of investing in gas utilities and has led investors to seek higher returns to offset these risks.

Q. Please describe the Company's request to update depreciation rates in this case.

A. NW Natural is filing an updated depreciation study performed by Gannett Fleming. Applying the depreciation rates from the depreciation study to Test Year plant balances results in an increase to depreciation expense of $10.0 million.

Q. The Company previously filed a depreciation study just one year ago. Why is NW Natural filing another depreciation study in this case?

A. NW Natural's updated depreciation study builds off the settlement in the Company's previous depreciation study that the Commission approved in Order No. 24-302. Specifically, the updated depreciation study incorporates most of what was previously agreed in that Commission-approved settlement, but the new study proposes to reduce the depreciable lives of service lines from 65 years to 60 years, among other small changes. Gannett Fleming recommended that NW Natural adopt this change to better align with the expected useful life and because a 65-year depreciable life for a service line is an industry outlier among natural gas utilities. A depreciable life of approximately 40-60 years is more in line with typical utility practice.

Q. In the Company's most recently filed depreciation study (Docket No. UM 2312), the Commission requested that NW Natural continue to address the issue of accelerated depreciation when it files its next depreciation study. How is NW Natural approaching this issue?

A. In Order No. 24-302, the Commission stated that it "appreciate[d] NW Natural's responsiveness" in addressing these issues in its prior study and requested that NW Natural continue to consider accelerated depreciation in future studies.[16]

[16] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Updated Depreciation Study,* Docket No. UM 2312, Order No. 24-302 at 3 (Aug. 29, 2024).

Given the importance of natural gas to the region's energy system, especially during periods of extremely cold weather in January 2024 and December 2022, as well as the fact that customers continue to choose gas service due to its efficiency, reliability, resiliency, and affordability, we continue to believe it is inadvisable to make wholesale conclusions about the future of the gas system that could put undue pressure on customer bills today.

However, to be responsive to the Commission's directive, we have again filed a depreciation study with this rate case, rather than wait until NW Natural is obligated to file another study.[17] We continue to believe it is very important to have our depreciation rates reflect the actual operations and depreciable lives of the assets on our system. While the resolution of our previous depreciation study was a step in that direction, we believe that the depreciable lives of certain assets should be further shortened to reflect actual operations.

Q. Is the Company proposing accelerated depreciation in this case?

A. No. Given that NW Natural is filing consecutive rate cases and is again revising depreciation rates upward, we do not believe that further increases to depreciation expense are appropriate at this time. However, as we said in our last general rate case, we are not attempting to foreclose that discussion in the future.

[17] Per OAR 860-027-0350, NW Natural must file a depreciation study every five years.

IV. ENERGY EQUITY AND AFFORDABILITY

Q. Please describe the Company's primary energy equity and affordability initiatives.

A. NW Natural continues to strengthen considerations of energy equity and affordability into its day-to-day operations and program offerings to customers. First, as mentioned above, our BDP is growing with participation and discount levels. Second, working with a third-party consultant, we have also completed our second EBA that analyzed energy burden in our service territory. Third, with our Winter Preparedness Fair, we continue to innovate and develop new channels to reach our customers to educate our customers about the energy system and our customer programs. The Direct Testimony of Cecelia J. Tanaka (NW Natural/200, Tanaka) fully discusses the Company's energy equity programs and initiatives, but we will touch on each here.

Q. What tools has the Company utilized to achieve these enrollment levels in the BDP?

A. NW Natural continues to build on its outreach efforts and remains committed to deploying new and creative ways to inform customers about its programs. Our outreach efforts have been well-received by a diverse range of stakeholders, including community-based organizations ("CBOs"), customers, advisory groups, and regulatory bodies. It is encouraging to see that our strategies have inspired similar initiatives among peer utilities, which have also sought our input to enhance their own outreach efforts.

NW Natural works with community partners throughout its service territory, such as community action agencies, school systems, housing networks, places of worship, food banks, culturally specific organizations, and healthcare networks. Community partners utilize a wide variety of communication channels including check-in calls with homebound seniors, inserts in food boxes at schools and food pantries, direct mail, community newsletters, and social media posts. Leveraging these relationships and networks is particularly valuable, enabling the Company to reach customers who might otherwise be inaccessible to deliver bill discount program information through other important and trusted sources.

In addition, we developed an Outreach & Communications Toolkit to ease the administrative lift for external partners. The Toolkit offers printable resources, digital materials and other customizable content to allow for easy integration into existing channels of communication—enabling organizations to customize what works best for their audience. Feedback on our bill discount program materials has been overwhelmingly positive with partners noting: the language tailored to an accessible reading level; the multi-language presentation covering the five most commonly used languages in our territory; and the inclusion of contact information for other utility bill discount programs.

These efforts are further supported by paid ads on local radio stations, including Spanish-language ads, and digital ads across various websites and social media platforms. NW Natural also prepares integrated communications plans annually, with the BDP prominently featured.

Q. What are some of the findings in the Company's EBA?

A. Key findings from the Energy Burden Assessment include the following:

- The enrollment rate (among the estimated pool of customers who meet income eligibility guidelines) reached 78 percent in the first two years of the program;
- The program is targeting customers most in need, evidenced by the highest participation rates in the lowest income tier;
- 12.5 percent of NW Natural's residential customers are eligible for the program;
- Low- and non low-income customers share the same average annual gas bill; and
- Average and median household natural gas energy burden rates are 1.4 and 0.9 percent, respectively.

Q. How does the Company plan to use this information?

A. The Company is eager to use findings from the EBA to guide program design, evaluate the performance of existing programs, refine marketing and targeted outreach strategies to reach underserved customers, and establish a baseline from which to draft, track, monitor and report on performance.

We are reviewing recommendations from Empower DataWorks, peer utilities, commissions, and other key stakeholders; we have also held several internal work sessions to discuss, evaluate, and prioritize next steps.

Q. Please describe the Winter Preparedness Fair.

A. In partnership with the Community Services Network, NW Natural developed a new educational outreach forum for winter preparedness that we are calling the Winter Preparedness Fair. The Winter Preparedness Fair was held on November 16, 2024, at Parkrose High School. The fair was borne out of increased expectations for stronger public engagement in the IRP and was heavily informed by input from our Community Equity Advisory Group ("CEAG"). While public engagement has always been part of the IRP process, this event is one of the new initiatives we are piloting for the 2025 IRP to build on these efforts.

In February 2024, we dedicated the first quarter CEAG meeting to NW Natural's IRP process and asked the group for feedback on ways to improve procedural equity practices and public engagement opportunities in the development of the IRP. CEAG members highlighted the need for a community-based, family-friendly event that provides tangible, meaningful resources. They emphasized partnering with trusted organizations, expanding the event's focus beyond energy planning, and scheduling it to accommodate working families and public transportation users.

From these conversations, we created a comprehensive, resource-rich event that offered free winter coats for kids, weatherization kits, a vaccine clinic, food boxes, a bill discount sign-up station covering several utilities and services for income-eligible households, and the opportunity for conversations about energy conservation, saving money, and staying warm---as well as improve awareness of energy planning and ultimately increase informed participation in the future.

Q. How was the community response to the Winter Preparedness Fair?

The community response was tremendous. Over 850 people attended, which marked the largest event in Community Services Network's history. There were over 45 social services tables providing community support. NW Natural hosted eight tables, providing outreach on a range of topics, and documented over 50 BDP sign-ups, provided over 250 weatherization kits, and demonstrated over 50 safe meter turn-off tutorials. We also added new contacts to the IRP Listserv distribution list. We intend to plan similar events in the future throughout our service territory.

V. <u>SUMMARY OF WITNESSES</u>

Q. Please briefly describe the testimony provided by other witnesses in this case.

A. Fifteen other witnesses describe the various components of cost that demonstrate the need for the requested rate increase.

Cecelia J. Tanaka, Energy Equity and Affordability Lead, describes the Company's initiatives and priorities regarding energy equity and inclusion, including details on the Company's EBA and low-income assistance offerings. NW Natural/200, Tanaka.

Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony explains the Company's financing strategy of maintaining a balance of long-term debt and equity financing. Mr. Wilson explains why the Company is targeting a capital structure of 52 percent common equity and 48 percent long-term debt, resulting in an ROR on rate base of 7.658 percent, which will maintain financial health and benefit customers. NW Natural/300, Wilson.

Jennifer E. Nelson, Assistant Vice President, of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, provides testimony about the Company's cost of equity, or in other words, the return that NW Natural should be given the opportunity to earn in order to attract capital. Her analysis shows that a reasonable range of the cost of equity is between 9.9 percent and 11.0 percent. Ms. Nelson recommends that NW Natural be allowed an opportunity to earn a 10.4 percent return on equity in the revenue requirement authorized in this proceeding. NW Natural/400, Nelson.

Daniel B. Kizer, Engineering Senior Director, and **Scott S. Johnson**, Senior Director of Gas Supply, provide testimony about aspects of the Company's long-term system planning and the Company's recent improvements to its system modeling, as well as the improvements to our distribution system and storage facilities that the Company has undertaken in order to keep our system safe, reliable, and economical. NW Natural/500, Kizer-Johnson.

Wayne K. Pipes, Director of Facilities, Security and Emergency Management, describes the Company's execution on its long-term facilities strategy, including acquiring land for the new resource center at The Dalles and continuing physical security enhancements. NW Natural/600, Pipes.

Brian E. Fellon, Vice President and Chief Information Officer, describes NW Natural's ongoing IT&S strategic approach and details the Company's cost-recovery requests with respect to major projects and crucial hiring needs. NW Natural/700, Fellon. Mr. Fellon also sponsors a separate testimony describing the Company's response to the emergency mandatory federal regulatory requirements in TSA Security Directive Pipeline-2021-02. NW Natural/800, Fellon (Sensitive Security Information).

Joe S. Karney, Vice President of Engineering and Utility Operations, provides an update on the Company's Meter Modernization Program. NW Natural/900, Karney.

Melinda B. Rogers, Vice President, Chief Human Resources and Diversity Officer, provides testimony on our labor costs, and describes the Company's practices related to compensation, which ensure that all employees receive compensation at market-median rates. Additionally, Ms. Rogers describes our overall employee count and the Company's request to include these costs in the Company's revenue requirement. NW Natural/1000, Rogers.

Cory A. Beck, Director of Customer Experience Services, provides testimony about the Company's communications to customers on matters of safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and opportunities to conserve and be educated about the products that they purchase from us. NW Natural/1100, Beck.

Kathryn M. Williams, Vice President, Chief Public Affairs and Sustainability Officer, provides an update on the Company's time-tracking for lobbying expenses and provides the basis for recovery for NW Natural's government affairs team. NW Natural/1200, Williams.

Tobin F. Davilla, Senior Manager of Financial Planning and Budget, provides testimony about the operations and maintenance expense levels that the Company has incurred and expects to incur in the Test Year, as well as overall capital spending, for which it requests recovery in this application. NW Natural/1300, Davilla.

John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, presents the depreciation study that is used to calculate the Company's depreciation rates. The depreciation study will also be filed in a separate docket. NW Natural/1400, Spanos.

Kyle T. Walker, Senior Manager of Rates and Regulatory Affairs, provides the calculation of the Company's revenue requirement, which represents the annual revenues needed to recover prudently incurred costs of operating the utility business, and presentation of tariffs. NW Natural/1500, Walker.

Robert J. Wyman, Rates and Regulatory Economist, provides the Company's use-per-customer forecast, long run incremental cost study, and the proposed spread across rates of the revenue requirement increase requested. NW Natural/1600, Wyman.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Justin B. Palfreyman and Zachary D. Kravitz

POLICY
EXHIBIT 101

December 30, 2024

EXHIBIT 101 – POLICY

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OREGON TECH

Soaring data center electricity demand could trigger Northwest blackouts, industry insiders say

Updated: Dec. 11, 2024, 5:09 p.m. | Published: Dec. 11, 2024, 1:44 p.m.

Power lines feed an Amazon data center near Boardman. Dave Killen / The Oregonian

By Mike Rogoway | The Oregonian/OregonLive

A panel of authorities on the data center industry told Northwest energy planners Wednesday that the tech sector will take all the electricity it can get its hands on, warning of severe consequences if the region doesn't respond in time.

"We're going to need to build more transmission faster than any time we have in the last 70 years as a region," said Robert Cromwell, who consults with Northwest power utilities. He said the region is already flirting with rolling blackouts because peak energy demand is already near the region's capacity to provide electricity.

Data center demand is soaring because of artificial intelligence, which uses massive amounts of electricity for advanced computation. These powerful machines already consume more than 10% of all of Oregon's power and forecasters say data center power use will be at least double that by 2030 — and perhaps some multiple higher.

If the Northwest fails to add enough generation and transmission to meet the growing energy needs, Cromwell said periodic blackouts are inevitable at times power demand is at its greatest. He used an industry term, "rotating load shedding," to describe rolling blackouts, which briefly cut off power to homes, businesses and even hospitals that need electricity to provide life-saving care.

"Nothing will change policy faster than elected officials going to constituent funerals, and it won't be for the better because it'll be reactionary and less than fully thought through," Cromwell told Wednesday's meeting of the Northwest Power and Conservation Council.

Oregon has one of the nation's largest and fastest-growing data center industries, owing in large part to some of the most generous tax breaks anywhere in the world. Data centers don't employ many people, but the wealthy tech companies that run them enjoy Oregon tax giveaways worth more than $225 million annually.

Amazon, Apple, Google and Meta operate enormous data centers in central and eastern Oregon. Several other companies, including Oracle, LinkedIn and the social network X, have huge installations in Hillsboro.

Earlier this year, the power council issued a forecast suggesting a range of possibilities for data center power demand through the end of the decade. In the middle case, the council said Northwest data centers would need 4,000 average megawatts of additional electricity in 2030.

That's an enormous jump in demand, equivalent to the power use of 3 million homes.

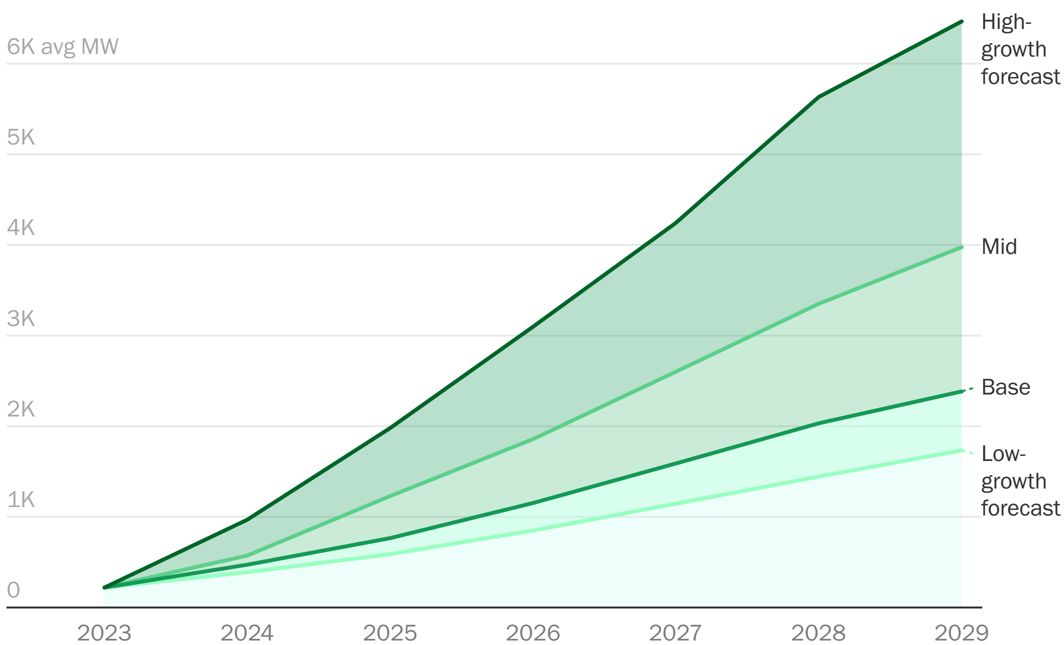
And yet on Wednesday, Cromwell said the council's median forecast is too low.

"Your medium case is not high enough and your high case is probably pretty close to spot on," he said.

The high forecast predicts that data centers will actually need an additional 6,500 average megawatts in the next few years — equivalent to the power needs of nearly 5 million homes.

Expected growth in NW electricity use by tech industry

Energy forecasters say Northwest data centers and chip factories could need thousands of additional megawatts of electricity by the end of the decade. They say 80% of the growth will come from data centers. At the high end of the forecast, new data centers could require nearly as much power as all the homes in Oregon and Washington use today.



The Northwest Power and Conservation Council says all four scenarios are possible. Outside consultants say the high forecast is the most likely.

Source: Northwest Power and Conservation Council • Get the data

OREGONLIVE
The Oregonian

"There's no question in my mind that the demand for computation and AI, and the demand to plug in (computer processors), exceeds the available power that we have by 2030," said Brian Janous, a former Microsoft vice president now consulting for industrial electricity users.

There's little prospect of blunting that growth by shifting demand to other data centers during peak times or through the invention of more efficient computers, Janous and others told the council on Wednesday. He said the demand for artificial intelligence is so high that data center operators will use all the electricity they can get and will operate all their facilities around the clock.

When power demand exceeds supply, during winter storms or heatwaves for example, utilities and governments must make wrenching decisions about who loses power and for how long. Turning off power to data centers could preserve power for homes and hospitals but would have its own negative consequences.

Think about the faulty CrowdStrike software update last summer, said panelist Sarah Smith, with the Lawrence Berkeley National Laboratory. That took down banks, hospitals, factories, news sites and many others as online systems went awry.

“Air travel was disrupted for days,” Smith said. “There was a lot of really wide-ranging impacts you could imagine.”

The Northwest Power and Conservation Council is a regional organization that works with utilities and governments in Idaho, Montana, Oregon and Washington to balance future power needs and environmental protections. It convened Wednesday’s panel on data centers to help plan a new forecast the council will issue next year.

Big tech companies generally accept the scientific consensus that carbon emissions are causing climate change. Until recently, most tech companies expressed public commitments to find renewable power for their data centers.

Recently, though, Janous said they’ve become “willing to compromise, in the short run” on their clean power goals because they’re desperate for any source of electricity.

Despite the data centers’ voracious appetite for power, the panelists expressed some hope that the region will be able to meet the challenge and, in time, push data center operators to return to their clean energy aspirations. They suggested a Northwest regional transmission authority, long under discussion, could help streamline the construction of new power lines and collaboration among western states.

Data centers’ power needs are triggering expensive upgrades to the Northwest’s power lines and prompting construction of new power plants. There is growing concern among ratepayer advocates, regulators and politicians that households will end up bearing much of the cost of data center growth through higher residential power bills.

On Wednesday, panelists said data center operators are highly motivated. They said tech companies probably be willing to bear the cost of additional power themselves, provided they have a pathway to get that energy quickly.

St. Johns Food Share has groceries for anyone who needs them, no questions asked: Season of Sharing 2024 Dec. 11, 2024, 10:00 a.m.

"The companies that are asking for this infrastructure are extraordinarily deep-pocketed and there's a huge willingness to pay," Janous said, "because the returns they earn on the back end are massive."

-- Mike Rogoway covers Oregon technology and the state economy. Reach him at mrogoway@oregonian.com.

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BEFORE THE

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NW Natural

Direct Testimony of Cecelia J. Tanaka

EQUITY
EXHIBIT 200

December 30, 2024

EXHIBIT 200 - DIRECT TESTIMONY – EQUITY

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Cecelia J. Tanaka. I am the Energy Equity & Affordability Lead at NW Natural.

Q. Please describe your education and employment background.

A. I hold a Master's in Public Administration, International Policy and Management from the New York University Robert F. Wagner Graduate School of Public Service; and an undergraduate degree in Humanities from the University of Colorado - Boulder. I have over 15 years of experience developing and leading major social impact and corporate responsibility initiatives that advance equity and social justice. I joined NW Natural in January 2021 to lead the Company's community investments focused on improving energy equity and easing energy burden for our most vulnerable communities—including energy efficiency resources for multi-family residents, discounted rate programs for income-eligible customers and philanthropic giving across our Oregon and Washington territories. In April 2024, I joined NW Natural's Regulatory Affairs team to lead the Company's energy equity and affordability efforts. Prior to NW Natural, I worked as a Vice President at JPMorgan Chase & Co., the Robin Hood Foundation and New York University; and consulted for the United Nations, Meyer Memorial Trust, and The Collins Foundation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to detail the Company's commitment to equity and inclusion that encompasses social, environmental and economic dimensions; and to provide an update on the Company's income-based offerings and energy burden assessment.

Q. Please summarize your testimony.

A. In my testimony, I present an overview of the Company's new and ongoing efforts in energy equity and affordability. I discuss the findings from our recently completed Energy Burden Assessment ("EBA"), highlighting key insights, lessons learned and early plans for next steps. My testimony details the significant progress we have made in delivering deeper discounts to more income eligible customers through our bill discount program, as well as updates on the Company's other energy assistance and efficiency offerings. I share updates on the Company's Community and Equity Advisory Group ("CEAG"), and detail how engagement with and feedback from the CEAG is informing our work. My testimony also details the Company's Oregon Low Income Energy Efficiency ("OLIEE") Program, highlighting recent major projects and their impacts. Finally, I outline the Company's initiatives to foster diversity, equity, and inclusion both within the organization and in the wider community.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I have included Exhibits NW Natural/201, Tanaka (NW Natural's Communication Engagement Strategy) and NW Natural/202, Tanaka (flyer for Winter Preparedness & Energy Planning Fair).

II. UPDATES FOR 2025 AND ONGOING PRIORITIES

Q. How has NW Natural considered equity and energy burden in this case?

A. Energy equity and affordability for all customers guide our work. The Company strives to continually incorporate new learnings into its programs, activities, and associated processes. We recognize that equity is dynamic, and its definition and application can vary across different contexts. It adapts to changing circumstances, responds to community needs, and evolves over time. Our journey involves taking thoughtful actions, making necessary adjustments, and listening to the voices of those we serve.

We remain steadfast in our commitment to equity; we also recognize that broader policy and historical issues have significantly impacted equitable and affordable energy access, and our utility is committed to focusing our resources and efforts on areas where we can make a direct, meaningful, and immediate impact. And by concentrating on what we can manage—such as expanding access to energy efficiency programs, designing and refining offerings to ease household natural gas burden, and enhancing community engagement practices, to name a few—we can make progress in advancing equity considerations and delivering on our core responsibility to deliver safe, reliable, and affordable natural gas service to all our customers.

Table 1 below provides a snapshot of energy equity and affordability actions NW Natural has made in the last year:

Table 1 – New Energy Equity and Affordability Initiatives

ISSUE AREA	DESCRIPTION
EBA	Review of EBA findings; prioritization of recommendations; implications for program design
Integrated Resource Planning ("IRP") – Equity Considerations	2025 IRP is being developed with focus on equity and enhanced public participation/stakeholder engagement requirements.
Implementation of UG 490 Rate Case Stipulations	• Increased discounts effective 11/1/2024 • Designs for past-due bill forgiveness (Arrearage Management Program) for customers in Tier 0 • Post-Enrollment Verification Timeline
Phase 2 of UM 2211	• Arrearage and disconnection workstream • Energy efficiency and programs workstream • Data collection and reporting workstream
OLIEE	• Communications plan • Impact and program evaluation

The initiatives in Table 1 were added in 2024 to NW Natural's existing slate of equity-centered programs and resources like robust energy assistance support, energy efficiency resources, energy education, and community philanthropy and engagement. These include the programs and activities described below in Table 2:

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Table 2 – Ongoing Energy Equity and Affordability Activities

Program/Activity	**Description**
Conservation Programs	Improve energy affordability through conservation efforts
Energy Education	Tools, programs and resources available to help customers lower bills
Residential Weatherization Kits	Improve energy efficiency / reduce energy bills
Oregon Gas Low-Income Assistance (“OLGA”)	Bill assistance
Gas Assistance Program (“GAP”)	Bill assistance
Oregon Bill Discount Program	Four-tiered program with highest discounts reserved for lowest income households
CEAG	Strengthen Procedural Equity practices; Broaden engagement and participation in energy planning
Community Partnerships and Outreach	Community event support and programmatic outreach
Community Grants and Funds	Support over 250 nonprofit organizations through NW Natural territory

Q. Please describe the Company’s goals, guiding principles and strategies that define its energy equity and affordability work.

A. Collectively, the Company’s equity work spans the following goals, guiding principles, and strategies in which we are:

- Prioritizing measures for vulnerable customers and focusing on interventions that target our lowest-income, highest-burdened customers;
- Developing and implementing measures informed by robust data analysis;
- Pursuing, vetting and prioritizing cost-effective solutions;
- Balancing immediate support with longer-term strategies; and

- Regularly evaluating efforts and adjusting strategies as needed to maintain and enhance their effectiveness.

III. ENERGY BURDEN ASSESSMENT

Q. Did the Company complete an Energy Burden Assessment this year?

A. Yes. NW Natural engaged Empower Dataworks to conduct its EBA. Empower Dataworks is a regional consulting firm that specializes in energy equity analytics and has performed similar assessments for numerous utilities throughout the Pacific Northwest. Three types of metrics were calculated: (1) those related to energy burden based on demographic and geographic characteristics, (2) participation in and funding levels for Energy Assistance Programs, and (3) customer energy use characteristics. The EBA was filed on September 16, 2024, as part of docket UM 2211. The report findings and recommendations, as prepared by Empower Dataworks, were presented to Commission Staff, UM 2211 stakeholders, and other stakeholders, including members of the Company's Washington GREAT Advisory Group at a workshop the Company hosted on September 11, 2024.

Q. What are some highlights from the Energy Burden Assessment?

A. Key findings from the NW Natural's Energy Burden Assessment include the following:

- 78 percent of estimated income-eligible customers are enrolled in the bill discount program in the first two years of the program;

- The program is targeting customers most in need, evidenced by the highest participation rates in the lowest income tier (Tier 0);
- 12.5 percent of NW Natural's residential customers are eligible for the program, meeting the household income guideline of less than 60 percent Oregon state median income ("SMI");
- Low- and non-low-income customers share the same average annual gas bill ($1,100); and
- Average and median household natural gas energy burden rates are 1.4 and 0.9 percent, respectively. These rates are driven by:
    - household incomes higher than those of non-natural gas customers ($114,000 in 2024);
    - a competitive energy rate (NW Natural's residential retail rate is approximately $1.33/therm, on par with other gas utilities in the region and just below the national average of $1.45/therm); and
    - a moderate climate.

Q. How does the Company plan to use this information?

A. The Company is eager to use findings from the EBA to guide program design; evaluate the performance of existing programs; refine marketing and outreach strategies to reach underserved customers; and establish a baseline from which to draft track, monitor, and report on performance. We are reviewing recommendations from Empower Dataworks, peer utilities, commissions, and other key stakeholders; and, we have also held several internal work sessions to discuss, evaluate, and prioritize next steps.

IV. BILL DISCOUNT PROGRAM

Q. What is NW Natural's residential bill discount program?

A. NW Natural launched its Oregon residential bill discount program for qualifying residential customers on November 1, 2022. The program features low barriers to participation that include auto-enrollment for customers who have received energy assistance, self-certification of income eligibility, and a tiered discount structure that provides larger discounts to households with lower incomes. Customers with income less than 60 percent of the Oregon state median income qualify for some level of assistance within the program's four tiers. Customers can qualify for up to an 85 percent discount on their monthly bill based on household size and income.

Q. What are the current enrollment figures for the bill discount program?

A. NW Natural's bill discount program continues to have robust enrollment. In the first two years of the program (November 1, 2022 – October 31, 2024), 55,272 customers enrolled, representing 78 percent of NW Natural's estimated low-income customer pool; and a 48 percent increase over the previous year.

Q. Were there changes to the bill discount program that have been implemented as a result of the last rate case (UG 490)?

A. Yes. NW Natural proposed deeper discounts for the lower income tiers as part of its direct testimony in docket UG 490. Through an agreement included in the Second Stipulation in that proceeding, the bill discount levels for three of the four tiers increased as shown in Table 3 below:

Table 3 – Bill Discount Levels in Bill Discount Program

Income tier	Revised Program Effective November 1, 2024	Original Program
0-15%SMI	85%	40%
16-30%SMI	50%	25%
31-45%SMI	30%	20%
46-60%SMI	15%	15%

In addition, NW Natural will be working with stakeholders regarding the post-enrollment income verification process for the bill discount program. NW Natural has not initiated post-enrollment verification yet, but planning for the collaboration and design of the process is underway. Consistent with the Company's commitments in the Third Stipulation in docket UG 490, made among NW Natural, the Coalition,[1] and Oregon Citizens' Utility Board, we will engage with stakeholders regarding the post-enrollment verification process, and the Company expects that elements of the process will be informed by feedback from stakeholders, with the process rolling out no sooner than March 1, 2025. A workshop to discuss the process will be held in January 2025. The Company will work with stakeholders on best practices for post-enrollment verification that consider and mitigate potential barriers a customer may have in providing documentation for verification.

Finally, an arrearage management program for customers in Tier 0, the lowest of the four income tiers, is under development, consistent with the Second

[1] In the UG 490 general rate case, the Coalition included Coalition of Communities of Color, Verde, Climate Solutions, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project, and the Sierra Club.

Stipulation. This new offering is anticipated to launch by April 1, 2025, with best efforts to begin sooner than that date, in compliance with the Commission's memorandum issued November 27, 2024, in docket UM 2211.

Q. How is NW Natural informing customers about energy assistance programs and the bill discount program?

A. NW Natural continues to build on its outreach efforts and remains committed to deploying new and creative ways to inform customers about its programs. Our outreach efforts have been well-received by a diverse range of stakeholders, including community-based organizations ("CBOs"), customers, advisory groups, and regulatory bodies. It is encouraging to see that our strategies have inspired similar initiatives among peer utilities, which have also sought our input to enhance their own outreach efforts.

NW Natural works with community partners throughout its service territory, such as community action agencies, CBOs, housing networks, places of worship, food banks, culturally specific organizations, and healthcare networks. Leveraging these relationships and networks are especially meaningful and allows the Company to reach customers we may not otherwise have been able to reach and deliver bill discount program information from other important and trusted resources.

Community partners utilize a wide variety of communication channels including check-in calls with homebound seniors, inserts in food boxes at schools and food pantries, direct mail, community newsletters, and social media posts. We developed an Outreach & Communications Toolkit to ease the administrative lift for external partners. The Toolkit offers printable resources, digital materials and other customizable content to allow for easy integration into existing channels of communication—enabling organizations to choose what works best for whom they serve and how. Feedback on our bill discount program materials has been overwhelmingly positive with partners noting appreciation for the accessible language, tailored to a 6th-8th grade reading level; the multi-language presentation covering the five most commonly used languages in our territory; and the inclusion of contact information for other utility bill discount program.

Q. Is the Company also advertising its income-based offerings?

A. Yes. These efforts are further supported by paid ads on local radio stations, including Spanish-language ads, and digital ads across various websites and social media platforms. NW Natural also prepares integrated communications plans annually, with the bill discount program prominently featured. These details are discussed more in the Direct Testimony of Cory A. Beck (NW Natural/1100, Beck).

V. <u>OTHER ENERGY AFFORDABILITY PROGRAMS</u>

Q. Please describe NW Natural's other income-based bill assistance programs.

A. NW Natural offers OLGA, which provides energy assistance grants to income-qualified customers, and GAP, a supplemental grant assistance program funded by NW Natural shareholders, employees, retirees, and customers matched up to $60,000 annually.

Q. Is there also federal energy assistance available to customers?

A. Yes. The Low Income Home Energy Assistance Program ("LIHEAP") is a federally funded program that provides grants to eligible customers to assist with their energy bills.

Q. How many customers do these programs reach?

A. NW Natural's bill assistance programs, OLGA and GAP, have seen steady participation over their 22-year histories. For the 2023-2024 program year, OLGA provided $3.7 million in assistance to 6,783 residential customers; and GAP delivered $133,000 in grant support to 1,104 customers. In total, program spending for energy affordability assistance reached $15 million this last program year—a 36 percent jump over the previous year and a three-fold increase over 2022. Tables 4 and 5 below reflect the historical participation in NW Natural's energy affordability programs.

Table 4 – Households Served by Energy Affordability Programs

	October 1 - September 30 Program Years				October 31 Count	
	OLGA	**OLIEE**	**GAP**	**LIHEAP**	**Bill Discount**	**Totals**
2019-20	5,942	248	1,091	2,129	n/a	9,410
2020-21	5,044	341	1,135	2,337	n/a	8,857
2021-22	6,086	165	954	2,537	n/a	9,742
2022-23	7,553	175	1,525	2,504	37,222	48,979
2023-24	6,783	223	1,104	2,932	55,272	66,314
	31,408	1,152	5,809	12,439	92,494	143,302

Table 5 – Energy Affordability Programs Spending

	October 1 - September 30 Program Years				Twelve months ended Oct 31	
	OLGA	**OLIEE**	**GAP**	**LIHEAP**	**Bill Discount**	**Totals**
2019-20	$2,459,130	$1,781,589	$126,584	$688,590	n/a	$5,055,892
2020-21	$2,243,670	$1,718,281	$122,029	$946,145	n/a	$5,030,125
2021-22	$2,628,328	$1,440,729	$114,247	$800,700	n/a	$4,984,004
2022-23	$3,688,238	$1,836,123	$195,588	$1,130,831	$4,110,835	$10,961,615
2023-24	$3,703,048	$2,682,334	$133,016	$1,331,297	$7,106,152	$14,955,846
	$14,722,414	$9,459,056	$691,464	$4,897,563	$11,216,986	$40,987,483

VI. OREGON LOW-INCOME ENERGY EFFICIENCY PROGRAM

Q. Please describe NW Natural's Oregon Low-Income Energy Efficiency program.

A. The OLIEE program is funded through a designated portion of the Public Purposes Funding Surcharge (see Schedule 320). OLIEE funds are used to finance weatherization projects, high-efficiency gas equipment and energy literacy services for NW Natural gas customers who qualify as low income, defined as less than 200 percent of the federal poverty line. The weatherization work is done in partnership with Community Action Agencies and approved service providers. OLIEE funds are delivered through two programs: (1) Community Action Plan ("CAP") and the (2) Open Solicitation Program ("OSP"). The OSP amplifies funding opportunities for certain types of dwellings, tenant profiles, investments and projects that fall outside of CAP parameters. The primary goal of the OSP is to provide cost-effective, energy efficiency assistance to a greater number of low-income households in NW Natural's Oregon service territory through a broad and diverse network of delivery channels. It serves as a funding vehicle or tool to unlock, expedite, and streamline the delivery of energy efficiency projects that help low-income customers reduce energy usage, save money and live in healthier homes. The OSP was introduced to Schedule 320 in 2013 as a supplemental, complementary resource to increase and accelerate the delivery of weatherization services to income-eligible households while adhering to the spirit of the OLIEE program.

Q. Have there been recent updates to the OLIEE?

A. Yes. The Commission approved changes to Schedule 320 in Spring 2024 which include fully funding energy efficiency measures as well as health safety and repairs. These changes were designed to close funding gaps in cost-prohibitive projects, expedite project completions, and accelerate OLIEE program funding. These changes are already yielding returns—evidenced by significant gains in project completions and spending. Growth was driven by our partnering with CAP Agencies, while OSP strengthened its impact by consolidating existing partnerships and establishing new collaborations within the NW Natural service territory. These efforts are expected to yield new projects that will enable NW Natural to reach more customers in program year 2024-2025. Total program spending on energy efficiency measures increased 58 percent in the last heating year, and changes to Health and Safety measure guidelines in Schedule 320 resulted in a 169 percent boost in spending for eligible repair, mold mitigation and other measures.

Since the relaunch of the program in 2022, OSP has delivered nearly $5.3 million in energy efficiency and weatherization funding and served roughly 705 low-income households and families. Spending reached this level after the program was dormant for several years to refine reporting and process document practices, enable higher transparency and establish staffing capacity to lead the program. A list of projects completed to date as well as expected projects for the upcoming year is provided in Table 6 below.

Table 6 – OLIEE Projects

Org	Project	Description	Heating YR
Oregon Energy Fund	**Albertina Kerr**	Multi-partner, multi-investment project for several buildings in Kerr's real estate portfolio that house, support and care for 320 individuals a year.	2022
	Agape Community	Full building energy retrofits for owner-occupied Habitat for Humanity condominium units in Portland.	2023
	Lindsey Lane	Full building energy retrofits for owner-occupied Habitat for Humanity community in Hillsboro.	2024
Homes for Good	**Mission**	Energy efficiency upgrades and structural repairs to Eugene Mission shelter.	2023
	Pilot Project	Dual fuel pilot with furnace as a backup for past weatherization assistance participants.	2024
Latino Built	**OSP/CAP Pilot**	New partnership with culturally specific organization; whole home upgrades and structural repairs to 25 single family homes; new approach to deploying OLIEE dollars; focus on single-family, high energy burdened households; plans in place for continued growth in the next year (est. 100 homes/year).	2024
African American Alliance for Homeownership	**OSP/CAP Pilot**	New partnership with culturally specific organization; whole home upgrades and structural repairs to 40 single family homes; new approach to deploying OLIEE dollars; focus on single-family, high energy burdened households.	2024
The Next Door	**Capacity & convening**	Convening for landlords and building managers of affordable, multiunit housing on benefits of energy efficiency and resources available through OSP funding.	2022

For detailed information regarding program year 2023-2024, the OLIEE year-end report will be filed under docket RG 13 by the end of December 2024.

Q. How is the OLIEE program marketed?

A. The OLIEE program is promoted through a multi-channel approach aimed at increasing awareness and participation among income-eligible customers. These efforts include a combination of online resources, direct outreach, and community engagement activities.

1) <u>Online and Print Marketing</u>

- Website: NW Natural's website highlights free energy efficiency upgrades for income-eligible customers, including contact information for program partners and details on income qualifications.
- Bill Inserts and Postcards: Marketing materials are distributed via bill inserts and postcards, as well as at community events
- Cross-Promotion: NW Natural cross-promotes all income eligible programs to maximize customer reach.

In addition, an emphasis on targeted outreach is achieved as a result of the following activities:

2) <u>Community-Based Energy Education</u>

Community Action Agencies play a key role in promoting OLIEE through energy education; agencies receive an additional 10 percent of their annual OLIEE budget for energy education activities. Program outreach is part of this work.

- Workshops: These encourage energy conservation and promote weatherization programs alongside bill discount programs
- Billboards: Messaging is targeted to underserved areas, enhancing visibility in communities with the highest need.
- Community Events: Agencies participate in health fairs, partnership meetings, and family events, where they share program details and provide tips on understanding heating systems. These events allow agencies to connect with a diverse pool of potential applicants, broadening program impact.

3) <u>Do-it-Yourself ("DIY") Weatherization Kits</u>

NW Natural developed DIY weatherization kits that contain door draft stoppers, socket sealers, insulation window kits, and other items that help customers lower bills, benefit from zero-cost enhancements, and better prepare for winter weather. This year, NW Natural distributed 600 kits at 12 outreach events throughout our territory. Feedback has been positive and plans are in place to amplify these efforts even further next year.

4) <u>Furnace Filter Replacement Pilot Program</u>

NW Natural launched a furnace filter replacement pilot program in partnership with Habitat for Humanity this year. Customers in Habitat for Humanity homes and complexes received free filters, energy education and instruction on system maintenance, and information about the OLIEE program. The program engaged 45 homeowners and is slated for expansion in program year 2024-2025.

Energy education and outreach spending for OLIEE reached $562,400 this year; plans are in place to continue to expand outreach, accelerate project delivery, engage more underserved communities, and increase program participation. A copy of the Company's Communication Engagement Strategy is included as Exhibit NW Natural/201, Tanaka.

VII. COMMUNITY EQUITY ADVISORY GROUP

Q. Please describe NW Natural's Community Equity Advisory Group.

A. The CEAG is an extension of existing community engagement priorities at NW Natural and a natural outgrowth of NW Natural's commitment to improving energy equity and easing energy burden for our most vulnerable customers. From a place of listening and learning, the CEAG seeks out and elevates historically underrepresented voices, perspectives, and lived experiences to advance inclusive practices and institutional actions and bring a racial equity and environmental justice lens to NW Natural's energy and operational planning.

Q. How is NW Natural demonstrating its commitment to advancing equity through the CEAG?

A. NW Natural is committed to an authentic and effective process: a core tenet of the group is to solicit ideas and encourage engagement from new perspectives, voices, and lived experiences in an authentic, non-extractive way—avoiding the pitfalls of diversity, equity, and inclusion work that can be transactional and performative. The CEAG convenes quarterly; member organizations are compensated for their time and expertise; and meetings are facilitated by a third-party consultant.

Q. Please provide a recent example of how CEAG feedback is being used.

A. A notable highlight of the year was CEAG engagement in the development of the Company's 2025 IRP. Enhancements to public participation in the IRP process play an important role in advancing equity principles and updates to the 2025 IRP center on strengthening inclusive and meaningful engagement in the development of the IRP—core elements of procedural justice and equity.

In February 2024, we dedicated the Q1 CEAG meeting to NW Natural's IRP process. Members learned about energy planning and IRPs; discussion and feedback centered on proposed public engagement strategies for the upcoming 2025 IRP process. From these conversations, the Winter Preparedness & Energy Planning Fair ("Fair") was born. The Fair, held on November 16, 2024, was a comprehensive, resource-rich event that offered weatherization kits, a vaccine clinic, winter coats for kids, food boxes, a bill discount sign-up station covering several utilities and services for income-eligible households (all at no cost)—as well as took early steps to improve awareness of energy planning and ultimately increase informed participation in energy planning in the future. While public engagement has always been part of the IRP process; this event is one of the new initiatives we are piloting for the 2025 IRP to build on past efforts.

Q. What other details on the Fair are there?

A. NW Natural partnered with Community Services Network and the City of Portland Bureau of Planning and Sustainability to bring this event to the community on

November 16th at Parkrose High School. Approximately 45 community-based groups hosted tables at the Fair; and an estimated 850 people attended (representing nearly 2,000 total household members). The flyer for the Fair is included here as Exhibit NW Natural/202, Tanaka.

VIII. NW NATURAL'S EFFORTS TO ADDRESS DIVERSITY, EQUITY AND INCLUSION

Q. What is NW Natural's philosophy regarding diversity, equity, and inclusion?

A. At NW Natural, diversity, equity and inclusion are core to our success and embedded in all aspects of our work, from the way we hire and operate every day, to the biggest decisions we make as a business. We recognize the interconnectedness of our actions with the well-being of our customers, communities and planet and are committed to a forward-thinking and strategic approach to equity.

As an employer, we strive to advance diversity, equity and inclusion to support our colleagues, customers, contractors, suppliers and community members, regardless of race, gender, color, sexual orientation, age, religion, national origin, or physical or mental disability, so everyone has an equal opportunity to thrive, engage, and belong. Our commitment to equity, diversity, and inclusion advances our culture and business success.

Our CEO and Officer team, in partnership with our DE&I Council, defined the following commitments:

- Reinforce our zero-tolerance policy for racism and discrimination at NW Natural;

- Hold listening sessions to understand the experience and needs of Black, Indigenous and People of Color ("BIPOC") employees;
- Foster an inclusive and diverse culture/workforce in our existing employee population;
- Recruit more diversity into NW Natural, focusing on BIPOC, female, trans, and non-binary talent, as well as people with disabilities;
- Assess and expand our ability to work with diverse suppliers, and increase the positive impact on our diverse supplier network;
- Foster diversity, equity & inclusion in our communities through partnerships, volunteering, and financial support; and
- Ensure all customers have equitable access to natural gas programs and resources.

Through NW Natural's Diversity, Equity and Inclusion Council, which has championed equity and inclusion in the Company and community for 20 years, we continue to grow our Employee Resource Groups ("ERGs"). A quarter of NW Natural employees are connected to an ERG. ERGs offer our employees the opportunity to influence our workplace culture: African American ERG, Asian American Network, Somos Unidos (LatinX ERG), Rainbow Alliance (LGBTQ+ ERG), Women's Network, and Veterans ERG. NW Natural is also proud to offer a Neurodiversity ERG, which is one of the first of its kind for U.S. utilities.

Deepening and expanding relationships with a diverse supplier base are integral to our corporate culture and strategy and procurement spending for women owned, minority owned, veteran owned, and small business continues to grow. In 2022, we laid the foundation to build out this capacity; and doubled our purchasing spend with diverse suppliers in 2023. We are also proud to report that we exceeded our target spend goal and reached $45,216,000 the end of the 3rd quarter (2024).

Our charitable investments and partnerships help create safe, healthy, and thriving communities where we live and work. Through our matching gifts program, we matched the time and dollars employees gave to the organizations they care about most. We recently announced $600,000 in support for organizations that serve families and children in Oregon and southwest Washington. This support is part of the Company's 2023 total giving, which is expected to exceed $1 million. Organizations benefiting from these gifts include: A Village for One, Q Center, Centro Cultural de Washington County, Youth Rights & Justice, FOOD for Lane County and Old Mill Center for Children & Families.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Cecelia J. Tanaka

EQUITY
EXHIBITS 201-202

December 30, 2024

EXHIBITS 201 – 202 – EQUITY

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Cecelia J. Tanaka

EQUITY
EXHIBIT 201

December 30, 2024

Communications to NW Natural customers with limited incomes

NW Natural

Purpose of NW Natural's Energy Efficiency Program

Improve the energy efficiency, energy savings and comfort of homes for customers with limited incomes in Oregon and Southwest Washington.

Connect these customers with free heating and weatherization upgrades and services to:

- Lower gas bills
- Lower gas use
- Reduce service disconnections
- Deliver core values of caring, environmental stewardship and safety

Audience

NW Natural customers who qualify for financial assistance from one of two programs, depending on gross annual income.

For customers with low incomes, Oregon Low-income Energy Efficiency (OLIEE) and Washington Low-income Energy Efficiency (WALIEE) income guidelines are the same as the Oregon and Washington Housing and Community Service's Low Income Home Energy Assistance weatherization program. Customers qualify for free weatherization services if their household income is at or below 80% of area median income.

Customers receive assistance and improvements by working with Community Agencies listed at nwnatural.com/Savings.

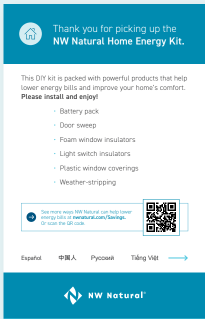
We also serve customers with moderate incomes through Savings Within Reach, offered in partnership with Energy Trust of Oregon. Savings Within Reach provides increased incentives to help offset the cost of insulation and heating upgrades. Customers receive assistance and improvements by working with Energy Trust of Oregon Savings Within Reach contractors.

Improving home energy efficiency and comfort in partnership with community organizations

Communications, outreach and engagement

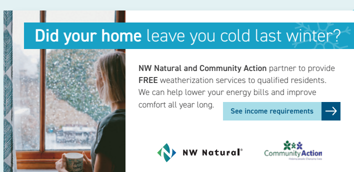
NW Natural helps customers with limited incomes save money and improve home energy efficiency via continual communication and outreach.

A variety of communication methods guide customers to one place, where they can learn about and enroll in beneficial NW Natural programs. All communications repeat the same messages, in several languages, to make the path to participate as clear and simple as possible.



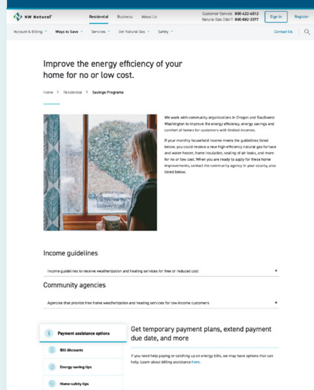
Outreach DIY kit card

Event and outreach card



Bill insert

Webpage and NW Natural team



Multnomah County

Community Action Team

Community action agencies and community-based organizations

Free heating and weatherization upgrades
via community organizations

+

Billing assistance
via state organizations

+

Additional NW Natural programs to lower bills and improve home energy efficiency

- Bill discounts
- Flexible payment plans
- Online account, billing and payment self-service
- Annual equipment inspections and tune-ups
- Safety resources and tips
- Energy education and smart thermostats
- More opportunities announced in newsletters, emails and social media

Key messages repeat throughout communications

- NW Natural can help lower your energy bills.
- We partner with community agencies to provide free heating and weatherization services for qualifying incomes.
- We can help improve comfort all year long.

Communications cross-promote additional NW Natural services that can help lower bills even more

- NW Natural Bill Discount Program: You could save 15% to 85% on your monthly bill.
- NW Natural payment assistance options: Get temporary payment plans, extend payment due date, and more.
- Energy-saving tips: Ways to help lower energy bills and gas use at home.
- Natural gas home safety tips.

In addition, Bill Discount Program materials cross-promote these same services, as well as contact information for electric utilities to save on electric bills.

Multiple languages: English, Spanish, Vietnamese, Russian, Chinese (simplified)

QR code to web page for income qualifications, community agencies and additional resources

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Cecelia J. Tanaka

EQUITY
EXHIBIT 202

December 30, 2024

Community Services Network pdx

Winter Preparedness Fair

Join us for a winter resource fair to learn how to keep yourself, your family, and your home safe and warm this winter season!

NOV 16 2024

PARKROSE HIGH SCHOOL

12003 NE SHAVER ST,
PORTLAND, OR 97220

11AM - 2PM

- NONPROFIT RESOURCES
- HEALTHCARE SIGNUP
- FAMILY ACTIVITIES
- FREE LUNCH
- WINTER COATS (INFANT - SIZE 12 YOUTH - LIMIT 2 PER FAMILY)
- FOOD BOXES
- HOME WEATHERIZATION KITS
- ENERGY EDUCATION
- BILL DISCOUNT OPPORTUNITIES
- VACCINATIONS

In Partnership With:

THE BUREAU OF PLANNING & SUSTAINABILITY

NW Natural® *We grew up here.*

Sponsored by:

THE DPI GROUP BUSINESS RESULTS WITH SOCIAL IMPACT

CareOregon

COMCAST

Come learn and celebrate with your community!

Community Services Network pdx

Feria de Preparacion para el invierno

ACOMPÁÑENOS EN UNA FERIA DE RECURSOS INVERNALES PARA APRENDER A MANTENERSE A SÍ MISMO, A SU FAMILIA Y A SU HOGAR SEGUROS Y CALIENTES ESTA TEMPORADA DE INVIERNO.

SAVE ENERGY

DE NOVIEMBRE
16
de 2024

ESCUELA SECUNDARIA PARKROSE

12003 NE SHAVER ST,
PORTLAND, OR 97220

11AM - 2PM

Regalo de un abrigo de invierno
Infantil - Juvenil Talla 12
***hasta agotar existencias**

- RECURSOS DE ORGANIZACIONES NO LUCRATIVAS
- INSCRIPCION DECUIDADO DE SALUD
- ACTIVIDADES FAMILIARES
- ALMUERZO GRATIS
- ROPA DE INVIERNO (INFANTIL - TALLA JUVENIL 12 - LIMITE 2 POR FAMILIA)
- CAJA DE ALIMENTOS
- KITS DE CLIMATIZACIÓN DE VIVIENDAS
- EDUCACIÓN ENERGÉTICA
- OPORTUNIDADES DE DESCUENTO DE FACTURAS
- VACUNAS

En colaboración con:

THE BUREAU OF PLANNING & SUSTAINABILITY

NW Natural® *We grew up here.*

Prepárese para el invierno!

Patrocinado por:

THE DPI GROUP BUSINESS RESULTS WITH SOCIAL IMPACT

CareOregon

COMCAST

¡Venga a aprender y celebrar con su comunidad!!

Community Services Network pdx

Зимовий Ярмарок Підготовки

Приєднуйтесь до нас на зимовому ярмарку ресурсів, щоб дізнатися, як зберегти себе, свою сім'ю та ваш дім у безпеці й теплі цієї зими!

ЛИСТОПАДА
16
2024 року

СТАРША ШКОЛА ПАРКРОУЗ

12003 NE SHAVER ST,
PORTLAND, OR 97220

З 11:00 ПО 14:00

Роздача зимових курток
Розміри: дитячі – до розміру 12
** поки є в наявності*

- **РЕСУРСИ ВІД НЕКОМЕРЦІЙНИХ ОРГАНІЗАЦІЙ**
- **РЕЄСТРАЦІЯ НА МЕДИЧНЕ ОБСЛУГОВУВАННЯ**
- **СІМЕЙНІ АКТИВНОСТІ**
- **БЕЗКОШТОВНИЙ ОБІД**
- **ЗИМОВІ КУРТКИ** (ДИТЯЧІ РОЗМІРИ ДО 12, НЕ БІЛЬШЕ 2-Х КУРТОК НА РОДИНУ)
- **ПРОДУКТОВІ НАБОРИ**
- **НАБОРИ ДЛЯ УТЕПЛЕННЯ ДОМУ**
- **ОСВІТА З ПИТАНЬ ЕНЕРГОЗБЕРЕЖЕННЯ**
- **МОЖЛИВОСТІ ОТРИМАТИ ЗНИЖКИ НА РАХУНКИ**
- **ВАКЦИНАЦІЯ** (ПЕРШІ 30 ОСІБ ОТРИМАЮТЬ БОНУС У РОЗМІРІ 10$)

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2024

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11 GIỜ TRƯA - 2 GIỜ CHIỀU

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*cho đến khi hết hàng

- CÁC NGUỒN PHI VỤ LỢI
- GHI DANH CHĂM SÓC SỨC KHỎE
- CÁC SINH HOẠT CHO GIA ĐÌNH
- ĂN TRƯA MIỄN PHÍ
- CÁC ÁO KHOÁC MÙA ĐÔNG (KÍCH CỠ TRẺ SƠ SINH - TRẺ 12 - GIỚI HẠN 2 CHO MỖI GIA ĐÌNH)
- NHỮNG HỘP THỨC ĂN
- BỘ DỤNG CỤ CHỐNG CHỊU THỜI TIẾT CHO NHÀ
- GIÁO DỤC VỀ NĂNG LƯỢNG
- NHỮNG CƠ HỘI GIẢM GIÁ HÓA ĐƠN
- CHỦNG NGỪA (30 NGƯỜI ĐẦU TIÊN NHẬN 10$ TƯỞNG THƯỞNG)

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 300

REDACTED

December 30, 2024

EXHIBIT 300 – DIRECT TESTIMONY– COST OF CAPITAL

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Brody J. Wilson. I am Vice President, Treasurer, Chief Accounting Officer, and Controller at NW Natural and Northwest Natural Holding Company ("NW Natural Holdings").

Q. Please state your experience and educational background.

A. I received a Bachelor of Arts in Accounting from George Fox University in 2001. From 2001 through 2012, I worked at PricewaterhouseCoopers, LLP, in the Power and Utilities Assurance practice. I joined NW Natural in 2012 as Accounting Director.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to support the Company's requested capital structure and explain the Company's financing strategy and how that leads to a financially healthy utility that benefits our customers.

Q. Please summarize your testimony.

A. The Company's financing strategy is to maintain a balance of long-term debt and equity financing by targeting a capital structure that supports our strong investment grade credit profile. The Company's strong investment grade credit ratings support its ability to access the capital markets. We work to manage interest rate risk and secure low-cost capital to fund utility infrastructure to maintain a safe and reliable system as well as utility operations. To do this, we intend to maintain a strong balance sheet and focus on financing the long-term assets of the Company through a balance of long-term debt and equity financing. To further explain our financing strategy, my testimony:

- Describes NW Natural's request for a capital structure of 52 percent common equity and 48 percent long-term debt, with an overall rate of return ("ROR") on rate base of 7.658 percent;
- Describes NW Natural's plan to maintain its proposed ratios of equity and debt;
- Explains how I calculated the cost of debt for the Test Year (November 1, 2025 through October 31, 2026); and
- Discusses the Company's current credit ratings and why it is important for the Company to maintain its current credit ratings.

II. CAPITAL STRUCTURE AND RATE OF RETURN

Q. What is NW Natural's current Commission-authorized capital structure for ratemaking purposes and overall ROR?

A. In UG 490, the Commission authorized the following capital structure, capital costs and overall ROR for NW Natural:

Table 1. NW Natural's Capital Structure and Rate of Return Order No. 24-359

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	4.712%	2.356%
Common Equity	50%	9.40%	4.70%
Total	**100%**		**7.056%**

Q. What is NW Natural's requested capital structure for ratemaking purposes and overall ROR in this proceeding?

A. NW Natural is requesting a capital structure of 48 percent long-term debt and 52 percent equity, with an overall ROR on rate base of 7.658 percent, based upon a 4.687 percent embedded cost of long-term debt and a 10.4 percent cost of equity. The following table presents the proposed capital structure along with the calculation of the Company's ROR for the Test Year:

Table 2. Requested Capital Structure and Rate Of Return

Component	Ratio	Cost	Weighted Cost
Long-term Debt	48%	4.687%	2.250%
Common Equity	52%	10.4%	5.408%
Total	**100%**		**7.658%**

Q. Will NW Natural's actual capital structure reach 52 percent equity?

A. Yes. NW Natural is targeting a higher equity ratio in its capital structure. The Company forecasts an equity ratio of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The equity percentage will fluctuate throughout the year primarily based on the seasonal nature of the business among other factors.

Q. Why is NW Natural changing its targeted capital structure?

A. NW Natural's target capital structure has been 50/50 for a number of years. In order to strengthen its balance sheet, attract investment and provide solid investment grade credit ratings, which benefit customer rates, NW Natural is taking steps to increase its capital structure to 52 percent equity and 48 percent long-term debt.

Generally, companies with higher debt ratios are considered riskier, as a higher debt layer in the capital structure inherently puts pressure on the credit metrics. By reducing our long-term debt ratio to 48 percent, the Company is improving its risk profile and moving to be in-line with its natural gas peer group. Reducing the Company's debt ratio to 48 percent is likely to be viewed positively by the rating agencies. Moody's methodology specifically looks at debt/capitalization ratios and both agencies use debt as a component in their metrics. A lower amount of debt improves the metrics. I discuss the importance of credit metrics in detail below.

This equity ratio demonstrates the Company's commitment to a strong and stable balance sheet, which helps maintain the Company's current credit ratings. Strong investment grade credit ratings provide the Company with financing flexibility and liquidity, thereby ensuring timely, efficient, and cost-effective access to capital markets, which in turn helps to lower the cost of capital. The cost of capital and capital structure directly impact the return for debt service and common equity investors within the revenue requirement calculation.

Q. What is NW Natural's plan to maintain the target equity ratio of 52 percent over the next few years?

A. The Company plans to rely on retained earnings growth each year, as well as continuing to request equity infusions from our parent company, as needed. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**.

Q. Has the Company received equity from the parent company, NW Natural Holdings, since the holding company structure was approved by the Commission?

A. Yes. The following table displays the equity contributions from NW Natural Holdings to the Company since 2019. Equity infusions from the parent company help the Company manage its common equity and maintain a strong balance sheet.

Table 3. Equity Contributions from NW Natural Holdings to NW Natural

2019	2020	2021	2022	2023	YTD[1] 2024
$93 million	$ -	$116 million	$179.4 million	$30 million	$45 million

Q. What are the credit concerns of the rating agencies for NW Natural?

A. The rating agencies' most significant factors in determining ratings are how constructive the regulatory framework is in the jurisdictions the Company does business (business risk), the ability of the Company to recover costs and earn a sufficient rate of return, and the financial strength of the organization as measured by its credit metrics. NW Natural's key credit metrics, which help investors evaluate the creditworthiness and risk profile of the Company, generally are quantitative measures of the Company's operating cash inflows, its capital requirements or outflows, and its debt profile. NW Natural's credit metrics have been inconsistent and below the rating agencies' downgrade thresholds over the

[1] As of the filing date of the general rate case.

last five years. By lowering the debt levels for the Company, NW Natural can improve its performance for these metrics.

Q. How does NW Natural's proposed capital structure compare with the natural gas peer group?

A. The Company's proposed capital structure will move it in line with its peer natural gas utilities. Currently, the Company has a significantly lower equity to capital ratio than the average of our peer group identified by Jennifer E. Nelson in the Company's Return on Equity Direct Testimony (NW Natural/400, Nelson). Specifically, our gas proxy group has an average equity ratio of 55.28 percent over the last three years, and the Combined Proxy Group has a three-year average common equity ratio of 53.15 percent.

Q. What are NW Natural's current credit ratings?

A. The table below and NW Natural/301, Wilson show the Company's current ratings for each type of debt security from Moody's Investor Service ("Moody's") and Standard and Poor's Ratings ("S&P"), as well as the outlook issued by each agency.

Table 4. Current Ratings

	Moody's	S&P
Corporate credit rating	n/a	A+
Senior unsecured (long-term debt)	Baa1	n/a
Senior Secured (long-term debt)	A2	AA-
Commercial Paper	P-2	A-1
Outlook	Stable	Stable

Q. Please explain the implications of the credit ratings in terms of NW Natural's ability to access capital markets.

A. Generally speaking, companies with higher credit ratings will have greater access to investors at lower yields, given the lower risk profile of such companies. Lower-rated companies may find it difficult to access capital, or potentially pay significantly more (i.e., risk premium), especially in challenging capital market conditions. The capital market environment changes as macro business cycles move up and down, which creates tighter and looser access to capital. To ensure that the Company continues to have favorable pricing or, at times, access to capital markets during all market environments, it is imperative that the Company maintain or improve its existing ratings.

Q. Are there important factors that the rating agencies review in determining NW Natural's ratings?

A. Yes. Moody's and S&P rate the Company's debt based on their independent review of the Company's financial condition and credit metrics. Independent credit reviews consist of qualitative and quantitative metrics; for example, the regulatory environment and cash flow metrics. Although each rating agency has a slightly different methodology for analyzing credit risk, many of the key financial ratios are similar and comparable.

The tables below display Moody's and S&P's benchmarks and consolidated NW Natural's financial forecast for the 2024 year-end ("YE") period.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CFO = Cash Flow from Operations
W/C = working capital

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

FFO = Funds From Operations
EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

[END CONFIDENTIAL]

Q. How do NW Natural's credit ratings benefit customers?

A. Investment grade credit ratings provide NW Natural access to capital to support capital improvements in order to maintain a high standard of safe and reliable operating practices. Credit ratings that are higher than investment grade, as is the case with NW Natural, generally provide access to capital at comparatively lower interest rates. This allows customers to benefit from lower interest expense. Access to capital markets during the most difficult times reduces the impacts that could occur from market disruptions that may require more expensive capital raising to fund ongoing operations. NW Natural has proven over time that as a result of its strong credit, it has been able to access capital markets and fund its operations without material disruption or cost to customers even during challenging capital market times.

Q. How has NW Natural performed under Moody's credit metrics?

A. The Moody's credit metrics are focused on understanding a company's cash flows and debt profile. As context, Moody's uses cash flow from operations ("CFO") in its metrics as CFO provides a picture of the Company's cash flow from ongoing, regular business or operating activities. The CFO pre-working capital ("W/C") is equal to CFO less net changes in working capital items (such as accounts receivable and payable) to arrive at Moody's definition of cash flow from operations. In Moody's retained cash flow metric, they can take CFO pre-W/C and subtract dividends because these payments to shareholders come with implications if they are stopped or changed, although they are not required like interest payments on a bond. The debt to total capitalization is to provide a view of the level of leverage at a company. Please see Table 7 below.

Table 7. Moody's Historical Credit Metrics for NW Natural

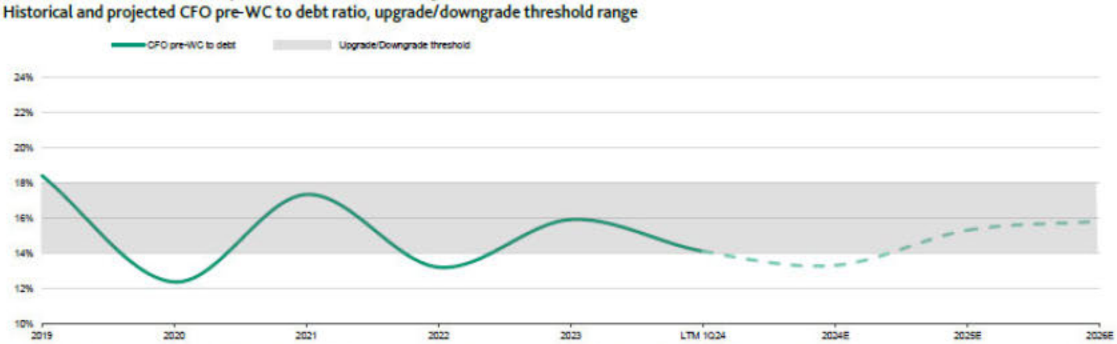
Moody's Metrics	2019	2020	2021	2022	2023	LTM[1]	Downgrade Threshold	Upgrade Threshold
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%	14%	18%
Retained Cash Flow (CFO pre-WC – Dividends/Debt)	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%	7%	14%
Debt/Capitalization	51.2%	55.2%	52.5%	49.3%	50.0%	49.3%	59% or more	50% or less

1 – Moody's metrics are based on last twelve months ended 3/31/24 per their report.
CFO = Cash Flow from Operations
W/C = working capital

For Moody's, the CFO pre-WC to debt ratio for NW Natural has been below the downgrade threshold for three of the previous years (2020, 2022 and 2024E). Per Moody's forecast, it is not expected to be close to the midpoint of the rating band until 2026. See below excerpt from the Moody's July 30, 2024 report.

Table 8. Moody's Historical and Projected CFO pre-WC to Debt Ratio

Exhibit 4
Consistent credit metrics expected over next several years
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period.
Source: Moody's Ratings

Furthermore, Moody's current forecasted FFO/debt metric in 2024 is below the downgrade threshold whereas projections published just one year previously on July 19, 2023 show 2024 metrics near the midpoint of the rating range. This inconsistency in the metrics and being close to or below the downgrade threshold puts NW Natural's credit rating in jeopardy of a downgrade, which would increase the cost of debt for the Company and result in higher rates for customers. For reference, the three peers to which Moody's has selected to compare NW Natural average 16.5 percent CFO pre-WC to debt ratio over the last three years, with one peer averaging 21.4 percent. The peers averaged a debt to capitalization rate of 41.0 percent with one peer averaging 32.8 percent.

According to Moody's methodology and specific scorecard for NW Natural, 40 percent of the rating is based on the financial strength of the Company as defined by its credit metrics. Because NW Natural's financial metrics are weaker, it is difficult for the Company to maintain its current senior unsecured long-term debt rating (Baa1) and also achieve the higher rating for which it qualifies (A3) in most respects, except its credit metrics.

In addition to the financial metrics, Moody's most recent report on July 30, 2024 cited credit challenges for NW Natural related to "[e]levated social risk due to higher scrutiny on natural gas as an energy source and long-term risks associated with environmental remediation costs and emission reduction requirements." Furthermore, Moody's stated that "[a] rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered due to state emission reduction requirements. A rating downgrade could also be considered if CFO pre-WF to debt is sustained below 14%."

Q. How has NW Natural performed under S&P's credit metrics?

A. As context, S&P looked at two key metrics in its cash flow analysis. Funds from operations divided by debt (FFO/Debt) is used in order to understand if the operating cash flows of the business activities (FFO) are sufficient relative to the leverage or debt a company is carrying. Another way to analyze if the company has the appropriate amount of leverage is to look at Debt/EBITDA (earnings before interest, taxes, depreciation and amortization). EBITDA is used to help track underlying profitability across companies by setting aside differences in depreciation assumptions or financing choices. The credit metrics for S&P, like Moody's, have fluctuated and repeatedly been below the downgrade threshold over the past five years. Below are the key financial metrics used by S&P.

Table 9. S&P's Historical Credit Metrics for NW Natural

S&P's Metrics	2019	2020	2021	2022	2023	Downgrade Threshold	Upgrade Threshold
FFO/Debt	18.9%	15.3%	15.3%	16.9%	15.0%	15%	21%
Debt/EBITDA	4.4	5.3	4.8	4.8	4.6	4x	3x

FFO = Funds From Operations
EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

S&P's latest report on NW Natural on June 24, 2024 stated several downside risks. Per S&P: "We could lower our rating on NWNG [NW Natural Gas] over the next 24 months if the company's consolidated financial performance weakened such that FFO to debt remained consistently below 15%. We could also lower our rating if the company's business risk increased. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE." Of particular note, S&P listed several key risks including "[c]ontinued negative discretionary cash flow over the next few years, indicating external funding needs."

When compared to peers of the same rating category, NW Natural has noticeably lower FFO/Debt with 15.0 percent in 2023 compared to the peer average of 18.7 percent for 2023 (based on peers disclosed in the S&P June 2024 report).

As mentioned in the June 2024 report, S&P is focused on a company's ability to consistently earn its authorized ROE. NW Natural has been earning below its authorized ROE for a number of years. While there have been some years of slight overearning, recently and consistently, NW Natural has under earned its authorized ROE to a greater extent than historically. The average underearning from 2020 – 2023 was 78 bps compared to average underearning of 49 bps from 2015-2017. Table 10 below does not include or contemplate the millions of dollars of expenses that the Company prudently incurs but does not recover, such as market-based compensation packages for employees that include pay-at-risk. The lack of recovery of these expenses further reduces the return provided to investors and limits NW Natural's ability to attract capital.

Table 10. Historical Earned vs. Authorized ROE for NW Natural

ROE	2015	2016	2017	2018	2019	2020	2021	2022	2023
Authorized ROE	9.50%	9.50%	9.50%	9.40%	9.40%	9.40%	9.40%	9.40%	9.40%
Earned ROE	9.18%	8.84%	9.00%	9.51%	10.05%	8.56%	8.68%	8.56%	8.67%
Difference	-0.32%	-.66%	-.50%	+.11%	+.65%	-.84%	-.72%	-.84%	-.73%

Q. How could NW Natural increase its credit metrics to continue to hold its current ratings and improve the liquidity of the organization to continue garnering capital?

A. As noted previously in this testimony, one way to improve the credit metrics is to decrease the debt component of NW Natural's capital structure. This decreases the amount of debt in the capital structure thereby improving the credit metrics.

Additionally, the Company also continuously monitors its funds from operations (FFO). The Company reviews and monitors items such as cash payments, accurate depreciation rates, timely collection of payments from customers, and swift recovery of deferrals.

Q. Have any of NW Natural's credit ratings changed since the Commission issued its order in the Company's last general rate case (UG 490)?

A. No, there have not been any changes to NW Natural's credit ratings since the filing of the last general rate case, UG 490. However, as shown in Table 4 above, there has been a change to the outlook issued by S&P. Specifically, in the report issued for NW Natural on April 19, 2024, S&P changed the outlook for NW Natural from negative to stable. The latest rating agency credit reports can be found in NW Natural/301, Wilson. Historical ratings for each rating agency can be found in NW Natural/302, Wilson.

Q. What reasons did S&P give for the stable outlook?

A. As context, S&P originally moved NW Natural's outlook to negative in October 2023. S&P gave three primary reasons for the negative outlook. First, S&P noted that our FFO (funds from operations) to debt ratio is near the low end of the range for its rating. S&P noted that overall financial measures have been negatively impacted by headwinds stemming from the COVID-19 pandemic, higher bad debt expenses, elevated capital spending, and inflationary pressures, including higher operating costs. Second, S&P explained that the negative outlook also reflects gradual weakening of the business risk metric, due to the ongoing energy transition risks in Oregon and Washington associated with the implementation of decarbonization mandates. In particular, decarbonization programs could be negative to NW Natural from a credit perspective to the extent decarbonization programs require NW Natural to finance costs ahead of recovery from customers rates. In addition, the limitation of the line extension allowance for new customers to connect to the system will likely increase the Company's risk relative to its peers as it restricts NW Natural's growth prospects potentially making it relatively risker of an investment versus gas companies with no restrictions. Finally, S&P noted that an inability to consistently earn its authorized return on equity also weighs on the rating.

On April 19, 2024, S&P moved NW Natural's outlook back to stable in recognition of the gas utility's strong ring-fencing provisions and S&P's expectation that NW Natural Gas Company's financial measures will consistently be above their downgrade threshold and the Company will maintain a FFO to debt of 15 percent - 18 percent through 2026. Despite the change in the S&P rating to stable, the cash flow metrics and the risks noted by S&P persist and must be closely managed in order for the Company to continue garnering strong investment grade ratings.

III. LONG-TERM DEBT

Q. How was the cost of long-term debt calculated for the Test Year?

A. Confidential NW Natural/303, Wilson presents the details of the Company's long-term debt outstanding **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the corresponding weighted average cost (4.687 percent) forecasted for the Test Year. The cost of long-term debt includes existing debt and forecasted debt. The weighted average cost of long-term debt was calculated by multiplying the debt outstanding, including future projected debt issuances, by the average cost for each debt issuance.

Column "s" of Confidential NW Natural/303, Wilson shows the annualized expense of each individual issuance in terms of an effective interest rate, which represents the total cost of issuance, including coupon rate, premiums or discounts, underwriter's commissions, gains on interest rate hedges, and other expenses related to the issuance such as legal fees and unamortized debt discounts and early redemption premiums assigned to refunding issuances. Unamortized debt discounts and early redemption premiums from previously outstanding debt issuances are added to the new debt issuance because the Company was able to achieve a lower annualized cost of debt due to net present value savings from the early redemption.

Q. [BEGIN CONFIDENTIAL][redacted]

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[redacted] **[END CONFIDENTIAL]**.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Brody J. Wilson

COST OF CAPITAL
EXHIBITS 301 – 305

December 30, 2024

EXHIBITS 301-305 – COST OF CAPITAL

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 301

December 30, 2024

S&P Global
Ratings

RatingsDirect®

Research Update:

Northwest Natural Holding Co. Downgraded To 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook To Stable

April 19, 2024

Rating Action Overview

- We concluded our review of the insulating measures in place and determined that they are sufficient to potentially rate Northwest Natural Holding Co. (NWNH) subsidiary Northwest Natural Gas Co. (NWNG) up to two notches higher than its parent's group credit profile (GCP). We also assess the cumulative value of these insulating measures as increasing risk for parent NWNH because they limit or even materially restrict NWNH's access to NWNG's cash flows.
- Consequently, we lowered our rating on parent NWNH to 'A' from 'A+'. The outlook is negative.
- At the same time, we revised our outlook on subsidiary NWNG to stable from negative and affirmed our ratings on NWNG, including the 'A+' long-term issuer credit rating (ICR), the 'A+' unsecured debt rating, the 'AA-' senior secured debt rating, and the 'A-1' short-term rating. The recovery rating on the senior secured debt remains '1+'.
- The stable outlook on NWNG reflects our assessment that the insulating measures in place are sufficient to potentially rate NWNG up to two notches above NWNH's GCP and as such a downgrade to NWNH would not directly lead to a downgrade at NWNG. The stable outlook also reflects our expectations that NWNG's stand-alone financial measures will consistently remain above our downgrade threshold. Specifically, we expect stand-alone funds from operations (FFO) to debt of 15%-18% through 2026.
- The negative outlook on NWNH reflects its weak consolidated financial measures for the current rating. FFO to debt in 2023 was around 12%, significantly below our 15% downgrade threshold. We expect financial performance in 2024 will remain weak but improve in 2025, primarily reflecting our expectations for a fair Oregon rate case order.

PRIMARY CREDIT ANALYST

Mayur Deval
Toronto
(1) 416-507-3271
mayur.deval
@spglobal.com

SECONDARY CONTACT

Matthew L O'Neill
New York
+ 1 (212) 438 4295
matthew.oneill
@spglobal.com

Rating Action Rationale

Our downgrade of NWNH to 'A' from 'A+' reflects higher risks because of material restrictions of cash flows within the company's corporate group. NWNG accounts for about 95% of NWNH's consolidated cash flows. We assess the cumulative value of the insulation measures in place as sufficient to rate NWNG up to two notches above NWNH's GCP. However, these insulating measures limit and could materially restrict NWNH's full access to NWNG cash flows. These insulating measures include dividend restrictions, a non-consolidation opinion, and independent directors on NWNG's board of directors that have effective influence on decision-making and whose vote is required for a voluntary bankruptcy filing.

The negative outlook on NWNH reflects its historical weak financial measures and our expectation that financial performance will remain weak for 2024. Since 2020, NWNH's FFO to debt has been consistently below our 15% downgrade threshold. The company's historical financial underperformance reflects its rising capital investments, including multiple acquisitions of water utilities, which increased its leverage and weakened its financial measures. More recently, NWNH's financial measures have been negatively affected by higher interest rates, higher cash taxes, and inflationary pressures, including higher operating costs.

We expect the company's financial measures will remain challenged in 2024 due to its elevated capital spending plan, including water utility acquisitions, investments in renewable natural gas (RNG) projects, and ongoing infrastructure investments. We expect financial improvement beginning in 2025, primarily reflecting a fair Oregon rate case order. However, financial measures could remain weak for the current rating if elevated capital investments and cash flow deficits are primarily debt funded or the company's rate case order is significantly below expectations.

We affirmed our 'A+' rating on subsidiary NWNG. Our rating largely reflects NWNG's low-risk regulated gas distribution operations in Oregon and Washington. NWNG provides natural gas service to approximately 800,000 customers with 65% of its margin generated from residential customers, 25% from commercial customers, and 7% from industrial customers. The company benefits from stable and supportive regulatory environments in both jurisdictions where it operates, with purchased gas adjustments and environmental cost recovery, decoupling and a forward-looking test year in Oregon, and multiyear rate case fillings in Washington. We view these mechanisms as supportive to its financial measures, allowing the company to largely mitigate regulatory lag. However, over the past few years, the company's earned return on equity (ROE) has been modestly weaker than its authorized ROEs, reflecting a potential weakening of management's ability to manage regulatory risk.

We also view the energy transition risks in Oregon and Washington as potentially increasing business risk. Washington has implemented decarbonization mandates and Oregon is contemplating various decarbonization initiatives. Furthermore, several cities are contemplating the implementation of a gas ban for new gas connections. We assess these evolving risks as potentially negative for credit quality and will continue to monitor future developments.

We assess NWNG's financial risk profile using our low-volatility benchmarks, reflecting the low-risk nature of its natural gas distribution operations and its track record of effective management of regulatory risk. We assume continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging of about $330 million, and annual dividends averaging of about $75 million. We expect NWNG's stand-alone financial measures to remain in the middle range of its financial risk profile category such that FFO to debt is 15%-18% through 2026.

We consider NWNG to be insulated from its parent NWNH. Based on the strength of the insulating measures, NWNG could potentially be rated up to two notches higher than NWNH's GCP. Currently, NWNG is rated only one notch higher than its GCP, limited by its 'a+' standalone credit profile.

The key insulating measures include:

- NWNG's financial performance and funding prospects are independent from those of the group.
- NWNG issues its own debt and has its own credit facility.
- NWNG is regulated by Oregon and Washington regulatory commissions.
- NWNG has dividend restrictions.
- NWNG's board is highly independent with 11 out of 12 board of directors being independent.
- Independent directors on NWNG's board have effective influence on decision making, and their votes are required for a voluntary bankruptcy filing.
- NWNG is unlikely to be drawn or forced into a NWNH bankruptcy.
- There is an independent third party which is the holder of the "golden share" whose vote is required to file for bankruptcy.

We revised our outlook on NWNG to stable reflecting the insulation measures and the strength of its stand-alone credit profile. The stable outlook reflects our view that NWNG, because of the cumulative value of the insulating measures, could potentially be rated up to two notches above its parent's NWNH GCP. Because of the insulating measures, a downgrade to parent NWNH would not directly lead to a downgrade at NWNG. In addition, the stable outlook reflects our expectation that the company will continue to effectively manage regulatory risk and maintain financial measures consistent with the middle range for its financial risk profile category. Specifically, we expect stand-alone FFO to debt of 15%-18% through 2026.

Outlook

Northwest Natural Holding Co. (NWNH)

The negative outlook on NWNH reflects its current weak financial measures and the possibility that financial measures could remain weak. Our base case assumes continued weak financial performance in 2024 and then for financial performance improvement in 2025. This improvement primarily reflects a fair Oregon rate case order, such that FFO to debt is consistently greater than 15%.

Downside scenario

We could lower our ratings on NWNH over the next 12 to 24 months if FFO to debt remains below 15%. We could also lower our ratings on NWNH if business risk increases. This could reflect an unfavorable rate case outcome, higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could affirm ratings and revise our outlook on NWNH back to stable over the next 12 to 24 months if FFO to debt improves to consistently greater than 15%, with no increase of business risk.

Outlook

Northwest Natural Gas Co. (NWNG)

The stable outlook on NWNG reflects our base-case assumption that NWNG will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including FFO to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if the company's consolidated financial performance weakens such that FFO to debt remains consistently below 15%.We could also lower our rating on NWNG if the company's business risk increases. This could reflect a higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12 to 24 months if the company's financial performance improves such that FFO to Debt is consistently above 21%, with no weakening of business risk.

Company Description

NWNH is the holding company of NWNG, NWNR and NW Natural Water Co. LLC (NWWC). NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 800,000 residential, commercial, and industrial natural gas customers in Oregon and Southwest Washington through 14,200 miles of pipeline systems. Approximately 90% of customers are in Oregon and 10% are in southwest Washington. NWNR is engaged in investing competitive RNG operations while NWWC owns and operates several regulated water utilities. Together, NWNR and NWWC contribute about 5% of NWNH's revenues while NWNG contributes the remaining 95% revenues.

Our Base-Case Scenario

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow.
- Annual capital spending averaging about $370 million over our forecast period.

- Small tuck-in regulated water utilities acquisitions funded in a credit supportive manner.
- Annual dividends averaging about $77 million.
- All debt maturities refinanced.

Liquidity

We assess NWNH's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for NWNH provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, NWNH has the ability to absorb high-impact, low-probability events, reflecting that the company maintains about $600 million in committed credit facilities through 2026, and our belief that the company can lower its high capital spending (averaging about $370 million annually) during stressful periods, indicative of a limited need for refinancing under such conditions.

Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banking group (which includes over four well-established banks). Overall, we believe the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has no large long-term debt maturity coming due, and we expect the company to proactively address any maturities well in advance of its scheduled due dates.

Principal liquidity sources

- Cash and cash equivalents of about $33 million;
- Credit facilities of about $600 million; and
- Cash FFO estimated of about $275 million.

Principal liquidity uses

- Debt maturities, including commercial paper outstanding of about $241 million;
- Capital expenditure (capex) of about $400 million; and
- Dividend payments of about $75 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNH.

Issue Ratings - Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1', based on our 'A+' issuer credit rating on the company. As on Dec 31, 2023, NWNG's capital structure consists of approximately $1.4 billion first mortgage bonds. The company also maintains a medium-term note program which is currently not utilized.

Analytical conclusions

We rate NWNG's medium-term notes program 'A+', equal to its issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings - Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+ and an issue-level rating one notch above the issuer credit rating.

Ratings Score Snapshot

Northwest Natural Holding Co.

Issuer credit rating: A/Negative/--

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Northwest Natural Gas Co.

Issuer credit rating: A+/Stable/A-1

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Entity status within group: Insulated (no impact)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded		
	To	**From**
Northwest Natural Holding Company		
Issuer Credit Rating	A/Negative/--	A+/Negative/--
Ratings Affirmed; Outlook Action		
	To	**From**
Northwest Natural Gas Co.		
Issuer Credit Rating	A+/Stable/A-1	A+/Negative/A-1
Ratings Affirmed; Recovery Ratings Unchanged		
Northwest Natural Gas Co.		
Senior Secured	AA-	AA-
Recovery Rating	1+	1+
Ratings Affirmed		
Commercial Paper	A-1	A-1

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.spglobal.com/ratings for further information. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

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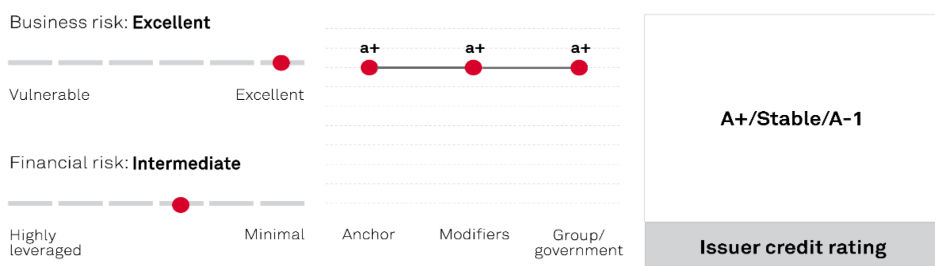
Northwest Natural Gas Co.

June 24, 2024

Ratings Score Snapshot



Primary contact

Mayur Deval
Toronto
1-416-507-3271
mayur.deval
@spglobal.com

Secondary contact

Matthew L O'Neill
New York
1-212-438-4295
matthew.oneill
@spglobal.com

Research contributor

Kashish C Khandheria
CRISIL Global Analytical Center, an S&P Global Ratings affiliate
Pune

Credit Highlights

Overview

Key strengths	Key risks
Primarily low-risk natural gas distribution operations with limited unregulated storage operations.	Limited geographic and regulatory diversity.
Effective management of regulatory risks with operations under the credit-supportive regulatory frameworks in Washington and Oregon.	Decarbonization initiatives add pressure to earnings and limit future growth.
Residential-focused customer base, which provides some cash flow stability.	Continued negative discretionary cash flow over the next few years, indicating external funding needs.

We continue to monitor the Oregon rate application. Northwest Natural Gas. Co. (NWNG) requested a revenue increase of about $154.9 million, along with a return on equity (ROE) of 10.1%, to which intervener proposed a rate change of about $74.2 million, along with an ROE of

9.2%, much lower than the initial request. The rate application, which includes the recovery of expenses such as operation and maintenance, taxes, and depreciation, could potentially result in an average customer bill increase of about 18%. Under our base case, we expect an outcome that is consistent with the historical rate applications in Oregon.

We consider NWNG to be insulated from its parent, Northwest Natural Holding Co. (NWNH). Based on the strength of the insulating measures, NWNG could potentially be rated up to two notches higher than NWNH's group credit profile (GCP). Currently, NWNG is rated only one notch higher than its GCP, limited by its 'a+' stand-alone credit profile.

Outlook

The stable rating outlook on NWNG reflects our base case assumption that the company will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including funds from operations (FFO) to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if the company's consolidated financial performance weakened such that FFO to debt remained consistently below 15%. We could also lower our rating if the company's business risk increased. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12-24 months if the company's financial performance improved such that FFO to debt were consistently above 21%, with no weakening of business risk.

Our Base-Case Scenario

Assumptions

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow through 2026.
- Annual capital spending averaging about $330 million through 2026.
- Annual dividends averaging about $80 million.
- All debt maturities refinanced.

Key metrics

Northwest Natural Gas Co. --Key Metrics*

	2023a	2024e	2025f	2026f

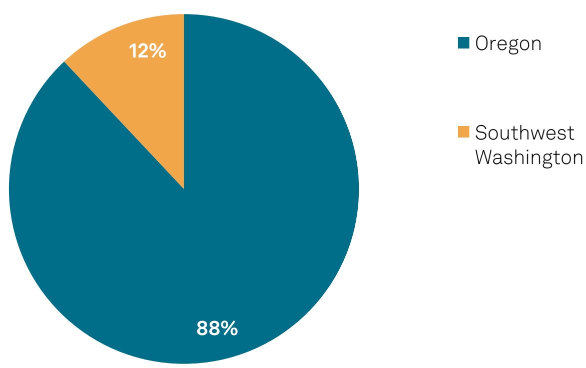
FFO to debt (%)	15	15-17	17-19	17-19
Debt to EBITDA (x)	4.6	4.5-5.0	4.0-4.5	4.0-4.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 799,000 residential, commercial, and industrial customers in Oregon and southwest Washington through 14,200 miles of pipeline systems. Approximately 88% of the company's customers are in Oregon and 12% are in southwest Washington.

Northwest Natural Gas Co.'s Customers by geographic area



Source: Company filings.

Peer Comparison

Northwest Natural Gas Co.--Peer Comparisons

	Northwest Natural Gas Co.	ONE Gas Inc.	Atmos Energy Corp.	Piedmont Natural Gas Co. Inc.

Northwest Natural Gas Co.--Peer Comparisons

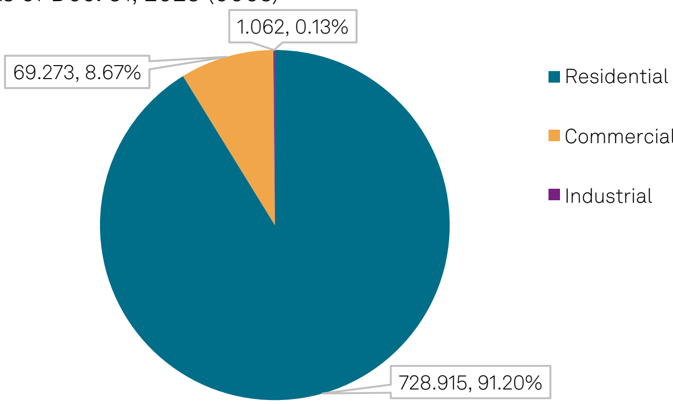
Foreign currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Local currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-09-30	2023-12-31
Mil.	$	$	$	$
Revenue	1,159	2,327	4,274	1,628
EBITDA	316	633	1,725	804
Funds from operations (FFO)	218	539	1,429	606
Interest	66	105	163	174
Cash interest paid	70	73	281	170
Operating cash flow (OCF)	283	911	3,471	756
Capital expenditure	291	661	2,790	1,028
Free operating cash flow (FOCF)	(8)	250	681	(272)
Discretionary cash flow (DCF)	(100)	103	250	(272)
Cash and short-term investments	20	19	15	0
Gross available cash	20	19	15	0
Debt	1,459	2,647	6,775	4,137
Equity	1,233	2,766	10,870	4,052
EBITDA margin (%)	27.2	27.2	40.3	49.4
Return on capital (%)	7.7	6.9	6.5	7.8
EBITDA interest coverage (x)	4.8	6.0	10.6	4.6
FFO cash interest coverage (x)	4.1	8.4	6.1	4.6
Debt/EBITDA (x)	4.6	4.2	3.9	5.1
FFO/debt (%)	15.0	20.4	21.1	14.6
OCF/debt (%)	19.4	34.4	51.2	18.3
FOCF/debt (%)	(0.5)	9.4	10.0	(6.6)
DCF/debt (%)	(6.8)	3.9	3.7	(6.6)

Business Risk

We assess NWNG's business risk based on its low-risk regulated gas distribution operations accounting for about 98% of consolidated operating revenue, residential-focused customer base, and effective management of regulatory risks. NWNG provides natural gas service to approximately 799,000 customers, with 65% of its margin generated from residential customers, 24% from commercial customers, and 6% from industrial customers. Residential and commercial customers accounted for slightly more than 60% of natural gas distribution volumes delivered. Almost 60% of the gas supply was from Canada while most of the rest was from the U.S. Rocky Mountain region. The company benefits from stable and supportive regulatory environments in both jurisdictions in which it operates, with purchased gas adjustments and environmental cost recovery, decoupling, and a forward-looking test year in Oregon and multiyear rate case fillings in Washington. We view these mechanisms as supportive of its financial measures, allowing the company to mitigate regulatory lag. In addition, NWNG has continued its strategy to diversify its business operations by purchasing small, regulated water utilities. Given the low-risk nature of water utilities, we view NWNG's entry into the regulated water utility space as a modest positive for its business risk profile. These factors support our view of the company's business risk profile at the stronger end of the excellent category.

Northwest Natural Gas Co.'s natural gas distribution segment customers

As of Dec. 31, 2023 (000s)



Source: Company filings.

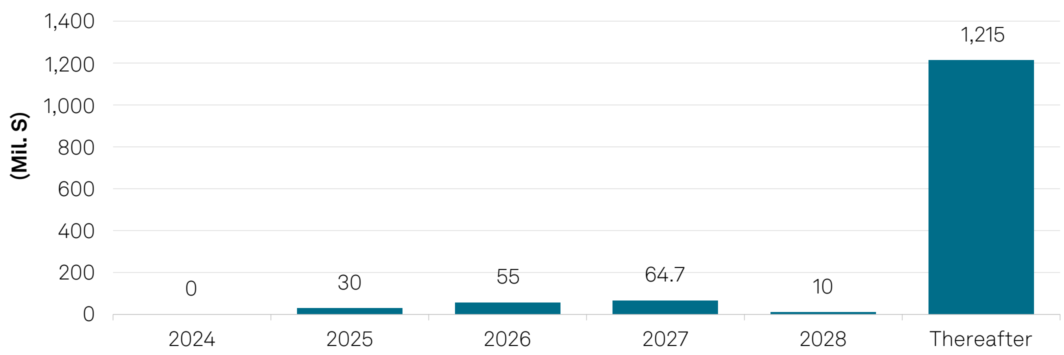
Financial Risk

Under our base case scenario, we assess NWNG using our low-volatility table, reflecting the low-risk nature of its natural gas distribution operations and effective management of regulatory risk. We incorporate our assumptions, including the continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $320 million, and annual dividends averaging about $80 million through 2026. NWNG plans to invest about 65% of capital spending in replacing and enhancing systems and technologies. We expect FFO to debt in the middle of the intermediate financial risk profile range, with FFO to debt about 15%-18% throughout 2026.

Our base case forecast includes the continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $330 million, and annual dividends averaging about $75 million. We expect NWNG's stand-alone financial measures to remain in the middle range of its financial risk profile category such that FFO to debt is 15%-18% through 2026.

Debt maturities

Northwest Natural Gas Co.'s Debt maturity schedule



Source: Company filings.

Northwest Natural Gas Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	706	740	759	843	1,014	1,159
EBITDA	226	245	257	286	292	316
Funds from operations (FFO)	157	202	207	211	236	218
Interest expense	43	41	44	49	52	66
Cash interest paid	41	40	44	48	51	70
Operating cash flow (OCF)	173	191	148	143	146	283
Capital expenditure	214	221	274	280	319	291
Free operating cash flow (FOCF)	(41)	(31)	(126)	(137)	(173)	(8)
Discretionary cash flow (DCF)	(80)	(84)	(182)	(193)	(236)	(100)
Cash and short-term investments	8	6	10	12	13	20
Gross available cash	8	6	10	12	13	20
Debt	1,121	1,066	1,353	1,379	1,397	1,459
Common equity	716	822	835	978	1,191	1,233
Adjusted ratios						
EBITDA margin (%)	32.0	33.0	33.9	33.9	28.8	27.2
Return on capital (%)	8.0	8.3	7.4	7.5	7.2	7.7
EBITDA interest coverage (x)	5.3	5.9	5.9	5.9	5.6	4.8
FFO cash interest coverage (x)	4.8	6.0	5.7	5.4	5.6	4.1
Debt/EBITDA (x)	5.0	4.4	5.3	4.8	4.8	4.6

Northwest Natural Gas Co.--Financial Summary

FFO/debt (%)	14.0	18.9	15.3	15.3	16.9	15.0
OCF/debt (%)	15.4	17.9	10.9	10.3	10.5	19.4
FOCF/debt (%)	(3.7)	(2.9)	(9.3)	(9.9)	(12.4)	(0.5)
DCF/debt (%)	(7.1)	(7.9)	(13.4)	(14.0)	(16.9)	(6.8)

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

		Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023										
Company reported amounts		1,382	1,233	1,159	305	186	61	316	282	92	291
Cash taxes paid		-	-	-	-	-	-	(28)	-	-	-
Cash interest paid		-	-	-	-	-	-	(64)	-	-	-
Lease liabilities		79	-	-	-	-	-	-	-	-	-
Operating leases		-	-	-	7	6	6	(6)	1	-	-
Postretirement benefit obligations/ deferred compensation		129	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments		(20)	-	-	-	-	-	-	-	-	-
Share-based compensation expense		-	-	-	3	-	-	-	-	-	-
Nonoperating income (expense)		-	-	-	-	12	-	-	-	-	-
Debt: other		(111)	-	-	-	-	-	-	-	-	-
Total adjustments		77	-	-	11	18	6	(98)	1	-	-
S&P Global Ratings adjusted		**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
		1,459	1,233	1,159	316	204	66	218	283	92	291

Liquidity

As of March 31, 2024, we assess NWNG's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months and covering uses even if forecast consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for NWNG provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, NWNG has the ability to absorb high-impact, low-probability events, reflecting that the company maintains about $400 million in committed credit facilities through 2026. It also reflects our belief that the company can lower its high capital spending (averaging about $320 million annually through 2026) during stressful periods, indicative of a limited need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management and sound relationships with its banking group (which includes over four well-established banks). Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months, with sufficient liquidity to meet its obligations. The company has no big long-term debt maturity coming due, and we expect it to proactively address this maturity well in advance of its scheduled due date.

Principal liquidity sources

- Cash and cash equivalents of about $61.9 million as of March 31, 2024;
- Credit facility of about $400 million; and
- Cash FFO estimated of about $245 million.

Principal liquidity uses

- Debt maturities of about $31.7 million,
- Capital expenditure of about $335 million,
- Working capital outflow of about $40 million, and
- Dividend payments of about $75 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNG.

Group Influence

Under our group rating methodology, we consider NWNH as the parent of the group with a GCP of 'a-'. We assess NWNG as a core subsidiary of NWNH because we view the utility as integral to the group's identity, highly unlikely to be sold, and having a strong commitment from NWNH's senior management, given the company's emphasis on maintaining its strategic focus on regulated gas distribution operations.

Because NWNG is operationally separate from NWNH and there are certain regulatory restrictions in place, we view the utility as having sufficient insulating measures that allow NWNG to be rated potentially up to two notches above the NWNH group. These regulatory protections include dividend restrictions, a highly independent board, and an independent third party that is the holder of the "golden share" whose vote is required to file for bankruptcy. That said, our issuer credit rating on NWNG is limited to just one notch above the parent since NWNG's stand-alone credit profile reflects one-notch above the parent's GCP.

Issue Ratings--Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is ‘A-1’ based on our ‘A+’ issuer credit rating on the company.

Analytical conclusions

We rate the company's medium-term notes program ‘A+’, equal to the issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings--Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A+/Stable/A-1
Local currency issuer credit rating	A+/Stable/A-1
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	Intermediate
Cash flow/leverage	Intermediate
Anchor	a+
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a+

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of June 24, 2024)*

Northwest Natural Gas Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured	AA-
Issuer Credit Ratings History	
19-Apr-2024	A+/Stable/A-1
09-Oct-2023	A+/Negative/A-1
25-Jan-2010	A+/Stable/A-1
Related Entities	
Northwest Natural Holding Company	
Issuer Credit Rating	A/Negative/--

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

MOODY'S
RATINGS

CREDIT OPINION
30 July 2024

Update

Send Your Feedback

RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)Baa1
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Edna R Marinelarena +1.212.553.1383
AVP-Analyst
edna.marinelarena@moodys.com

Lily Cochran +1.212.553.4795
Ratings Associate
lily.cochran@moodys.com

Ryan Wobbrock +1.212.553.7104
VP-Sr Credit Officer
ryan.wobbrock@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Northwest Natural Gas Company

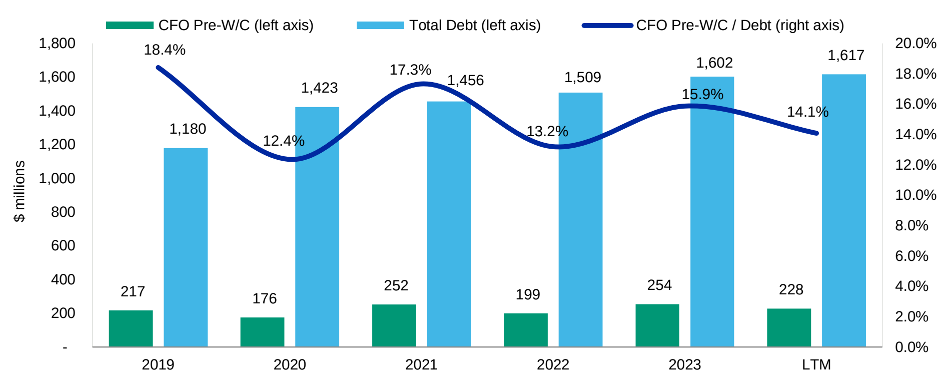
Update to credit analysis

Summary

Northwest Natural Gas Company's (NW Natural, Baa1 stable) credit profile reflects the low business risk nature of its business as a local gas distribution company (LDC) operating in generally constructive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported the utility's solid cash flow generation and financial metrics.

Because of its supportive regulatory outcomes, NW Natural has historically sustained credit metrics, including a cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, in the mid to high teens range over the last several years. The years of financial declines were due to one time events including the coronavirus pandemic (2020) and an increase in commodity prices that drove an increase in gas cost deferrals (2022). Favorably, the utility was authorized full recovery of these costs thereby driving the improvement in the utility's credit metrics in 2023. We expect NW Natural's financial profile to remain consistent over the next several years.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



Source: Moody's Financial Metrics™

Credit strengths

» Low business risk local gas distribution company

» Supportive regulatory jurisdiction, including cost tracking mechanisms and legislation that can help investment prospects

» Good stakeholder relationships and ongoing dialogue to resolve most issues

Credit challenges

» Elevated social risk due to higher scrutiny on natural gas as an energy source

» Long-term risks associated with environmental remediation costs and emission reduction requirements

Rating outlook

The stable outlook reflects our expectation that NW Natural's track record of solid financial performance and credit supportive regulatory outcomes will continue over the next several years. We see credit metrics sustaining at levels sufficient for the current credit profile including a ratio of CFO pre-WC to debt in the mid-teens percent range over the longer-term.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's credit metrics improve such that CFO pre-WC to debt ratio increases to 18% and CFO pre-WC less dividends to debt is consistently above 14%.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered due to state emission reduction requirements. A rating downgrade could also be considered if CFO pre-WC to debt is sustained below 14%.

Key indicators

Exhibit 2

Northwest Natural Gas Company [1]

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	5.5x	4.5x	5.8x	4.4x	4.5x	4.0x
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
CFO Pre-W/C – Dividends / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
Debt / Capitalization	51.2%	55.2%	52.5%	49.3%	50.0%	49.3%

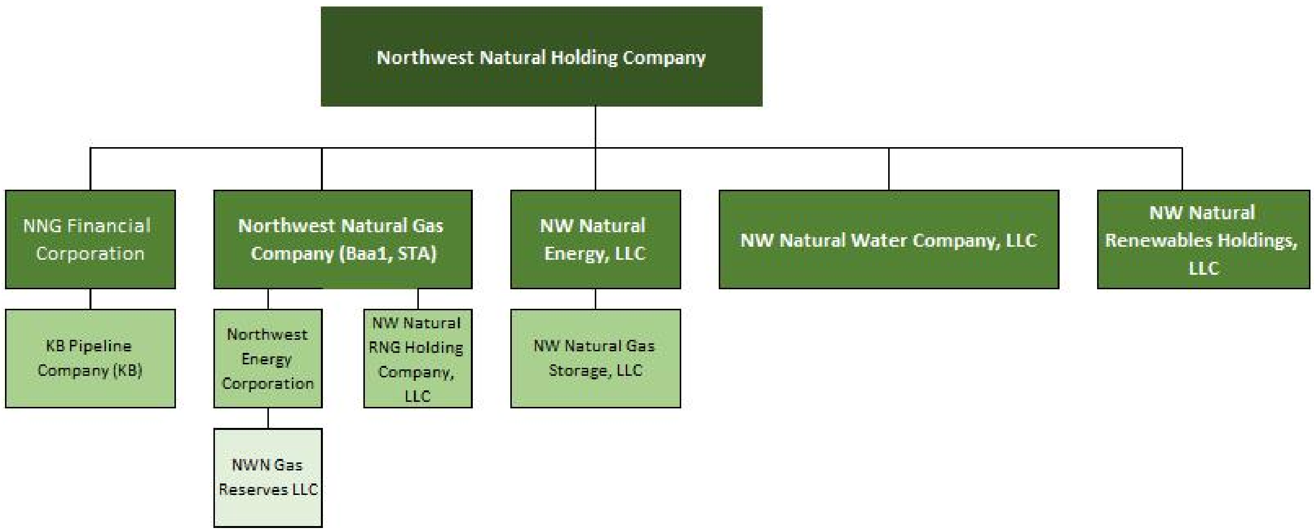
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 800,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, and other businesses and activities. NW Natural is NW Holdings' largest subsidiary and an illustrative organizational chart is shown in Exhibit 3.

Exhibit 3
NW Natural simplified organizational chart



Source: NW Natural presentation

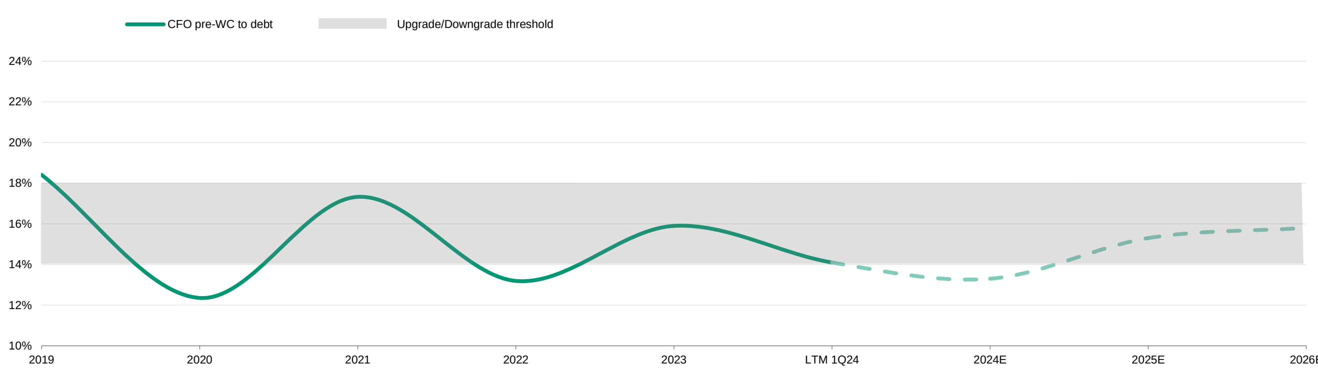
Detailed credit considerations

Consistent track record of solid financial performance expected to continue

NW Natural has a strong track record of producing solid financial performance as a result of its credit supportive regulatory framework and balanced fiscal policies. Over the last five years, the utility averaged about $220 million in cash flow from operations. This led to an average CFO pre-WC to debt ratio of about 15% from 2019 to 2023. As of the last twelve months ending 31 March 2024, the ratio was about 14%, as shown in Exhibit 4.

For 2024, credit metrics may fall to about 13% due to higher debt issued in 2023 and pressured cash flow due to higher O&M costs. NW Natural has a pending general rate case that is expected to conclude in a constructive manner with new rates effective November 2024; coupled with lower capital expenditures starting in 2025, we see credit metrics including its CFO pre-WC to debt ratio improving and sustaining in the 15% range over the next several years.

Exhibit 4
Consistent credit metrics expected over next several years
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period.
Source: Moody's Ratings

NW Natural's capital expenditures have averaged about $275 million from 2019 to 2023. In 2022 and 2023, capital spending increased to $319 million and $291 million, respectively. For 2024, NW Natural is projecting about $360 million. Capex has increased largely due to investments in technology of which much of it was related to the federal cybersecurity mandates. With the conclusion of these major projects, from 2025 to 2027, capital expenditures are projected to decrease totaling about $900 million or an average of about $225 million annually.

The utility had two years over this period where credit metrics dropped below 14% (its established downgrade threshold). In 2020, the utility's cash flow was affected by the impacts from the coronavirus pandemic as well as debt levels that increased to ensure adequate liquidity for the year amid the pandemic uncertainties. The pandemic-related debt was subsequently repaid in 2021. In 2022, the weaker metrics were due to cost inflation pressures, primarily within the materials used in field work, higher natural gas prices and related short term debt to cover the initial cost. Notably, these were pressures that plagued the industry during most of 2022. Favorably, the utility was able to recover the deferred costs within a year as reflected in its stronger credit metrics for 2023.

Supportive legislative and regulatory framework in Oregon and Washington

NW Natural's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which allows for several cost recovery mechanisms that help provide stability and predictability of the utility's cash flow.

Oregon

Since 88% of the utility's margins are derived from Oregon customers, the legislative and regulatory support that NW Natural receives from the OPUC is a fundamental credit driver for the utility. In general, NW Natural has cooperative relationships with stakeholders in the state and has been able to negotiate constructive rate case outcomes and acquire tracking mechanisms for its most material costs.

The most important cost recovery mechanisms include: NW Natural's use of forward test years for capital expenditures; weather adjusted rate mechanism (WARM); conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help support recovery of the most significant costs that NW Natural faces.

The utility filed its most recent Oregon general rate case on 29 December 2023 requesting $154.9 million revenue increase (16.6%), a 10.10% ROE, 50% equity layer and a $2.14 billion rate base. On 24 July 2024, NW Natural entered into an all-party settlement agreement that included a $95 million revenue increase (10.2%) and a 9.4% ROE and 50% equity layer, which remain unchanged. If approved by the OPUC, we view the settlement as credit supportive and consistent with prior rate case outcomes that have also been constructive. It also illustrates NW Natural's robust relationship with its regulatory authority. NW Natural's initial filing represented the largest base rate increase requested in recent years, underscoring the inflationary pressures the utility has been navigating. NW Natural expects new rates to take effect 1 November 2024.

From a legislative perspective, Oregon has frequently been on the forefront of progressive environmental measures, including the 2019 passage of Senate Bill 98 (SB 98), which allows utilities to acquire renewable natural gas (RNG) on behalf of customers. In July 2020, the parameters surrounding the rulemaking for RNG cost recovery were determined, which allowed for NW Natural to sign its first RNG investment in December 2020. We see this as an important step in supporting ongoing investment and growth for NW Natural in the face of the threat of electrification. The state support for RNG development can be a helpful tool for the company to maintain its place as a significant energy provider for customers, at the same time as state reduces carbon and methane emissions.

We also view the company as having low stranded asset risk given the state's policy goals of advancing renewable natural gas as a form of decarbonization and OPUC ongoing support of cost recovery for these projects. In the 2021 general rate case, the OPUC approved the recovery of costs associated with the Lexington RNG facility under Senate Bill 98 and authorized the adoption of an automatic adjustment clause that allows the utility to add costs associated with its renewable natural gas projects to rates annually on 1 November.

Washington

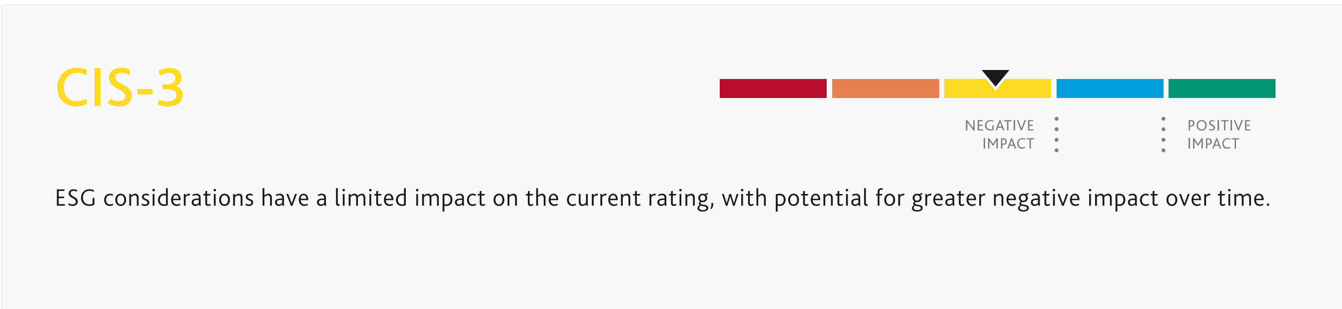
In October 2021, the WUTC issued an order authorizing an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November

2022. The order was based on an average rate base of $247.3 million. The filing was based on system investments including costs associated with resiliency and reliability, consumer focused technology and building improvements and upgrades. The new WUTC order does not specify the underlying inputs of the cost of capital such as capital structure and ROE. This multiyear rate case is purposed to recover investments and costs for system resiliency and reliability as well as headquarter leasehold improvements and rent costs. It also provides for recovery of upgrades to the Vancouver, Washington service center.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

Exhibit 5
ESG credit impact score



Source: Moody's Ratings

NW Natural's **CIS-3** indicates that its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The utility's scores reflect a combination of higher risk exposure to carbon transition, physical climate and demographic and societal trends.

Exhibit 6
ESG issuer profile scores

Source: Moody's Ratings

Environmental

NW Natural's **E-3** issuer profile score is driven by its moderately negative carbon transition and physical climate risks. Favorably, the company has a strong track record of meeting established emissions targets set by legislative (Oregon Senate Bill 98) and regulatory policies. NW Natural established a Low Carbon Savings goal of 30% by 2035 that includes customers emissions and a goal of being a carbon neutral provider by 2050. This will be achieved through increasing the use of renewable natural gas as well as hydrogen blending. Although the utility is exposed to moderately high physical climate risks, the company worked to mitigate these risks by removing all bare steel pipe from its system by completing the multi-year investment in 2015. Additionally, the system is predominantly underground, which makes the infrastructure more resilient and less vulnerable to weather or other events that could disrupt power to the region.

Social

NW Natural's **S-3** issuer profile score reflects higher risk to responsible production and demographics and societal trends that increase public concern over environmental, social, or affordability issues that could lead to adverse regulatory political intervention. These risks are balanced by neutral to low exposure to health and safety, human capital, and customer relations. NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years. Additionally, the company has a strong hedging program including storage and contracts that draw from a diverse supply to ensure reliability and reduce commodity risk

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk. This is supported by neutral to low exposure to financial strategy and risk management and management credibility and track record.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

NW Natural maintains adequate liquidity through the use of external credit facilities and market issuances to fund negative free cash flow. As of the last twelve months ending 31 March 2024, NW Natural's internal liquidity included about $62 million of cash on hand and produced about $225 million in cash flow from operations; this compares to about $299 million in capital expenditures and $94 million in dividends for the same last twelve month period.

The utility has access to a $400 million revolving credit agreement that expires on 3 November 2026. The credit agreement includes a feature that allows NW Natural to request an increase to the total amount up to $600 million as well as request to extend the agreement for two additional one-year periods, subject to lender approval. Additionally, the credit agreement also permits the issuance of letters of credit in an aggregate amount of up to $60 million. As of 31 March 2024, NW Natural did not have any outstanding balance drawn under its credit facility or letters of credit. The primary restrictive covenant requires the company to maintain a debt to capitalization ratio of 70% or less, which NW Natural was in compliance with at 31 March 2024 (52.1%).

NW Natural’s next debt maturities are due in September 2025 and December 2025, when $20 million and $10 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

Exhibit 7
Methodology Scorecard Factors
Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 7/8/2024 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	15.0%	Baa	15% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.3%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	49.4%	A	48% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				(P)Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financial Metrics

Appendix

Exhibit 8

Cash Flow and Credit Metrics [1]

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**219**	**184**	**227**	**207**	**238**	**223**
+/- Other	(2)	(8)	25	(8)	16	4
CFO Pre-WC	**217**	**176**	**252**	**199**	**254**	**228**
+/- ΔWC	(20)	(3)	(105)	(53)	29	(1)
CFO	**198**	**173**	**148**	**146**	**283**	**227**
- Div	53	55	56	63	92	94
- Capex	226	267	280	320	293	301
FCF	(82)	(149)	(189)	(237)	(102)	(168)
(CFO Pre-W/C) / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
(CFO Pre-W/C - Dividends) / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
FFO / Debt	18.6%	12.9%	15.6%	13.7%	14.9%	13.8%
RCF / Debt	14.1%	9.0%	11.8%	9.5%	9.1%	8.0%
Revenue	740	759	843	1,014	1,159	1,127
Interest Expense	48	51	53	59	74	75
Net Income	81	75	85	86	95	88
Total Assets	3,321	3,599	3,898	4,453	4,511	4,495
Total Liabilities	2,505	2,764	2,921	3,262	3,279	3,212
Total Equity	816	835	978	1,191	1,233	1,282

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 9

Peer Comparison Table [1]

	Northwest Natural Gas Company (P)Baa1 Stable			Berkshire Gas Company A3 Stable			Wisconsin Gas LLC A3 Stable			Southwest Gas Corporation Baa1 Stable		
(in $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	1,014	1,159	1,127	102	97	91	917	770	681	1,935	2,500	2,638
CFO Pre-W/C	199	254	228	18	20	20	170	154	154	449	525	510
Total Debt	1,509	1,602	1,617	80	93	96	1,081	1,112	1,080	3,648	3,621	3,622
CFO Pre-W/C + Interest / Interest	4.4x	4.5x	4.0x	6.3x	5.9x	5.4x	8.9x	4.9x	4.7x	4.6x	4.3x	4.3x
CFO Pre-W/C / Debt	13.2%	15.9%	14.1%	21.9%	21.6%	20.6%	15.7%	13.9%	14.3%	12.3%	14.5%	14.1%
CFO Pre-W/C – Dividends / Debt	9.0%	10.1%	8.3%	9.5%	21.6%	20.6%	10.2%	-1.5%	11.0%	9.0%	10.3%	9.7%
Debt / Capitalization	49.3%	50.0%	49.3%	31.5%	33.5%	33.4%	42.0%	41.2%	39.5%	52.9%	47.9%	47.1%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Ratings

Exhibit 10

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured MTN	(P)Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Ratings

REPORT NUMBER 1414632

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 302

December 30, 2024

NW Natural
UG 520 - Exhibit 302
NW Natural Credit Ratings 2018 - 2024

Debt Rating History

Standard & Poors

Rating Type	7/20/2018	3/23/2021	6/15/2022	6/15/2023	10/9/2023	Current
Outlook	Stable	Stable	Stable	Stable	Negative	Stable
Senior Secured LT Debt	AA-	AA-	AA-	AA-	AA-	AA-
Corporate Credit Rating	A+	A+	A+	A+	A+	A+
Short-Term	A-2	A-1	A-1	A-1	A-1	A-1

Moody's Investor Service

Rating Type	2/1/2018	1/10/2019	5/17/2019	6/21/2021	6/27/2022	7/19/2023	Current
Outlook	Negative	Negative	Stable	Stable	Stable	Stable	Stable
Senior Secured LT Debt	A1	A1	A2	A2	A2	A2	A2
Corporate Credit Rating	A3	A3	Baa1	Baa1	Baa1	Baa1	Baa1
Short-Term	P-2	P-2	P-2	P-2	P-2	P-2	P-2

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 303

REDACTED

December 30, 2024

NORTHWEST NATURAL GAS COMPANY
EMBEDDED COST OF LONG-TERM DEBT CAPITAL AT
October 31, 2026

#	Coupon Rate	Description of Issue	Date Issued	Maturity Date	10/31/2026 Years to Maturity	Outstanding	Offered	Premium or Discount: Amount	Premium or Discount: Per $ 100 Principal Amount	Underwriter's Commission: Amount	Underwriter's Commission: Per $ 100 Principal Amount	Expense of Issue: Amount	Expense of Issue: Per $ 100 Principal Amount	Net Proceeds: Amount	Net Proceeds: Per $100 Principal Amount	Original Term to Maturity Yrs.	Cost of Money (Bond Table)	Annual Cost Outstanding Debt
		(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Medium-Term Notes																
		First Mortgage Bonds:																
1	3.211%	3.211% Series	12/5/2016	12/5/2026	0.1	35,000,000	35,000,000	0	0.00	218,750	0.625	288,003	0.82	34,493,247	98.552	10	3.383%	1,184,050
2	7.000%	7.000% Series	5/20/1997	5/21/2027	0.6	20,000,000	20,000,000	0	0.00	125,000	0.625	28,906	0.14	19,846,094	99.230	30	7.062%	1,412,400
3	2.822%	2.822% Series	9/13/2017	9/13/2027	0.9	25,000,000	25,000,000	0	0.00	150,000	0.600	159,885	0.64	24,690,115	98.760	10	2.966%	741,500
4	6.650%	6.650% Series	11/10/1997	11/10/2027	1.0	19,700,000	19,700,000	0	0.00	125,000	0.635	37,800 [5]	0.19	19,537,200	99.174	30	6.714%	1,322,658
5	6.650%	6.650% Series	6/1/1998	6/1/2028	1.6	10,000,000	10,000,000	0	0.00	75,000	0.750	23,300	0.23	9,901,700	99.017	30	6.727%	672,700
6	3.141%	3.141% Series	6/17/2019	6/15/2029	2.6	50,000,000	50,000,000	0	0.00	312,500	0.625	255,252	0.51	49,432,248	98.864	10	3.275%	1,637,500
7	7.740%	7.740% Series	8/29/2000	8/29/2030	3.8	20,000,000	20,000,000	0	0.00	150,000	0.750	1,354,914 [1]	6.77	18,495,086	92.475	30	8.433%	1,686,600
8	7.850%	7.850% Series	9/6/2000	9/1/2030	3.8	10,000,000	10,000,000	0	0.00	75,000	0.750	678,107 [3]	6.78	9,246,893	92.469	29	8.551%	855,100
9	5.820%	5.820% Series	9/24/2002	9/24/2032	5.9	30,000,000	30,000,000	0	0.00	225,000	0.750	165,382	0.55	29,609,618	98.699	30	5.913%	1,773,900
10	5.660%	5.660% Series	2/25/2003	2/25/2033	6.3	40,000,000	40,000,000	0	0.00	300,000	0.750	56,663	0.14	39,643,337	99.108	30	5.723%	2,289,200
11	5.250%	5.250% Series	6/21/2005	6/21/2035	8.6	10,000,000	10,000,000	0	0.00	75,000	0.750	22,974	0.23	9,902,026	99.020	30	5.316%	531,600
12	4.000%	4.000% Series	10/30/2012	10/31/2042	16.0	50,000,000	50,000,000	0	0.00	300,000	0.600	235,479	0.47	49,464,522	98.929	30	4.062%	2,031,000
13	4.136%	4.136% Series	12/5/2016	12/5/2046	20.1	40,000,000	40,000,000	0	0.00	300,000	0.750	307,712	0.77	39,392,288	98.481	30	4.226%	1,690,400
14	3.685%	3.685% Series	9/13/2017	9/13/2047	20.9	75,000,000	75,000,000	0	0.00	562,500	0.750	367,946	0.49	74,069,554	98.759	30	3.754%	2,815,500
15	4.110%	4.110% Series	9/10/2018	9/10/2048	21.9	50,000,000	50,000,000	0	0.00	125,000	0.250	174,695	0.35	49,700,305	99.401	30	4.145%	2,072,500
16	3.869%	3.869% Series	6/17/2019	6/15/2049	22.6	90,000,000	90,000,000	0	0.00	675,000	0.750	415,358	0.46	88,909,642	98.788	30	3.938%	3,544,200
17	3.600%	3.600% Series	3/31/2020	3/15/2050	23.4	150,000,000	150,000,000	(598,500)	0.40	1,125,000	0.750	713,011	0.48	147,563,490	98.376	30	3.690%	5,535,000
18	3.078%	3.078% Series	11/15/2021	12/1/2051	25.1	130,000,000	130,000,000	0	0.00	975,000	0.750	451,489	0.35	128,573,511	98.903	30	3.135%	4,075,500
19	4.780%	4.780% Series	9/30/2022	9/30/2052	25.9	140,000,000	140,000,000	0	0.00	424,000	0.303	143,604	0.10	139,432,396	99.595	30	4.806%	6,728,400
20	5.430%	5.430% Series	1/6/2023	1/6/2053	26.2	100,000,000	100,000,000	0	0.00	248,409	0.248	253,523	0.25	99,498,068	99.498	30	5.464%	5,464,000
21	5.750%	5.750% Series	3/8/2023	3/8/2033	6.4	100,000,000	100,000,000	(220,000)	0.22	625,000	0.625	456,295	0.46	98,698,705	98.699	10	5.924%	5,924,000
22	5.180%	5.180% Series	8/4/2023	8/4/2034	7.8	80,000,000	80,000,000	0	0.00	232,253	0.290	133,001	0.17	79,634,746	99.543	11	5.235%	4,188,000
23	5.230%	5.230% Series	8/4/2023	8/4/2038	11.8	50,000,000	50,000,000	0	0.00	158,036	0.316	74,871	0.15	49,767,092	99.534	15	5.275%	2,637,500

[redacted]

[redacted] **EQUALS = 4.687%**

WEIGHTED EMBEDDED COST:

[1] INCLUDES $992,143 PREMIUM, $178,966 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $148,605 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.74% SERIES.
[2] INCLUDES $826,786 PREMIUM, $149,139 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $123,837 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.72% SERIES.
[3] INCLUDES $496,071 PREMIUM, $89,483 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $74,302 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.85% SERIES.
[4] INCLUDES $150,000 PREMIUM AND $405,971 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.50% SERIES BONDS, $413,600 PREMIUM AND $1,116,479 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.52% SERIES BONDS AND $730,000 PREMIUM AND $136,800 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.25% SERIES BONDS ALLOCATED TO 5.62% SERIES.
[5] In November 2009 one investor exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 304

December 30, 2024

NW Natural
UG 520 - Exhibit 304
Market Implied Treasury Forwards

Market Implied Treasury Forwards

	2024	2025				2026			
Indices	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Fed Funds Effective (Avg.)	4.37	3.965	3.585	3.335	3.18	3.065	3.02	2.985	2.97
3-Month SOFR	4.35	3.95	3.59	3.37	3.2	3.14	3.09	3.05	3.04
5-Year UST Note	3.63	3.54	3.46	3.43	3.39	3.35	3.35	3.35	3.4
10-Year UST Note	3.9	3.82	3.77	3.75	3.73	3.67	3.64	3.63	3.7
30-Year UST Note	4.15	4.1	4.05	4.03	3.99	4	4	3.99	4.01

Source: Bloomberg, as of October 25, 2024

NW Natural's Calculation

	2024	2025				2026			
Implied 20-Year UST Note	4.03	3.96	3.91	3.89	3.86	3.84	3.82	3.81	3.86

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 305

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 400

December 30, 2024

EXHIBIT 400 - DIRECT TESTIMONY – RETURN ON EQUITY

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I. INTRODUCTION AND SUMMARY

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

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors ("Concentric"). Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please describe your professional background and education.

A. I have more than 15 years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist for the State of Alaska. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts. I hold a Bachelor's degree in Business Economics from

Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exhibit NW Natural/401, Nelson.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or "the Company").

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding an appropriate return on equity ("ROE") for the Company's regulated natural gas utility operations and to assess the reasonableness of the Company's proposed capital structure for ratemaking purposes. My analyses and conclusions are supported by the data presented in Exhibit NW Natural/402, Nelson, to Exhibit NW Natural/414, Nelson, which have been prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that you conducted to support your ROE recommendation.

A. My ROE recommendation is based on the results from the Discounted Cash Flow ("DCF") model, the Bond Yield Plus Risk Premium method ("Risk Premium"), the Capital Asset Pricing Model ("CAPM"), and the Expected Earnings approach applied to a proxy group of six publicly traded natural gas utilities. The use of multiple models mitigates the effects of market factors that may unduly influence any one model's results. My application of the DCF model is based on reputable third-party growth rate projections, as well as market-based data on current annualized dividends and recent stock prices. The Risk Premium model is based on a current average and projected Treasury bond yield and the relationship between authorized ROEs for natural gas utilities in the U.S. and bond yields. The CAPM analysis is based on a risk-free rate, market risk premium ("MRP"), and Beta coefficients from reputable sources. The Expected Earnings approach is based on projected returns from the Value Line Investment Survey[1] ("Value Line") for the companies in the proxy group of comparable natural gas utilities. As a check on the reasonableness of the results produced by the Gas Proxy Group, I also present the results of these same models for a Combined Proxy Group that includes electric utilities with material regulated natural gas operations to provide additional context. In the end, my final ROE recommendation is based on the results produced by the Gas Proxy Group, including an adjustment for equity issuance costs.

In addition to the analyses discussed above, I also consider the Company's (1) regulatory risk and the need to access capital to fund its capital expenditure program; (2) the risks associated with electrification and energy transition; and (3) NW Natural's significantly smaller size relative to a group of proxy companies to

[1] Value Line is a publication that provides investment information on over 1,700 companies across numerous industries, including regulated utilities.

assist with determining the appropriate ROE. In a recent credit report for NW Natural, S&P Global Ratings ("S&P") noted a potential increase in the Company's business risk associated with ongoing energy transition risks in Oregon and Washington.[2] Similarly, Moody's noted "elevated social risk due to higher scrutiny on natural gas as an energy source"[3] as a credit challenge for NW Natural.

Q. What is your conclusion regarding the appropriate cost of equity for the Company?

A. The ROE results presented in my Direct Testimony indicate that a reasonable ROE range for NW Natural is 9.90 percent to 11.00 percent using a combination of models and alternative input assumptions. Based on the results of all estimation methods (DCF, Risk Premium, CAPM, and Expected Earnings) and considering the business risks of NW Natural relative to the proxy group, combined with my observations regarding the current capital market conditions, it is my opinion that 10.40 percent is a reasonable estimate of the Company's cost of equity.

Q. What is your conclusion regarding the Company's proposed capital structure?

A. I support NW Natural's requested capital structure of 52.00 percent common equity and 48.00 percent long-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies. The

[2] S&P Global Ratings, "Northwest Natural Holding Co. Downgraded To 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook To Stable," at 2 (April 19, 2024).

[3] Moody's Investors Service, Credit Opinion, Northwest Natural Gas Company, Update to credit analysis, at 1 (July 30, 2024).

Company's requested weighted average cost of capital ("WACC") is shown in Figure 1 below.

Figure 1: Requested WACC

	% of Capital	Cost (%)	Weighted Cost
Long-Term Debt	48.00%	4.687%	2.250%
Common Equity	52.00%	10.40%	5.408%
Total	100.00%		7.658%

Q. How is the remainder of your Direct Testimony organized?

A. The balance of my Direct Testimony is organized as follows:

- Section III – Summarizes the regulatory guidelines and principles relevant to the cost of capital estimation in regulatory proceedings;
- Section IV – Reviews the current capital market conditions and the effect on the cost of equity;
- Section V – Explains the development of the proxy groups used to develop my analytical results;
- Section VI – Describes the analyses on which my ROE determination is based;
- Section VII – Discusses the Company's business risks relative to the proxy group that affect its cost of equity;
- Section VIII – Provides an assessment of the Company's proposed capital structure; and
- Section IX – Summarizes my conclusions and recommendations.

III. REGULATORY PRINCIPLES

Q. Before addressing the specific aspects of this proceeding, please explain the connection between the cost of capital and a utility's cost of service.

A. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement, since the utility's revenues must be sufficient to recover its costs to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity investors for the use of their financial capital. From that important perspective, the return on capital reflects a cost to the utility just as any other component of the revenue requirement.

Q. Please describe the guiding principles used in establishing the cost of capital for a regulated utility.

A. Utilities are entitled by law to receive a fair rate of return sufficient to attract needed capital at reasonable rates. The basic tenets of this regulatory doctrine originate from several bellwether decisions by the United States Supreme Court, and that doctrine is followed across the country with respect to state-level ratemaking, including in Oregon.[4]

Q. Please briefly discuss how those principles apply in the context of the regulated rate of return.

A. Regulated utilities rely primarily on long-term sources of capital, including common equity and long-term debt to finance their property, plant, and equipment. The allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital are weighted by their respective balances. The ROE represents the cost of raising and retaining equity capital and is estimated through one or more analytical techniques to quantify investor expectations regarding equity returns.

Notably, the ROE cannot be derived solely through quantitative methods. To properly estimate the ROE, the financial, regulatory, and economic context in which the analysis takes place must also be considered. The DCF, Risk Premium, CAPM, and Expected Earnings approaches, while fundamental to the ROE determination, are still only models. One should not assume that the results of these models can be mechanically applied without also considering informed judgment, the context of capital market conditions, and the relative risk of NW Natural as compared to the proxy group companies.

[4] See, e.g., *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 21 (December 18, 2020).

Also, it is important to note that the U.S. Supreme Court has held that under the statutory standard of "just and reasonable," it is the result reached, not the method employed, which is controlling.[5] Consequently, it is appropriate to consider a variety of approaches and data sources when arriving at a recommended ROE.

Based on these widely recognized standards, the Commission's order in this case should provide NW Natural with the opportunity to earn a return on equity that is:

- Commensurate with returns on investments in enterprises having comparable risks;
- Adequate to attract capital on reasonable terms, thereby enabling NW Natural to provide safe, reliable service; and
- Sufficient to ensure the financial soundness of NW Natural's operations.

Importantly, a fair return must satisfy all three of these standards. The allowed ROE should enable NW Natural to finance capital expenditures on reasonable terms and provide financial flexibility over the period during which rates are expected to remain in effect.

Q. What is the relationship between the regulatory environment and capital market expectations?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility

[5] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591. 602 (1944).

services, the utility must have the opportunity to recover the return of invested capital, and the market-required return on that capital. Because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital on reasonable terms. Such decisions balance the long-term interests of customers and shareholders. The financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which they operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. It is therefore important for the ROE authorized in this proceeding to take into consideration the current and expected capital market conditions with which NW Natural must contend, as well as investors' expectations and requirements regarding both risks and returns.

IV. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. Do economic conditions influence the required cost of capital, including the ROE?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

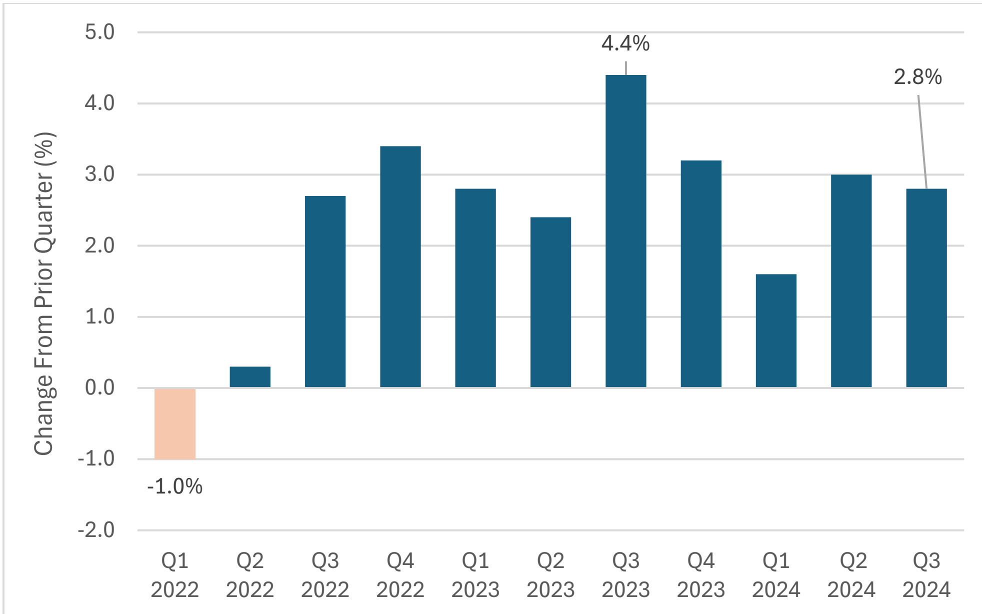
Q. What are the key factors affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utilities is affected by several key factors, including: (1) the interest rate environment and central bank monetary policy; (2) inflationary pressure and the longer-term outlook for inflation; and (3) uncertainty in the economic environment as a result of a change in administration at the federal level. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

Q. Please discuss current economic and capital market conditions.

A. Economic conditions were unsettled in 2022 and 2023 due to (1) ongoing inflationary pressures stemming from the global response to the COVID-19 pandemic, (2) significantly tighter monetary policy, and (3) the war in Ukraine. The prospects for weaker economic growth or a possible recession were heightened as the Federal Reserve continued to tighten monetary policy to combat higher than expected inflation. Real Gross Domestic Product ("GDP") grew at an annual rate of 2.5 percent in 2023 compared to 1.9 percent in 2022. Figure 2 shows that real GDP growth ranged from -1.0 percent to 4.4 percent over the past ten quarters and settled most recently at 2.8 percent in the third quarter of 2024.

Figure 2: Percent Change in Real GDP (From Previous Quarter)[6]

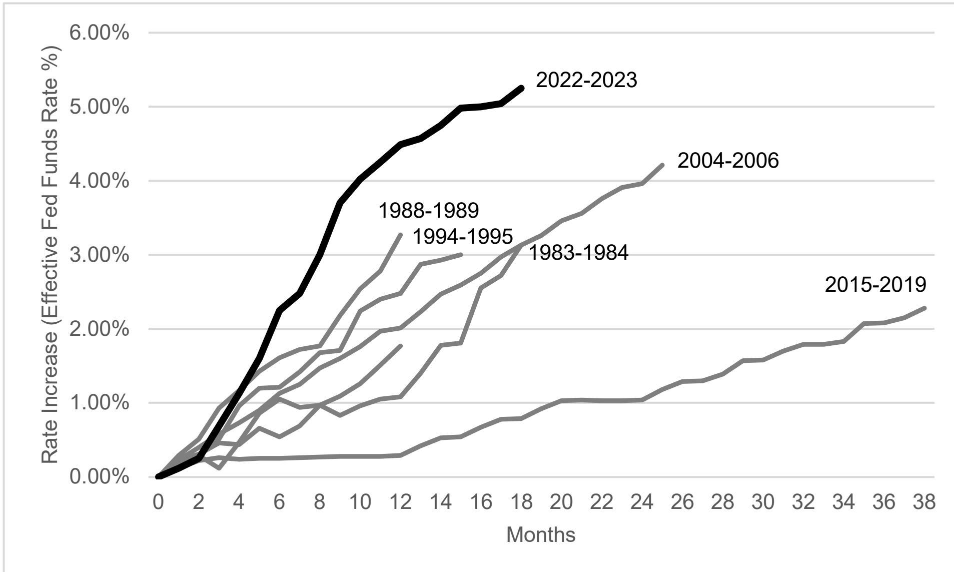


Q. Please discuss the changes in monetary policy that have occurred.

A. In 2022 and 2023, the U.S. Federal Reserve (the "Fed") tightened monetary policy at the fastest pace in the last 40 years to slow economic growth and combat higher than expected inflation. Specifically, the Fed raised the Federal Funds rate from a range of 0.00 percent to 0.25 percent in March 2022 to a range of 5.25 to 5.50 percent by July 2023 (see Figure 3 below), which it held constant until September 2024.

[6] Source: U.S. Bureau of Economic Analysis.

Figure 3: Federal Funds Rate Increases[7]



At the December 2023 Federal Open Market Committee ("FOMC") meeting, the Fed signaled that it was likely finished raising the federal funds rate. Capital markets interpreted this as an indication that the Fed would start cutting short-term interest rates sooner than expected. However, throughout the first half of 2024, Chair Jerome Powell reiterated repeatedly that the timing of future interest rate cuts remained dependent on progress toward achieving the Fed's goal of returning to the two percent inflation target and that the FOMC was "prepared to maintain the current target range for the federal funds rate for longer, if appropriate."[8,9]

[7] Federal Reserve Bank of St. Louis, Federal Reserve Economic Data ("FRED") available at https://fred.stlouisfed.org/.

[8] Transcript of Chair Powell's Press Conference, March 20, 2024, at 3.

[9] Semiannual Monetary Policy Report to Congress, Chair Jerome H. Powell, Before the Committee on Financial Services, U.S. House of Representatives, March 6, 2024.

In August 2024, Chair Powell signaled that the economic data on inflation and unemployment was likely to lead to a reduction in short-term interest rates. During a speech at Jackson Hole, Wyoming, Chair Powell stated:

> Overall, the economy continues to grow at a solid pace. But the inflation and labor market data show an evolving situation. The upside risks to inflation have diminished. And the downside risks to employment have increased. As we highlighted in our last FOMC statement, we are attentive to the risks to both sides of our dual mandate.[10]

The FOMC subsequently cut the Federal Funds rate by 50 basis points in September 2024 as the FOMC gained greater confidence that inflation is moving sustainably toward its two percent target, and that risks to achieving employment and inflation goals are roughly in balance. However, the FOMC noted that "the economic outlook is uncertain, and the Committee is attentive to the risks to both sides of its dual mandate."[11] In November 2024, the FOMC further reduced the Federal Funds rate by 25 basis points. In its press release, the FOMC reiterated these points and noted that "inflation has made progress toward the Committee's 2-percent objective but remains somewhat elevated."[12]

[10] Review and Outlook, Remarks by Jerome H. Powell, Chair, Board of Governors of the Federal Reserve System, at "Reassessing the Effectiveness and Transmission of Monetary Policy," an economic symposium sponsored by the Federal Reserve Bank of Kansas City, Jackson Hole, Wyoming, August 23, 2024, at 3.

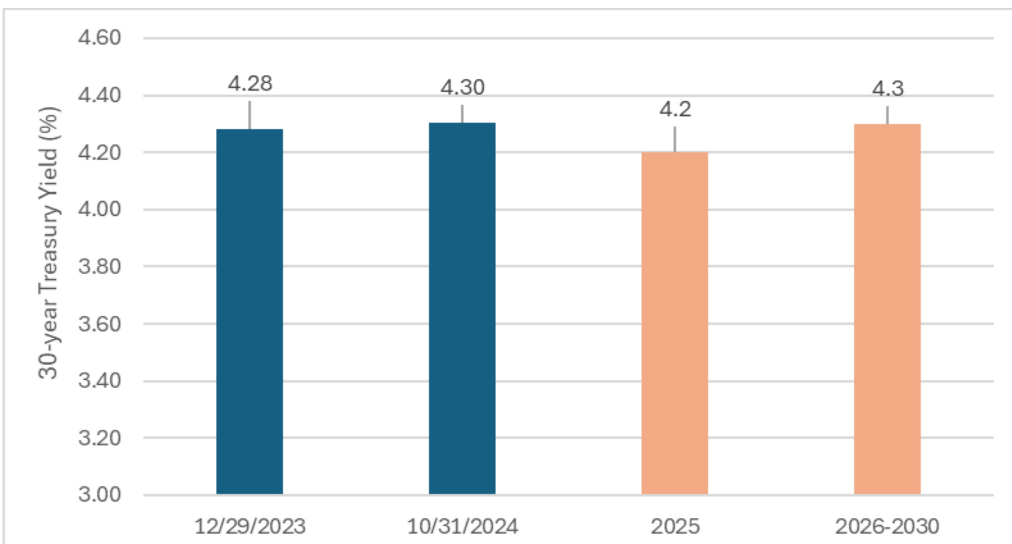
[11] Federal Reserve FOMC Press Release, September 18, 2024.

[12] Federal Reserve FOMC Press Release, November 7, 2024; https://www.federalreserve.gov/newsevents/pressreleases/monetary20241107a.htm

Q. Please discuss the recent developments in government and utility bond yields.

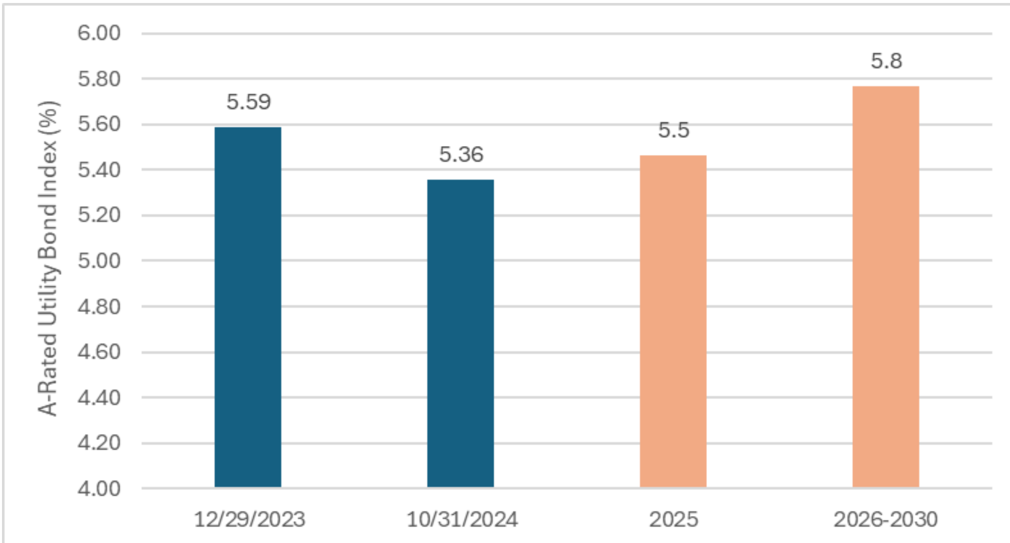
A. As the U.S. economy improved and the Federal Reserve moved aggressively in 2022 and 2023 to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates rose to their highest levels since 2010. As shown in Figure 4 and Figure 5, near term government and utility bond yields are approximately equal to the yields observed when the Company filed its last rate case in UG 490, and economists are forecasting longer term yields to remain at similar levels over the near term.

Figure 4: Comparison of 30-Year Treasury Bond Yields[13]



[13] Sources: Bloomberg Professional spot yield of 30-Year treasury bond, Blue Chip Financial Forecasts, Vol. 43, Issue No. 11, November 1, 2024, at 2, Blue Chip Financial Forecasts, Vol. 43, Issue No. 6, May 31, 2024, at 14.

Figure 5: Comparison of A-rated Utility Bond Yields[14]



Recent cuts to the Federal Funds rate by the Federal Reserve have had little effect on long-term government and utility bond yields. Long-term bond yields are less sensitive to the Federal Reserve's monetary policy, and as such have not declined as much as short-term yields, even as the Fed has reduced the Federal Funds rate. As shown in Figure 6 below, since the end of June 2024, the 1-year, 2-year, and 5-year Treasury yields have declined by 18 to 82 basis points, whereas the 30-year Treasury yield has declined by only 4 basis points.

[14] Sources: Federal Reserve Bank of St. Louis, FRED Economic Database, Bloomberg Professional spot yield of 30-Year treasury bond, Blue Chip Financial Forecasts, Vol. 43, Issue No. 11, November 1, 2024, at 2, Blue Chip Financial Forecasts, Vol. 43, Issue No. 6, May 31, 2024, at 14. Projected Utility "A" bond yields are estimated from Blue Chip's projected AAA corporate bond yields plus the average historical spread between A-rated corporate and utility bond yields over the last five years.

Figure 6: U.S. Treasury Yields (June 2024 vs. October 2024)[15]

	1-year Treasury	2-year Treasury	5-yr Treasury	30-Year Treasury
June 28, 2024	5.09%	4.71%	4.33%	4.51%
October 31, 2024	4.27%	4.16%	4.15%	4.47%
Change	-0.82%	-0.55%	-0.18%	-0.04%

Therefore, current long-term yields have not declined commensurately with reductions in the Federal Funds rate, and incorporate the market's expectations for the Federal Reserve's rate cuts. These movements are consistent with the normalization of the yield curve, where long-term rates (i.e., the 30-year Treasury yield) are expected to exceed the shorter end of the yield curve.

Q. Please explain the implications of current and projected interest rates for equity investors in the utility sector and how they affect the ROE analysis.

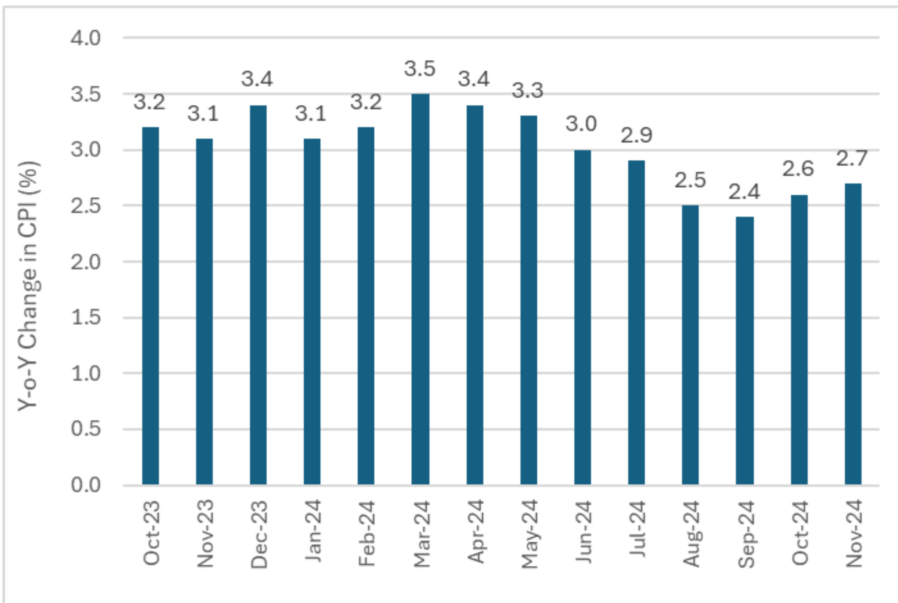
A. The 30-yield Treasury bond yield is a direct input to both the CAPM and the Risk Premium models. Further, while interest rates are not a direct input to the DCF model, dividend yields on utility stocks must compete with yields on Treasury bonds. Although the Federal Reserve has begun to reduce the Federal Funds rate, these reductions have not affected longer-term interest rates used in the ROE models. Consequently, the cost of equity for utilities is not expected to decline commensurately with reductions in shorter term interest rates.

[15] Source: Spot yields reported by Federal Reserve Board of Governors, H15 Selected Interest Rates. https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Q. What has been the path of inflation in the last year?

A. Inflation levels are down significantly from its peak of 9.1 percent in June 2022 but remain somewhat elevated at 2.7 percent as of November 2024, relative to the Federal Reserve's target of 2.0 percent. Notably the CPI reversed its downward trend in October 2024, increasing 0.2 percent on a year-over-year basis, a trend that continued in November 2024.

Figure 7: Consumer Price Index, 12-month Percentage Change[16]



While inflation has subsided from the historic levels experienced in 2022, the era of record low interest rates and low inflation has likely ended. As noted above, expectations for longer-term interest rates are markedly higher than in the years prior to the COVID-19 pandemic. As Blue Chip Financial Forecasts explains:

[16] Source: Bureau of Labor Statistics https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm

> Of particular interest is that even though the economy is expected to grow at around its potential rate and that inflation is expected to stabilize near the Fed's target, these occur at markedly higher expected interest rate levels (both short- and long-term) than in the five years prior to the pandemic and marginally higher than the consensus envisaged last December. This points to a meaningfully higher neutral [Federal Funds Rate] and higher real interest rates over the longer term than experienced just prior to the pandemic.[17]

Furthermore, even though the pace of inflation has slowed, U.S. consumers continue to expect inflation to remain elevated. As the University of Michigan's October survey explains regarding consumer sentiment on inflation: "[a]s of October 2024, long-run expectations remain slightly elevated relative to the two years pre-pandemic."[18] While inflation expectations have moderated since 2022, as of October 2024, they have not returned to pre-pandemic levels.[19]

Q. How might the change in presidential administration affect inflation and bond yields?

A. President-elect Trump campaigned on higher tariffs and, although the details have yet to be announced and the effect on the economy is uncertain, economists generally agree that higher tariffs increase inflation by increasing the cost of consumer goods. Higher inflation could complicate the Federal Reserve's unwinding of restrictive monetary policies, as well as increase long-term bond yields like the 30-year Treasury yield. Longer-term bonds are more sensitive than

[17] Blue Chip Financial Forecasts, Vol. 43, No. 6, at 1. Clarification added.

[18] University of Michigan, Survey of Consumers, October 2024. https://data.sca.isr.umich.edu/fetchdoc.php?docid=77164

[19] University of Michigan, Survey of Consumers, October 2024. https://data.sca.isr.umich.edu/fetchdoc.php?docid=77164

shorter-term bonds to inflation expectations because their value is influenced more by inflation due to their longer maturity holding period and reinvestment rate implications; thus, as the value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. If realized, all these factors would suggest that the cost of capital for utilities may increase in the future.

Q. What are your conclusions regarding the effects of the current market environment on the cost of equity for NW Natural?

A. Economic conditions have not changed much since the Company's last rate case. Government and utility bond yields are well above levels experienced prior to the COVID-19 pandemic and are not expected to decline commensurately with reductions to the Federal Funds rate. These circumstances are reflected in the results of the models used to estimate the cost of equity. Although inflation has subsided from its peak in 2022, inflation is expected to remain at higher levels than experienced prior to the COVID-19 pandemic. Lastly, the effect of the new presidential administration on the economy is uncertain, and proposals for higher tariffs, for example, could complicate investor expectations for lower inflation and interest rates. These factors emphasize the importance of considering the results of multiple models, and the use of both current and forecasted bond yields, as I have with my analysis.

V. PROXY GROUP SELECTION

Q. Why is it necessary to select a proxy group to estimate the fair return on equity for NW Natural?

A. In this proceeding, we are focused on estimating the cost of equity for NW Natural's Oregon-jurisdictional operations. Since the ROE is a market-based concept and NW Natural's Oregon service territory is not a separate entity with its own stock price, it is necessary to select a group of companies that are both publicly traded and comparable to certain NW Natural business and financial characteristics to serve as a "proxy" for purposes of the ROE estimation process. Even if NW Natural's regulated gas utility operations in Oregon made up the entirety of the publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another over a given period. A significant benefit of using a proxy group is the ability to mitigate the effects of company-specific events that may not be representative of the industry or long-term trends. As a result of the screening criteria used to select the proxy group, the companies included in the proxy groups and used in my ROE analyses have similar business and operating characteristics to NW Natural's regulated utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

Q. Please provide a brief overview of NW Natural's operations.

A. NW Natural distributes natural gas to approximately 799,000 residential commercial and industrial customers in Oregon and southwest Washington. The Company's Oregon territory represents approximately 88 percent of its customer base, while 12 percent of its customer base is in Washington.[20] NW Natural's long-term issuer rating is A+ from Standard & Poor's ("S&P"). The Company's senior unsecured shelf rating from Moody's Investor Services ("Moody's") is (P)Baa1.[21]

Q. Please describe the specific screening criteria you have utilized in selecting your proxy groups.

A. As explained below, I have developed two proxy groups: a Gas Proxy Group and a Combined Proxy Group. The Gas Proxy Group is utilized to develop my ROE recommendation. The Combined Proxy Group is utilized to inform, verify, and support my ROE recommendation. To develop the Gas Proxy Group, I first began with the nine companies that Value Line classifies as "Natural Gas Utilities" and then screened companies according to the following criteria to develop a proxy group reasonably comparable to NW Natural:

1. Pays quarterly cash dividends that have not been reduced or omitted in the last two years;
2. Maintains an investment grade long-term issuer rating (BBB- or higher from S&P or Baa3 or higher from Moody's) from both S&P and Moody's;
3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), S&P, and Zacks Investment Research ("Zacks");

[20] Northwest Natural Holding Company, 2023 SEC Form 10-K, at 8.

[21] NW Natural's rating from Moody's is a provisional rating.

5. Regulated net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2023;
6. Natural gas distribution net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2023; and
7. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

Q. Do you include Northwest Natural Holding Company in your proxy groups?

A. No. It is my general practice to exclude the subject company, or its publicly traded parent company, from the proxy group due to the circular logic that would occur by including those results.

Q. What is the composition of your Gas Proxy Group?

A. Based on the screening criteria discussed above, and removing Northwest Natural Gas Holding Company, I arrived at a proxy group consisting of six publicly traded natural gas utilities shown in Figure 8.

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Figure 8: Gas Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource, Inc.	NI
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

Please refer to Exhibit NW Natural/403, Nelson, for the proxy group screening data and results.

Q. Does the Gas Proxy Group of six companies provide a reasonable basis to estimate NW Natural's ROE?

A. Yes. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by NW Natural, while at the same time ensuring that there is a sufficient number of companies in the proxy group. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's cost of equity to the extent that the selected proxy companies are fundamentally comparable to the subject utility. A larger proxy group does not necessarily improve the representative nature of the proxy group. Including companies whose fundamental comparability may be questionable simply for the purpose of expanding the number of observations does not improve the reliability of the results or the conclusions drawn from them. On balance, the Gas Proxy Group is reasonably comparable to NW Natural and is an appropriate set of companies to use in the ROE estimation process.

Q. Please describe your Combined Proxy Group alternative and the specific screening criteria you utilized to develop that group.

A. Due to consolidation in the natural gas industry over the last decade, the universe of publicly traded natural gas utilities covered by Value Line has been reduced to nine companies. The Gas Proxy Group screening criteria described above narrowed that group to six companies. Although it is my opinion that a proxy group of six natural gas companies is sufficient in size for the purpose of estimating NW Natural's cost of equity, I recognize that it may be appropriate to develop a larger proxy group to evaluate the reasonableness of Gas Proxy Group's ROE model results. A Combined Proxy Group may be necessary in the future if there is further consolidation in the gas industry reducing the number of companies in the Natural Gas Utilities universe. Therefore, I developed a Combined Proxy Group consisting of the six natural gas utilities contained in the Gas Proxy Group, supplemented with electric utilities that have a meaningful amount of natural gas operations.

To screen the universe of 37 electric utilities covered by Value Line for inclusion in the Combined Proxy Group, I relied on the following criteria:

1. Pays quarterly cash dividends that have not been reduced or omitted in the last two years;
2. Maintains an investment grade long-term issuer rating (BBB- or higher from S&P or Baa3 or higher from Moody's) from both S&P and Moody's;

3. Is covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, S&P, and Zacks;
5. Regulated net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2023;
6. Natural gas distribution net operating income makes up more than 15 percent of the consolidated company's net operating income, on average, for the three years ended 2023; and
7. Is not involved in a merger or other transformative transaction for an approximate six-month period prior to my analysis.

Based on this screening criteria, nine electric utilities were added to the six gas proxy companies to produce a Combined Proxy Group consisting of the following fifteen companies (see also Exhibit NW Natural/403, Nelson), as shown in Figure 9:

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Figure 9: Combined Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource, Inc.	NI
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR
Ameren Corporation	AEE
Avista Corporation	AVA
Black Hills Corporation	BKH
CMS Energy Corporation	CMS
Consolidated Edison	ED
DTE Energy Company	DTE
Public Service Enterprise Group Inc.	PEG
Southern Company	SO
WEC Energy Group	WEC

Q. Do your screening criteria result in groups of companies that investors would view as comparable to NW Natural?

A. Yes. The proxy groups have been selected to develop two groups of companies that are reasonably comparable (but not identical) to the financial and operational characteristics of NW Natural in aggregate. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like NW Natural, are generally in sound financial condition. Additionally, I have screened on the percentage of net operating income from regulated natural gas distribution operations to differentiate utilities that derive a meaningful proportion of income from regulated natural gas distribution operations from those with substantial unregulated risks. These screens collectively reflect the risk factors that investors consider in making their investment decisions in utility companies.

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. What models did you use to estimate the Company's ROE?

A. I have considered the results of four ROE estimation models, specifically, the constant growth, multistage, and quarterly growth forms of the DCF model, the CAPM, Risk Premium approach, and Expected Earnings model.

A. Discounted Cash Flow Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate:

$$k = D/P + g \qquad [1]$$

Where "*k*" equals the required equity return, "*D*" is the expected dividend, "*P*" represents the subject company's stock price, and "*g*" is the expected growth rate.

1. Constant Growth DCF Model

Q. What are the assumptions underlying the Constant Growth DCF model?

A. The Constant Growth DCF model is based on the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Q. Please summarize your application of the Constant Growth DCF model.

A. I calculated DCF results for each of the proxy group companies using the following inputs:

1. Average stock prices for the historical period, over 30, 90 and 180 trading days through October 31, 2024;
2. Annualized dividend per share as of October 31, 2024; and
3. Company-specific earnings growth forecasts from Value Line, S&P, and Zacks as of October 31, 2024.

My application of the Constant Growth DCF model is provided in Exhibit NW Natural/404, Nelson.

Q. Why did you use three averaging periods of 30, 90, and 180 days?

A. The use of an average of recent trading days to calculate the subject company's stock price in the DCF model ensures that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, it is important to reflect the conditions that have defined the financial markets over the recent past. The use of three averaging periods reasonably balances those considerations.

Q. Did you adjust the dividend yield to account for periodic growth in dividends?

A. Yes. Utility companies tend to increase their quarterly dividends at different times throughout the year, so it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth for the purposes of calculating this component of the DCF model. Accordingly, the DCF estimates reflect one-half of the expected growth in the dividend yield.

Q. What sources of growth have you used in your DCF analysis?

A. I have used the consensus analyst five-year growth estimates in earnings per share ("EPS") from S&P and Zacks, as well as projected EPS growth rates published by Value Line.

Q. Why did you rely on earnings per share growth?

A. The Constant Growth DCF model assumes that dividends grow at a single growth rate in perpetuity. Accordingly, to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that EPS, dividends per share and book value per share will all grow at the same constant rate. It is therefore important to focus on measures of long-term earnings growth from credible sources as an appropriate measure of long-term growth in the DCF model.

Q. Are sources of projected dividend growth available to investors?

A. Yes, from one source: Value Line. However, that does not mean that investors incorporate Value Line's estimates into their investment evaluations. Academic studies suggest that investors base their investment decisions on analysts' expectations of growth in earnings, not dividends.[22] In addition, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. Further, the reliance on projected dividend growth rates from one source exposes the analysis to potential bias or anomalies in the data. The fact that earnings growth projections are the only widely reported estimates of growth further supports the use of earnings growth as the most meaningful measure of growth among the investment community.

Q. How did you calculate the Mean High, Mean Low, and Mean DCF results?

A. I calculated the Mean High DCF result using the maximum growth rate (*i.e.*, the maximum of the Value Line, Zacks, and S&P EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies. I used a similar approach to calculate the Mean Low DCF results, using the minimum growth rate for each company. The Mean DCF results reflect the average growth rate for each company in combination with the expected dividend yield.

Q. What are the results of your Constant Growth DCF analysis?

A. The results of the Constant Growth DCF analysis are provided in Exhibit NW Natural/404, Nelson, and summarized in Figure 10 below.

[22] *See*, *e.g.*, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Financial Management, 21 (Summer 1992), and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

Figure 10: Constant Growth DCF Results

	Mean Low	Mean	Mean High
Gas Proxy Group			
30-day average	8.81%	9.93%	11.11%
90-day average	8.93%	10.05%	11.24%
180-day average	9.08%	10.21%	11.39%
Combined Proxy Group			
30-day average	8.82%	9.74%	10.67%
90-day average	8.97%	9.88%	10.82%
180-day average	9.15%	10.07%	11.00%

2. Multi-Stage DCF Model

Q. Have you considered another form of the DCF model?

A. Yes, I have. I understand that the Commission has given substantial weight to the Multi-Stage DCF model in prior decisions.[23] In deference to the Commission, I have also considered a Multi-Stage DCF model.

Q. Please summarize your Multi-Stage DCF model.

A. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional, and long-term growth rates.

The Multi-stage DCF model transitions from near-term growth (i.e. the average of Value Line, Zacks, and S&P earnings forecasts used in the Constant

[23] See, e.g., *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 30 (December 18, 2020).

Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP (or a total of 200 years). The return on equity is the internal rate of return based on the current average stock price and this stream of dividend payments.

Nominal GDP growth rates for the proxy groups were developed using data for reported by Blue Chip Financial Forecasts for the period from 2031-2035.[24] These forecasts are based on a projected real (constant dollar) GDP growth rate of 2.00 percent and projected inflation rate of 2.20 percent. The estimate of nominal GDP growth is 4.24 percent.[25]

The results of the Multi-Stage DCF analysis is shown in Figure 11 below (see also Exhibit NW Natural/405, Nelson).

Figure 11: Multi-Stage Growth DCF Results

	Gas Proxy Group	Combined Proxy Group
30-day average	8.51%	8.45%
90-day average	8.66%	8.62%
180-day average	8.85%	8.85%

[24] Blue Chip Financial Forecast, June 1, 2023, Vol. 42, No. 6, at 14.

[25] 4.24% = (1 + 2.0%)(1+ 2.2%) – 1

Q. Do you have concerns with the Multi-Stage DCF model, and the results produced by it?

A. Yes, I do. The Multi-Stage DCF results are below all but nine ROEs authorized for a natural gas utility in the last 45 years and, therefore, fail to meet the *Hope* and *Bluefield* comparable return standard. All nine of those decisions were by the New York Public Service Commission and occurred between 2017 and 2021 when capital costs were significantly lower than they are now.

Moreover, the Multi-Stage DCF model is based on the premise that expected EPS growth rate changes over time, and transitions to a growth rate equal to expected growth in the overall economy in perpetuity. One concern with the Multi-Stage DCF analysis is that it does not account for the fact that the dividend yield and growth rate are interrelated; the dividend yield remains constant whereas the growth rate changes over time. All else equal, the dividend yield and growth rate are typically inversely related, since higher expected growth increases demand for a stock pushing up its price, and reducing the dividend yield and vice versa. Consequently, an assumption that the expected dividend yield remains constant in light of lower expected growth over time is flawed and inconsistent with the fact that if investors expected lower growth in the future, they would likely pay less for the stock than is assumed by the current stock price.

A second, related concern is the assumption that all companies' growth will equal GDP growth in the long-term, when in fact each company is unique and the growth and prospects of each company are unique. Using a single long-term growth rate for all proxy companies is illogical and inconsistent with financial theory.

Q. Has any other regulatory commission agreed with these concerns regarding the Multi-Stage DCF model?

A. Yes. In a recent order for Duke Energy Carolinas, the North Carolina Utilities Commission acknowledged these flaws with the Multi-Stage DCF model and rejected the results produced by it, which ranged from 8.41 percent to 8.56 percent.[26]

Q. What is your recommendation regarding the results from the Multi-Stage DCF analysis?

A. The presumptions that all companies will grow at the rate of GDP in the long run, and that the dividend yield will remain constant as growth declines over time, limit the usefulness of the Multi-Stage DCF model. Therefore, in my opinion, it is inappropriate to give substantial or exclusive weight to the results of the Multi-Stage DCF model. However, I recognize the Commission's past preference for the model, and have considered it with the results of the other DCF model approaches.

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[26] North Carolina Utilities Commission Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, at 201-203.

3. Quarterly Growth DCF Model

Q. Please briefly describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly basis. Although the dividend yield adjustment discussed earlier in the Constant Growth DCF section is intended to reflect that assumption by increasing the current dividend yield by one-half of the expected growth rate, it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the cost of equity by understating the effect of the quarterly timing and compounding reinvestment of dividends. The Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule ... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[27]

[27] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., 2006, at 344.

Q. How is the dividend yield component of the Quarterly Growth DCF model calculated?

A. To reflect the timing and compounding of quarterly dividends more accurately, the model replaces the "D" component of the Constant Growth DCF equation with the following equation:

$$D = d_1(1+k)^{0.75} + d_2(1+k)^{0.50} + d_3(1+k)^{0.25} + d_4(1+k)^{0} \quad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.[28]

To calculate the expected dividends over the coming year for the proxy companies (i.e., d1, d2, d3, and d4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the earnings growth rate (i.e., 1 + g). For the P component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy company.

Q. What are the results of your Quarterly Growth DCF analysis?

A. My Quarterly Growth DCF results are summarized in Figure 12, below (see also Exhibit NW Natural/406, Nelson).

[28] Because the required ROE (k) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Figure 12: Quarterly Growth DCF Results[29]

	Mean Low	Mean	Mean High
Gas Proxy Group			
30-day average	8.98%	10.13%	11.36%
90-day average	9.10%	10.26%	11.49%
180-day average	9.27%	10.43%	11.66%
Combined Proxy Group			
30-day average	8.99%	9.93%	10.90%
90-day average	9.14%	10.09%	11.06%
180-day average	9.34%	10.29%	11.26%

B. CAPM Analysis

Q. Please briefly describe the general form of the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[30] As shown in Equation [3], the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

[29] Exhibit NW Natural/406, Nelson.

[30] Under the CAPM theory, systematic risks are fundamental market risks that reflect aggregate economic measures and therefore cannot be mitigated through diversification. Unsystematic risks reflect company-specific risks that can be mitigated and ultimately eliminated through investments in a portfolio of companies and/or market sectors.

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required ROE for a given security;

r_f = the risk-free rate of return;

β = the Beta coefficient of an individual security; and

r_m = the required return for the market as a whole.

The term $(r_m - r_f)$ represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with and compensated for systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [4]$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [4], is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, the Beta coefficient represents the risk that the selected security will not be effective in diversifying systematic market risks.

Q. What risk-free rates did you use in your CAPM analysis?

A. I applied two estimates of the risk-free rate. First, I considered the current 30-day average yield on 30-year Treasury bonds (4.30 percent). However, the CAPM models assume long-term investment horizons, I also considered a projected yield on 30-year Treasury bonds of 4.28 percent, calculated as the average of the near-term and long-term forecasts from Blue Chip Financial Forecasts.[31] Using a projected Treasury bond yields as the risk-free rate in the CAPM formula appropriately reflects the market's expectation for forward-looking interest rates. Utilizing both current and forecast interest rates is the approach recommended by Dr. Roger Morin in his text on regulatory finance:

> There are two possibilities for proxying investors' expectations of the risk-free rate expected to prevail in one year: actual and forecast interest rates. Each offers distinct advantages and limitations. At the conceptual level, given that ratemaking is a forward-looking process, interest rate forecasts are preferable. Moreover, the conceptual models used in the determination of the cost of equity, such as the CAPM, are prospective in nature and require expectational inputs.
>
> …
>
> One reasonable option for the regulator is to accord equal weight to both current interest rate levels and the analysts' consensus forecast. Each proxy for expected interest rates brings information to the judgement process from a different light.[32]

[31] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q1 2026; and (2) the average long-term projected 30-year Treasury yield for the years 2026-2030 and 2031-2035 reported by Blue Chip Financial Forecast. See, Blue Chip Financial Forecast, Vol. 43, No. 11, November 1, 2024, at 2 and Blue Chip Financial Forecast, Vol. 43, No. 6, May 31, 2024, at 14.

[32] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, 2006, pp. 172-173.

Q. What measures of the Beta coefficient did you use in your CAPM analysis?

A. As shown in Exhibit NW Natural/407, Nelson, my CAPM analyses rely on the average Beta coefficients from Value Line and Bloomberg for each proxy company as of October 31, 2024. Beta coefficients from both services are calculated using weekly returns over a five-year period, adjusted to reflect the tendency of Beta coefficients to regress toward the market mean of 1.00.

Q. What estimates of the expected market return do you use to calculate the market risk premium?

A. I consider two estimates of the expected market return. The first estimate calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model to the S&P 500 Index. The second estimate is the long-run historical arithmetic average market return of 12.04 percent reported by Kroll (formerly Duff & Phelps) for the years 1926 to 2023.[33]

Q. Please further explain the forward-looking DCF approach to estimating the expected total market return.

A. For the forward-looking market return estimate, I used the Constant Growth DCF formula to estimate the total market return for the S&P 500 Index. I used projected earnings growth rates and dividend yields from three sources: (1) S&P's Earnings and Estimates report; (2) Bloomberg Professional; and (3) Value Line. As shown in Figure 13, these independent estimates of the expected market return range from 15.07 percent to 16.42 percent. (see also Exhibit NW Natural/408, Nelson).

[33] Source: Kroll, Cost of Capital Navigator.

To be conservative, I rely on the Value Line estimate of 15.07 percent as the forward-looking market return estimate.

Figure 13: DCF-Based Expected Market Return

Source	Market Return
S&P Earnings & Estimates	16.42%
Bloomberg Professional	15.93%
Value Line	15.07%

To moderate the effect of the forward-looking market return, I averaged the forward-looking return of 15.07 percent with the long-term average historical return between 1926 and 2023 of 12.04 percent as reported by Kroll (formerly Duff & Phelps). I then subtracted the current and projected risk-free rates to calculate a "blended" MRP of 9.25 percent and 9.27 percent, respectively.

Q. Did you also perform a CAPM analysis applying only the MRP calculated using the long-term historical average market return?

A. Yes. Although the estimation of the cost of equity is a forward-looking analysis, I also performed a separate CAPM analysis using only the current long-term historical average market return of 12.04 percent. Subtracting the current and projected risk-free rates from long-term historical average market return of 12.04 percent produces MRP estimates of 7.74 percent and 7.76 percent, respectively.

Q. What are the results of your CAPM analyses?

A. The CAPM results are shown in Exhibit NW Natural/407, Nelson, and summarized below in Figure 14.

Figure 14: CAPM Results

Gas Proxy Group	Blended MRP	Historical MRP
Current Average Risk-Free Rate (R_f = 4.30%)	12.42%	11.09%
Projected Risk-Free Rate (R_f = 4.28%)	12.42%	11.09%
Combined Proxy Group	**Blended MRP**	**Historical MRP**
Current Average Risk-Free Rate (R_f = 4.30%)	12.50%	11.16%
Projected Risk-Free Rate (R_f = 4.28%)	12.50%	11.15%

C. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach that you used.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to account for the incremental residual risk associated the cost of equity as the sum of equity risk premium and the yield on a particular class of bonds.

Q. Please explain how you perform your Bond Yield Plus Risk Premium Analysis.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing 30-year Treasury bond yield, using the authorized ROE for 1,317 natural gas utility rate proceedings between January 1, 1980, and October 31, 2024. To reflect the prevailing bond yields during the pendency of each proceeding, I calculate the average 30-year Treasury yield over the average lag period between the filing of the rate case and the date of the final order (approximately 187 days for natural gas rate cases and 199 days for the electric rate cases). For the electric utilities in the Combined Proxy Group, I performed the same analysis using 1,806 electric utility rate cases between January 1, 1980 and October 31, 2024.

Because the data covers several economic cycles over more than four decades, the analysis incorporates changes in the equity risk premium over time. Prior research has shown that the equity risk premium is inversely related to the level of bond yields.[34]

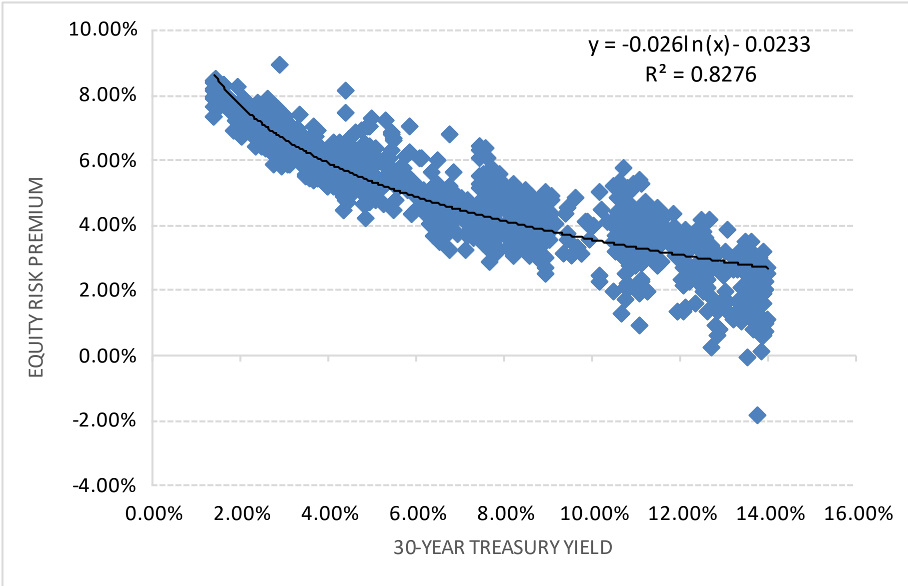
Q. How do you analyze the relationship between bond yields and the equity risk premium?

A. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I use the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

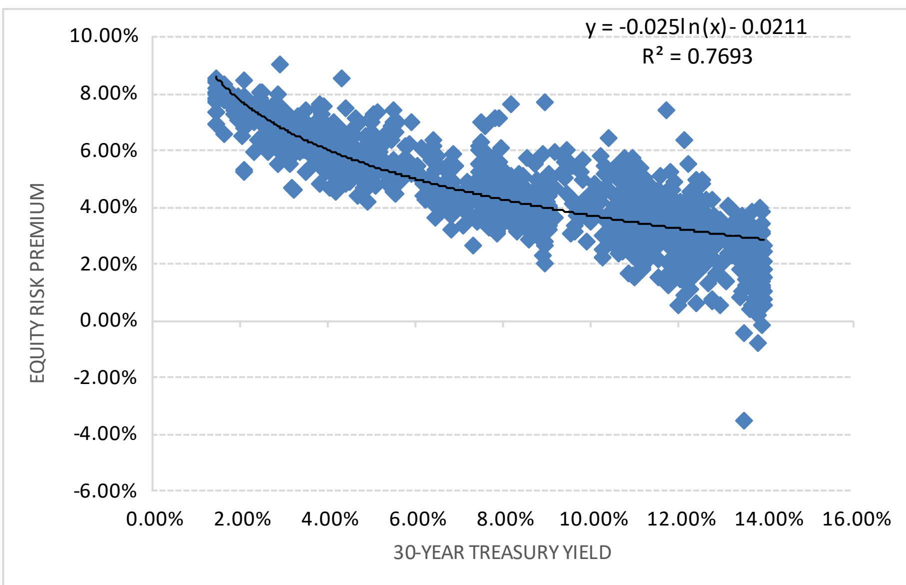
$$RP = \alpha + \beta(LN(T_{30})) \qquad [5]$$

[34] See, e.g., Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, at 89-95 (Autumn 1995).

1 **Figure 15: Gas Equity Risk Premium[35]**



2 **Figure 16: Electric Equity Risk Premium[36]**



[35] Exhibit NW Natural/409, Nelson.

[36] Exhibit NW Natural/409, Nelson.

As Figure 15 and Figure 16 illustrate, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin cites several studies and concludes that, "beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[37] Applying the regression coefficients in Figure 15 and Figure 16 produce ROE estimates of 10.07 percent to 10.14 percent (see also Exhibit NW Natural/409, Nelson), as shown below in Figure 17.

Figure 17: Risk Premium Results Using 30-Year Treasury Yield

Gas Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	4.30%	5.77%	10.07%
Projected 30-Year Treasury	4.28%	5.78%	10.07%
Electric Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	4.30%	5.84%	10.14%
Projected 30-Year Treasury	4.28%	5.85%	10.13%

[37] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 128 (2006).

Q. Why are authorized ROEs in other jurisdictions relevant?

A. Authorized ROEs in other jurisdictions are a significant part of the market information that investors consider when evaluating their investment alternatives. Therefore, they are a measure of returns available to other natural gas utilities, consistent with the *Hope* and *Bluefield* decisions. The level of authorized ROE also provides a signal to investors about the level of regulatory support that a company can expect with regard to its ability to compete for capital and to ensure its financial integrity. An ROE below its peers for a given period may be an impediment to the Company's ability to attract capital and invest in infrastructure necessary to provide safe, reliable service to its customers. As discussed in Section VII, NW Natural expects to invest approximately $1.5 billion in infrastructure in the 2024-2028 period, or approximately 61 percent of the Company's end of 2023 net utility plant. As Company witness Brody J. Wilson explains (NW Natural/300, Wilson), it is important that NW Natural maintain a strong balance sheet to attract both debt and equity capital on reasonable terms for the benefit of customers.

Q. Which Risk Premium results do you rely on for your two proxy groups?

A. For the Gas Proxy Group, I rely on the average of the Gas Risk Premium results using current and projected 30-year Treasury bond yields. For the Combined Proxy Group, I rely on the average of both the gas and electric risk premium results using both the current and projected 30-year Treasury bond yields.

D. Expected Earnings Analysis

Q. Have you conducted any other analysis to estimate the cost of equity for NW Natural?

A. Yes. I have also conducted an Expected Earnings analysis to estimate the cost of equity for NW Natural based on the projected ROEs for the proxy group companies.

Q. What is an Expected Earnings Analysis?

A. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The Expected Earnings analysis is a forward-looking estimate of investors' expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk comparable companies to the subject company. This range is useful in determining the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

Q. How did you develop the Expected Earnings Approach?

A. I relied on the projected ROE for the proxy companies as reported by Value Line for the period from 2027-2029. I then adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the entire period. As shown in Exhibit NW Natural/410, Nelson (and summarized in Figure 18), the Expected Earnings analysis produces mean ROE estimates of 9.28 percent and 10.55 percent, respectively, for the Gas Proxy Group and Combined Proxy Group.

Figure 18: Expected Earnings Results

	Gas Proxy Group	Combined Proxy Group
Mean	9.28%	10.55%

Q. The Commission has not historically given weight to the Expected Earnings Model. Why is the Expected Earnings approach reasonable and should be considered?

A. I recognize that the Commission has traditionally not given weight to the Expected Earnings approach,[38] in part citing to the FERC, and I respectfully disagree. First, reliance on multiple models allows for a more robust and reliable ROE estimate. The fewer models that are relied upon, the greater the likelihood that model risk biases the ultimate ROE determination. For the same reasons that diversity is a wise and prudent investment strategy, diversity of the models used to estimate the ROE is similarly prudent, as it reduces the risk that the results of any single model may not reasonably reflect investors' true return requirements. An advantage of the Expected Earnings approach is its simplicity and reliance on fewer contentious inputs.

[38] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 30 (December 18, 2020).

Second, market-based models like the DCF and CAPM models are more vulnerable to changes in market and economic data than the Expected Earnings approach. Therefore, the Expected Earnings approach adds a measure of stability. Lastly, because the cost of capital is applied to the book value of rate base to determine the revenue requirement, the book-based Expected Earnings approach is well-suited to regulatory applications.[39] For these reasons, I believe the Expected Earnings approach is reasonable and should be given equal consideration.

E. Flotation Costs

Q. What are flotation costs?

A. Flotation costs are the costs associated with issuing equity, including out-of-pocket costs for preparing, filing, underwriting, and other costs of issuing equity. These costs reduce the net proceeds a company receives from an equity issuance. As explained below, failing to allow for the recovery of flotation costs inhibits a utility's ability to fully earn its authorized ROE, diminishing its ability to efficiently attract capital.

Q. Why is it important to recognize flotation costs in the authorized ROE?

A. To attract and retain investors, a regulated utility must have a reasonable opportunity to earn a return that is competitive with returns available to other investments of similar risk. To the extent a company is denied the opportunity to

[39] Roger A. Morin, Ph.D., New Regulatory Finance, at 394-395 (2006).

recover equity issuance costs, actual returns will fall short of expected (or required) returns, diminishing its ability to attract capital on reasonable terms.

Q. Are flotation costs part of the utility's invested costs or expenses?

A. Flotation costs are invested (i.e., capital) costs of the utility and are reflected on the balance sheet under "paid in capital." They are not expenses; therefore, they are not on the income statement or included in the Company's revenue requirement. Like rate base or long-term debt issuance costs, equity issuance costs are incurred over time when a utility sources equity capital. Although much of a utility's equity issuance costs are incurred prior to the test year, they remain part of the capital structure long after they are incurred. As such, recovery of equity issuance costs is appropriate for the same reasons debt issuance costs are recoverable. Even if no new issuances are planned in the near future, failure to allow such cost recovery may deny NW Natural the opportunity to earn its required rate of return going forward.

Q. Do the ROE models account for the effect of flotation costs?

A. No. The models used to estimate the investor-required return assume no transaction costs (i.e., "friction"); therefore, flotation costs are not reflected in stock prices or the risk premium. Consequently, an adjustment must be made to the quantitative model results to reflect equity issuance costs.

Q. Does Staff include flotation costs in its ROE analyses and recommendations?

A. Yes, Staff has routinely included 12.5 basis points for flotation costs.[40]

Q. How do you calculate the effect of flotation costs on the cost of equity?

A. As shown in Exhibit NW Natural/411, Nelson, I calculate the weighted average issuance costs for the two most recent equity issuances for each Gas proxy company, as applicable. I then modified the DCF calculation to adjust the dividend yield to reimburse investors for direct equity issuance costs. As Exhibit NW Natural/411, Nelson shows, a reasonable estimate of flotation costs is approximately nine basis points (0.09 percent). Thus, I have added nine basis points to my recommended ROE range and to account for flotation costs.

F. Evaluation of Model Results

Q. Please explain how you considered the results of the DCF, CAPM, Risk Premium, and Expected Earnings analysis to arrive at your ROE recommendation.

A. I have placed equal weight on the results of the DCF, CAPM, Bond Yield Risk Premium, and Expected Earnings analyses. However, I recognize that the Commission has not historically given weight to the Expected Earnings approach, so I also present a 3-model average excluding that methodology. As shown in Figure 19 below (see also Exhibit NW Natural/402, Nelson), I derive an ROE estimate range of approximately 9.90 percent to 11.00 percent for the Gas Proxy

[40] See, e.g., Docket No. UG 490, Staff Exhibit 103; Docket No. UG 435, Staff Exhibit 104.

Group, inclusive of flotation costs. The low end of my recommended range is based on the four-model average using the most conservative approaches for the Gas Proxy Group (the Multi-Stage DCF, historical CAPM, Risk Premium, and Expected Earnings results). The high end of my recommended range is the three-model average using the higher model approaches and excluding the Expected Earnings approach. Notably, the midpoint of my recommended range is approximately equal to the 4-model average, thus confirming the reasonableness of the four-model average.

Figure 19: Analytical Model Results

	Gas Proxy Group	Combined Proxy Group
Multi-Stage DCF	8.67%	8.64%
Constant Growth DCF	10.06%	9.90%
Quarterly Growth DCF	10.28%	10.11%
Average DCF	9.67%	9.55%
Blended CAPM	12.42%	12.50%
Historical CAPM	11.09%	11.16%
Risk Premium	10.07%	10.10%
Expected Earnings	9.28%	10.55%
4-model average	10.36%	10.67%
Low	9.78%	10.11%
High	10.92%	10.90%
Midpoint of Range	10.35%	
Flotation Costs	0.09%	
Range (including flotation costs)	9.87% - 11.02%	
Recommendation (Rounded)	10.40%	

In my opinion, the ROE analyses applied to the larger Combined Proxy Group confirm the reasonableness of the Gas Proxy Group as a basis for estimating NW Natural's cost of equity. Therefore, I recommend an ROE of 10.40 percent for NW Natural.

VII. BUSINESS RISKS

Q. Are there factors specific to NW Natural's operating environment that you considered in your ROE recommendation?

A. Yes, there are several additional factors that have a direct bearing on NW Natural's ability to earn a fair return and on the Company's riskiness relative to the proxy group, including (1) its capital expenditure plan, the regulatory environment in which it operates, and the need to maintain access to capital, (2) the risk associated with decarbonization legislation and electrification, and (3) the Company's relatively small size. These factors increase NW Natural's risk relative to the proxy group. While I have not made an explicit adjustment to my ROE recommendation to account for these risks, it is important that they are considered in determining the Company's ROE and capital structure in this proceeding.

A. Regulatory Risk and Capital Access

Q. Do you have any preliminary thoughts on the importance of access to capital for natural gas utilities such as NW Natural?

A. Yes, I do. As a capital-intensive enterprise, the authorized ROE should enable NW Natural to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness to the benefit of customers.

Natural gas utilities are one of the most capital-intensive market sectors. On average, natural gas utilities generate less than half of the revenue per dollar of assets than the non-utility U.S. companies covered by Value Line.[41] To fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure, natural gas utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. Because natural gas utilities tend to be cash flow negative (i.e., cash spent on plant investment is more than cash flow received from operations), it is critical that regulation provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

Q. Please summarize the Company's capital expenditure plan.

A. The Company estimates that from 2024-2028 it will invest approximately $1.5 billion in capital, or about $300 million per year.[42] The investments are primarily related to safety and reliability investments in the pipeline and storage systems, the Company's meter modernization program, public works projects, information technology migration to cloud, seismic readiness of resource centers, renewable natural gas projects, and customer growth. In total, these capital expenditures are

[41] Source: WP Gas Utility Capital Intensity, Value Line, accessed December 2, 2024.

[42] Source: Northwest Natural Investor Presentation, October 2024, slide 17.

equal to approximately 61 percent of the Company's total net utility plant in service of $2.46 billion as of December 31, 2023.[43]

Q. How does the regulatory environment in which a utility operates affect its cost of capital?

A. The regulatory environment is one of the most important factors investors consider when assessing a utility's risk, as it is a significant driver of earnings and cash flow that are of utmost importance to investors.[44] Investors and rating agencies understand that a constructive regulatory environment is critical to utilities' credit and financial integrity, especially during stressed market conditions. In fact, 50 percent of the weighting factors in Moody's ratings determinations relate to the nature of regulation. Predictability and consistency of regulatory actions are among the factors considered by Moody's in assessing the regulatory framework:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality.
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> ***
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> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[45]

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[43] Commission Docket RG 40, *NW Natural's Earnings Review for the 12 Months Ended December 31, 2023* (filed April 24, 2024); Washington Utilities & Transportation Commission Docket 240283, NW *Natural's Annual Commission Basis Report for the 12 Months Ended December 31, 2023 with Workpapers* (filed April 29, 2024).

[44] Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, at 4 (June 23, 2017).

[45] Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, at 2 (June 18, 2010).

Similarly, S&P observes that the regulatory environment in the jurisdictions where a utility operates is a "significant aspect of regulatory risk that influences credit quality".[46] S&P explains:

> [w]hen we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.[47]

Consequently, a utility that operates in a less predictable and more challenging regulatory environment is likely to be viewed as a riskier investment, and may result in lower credit ratings, constrained access to capital (particularly in volatile and adverse market environments), and higher costs of both debt and equity, all else equal. To satisfy the utility's obligation to serve, it is in customers' best interests to ensure that a utility has efficient access to capital on reasonable terms in all market environments.

Q. Are there aspects of the Commission's order in UG 490 that may be viewed as increasing the Company's risk?

A. Yes. In its last rate case in Docket No. UG 490, the Company reached a settlement on most issues, including the cost of capital (i.e., the ROE, capital structure, and cost of debt). However, a settlement was not reached on NW Natural's line extension allowance, and the Commission ultimately ordered that the Company's

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[46] S&P Global Ratings, RatingsDirect, *Assessing U.S. Investor-Owned Utility Regulatory Environments,* at 2 (August 10, 2016).

[47] S&P Global Ratings, RatingsDirect, *Assessing U.S. Investor-Owned Utility Regulatory Environments,* at 6 (August 10, 2016).

allowance for new gas customers to connect to the system be phased out by November 1, 2027. While settlements are typically viewed as constructive by the financial community, termination of the allowance for new customers to connect to the system is likely to impede the Company's ability to add new customers, thus increasing its risk relative to its peers that operate in jurisdictions that are not disincentivizing gas utility customer growth. In other words, removing the line extension policy affects NW Natural's growth prospects and will make it a less attractive investment relative to other gas utilities without such restrictions. Additionally, restrictions on NW Natural's ability to add customers may place a greater burden of capital and operating costs on existing customers, which could result in higher rates for existing customers than would occur if NW Natural retained its line extension allowance. In the end, investors will require a higher return to compensate for the increase in NW Natural's risk.

Q. What are your conclusions regarding the Company's capital investment plan on its cost of equity?

A. NW Natural requires ongoing access to capital market access on favorable terms to provide safe and reliable service. The regulatory environment, including the return authorized in this proceeding, is a key determinant of the Company's ability to access external markets under a variety of capital market circumstances as it executes its capital investment plan. It is in the customers' best interests that the outcome of this proceeding is constructive and the regulatory environment for gas utilities in Oregon is viewed as stable and predictable.

B. Energy Transition Risk

Q. Please briefly summarize the risk associated with energy transition policies.

A. Energy transition is a relatively new risk impacting all utilities; however, the risk varies considerably by jurisdiction and specific public policies. Addressing climate change is an increasing area of focus for federal, state, and local governments. As shown in Figure 20 below, at least a dozen states have committed to net zero or 100 percent renewable power targets by 2050 or earlier. Oregon has set a statewide goal to reduce GHG emissions by at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050.[48] As shown in Figure 20 Oregon is among the states with "aggressive" clean energy or renewable goals.[49]

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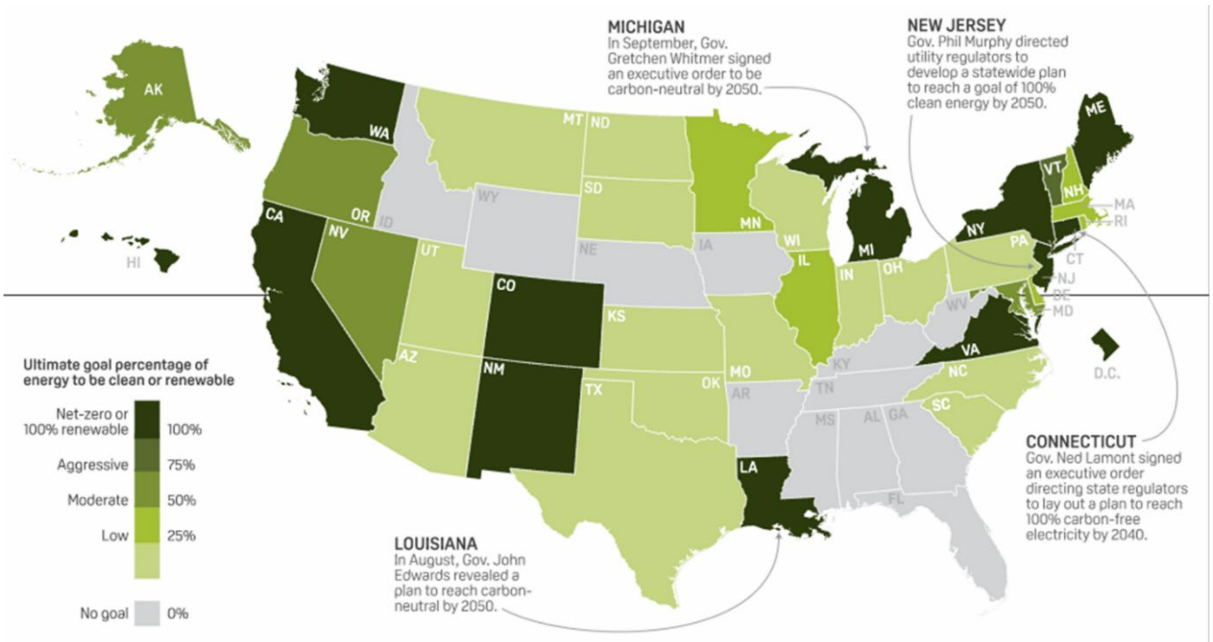
[48] EO-20-04, at 5.

[49] NW Natural also operates in Washington, which is ranked in the category with the most aggressive decarbonization goals shown in Figure 20.

Figure 20: U.S. Renewable Targets [50]



Declining electric heating equipment costs and government support for alternatives to gas space heating have created new risks for natural gas utilities. As a report by The Brattle Group recently observed:

> Traditional gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals. Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector. The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.[51]

[50] S&P Global Platts, "Commodities 2021: States Racing to Set Goals Towards Net-Zero Emission, 100% Renewable Electricity," December 24, 2020.

[51] The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

Moody's concluded in a September 2020 report that "long-term challenges to natural gas infrastructure are increasing," which raises "operating risks and cost of capital."[52] Additionally, S&P has observed that the "'electrification' movements in states like California, Massachusetts, New York and Washington are raising questions about the future of gas utilities in the U.S."[53]

Both short-term and long-term risk are important from an investor's perspective, and regulation generally is better at addressing short-term risk, whereas long-term risk cannot be mitigated as effectively by regulation. If NW Natural's growth prospects over the long-term are impeded because of changes in environmental policy or investor sentiment toward the natural gas industry, it is unlikely that regulation can fully mitigate that risk. As noted earlier, the Commission's order in UG 490 to phase out the line extension allowance may impede the Company's customer growth prospects, thereby increasing the Company's risk.

Q. Have the credit rating agencies noted energy transition risk as a specific risk for NW Natural?

A. Yes. For example, in an April 2024 credit rating report for the Company, S&P explained:

[52] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

[53] S&P Global Market Intelligence, "RRA Regulatory Focus: 2021 Energy Utility Regulatory Focus," February 11, 2021, at 10.

> We also view the energy transition risks in Oregon and Washington as potentially increasing business risk. Washington has implemented decarbonization mandates and Oregon is contemplating various decarbonization initiatives. Furthermore, several cities are contemplating the implementation of a gas ban for new gas connections. We assess these evolving risks as potentially negative for credit quality and will continue to monitor future development.[54]

Similarly, Moody's noted "[e]levated social risk due to higher scrutiny on natural gas as an energy source" and "[l]ong-term risks associated with environmental remediation costs and emission reduction requirements" as credit challenges for NW Natural.[55] Moody's further stated that "[a] rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered."[56] With respect to the Company's ability to meet emissions reductions mandates, Moody's noted the importance of regulatory support, most notably continued support for cost recovery of Renewable Natural Gas ("RNG") investments.

> From a legislative perspective, Oregon has frequently been on the forefront of progressive environmental measures, including the 2019 passage of Senate Bill 98 (SB 98), which allows utilities to acquire renewable natural gas (RNG) on behalf of customers. In July 2020, the parameters surrounding the rulemaking for cost recovery were determined, which allowed for NW Natural to sign its first RNG investment in December 2020. **We see this as an important step in supporting ongoing investment and growth for NW Natural in the face of the threat of electrification.** The state support for RNG development can be a helpful tool for the

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[54] S&P Global Ratings, "Northwest Natural Holding Co. Downgraded to 'A'; Outlook Negative; Subsidiary Ratings Affirmed; Outlook To Stable," at 2 (April 24, 2024).

[55] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 1-2 (July 30, 2024).

[56] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 30, 2024).

> company to maintain its place as a significant energy provider for customers at the same time as reducing carbon and methane emissions.
>
> We also view the company as having low stranded asset risk **given the state's policy goals of advancing renewable natural gas as a form of decarbonization and OPUC ongoing support of cost recovery for these projects**. In the 2021 general rate case, the OPUC approved the recovery of costs associated with the Lexington RNG facility under Senate Bill 98 and authorized the adoption of an automatic adjustment clause that allows the utility to add costs associated with its renewable natural gas projects to rates annually on 1 November.[57]

Lastly, Moody's observed that "NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years."[58] In other words, regulatory support is critical to the Company's ability to mitigate energy transition risks it faces.

Q. Do the natural gas utilities in the proxy group also face energy transition risk?

A. Yes, however, to a somewhat lesser extent. All but one of the Gas Proxy Group companies operate in multiple jurisdictions, which mitigates the effect of energy transition risk through diversification. For example, Atmos Energy, NiSource, ONE Gas, and Spire operate in jurisdictions with "low" to no renewable energy targets

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[57] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 4 (July 30, 2024). Emphasis added.

[58] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 6 (July 30, 2024).

shown in Figure 20 above (e.g., Alabama, Mississippi, Louisiana, Kentucky, Kansas, Texas, Missouri, among others).

Q. What are your conclusions regarding the risk associated with energy transition on NW Natural's cost of equity?

A. While energy transition is a risk for all utilities, as a natural gas-only utility that operates in jurisdictions with more aggressive decarbonization policies, NW Natural is more exposed to the long-term threats to the natural gas utility business. It is critical that supportive regulation enables NW Natural to meet its decarbonization goals while maintaining access to capital.

C. Small Size

Q. To what extent does NW Natural's relatively small size affect its risk profile?

A. Academic literature recognizes that, over the long term, the total returns of smaller companies tend to be higher and more volatile, than larger companies even after the relative illiquidity of smaller company stock is taken into account.[59] Figure 21 below shows NW Natural's market capitalization relative to the Gas Proxy Group.

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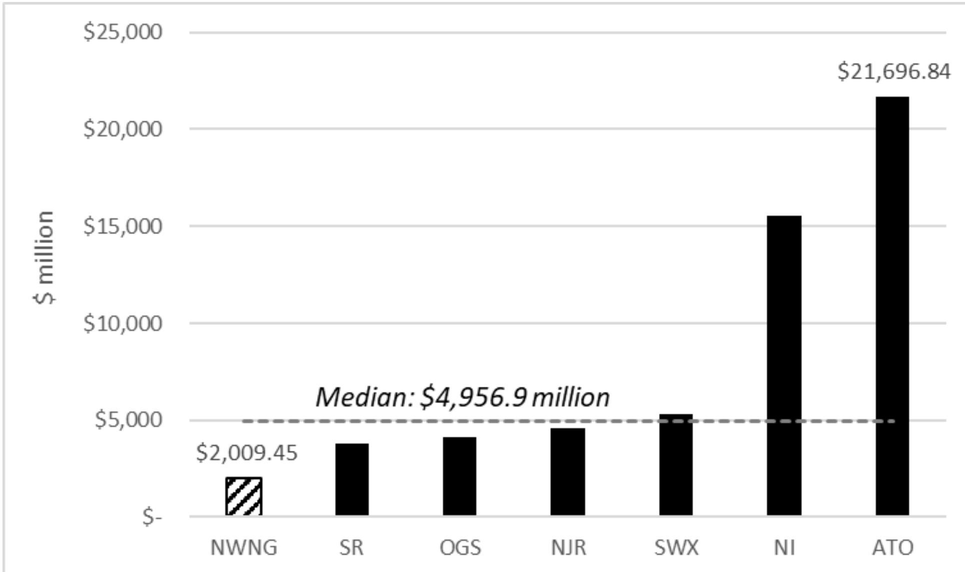
[59] See, e.g. "Firm Size and Return," Ibbotson SBBI 2015 Classic Yearbook, at 99-100.

Figure 21: Comparison of Market Capitalization – Gas Proxy Group



NW Natural's small size relative to its natural gas utility peers means that the Company's earnings may be disproportionately affected by adverse events such as weaker than expected demand for natural gas, plant outages, adverse regulatory rulings, or new legislation. The larger companies in the proxy group can be expected to have an advantage in raising capital, suggesting that the ROE model results derived from this group could understate NW Natural's cost of equity. For example, Company witness Brody J. Wilson explains that as a smaller utility, NW Natural's relatively smaller debt issuances are less liquid and therefore command a premium in the market.[60]

[60] NW Natural/300, Wilson.

Q. How did you estimate the size premium for NW Natural?

A. In its Cost of Capital Navigator, Kroll presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. The size premium associated with NW Natural can be estimated as the difference in Kroll's size risk premiums for the proxy group median market capitalization and NW Natural's implied market capitalization.

As shown in Exhibit NW Natural/412, Nelson, the Combined Proxy Group median market capitalization of $4.96 billion corresponds to the fourth decile of Kroll's market capitalization data. Based on Kroll's analysis, the fourth decile has a size premium of 0.64 percent (or 64 basis points). The implied market capitalization for NW Natural is approximately $2.0 billion,[61] which falls within the sixth decile and corresponds to a size premium of 1.21 percent (or 121 basis points). The difference between those size premiums is 57 basis points (1.21 percent – 0.64 percent).

Q. Are there additional observations that support the consideration of a small size premium for NW Natural?

A. Yes, there are. Smaller companies typically have fewer shares outstanding and fewer shares traded than larger companies. Institutional investors[62] typically hold larger numbers of shares in each of their investments for management efficiency.

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[61] $2.0 billion = NW Natural's 2023 common equity of $1.23 billion x the Gas Proxy Group median market-to-book ratio of 1.63.

[62] An institutional investor is a financial entity that invests money on behalf of clients or members, and includes entities such as mutual funds, pension funds, insurance companies, and endowments.

Because institutional investors tend to have minimum dollar amounts for individual investments and smaller companies have fewer shares outstanding and lower trading volume, institutional investors' positions in smaller companies result in them owning a greater proportion of outstanding shares. If an institutional investor holds a relatively large portion of the shares of a company, its ability to sell its position without adversely affecting the market price of shares may be limited by the volume of shares traded each day. In other words, their investment is less liquid than it would be for a larger company with more shares outstanding and a higher trading volume. The uncertainty of institutional investors' ability to sell their shares quickly when needed is often referred to as "liquidity risk," and requires a higher expected return.

Amihud and Mendelson explained the following regarding liquidity and the effect on the expected return:

> Liquidity is an important factor in asset pricing. For both stocks, and bonds, the lower the liquidity of an asset (that is, the higher the cost of trading it), the higher the return it is expected to yield.
>
> ***
>
> Risk-averse investors require higher expected returns to compensate for greater risk. Similarly, investors prefer to commit capital to liquid investments, which can be traded quickly and at low cost whenever the need arises. Investments with less liquidity must offer higher expected returns to attract investors.[63]

[63] Yakov Amihud and Haim Mendelson, Liquidity, Asset Prices and Financial Policy, Financial Analysts Journal, Vol. 47, No. 6 (Nov-Dec 1991), at 56.

Q. Have you analyzed measures of liquidity for NW Natural relative to the proxy group?

A. Yes, I analyzed three measures of liquidity for the publicly traded holding company (Northwest Natural Holding Company, “NWNH”) to the companies in the Gas Proxy Group: (1) trading volume, (2) share turnover, and (3) the bid-ask spread as a percentage of the stock price.

Northwest Natural Holding Company’s trading volume is significantly lower than the Gas Proxy Group companies on average. As Figure 22 below shows, Northwest Natural Holding Company’s average daily trading volume has been 23.65 percent of the Gas Proxy Group’s trading volume. Lower trading volume indicates lower liquidity, which can be an underlying factor of the size premium.

Figure 22: Market Capitalization and Trading Volume[64]

	Northwest Natural Holding Co.	Gas Proxy Group Average	NWNH % of Proxy Group
Market Capitalization ($ Million)	$1,542	$8,895	17.33%
Average Daily Volume	250,398	1,058,674	23.65%

I also calculated the average daily share turnover of Northwest Natural Holding Company’s stock relative to the proxy companies. Share turnover is calculated as the percentage of outstanding shares traded on an average day (*i.e.*, volume traded divided by shares outstanding). Between 2018 and 2024, Northwest Natural Holding Company’s average daily share turnover was approximately 0.62 percent, compared to 0.67 percent for the Gas Proxy Group.

[64] Source: S&P Capital IQ Pro. 30-trading day average ended October 31, 2024.

Further, over the last six years, Northwest Natural Holding Company had a lower share turnover than the proxy group on average in nearly 70 percent of the 1,784 trading days.[65]

Next, I measured the relative difference in the average spread between the bid price and ask price in Northwest Natural Holding Company's stock price relative to the proxy group. As Dr. Aswath Damodaran of New York University explains, less liquid assets have higher transaction costs, and the bid-ask spread is one measure of a stock's transaction costs.[66] Dr. Damodaran cites to studies demonstrating the bid-ask spread as a percentage of a stock's price increased as firm size decreased.[67] Similarly, Amihud and Mendelson found that "[a]sset illiquidity is inversely related to the bid-ask spread."[68] In a 1989 study, Amihud and Mendelson concluded that the annual expected return increased by 0.24 percent to 0.26 percent for every one percent increase in the bid-ask spread as a percent of the stock price.[69] Figure 23 below summarizes the average bid-ask spread as a percentage of the average stock price for Northwest Natural Holding Company's and the companies in the Gas Proxy Group.

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[65] Source: Bloomberg Professional January 1, 2018 - October 31, 2024.

[66] Aswath Damodaran, "Marketability and Value: Measuring the Illiquidity Discount", Stern School of Business (July 2005), https://people.stern.nyu.edu/adamodar/pdfiles/papers/liquidity.pdf

[67] Aswath Damodaran, "Marketability and Value: Measuring the Illiquidity Discount", Stern School of Business (July 2005), https://people.stern.nyu.edu/adamodar/pdfiles/papers/liquidity.pdf

[68] Yakov Amihud and Haim Mendelson, Liquidity, Asset Prices and Financial Policy, Financial Analysts Journal, Vol. 47, No. 6 (Nov-Dec 1991), at 57.

[69] Amihud, Y. and Mendelson, 1989, The Effects of Beta, Bid-Ask Spread, Residual Risk and Size on Stock Returns, Journal of Finance, v. 44, 479-486.

Figure 23: Bid-Ask Spread as a Percent of Stock Price[70]

	30-day Average	90-day Average	180-day Average	YTD 2024 Average
NWNH	0.0658%	0.0688%	0.0647%	0.0637%
Gas Proxy Group (Avg)	0.0245%	0.0299%	0.0320%	0.0317%
Difference	2.69x	2.30x	2.02x	2.01x

As Figure 23 shows, the bid-ask spread as a percentage of the stock price for Northwest Natural Holding Company is approximately 2.0x to 2.7x higher than the Gas Proxy Group companies on average. Both the analyses shown in Figure 22 and Figure 23 indicate that Northwest Natural Holding Company is smaller in size and its stock is less liquid than the Gas Proxy Group, for which investors require a higher return as compensation.

Q. Do you propose an explicit risk adjustment to your ROE recommendation of 0.57 percent to reflect NW Natural's small size?

A. No. While I have quantified a 57-basis point premium associated with the Company's small size, I did not explicitly factor it into my ROE recommendation.

D. Business Risk Conclusion

Q. What is your conclusion regarding NW Natural's business risk factors and the implication on your ROE recommendation?

A. NW Natural is significantly smaller in size than the proxy group and is more exposed to energy transition risk than the Gas Proxy Group on average. As a smaller company, the potential for these risks to adversely affect the Company's

[70] Source: Bloomberg Professional as of October 31, 2024.

financial profile is more acute because they may have a greater impact on revenues and expenses. While I have not made an explicit adjustment for the risk factors, they should be considered when determining the appropriate ROE and capital structure for NW Natural.

VIII. CAPITAL STRUCTURE

Q. What common equity ratio is the Company proposing?

A. NW Natural is proposing a capital structure that includes 52.00 percent common equity and 48.00 percent long-term debt, as discussed in the testimony of Company witness Brody J. Wilson (NW Natural/300, Wilson). The Company's proposed capital structure reflects its projected capital structure over the coming 12 to 24 months and is needed to strengthen its balance sheet and support its credit rating.

Q. How does the capital structure affect the cost of capital?

A. A company's total risk consists of business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, while financial risk is the incremental risk associated with greater debt. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk of financial distress.[71] Therefore, the capital structure reflects the financial risk that a company may not have adequate cash flows to meet its financial obligations.

[71] *See,* Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 45-46 (2006).

Q. How does NW Natural's proposed capital structure compare to those of the proxy group companies?

A. The reasonableness of NW Natural's requested capital structure is assessed within the context of industry practice and investor requirements. The capital structure should (1) be reasonably consistent with industry practice, (2) enable the subject company to sustain its operations and its financial integrity, and (3) allow it to maintain access to capital at competitive rates under a variety of market conditions.

As shown in Exhibit NW Natural/413, Nelson, NW Natural's proposed capital structure is within the range, but somewhat more leveraged (i.e., more debt in relation to equity) than, the actual capital structures of the operating utilities held by the proxy group companies. For the three years ending 2023, I calculate the common equity, long-term debt, and preferred equity ratios at the regulated utility operating company level for the two proxy groups. I then "roll up" the individual operating company capital ratios to the holding company level by calculating the weighted average common equity, long-term debt, and preferred equity ratios of the utility operating companies within each proxy company. The Gas Proxy Group has an average equity ratio of 55.28 percent over the last three years, and the Combined Proxy Group has a three-year average common equity ratio of 53.15 percent. NW Natural's proposed 52 percent common equity ratio is below these proxy group averages. Although this places equity holders at greater risk relative to the proxy group, I have not made an adjustment to my recommended ROE as a result of the proposed capital structure.

Q. Have you also reviewed the current authorized equity ratios for the proxy group?

A. Yes. As shown in NW Natural/414, Nelson, the current authorized equity ratios for the natural gas operating companies within the proxy group range from 49.86 percent to 62.38 percent, with a mean and median of 55.90 percent and 57.16 percent, respectively. NW Natural's requested equity ratio of 52.00 percent on the lower end of the range of the proxy group authorized equity ratios. Notably, as shown in Figure 24 below, 20 of the 34 regulated natural gas operating utilities within the proxy group (i.e., 59 percent) currently have an authorized equity ratio greater than 55.00 percent. NW Natural's requested equity ratio is lower than the majority of the equity ratios authorized for the proxy group companies.

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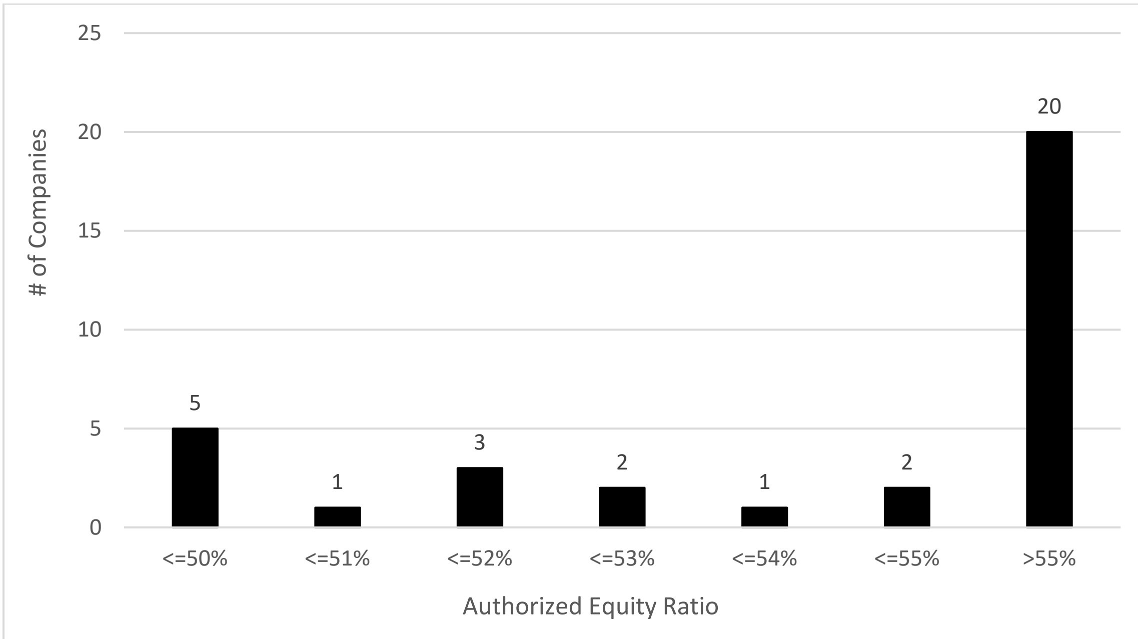
Figure 24: Proxy Group Operating Company Current Authorized Equity Ratio[72]



Q. Are there other factors that support NW Natural's request for a 52 percent equity ratio?

A. Yes. As Company witness Brody J. Wilson shows in his Tables 5, 6, and 7 (NW Natural/300, Wilson), NW Natural's credit metrics have been at the edge of or weaker than the rating agencies downgrade thresholds for its current credit rating. The rating agencies have stated that a rating downgrade could occur if its metrics are below the rating agencies' thresholds for a sustained period. By operating close to its downgrade thresholds, NW Natural risks an adverse event beyond its control jeopardizing its credit rating.

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[72] Source: Regulatory Research Associates; proxy company SEC Form 10-Ks. *See* Exhibit NW Natural/414, Nelson.

Q. Do customers benefit from a utility that maintains a strong financial profile?

A. Yes, in two important ways. First, both debt and equity investors require higher returns for a riskier utility with a lower credit rating. Because the cost of capital is a cost that customers ultimately bear, customers benefit from a utility that maintains a strong financial profile. Second, a utility with a stronger financial profile will have better access to capital at lower costs than a financially weaker utility. Better access to capital enables NW Natural to invest in its system and provide customers with safe and reliable service in all market environments.

IX. SUMMARY AND CONCLUSIONS

Q. Please summarize your ROE recommendation based on this range of results.

A. Based on my analyses of four widely used analytical approaches applied to a proxy group of six natural gas utilities, I estimate that the Company's cost of equity is within a range of 9.90 percent to 11.00 percent. Within that range, I conclude that 10.40 percent is reasonable. Given the small size of the proxy group of natural gas utilities, I evaluated the reasonableness of my recommendation by applying the same analytical approaches to an expanded proxy group that added nine electric utilities with meaningful gas operations to the group of six natural gas utilities. The results of the expanded Combined Proxy Group produced a recommended ROE range of approximately 10.20 percent to 11.00 percent, with a midpoint of 10.60 percent inclusive of flotation costs. Therefore, it is my opinion that an ROE of 10.40 percent based on the model results for the Gas Proxy Group is reasonable.

Additionally, I considered the Company's business risk profile, including its capital expenditure plan, its exposure to energy transition risk, and its significantly smaller size relative to the proxy companies. My 10.40 percent ROE recommendation does not include an explicit adjustment for these risks; therefore, my recommendation is on the conservative side.

Q. What is your conclusion regarding the Company's proposed capital structure?

A. I support NW Natural's requested capital structure of 52.00 percent common equity and 48.00 percent long-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

Q. Does this conclude your Direct Testimony?

A. Yes.

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JENNIFER E. NELSON
ASSISTANT VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with more than fifteen years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, renewable power contracts, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, New Hampshire, New Mexico, North Carolina, South Carolina, and Texas regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Florida, North Carolina, Ohio, Oregon South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Delaware Public Service Commission regarding the utility's proposed pilot performance based rate plan.

- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Arkansas Public Service Commission				
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Delaware Public Service Commission				
Delmarva Power & Light Company	08/24	Delmarva Power & Light Company	24-0868	Alternative Ratemaking Proposal
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed CIRA capital tracking mechanism
Montana Public Utilities Commission				
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	03/24	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 694	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Public Utilities Commission of Ohio				
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company dba NW Natural	12/23	Northwest Natural Gas Company dba NW Natural	UG 490	Cost of Capital
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Public Utilities Commission of Texas				
Wind Energy Transmission Texas, LLC dba WETT	12/24	Wind Energy Transmission Texas, LLC dba WETT	52799	Cost of Capital
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
Utah Public Service Commission				
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

BEFORE THE

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RETURN ON EQUITY
EXHIBIT 402

December 30, 2024

SUMMARY OF ROE MODEL RESULTS AND ROE RECOMMENDATION

Proxy Group Mean	**Gas Proxy Group**	**Combined Proxy Group**
Multi-Stage DCF	8.67%	8.64%
Constant Growth DCF	10.06%	9.90%
Quarterly Growth DCF	10.28%	10.11%
Average DCF	9.67%	9.55%
Blended CAPM	12.42%	12.50%
Historical CAPM	11.09%	11.16%
Risk Premium	10.07%	10.10%
Expected Earnings	9.28%	10.55%
4-model average [1]	10.36%	10.67%
3-model average [2]	10.72%	10.72%
Low [3]	9.78%	10.11%
High [4]	10.92%	10.90%
Midpoint of Range	10.35%	10.51%
Flotation Costs	0.09%	0.09%
Recommendation (Rounded)	10.40%	10.60%

	Low	High
Range (Gas Proxy Group)	**9.78%**	**10.92%**
Flotation Costs	**0.09%**	**0.09%**
Total Range	**9.87%**	**11.02%**
NW Natural Recommendation	**10.40%**	

[1] Average of the Average DCF, Blended CAPM, Risk Premium, and Expected Earnings results
[2] Average of the Average DCF, Blended CAPM, and Risk Premium results
[3] Average of the MSDCF, Historical CAPM, Risk Premium, and Expected Earnings Results
[4] Average of the QGDCF, Blended CAPM, Risk Premium

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PROXY GROUP SELECTION

Company		[1] Pays Dividends (Yes/No)	[2] S&P Rating	[3] Positive Earnings Growth by more than one Source (Yes/No)	[4] % Regulated Net Operating Income / Total Net Operating Income (2021-2023) >50%	[5] % Natural Gas Distribution Net Operating Income / Total Net Operating Income (2021-2023) >50% (15% for electric utilities)	[6] Involved in Merger or Significant Transaction (Yes/No)	Include (Yes/No)	Notes
Natural Gas Utilities									
Atmos Energy Corporation	ATO	Yes	A-	Yes	100%	66%	No	Yes	
Chesapeake Utilities Corporation	CPK	Yes	NR	Yes	82%	37%	Yes	No	
New Jersey Resources Corporation	NJR	Yes	A1 [7]	Yes	59%	53%	No	Yes	
NiSource Inc.	NI	Yes	BBB+	Yes	100%	68%	No	Yes	
Northwest Natural Gas Holding Co.	NWN	Yes	A	Yes	100%	91%	No	No	*Parent of NW Natural*
ONE Gas, Inc.	OGS	Yes	A-	Yes	100%	100%	No	Yes	
Southwest Gas Holdings, Inc.	SWX	Yes	BBB-	Yes	77%	77%	No	Yes	
Spire, Inc.	SR	Yes	BBB+	Yes	83%	83%	No	Yes	
UGI Corporation	UGI	Yes	A3	Yes	10%	10%	Yes	No	
Electric Utilities									
ALLETE, Inc.	ALE	Yes	BBB	Yes	98%	0%	Yes	No	
Alliant Energy Corporation	LNT	Yes	A-	Yes	97%	9%	No	No	
Ameren Corporation	AEE	Yes	BBB+	Yes	98%	15%	No	Yes	
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	98%	0%	No	No	
Avangrid, Inc.	AGR	Yes	BBB+	Yes	99%	21%	Yes	No	
Avista Corporation	AVA	Yes	BBB	Yes	100%	26%	No	Yes	
Black Hills Corporation	BKH	Yes	BBB+	Yes	100%	51%	No	Yes	
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Yes	100%	41%	Yes	No	
CMS Energy Corporation	CMS	Yes	BBB+	Yes	86%	31%	No	Yes	
Consolidated Edison, Inc.	ED	Yes	A-	Yes	84%	25%	No	Yes	
Dominion Energy, Inc.	D	Yes	BBB+	Yes	92%	0%	Yes	No	
DTE Energy Company	DTE	Yes	BBB+	Yes	90%	20%	No	Yes	
Duke Energy Corporation	DUK	Yes	BBB+	Yes	95%	9%	No	No	
Edison International	EIX	Yes	BBB	Yes	101%	0%	No	No	
Entergy Corporation	ETR	Yes	BBB+	Yes	99%	1%	No	No	
Eversource Energy	ES	Yes	A-	Yes	95%	15%	Yes	No	
Exelon Corporation	EXC	Yes	BBB+	Yes	100%	9%	No	No	
FirstEnergy Corporation	FE	Yes	BBB	Yes	100%	0%	Yes	No	
Evergy, Inc.	EVRG	Yes	BBB+	Yes	100%	0%	No	No	
Hawaiian Electric Industries, Inc.	HE	No	B-	No	79%	0%	No	No	
IDACORP, Inc.	IDA	Yes	BBB	Yes	100%	0%	No	No	
MGE Energy, Inc.	MGEE	Yes	AA-	No	75%	18%	No	No	
NextEra Energy, Inc.	NEE	Yes	A-	Yes	88%	0%	No	No	
NorthWestern Energy Group, Inc.	NWE	Yes	BBB	Yes	100%	14%	No	No	
OGE Energy Corporation	OGE	Yes	BBB+	Yes	100%	0%	No	No	
Otter Tail Corporation	OTTR	Yes	BBB	Yes	33%	0%	No	No	
PG&E Corporation	PCG	Yes	BB	Yes	100%	50%	No	No	
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	100%	0%	No	No	
Portland General Electric Company	POR	Yes	BBB+	Yes	100%	0%	No	No	
PPL Corporation	PPL	Yes	A-	Yes	100%	6%	No	No	

Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Yes	84%	18%	No	Yes	
Sempra Energy	SRE	Yes	BBB+	Yes	47%	19%	No	No	
The Southern Company	SO	Yes	A-	Yes	94%	17%	No	Yes	
TXNM Energy, Inc.	TXNM	Yes	BBB	Yes	100%	0%	No	No	
Unitil Corporation	UTL	Yes	BBB+	No	100%	64%	Yes	No	*Does not have a full Value Line Report*
WEC Energy Group, Inc.	WEC	Yes	A-	Yes	99%	42%	No	Yes	
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	100%	14%	No	No	

[1] Source: Bloomberg Professional
[2] Source: S&P Capital IQ Pro
[3] Source: Value Line, Zacks and S&P Capital IQ
[4] Source: Company 10-K reports, average of three most recent years
[5] Source: Company 10-K reports, average of three most recent years
[6] Source: Bloomberg Professional
[7] New Jersey Natural Gas Co is rated A1 by Moody's

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30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$139.77	2.30%	2.38%	7.00%	7.00%	7.00%	7.00%	9.38%	9.38%	9.38%
New Jersey Resources Corporation	NJR	$1.80	$46.44	3.88%	4.00%	5.00%	7.60%	n/a	6.30%	8.97%	10.30%	11.62%
NiSource Inc.	NI	$1.06	$34.58	3.07%	3.19%	9.50%	7.95%	7.00%	8.15%	10.17%	11.34%	12.71%
ONE Gas, Inc.	OGS	$2.64	$73.19	3.61%	3.67%	3.50%	2.00%	5.00%	3.50%	5.64%	7.17%	8.70%
Southwest Gas Holdings, Inc.	SWX	$2.48	$74.03	3.35%	3.48%	10.00%	n/a	6.00%	8.00%	9.45%	11.48%	13.52%
Spire, Inc.	SR	$3.02	$65.54	4.61%	4.73%	4.50%	6.00%	5.00%	5.17%	9.21%	9.89%	10.75%
Ameren Corporation	AEE	$2.68	$87.24	3.07%	3.17%	6.50%	6.13%	6.60%	6.41%	9.30%	9.58%	9.77%
Avista Corporation	AVA	$1.90	$38.03	5.00%	5.12%	5.00%	4.66%	4.80%	4.82%	9.77%	9.94%	10.12%
Black Hills Corporation	BKH	$2.60	$60.44	4.30%	4.39%	4.00%	4.62%	3.50%	4.04%	7.88%	8.43%	9.02%
CMS Energy Corporation	CMS	$2.06	$70.48	2.92%	3.03%	6.00%	7.50%	7.60%	7.03%	9.01%	10.06%	10.63%
Consolidated Edison, Inc.	ED	$3.32	$104.04	3.19%	3.28%	6.00%	5.58%	5.60%	5.73%	8.86%	9.01%	9.29%
DTE Energy Company	DTE	$4.08	$126.66	3.22%	3.33%	4.50%	7.00%	8.20%	6.57%	7.79%	9.89%	11.55%
Public Service Enterprise Group Inc.	PEG	$2.40	$89.41	2.68%	2.77%	5.00%	6.00%	8.30%	6.43%	7.75%	9.20%	11.10%
The Southern Company	SO	$2.88	$90.75	3.17%	3.28%	6.50%	6.25%	7.00%	6.58%	9.52%	9.86%	10.28%
WEC Energy Group, Inc.	WEC	$3.34	$96.36	3.47%	3.59%	6.00%	6.75%	8.00%	6.92%	9.57%	10.50%	11.60%
GAS PROXY GROUP MEAN				3.47%	3.58%	6.58%	6.11%	6.00%	6.35%	8.81%	9.93%	11.11%
COMBINED PROXY GROUP MEAN				3.46%	3.56%	5.93%	6.07%	6.40%	6.18%	8.82%	9.74%	10.67%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$131.16	2.45%	2.54%	7.00%	7.00%	7.00%	7.00%	9.54%	9.54%	9.54%
New Jersey Resources Corporation	NJR	$1.80	$45.70	3.94%	4.06%	5.00%	7.60%	n/a	6.30%	9.04%	10.36%	11.69%
NiSource Inc.	NI	$1.06	$32.52	3.26%	3.39%	9.50%	7.95%	7.00%	8.15%	10.37%	11.54%	12.91%
ONE Gas, Inc.	OGS	$2.64	$69.63	3.79%	3.86%	3.50%	2.00%	5.00%	3.50%	5.83%	7.36%	8.89%
Southwest Gas Holdings, Inc.	SWX	$2.48	$72.69	3.41%	3.55%	10.00%	n/a	6.00%	8.00%	9.51%	11.55%	13.58%
Spire, Inc.	SR	$3.02	$64.82	4.66%	4.78%	4.50%	6.00%	5.00%	5.17%	9.26%	9.95%	10.80%
Ameren Corporation	AEE	$2.68	$81.71	3.28%	3.39%	6.50%	6.13%	6.60%	6.41%	9.51%	9.79%	9.99%
Avista Corporation	AVA	$1.90	$37.72	5.04%	5.16%	5.00%	4.66%	4.80%	4.82%	9.82%	9.98%	10.16%
Black Hills Corporation	BKH	$2.60	$58.66	4.43%	4.52%	4.00%	4.62%	3.50%	4.04%	8.01%	8.56%	9.15%
CMS Energy Corporation	CMS	$2.06	$66.69	3.09%	3.20%	6.00%	7.50%	7.60%	7.03%	9.18%	10.23%	10.81%
Consolidated Edison, Inc.	ED	$3.32	$99.95	3.32%	3.42%	6.00%	5.58%	5.60%	5.73%	9.00%	9.14%	9.42%
DTE Energy Company	DTE	$4.08	$121.83	3.35%	3.46%	4.50%	7.00%	8.20%	6.57%	7.92%	10.03%	11.69%
Public Service Enterprise Group Inc.	PEG	$2.40	$82.16	2.92%	3.02%	5.00%	6.00%	8.30%	6.43%	7.99%	9.45%	11.34%
The Southern Company	SO	$2.88	$86.61	3.33%	3.43%	6.50%	6.25%	7.00%	6.58%	9.68%	10.02%	10.44%
WEC Energy Group, Inc.	WEC	$3.34	$90.36	3.70%	3.82%	6.00%	6.75%	8.00%	6.92%	9.81%	10.74%	11.84%
GAS PROXY GROUP MEAN				3.59%	3.70%	6.58%	6.11%	6.00%	6.35%	8.93%	10.05%	11.24%
COMBINED PROXY GROUP MEAN				3.60%	3.71%	5.93%	6.07%	6.40%	6.18%	8.97%	9.88%	10.82%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Corporation	ATO	$3.22	$123.59	2.61%	2.70%	7.00%	7.00%	7.00%	7.00%	9.70%	9.70%	9.70%
New Jersey Resources Corporation	NJR	$1.80	$44.25	4.07%	4.20%	5.00%	7.60%	n/a	6.30%	9.17%	10.50%	11.82%
NiSource Inc.	NI	$1.06	$30.08	3.52%	3.67%	9.50%	7.95%	7.00%	8.15%	10.65%	11.82%	13.19%
ONE Gas, Inc.	OGS	$2.64	$65.97	4.00%	4.07%	3.50%	2.00%	5.00%	3.50%	6.04%	7.57%	9.10%
Southwest Gas Holdings, Inc.	SWX	$2.48	$72.87	3.40%	3.54%	10.00%	n/a	6.00%	8.00%	9.51%	11.54%	13.57%
Spire, Inc.	SR	$3.02	$62.54	4.83%	4.95%	4.50%	6.00%	5.00%	5.17%	9.44%	10.12%	10.97%
Ameren Corporation	AEE	$2.68	$77.09	3.48%	3.59%	6.50%	6.13%	6.60%	6.41%	9.71%	10.00%	10.19%
Avista Corporation	AVA	$1.90	$36.43	5.21%	5.34%	5.00%	4.66%	4.80%	4.82%	10.00%	10.16%	10.35%
Black Hills Corporation	BKH	$2.60	$56.26	4.62%	4.71%	4.00%	4.62%	3.50%	4.04%	8.20%	8.75%	9.34%
CMS Energy Corporation	CMS	$2.06	$63.28	3.26%	3.37%	6.00%	7.50%	7.60%	7.03%	9.35%	10.40%	10.98%
Consolidated Edison, Inc.	ED	$3.32	$95.71	3.47%	3.57%	6.00%	5.58%	5.60%	5.73%	9.15%	9.30%	9.57%
DTE Energy Company	DTE	$4.08	$116.43	3.50%	3.62%	4.50%	7.00%	8.20%	6.57%	8.08%	10.19%	11.85%
Public Service Enterprise Group Inc.	PEG	$2.40	$75.27	3.19%	3.29%	5.00%	6.00%	8.30%	6.43%	8.27%	9.72%	11.62%
The Southern Company	SO	$2.88	$79.97	3.60%	3.72%	6.50%	6.25%	7.00%	6.58%	9.96%	10.30%	10.73%
WEC Energy Group, Inc.	WEC	$3.34	$85.60	3.90%	4.04%	6.00%	6.75%	8.00%	6.92%	10.02%	10.95%	12.06%
GAS PROXY GROUP MEAN				3.74%	3.85%	6.58%	6.11%	6.00%	6.35%	9.08%	10.21%	11.39%
COMBINED PROXY GROUP MEAN				3.78%	3.89%	5.93%	6.07%	6.40%	6.18%	9.15%	10.07%	11.00%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of October 31, 2024
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 405

December 30, 2024

30-DAY MULTI-STAGE DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Atmos Energy Corporation	ATO	$3.22	$139.77	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.20%
New Jersey Resources Corporation	NJR	$1.80	$46.44	6.30%	5.96%	5.61%	5.27%	4.93%	4.59%	4.24%	9.03%
NiSource Inc.	NI	$1.06	$34.58	8.15%	7.50%	6.85%	6.20%	5.55%	4.90%	4.24%	8.49%
ONE Gas, Inc.	OGS	$2.64	$73.19	3.50%	3.62%	3.75%	3.87%	4.00%	4.12%	4.24%	7.96%
Southwest Gas Holdings, Inc.	SWX	$2.48	$74.03	8.00%	7.37%	6.75%	6.12%	5.50%	4.87%	4.24%	8.84%
Spire, Inc.	SR	$3.02	$65.54	5.17%	5.01%	4.86%	4.71%	4.55%	4.40%	4.24%	9.56%
Ameren Corporation	AEE	$2.68	$87.24	6.41%	6.05%	5.69%	5.33%	4.97%	4.60%	4.24%	8.06%
Avista Corporation	AVA	$1.90	$38.03	4.82%	4.72%	4.63%	4.53%	4.44%	4.34%	4.24%	9.89%
Black Hills Corporation	BKH	$2.60	$60.44	4.04%	4.07%	4.11%	4.14%	4.18%	4.21%	4.24%	8.86%
CMS Energy Corporation	CMS	$2.06	$70.48	7.03%	6.57%	6.10%	5.64%	5.17%	4.71%	4.24%	8.02%
Consolidated Edison, Inc.	ED	$3.32	$104.04	5.73%	5.48%	5.23%	4.99%	4.74%	4.49%	4.24%	8.04%
DTE Energy Company	DTE	$4.08	$126.66	6.57%	6.18%	5.79%	5.41%	5.02%	4.63%	4.24%	8.28%
Public Service Enterprise Group Inc.	PEG	$2.40	$89.41	6.43%	6.07%	5.70%	5.34%	4.97%	4.61%	4.24%	7.58%
The Southern Company	SO	$2.88	$90.75	6.58%	6.19%	5.80%	5.41%	5.02%	4.63%	4.24%	8.23%
WEC Energy Group, Inc.	WEC	$3.34	$96.36	6.92%	6.47%	6.03%	5.58%	5.13%	4.69%	4.24%	8.69%
GAS PROXY GROUP MEAN											8.51%
COMBINED PROXY GROUP MEAN											8.45%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of October 31, 2024
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2031-2035 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

90-DAY MULTI-STAGE DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Atmos Energy Corporation	ATO	$3.22	$131.16	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.40%
New Jersey Resources Corporation	NJR	$1.80	$45.70	6.30%	5.96%	5.61%	5.27%	4.93%	4.59%	4.24%	9.11%
NiSource Inc.	NI	$1.06	$32.52	8.15%	7.50%	6.85%	6.20%	5.55%	4.90%	4.24%	8.76%
ONE Gas, Inc.	OGS	$2.64	$69.63	3.50%	3.62%	3.75%	3.87%	4.00%	4.12%	4.24%	8.16%
Southwest Gas Holdings, Inc.	SWX	$2.48	$72.69	8.00%	7.37%	6.75%	6.12%	5.50%	4.87%	4.24%	8.92%
Spire, Inc.	SR	$3.02	$64.82	5.17%	5.01%	4.86%	4.71%	4.55%	4.40%	4.24%	9.62%
Ameren Corporation	AEE	$2.68	$81.71	6.41%	6.05%	5.69%	5.33%	4.97%	4.60%	4.24%	8.32%
Avista Corporation	AVA	$1.90	$37.72	4.82%	4.72%	4.63%	4.53%	4.44%	4.34%	4.24%	9.94%
Black Hills Corporation	BKH	$2.60	$58.66	4.04%	4.07%	4.11%	4.14%	4.18%	4.21%	4.24%	9.00%
CMS Energy Corporation	CMS	$2.06	$66.69	7.03%	6.57%	6.10%	5.64%	5.17%	4.71%	4.24%	8.23%
Consolidated Edison, Inc.	ED	$3.32	$99.95	5.73%	5.48%	5.23%	4.99%	4.74%	4.49%	4.24%	8.19%
DTE Energy Company	DTE	$4.08	$121.83	6.57%	6.18%	5.79%	5.41%	5.02%	4.63%	4.24%	8.44%
Public Service Enterprise Group Inc.	PEG	$2.40	$82.16	6.43%	6.07%	5.70%	5.34%	4.97%	4.61%	4.24%	7.87%
The Southern Company	SO	$2.88	$86.61	6.58%	6.19%	5.80%	5.41%	5.02%	4.63%	4.24%	8.42%
WEC Energy Group, Inc.	WEC	$3.34	$90.36	6.92%	6.47%	6.03%	5.58%	5.13%	4.69%	4.24%	8.98%
GAS PROXY GROUP MEAN											8.66%
COMBINED PROXY GROUP MEAN											8.62%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of October 31, 2024
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2031-2035 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

180-DAY MULTI-STAGE DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$3.22	$123.59	7.00%	6.54%	6.08%	5.62%	5.16%	4.70%	4.24%	7.60%
New Jersey Resources Corporation	NJR	$1.80	$44.25	6.30%	5.96%	5.61%	5.27%	4.93%	4.59%	4.24%	9.27%
NiSource Inc.	NI	$1.06	$30.08	8.15%	7.50%	6.85%	6.20%	5.55%	4.90%	4.24%	9.12%
ONE Gas, Inc.	OGS	$2.64	$65.97	3.50%	3.62%	3.75%	3.87%	4.00%	4.12%	4.24%	8.38%
Southwest Gas Holdings, Inc.	SWX	$2.48	$72.87	8.00%	7.37%	6.75%	6.12%	5.50%	4.87%	4.24%	8.91%
Spire, Inc.	SR	$3.02	$62.54	5.17%	5.01%	4.86%	4.71%	4.55%	4.40%	4.24%	9.82%
Ameren Corporation	AEE	$2.68	$77.09	6.41%	6.05%	5.69%	5.33%	4.97%	4.60%	4.24%	8.56%
Avista Corporation	AVA	$1.90	$36.43	4.82%	4.72%	4.63%	4.53%	4.44%	4.34%	4.24%	10.15%
Black Hills Corporation	BKH	$2.60	$56.26	4.04%	4.07%	4.11%	4.14%	4.18%	4.21%	4.24%	9.21%
CMS Energy Corporation	CMS	$2.06	$63.28	7.03%	6.57%	6.10%	5.64%	5.17%	4.71%	4.24%	8.45%
Consolidated Edison, Inc.	ED	$3.32	$95.71	5.73%	5.48%	5.23%	4.99%	4.74%	4.49%	4.24%	8.37%
DTE Energy Company	DTE	$4.08	$116.43	6.57%	6.18%	5.79%	5.41%	5.02%	4.63%	4.24%	8.64%
Public Service Enterprise Group Inc.	PEG	$2.40	$75.27	6.43%	6.07%	5.70%	5.34%	4.97%	4.61%	4.24%	8.21%
The Southern Company	SO	$2.88	$79.97	6.58%	6.19%	5.80%	5.41%	5.02%	4.63%	4.24%	8.77%
WEC Energy Group, Inc.	WEC	$3.34	$85.60	6.92%	6.47%	6.03%	5.58%	5.13%	4.69%	4.24%	9.25%
GAS PROXY GROUP MEAN											8.85%
COMBINED PROXY GROUP MEAN											8.85%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 180-day average as of October 31, 2024
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2031-2035 Real GDP growth (2.0%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 406

December 30, 2024

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Value Line Earnings Growth	[11] S&P Earnings Growth	[12] Zacks Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.81	$0.86	$0.86	$0.86	$0.86	$139.77	7.00%	7.00%	7.00%	7.00%	9.55%	9.55%	9.55%
New Jersey Resources Corporation	NJR	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$0.48	$46.44	5.00%	7.60%	n/a	6.30%	8.99%	10.36%	11.73%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.27	$0.29	$0.29	$0.29	$0.29	$34.58	9.50%	7.95%	7.00%	8.15%	10.41%	11.61%	13.02%
ONE Gas, Inc.	OGS	$0.65	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$73.19	3.50%	2.00%	5.00%	3.50%	5.74%	7.32%	8.90%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$74.03	10.00%	n/a	6.00%	8.00%	9.68%	11.77%	13.87%
Spire, Inc.	SR	$0.76	$0.76	$0.76	$0.76	$0.79	$0.79	$0.79	$0.79	$65.54	4.50%	6.00%	5.00%	5.17%	9.48%	10.19%	11.08%
Ameren Corporation	AEE	$0.63	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$87.24	6.50%	6.13%	6.60%	6.41%	9.45%	9.74%	9.94%
Avista Corporation	AVA	$0.46	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$38.03	5.00%	4.66%	4.80%	4.82%	10.04%	10.21%	10.40%
Black Hills Corporation	BKH	$0.63	$0.65	$0.65	$0.65	$0.65	$0.68	$0.68	$0.68	$60.44	4.00%	4.62%	3.50%	4.04%	8.04%	8.61%	9.22%
CMS Energy Corporation	CMS	$0.49	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$70.48	6.00%	7.50%	7.60%	7.03%	9.16%	10.23%	10.82%
Consolidated Edison, Inc.	ED	$0.81	$0.83	$0.83	$0.83	$0.86	$0.88	$0.88	$0.88	$104.04	6.00%	5.58%	5.60%	5.73%	9.04%	9.19%	9.48%
DTE Energy Company	DTE	$1.02	$1.02	$1.02	$1.02	$1.09	$1.09	$1.09	$1.09	$126.66	4.50%	7.00%	8.20%	6.57%	7.97%	10.13%	11.84%
Public Service Enterprise Group Inc.	PEG	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$89.41	5.00%	6.00%	8.30%	6.43%	7.86%	9.35%	11.29%
The Southern Company	SO	$0.70	$0.70	$0.72	$0.72	$0.75	$0.75	$0.77	$0.77	$90.75	6.50%	6.25%	7.00%	6.58%	9.69%	10.04%	10.48%
WEC Energy Group, Inc.	WEC	$0.78	$0.84	$0.84	$0.84	$0.83	$0.89	$0.89	$0.89	$96.36	6.00%	6.75%	8.00%	6.92%	9.74%	10.70%	11.84%
GAS PROXY GROUP MEAN															8.98%	10.13%	11.36%
COMBINED PROXY GROUP MEAN															8.99%	9.93%	10.90%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals 30-day average as of October 31, 2024
[10] Source: Value Line
[11] Source: S&P Capital IQ
[12] Source: Zacks
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Value Line Earnings Growth	[11] S&P Earnings Growth	[12] Zacks Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.81	$0.86	$0.86	$0.86	$0.86	$131.16	7.00%	7.00%	7.00%	7.00%	9.72%	9.72%	9.72%
New Jersey Resources Corporation	NJR	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$0.48	$45.70	5.00%	7.60%	n/a	6.30%	9.06%	10.43%	11.80%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.27	$0.29	$0.29	$0.29	$0.29	$32.52	9.50%	7.95%	7.00%	8.15%	10.62%	11.83%	13.24%
ONE Gas, Inc.	OGS	$0.65	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$69.63	3.50%	2.00%	5.00%	3.50%	5.94%	7.52%	9.10%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$72.69	10.00%	n/a	6.00%	8.00%	9.75%	11.84%	13.94%
Spire, Inc.	SR	$0.76	$0.76	$0.76	$0.76	$0.79	$0.79	$0.79	$0.79	$64.82	4.50%	6.00%	5.00%	5.17%	9.54%	10.25%	11.14%
Ameren Corporation	AEE	$0.63	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$81.71	6.50%	6.13%	6.60%	6.41%	9.68%	9.97%	10.17%
Avista Corporation	AVA	$0.46	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$37.72	5.00%	4.66%	4.80%	4.82%	10.08%	10.26%	10.45%
Black Hills Corporation	BKH	$0.63	$0.65	$0.65	$0.65	$0.65	$0.68	$0.68	$0.68	$58.66	4.00%	4.62%	3.50%	4.04%	8.18%	8.75%	9.36%
CMS Energy Corporation	CMS	$0.49	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$66.69	6.00%	7.50%	7.60%	7.03%	9.34%	10.42%	11.01%
Consolidated Edison, Inc.	ED	$0.81	$0.83	$0.83	$0.83	$0.86	$0.88	$0.88	$0.88	$99.95	6.00%	5.58%	5.60%	5.73%	9.18%	9.34%	9.62%
DTE Energy Company	DTE	$1.02	$1.02	$1.02	$1.02	$1.09	$1.09	$1.09	$1.09	$121.83	4.50%	7.00%	8.20%	6.57%	8.10%	10.27%	11.98%
Public Service Enterprise Group Inc.	PEG	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$82.16	5.00%	6.00%	8.30%	6.43%	8.12%	9.61%	11.55%
The Southern Company	SO	$0.70	$0.70	$0.72	$0.72	$0.75	$0.75	$0.77	$0.77	$86.61	6.50%	6.25%	7.00%	6.58%	9.86%	10.21%	10.64%
WEC Energy Group, Inc.	WEC	$0.78	$0.84	$0.84	$0.84	$0.83	$0.89	$0.89	$0.89	$90.36	6.00%	6.75%	8.00%	6.92%	9.99%	10.96%	12.10%
GAS PROXY GROUP MEAN															9.10%	10.26%	11.49%
COMBINED PROXY GROUP MEAN															9.14%	10.09%	11.06%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals 90-day average as of October 31, 2024
[10] Source: Value Line
[11] Source: S&P Capital IQ
[12] Source: Zacks
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Value Line Earnings Growth	[11] S&P Earnings Growth	[12] Zacks Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.81	$0.86	$0.86	$0.86	$0.86	$123.59	7.00%	7.00%	7.00%	7.00%	9.89%	9.89%	9.89%
New Jersey Resources Corporation	NJR	$0.42	$0.42	$0.42	$0.45	$0.45	$0.45	$0.45	$0.48	$44.25	5.00%	7.60%	n/a	6.30%	9.19%	10.56%	11.94%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.27	$0.29	$0.29	$0.29	$0.29	$30.08	9.50%	7.95%	7.00%	8.15%	10.92%	12.13%	13.55%
ONE Gas, Inc.	OGS	$0.65	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$65.97	3.50%	2.00%	5.00%	3.50%	6.16%	7.74%	9.33%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$72.87	10.00%	n/a	6.00%	8.00%	9.74%	11.83%	13.93%
Spire, Inc.	SR	$0.76	$0.76	$0.76	$0.76	$0.79	$0.79	$0.79	$0.79	$62.54	4.50%	6.00%	5.00%	5.17%	9.73%	10.44%	11.33%
Ameren Corporation	AEE	$0.63	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$77.09	6.50%	6.13%	6.60%	6.41%	9.89%	10.19%	10.39%
Avista Corporation	AVA	$0.46	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$36.43	5.00%	4.66%	4.80%	4.82%	10.28%	10.45%	10.64%
Black Hills Corporation	BKH	$0.63	$0.65	$0.65	$0.65	$0.65	$0.68	$0.68	$0.68	$56.26	4.00%	4.62%	3.50%	4.04%	8.38%	8.96%	9.57%
CMS Energy Corporation	CMS	$0.49	$0.52	$0.52	$0.52	$0.52	$0.55	$0.55	$0.55	$63.28	6.00%	7.50%	7.60%	7.03%	9.52%	10.60%	11.20%
Consolidated Edison, Inc.	ED	$0.81	$0.83	$0.83	$0.83	$0.86	$0.88	$0.88	$0.88	$95.71	6.00%	5.58%	5.60%	5.73%	9.35%	9.50%	9.79%
DTE Energy Company	DTE	$1.02	$1.02	$1.02	$1.02	$1.09	$1.09	$1.09	$1.09	$116.43	4.50%	7.00%	8.20%	6.57%	8.27%	10.44%	12.16%
Public Service Enterprise Group Inc.	PEG	$0.57	$0.60	$0.60	$0.60	$0.61	$0.64	$0.64	$0.64	$75.27	5.00%	6.00%	8.30%	6.43%	8.41%	9.90%	11.86%
The Southern Company	SO	$0.70	$0.70	$0.72	$0.72	$0.75	$0.75	$0.77	$0.77	$79.97	6.50%	6.25%	7.00%	6.58%	10.16%	10.51%	10.95%
WEC Energy Group, Inc.	WEC	$0.78	$0.84	$0.84	$0.84	$0.83	$0.89	$0.89	$0.89	$85.60	6.00%	6.75%	8.00%	6.92%	10.22%	11.19%	12.33%
GAS PROXY GROUP MEAN															9.27%	10.43%	11.66%
COMBINED PROXY GROUP MEAN															9.34%	10.29%	11.26%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals 180-day average as of October 31, 2024
[10] Source: Value Line
[11] Source: S&P Capital IQ
[12] Source: Zacks
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 407

December 30, 2024

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, BLENDED MRP

$K = Rf + \beta\ (Rm - Rf)$

Company	Ticker	[1] 30-day Average of 30-Year U.S. Treasury Bond Yield	[2] Value Line Beta (β)	[3] Bloomberg Beta (β)	[4] Average Beta (β)	[5] Forward Market Return (Rm)	[6] Long Term Historical Market Return (Rm)	[7] Average Market Risk Premium (Rm − Rf)	[8] ROE (K)
Atmos Energy Corporation	ATO	4.30%	0.85	0.83	0.84	15.07%	12.04%	9.25%	12.05%
New Jersey Resources Corporation	NJR	4.30%	1.00	0.84	0.92	15.07%	12.04%	9.25%	12.81%
NiSource Inc.	NI	4.30%	0.95	0.88	0.91	15.07%	12.04%	9.25%	12.74%
ONE Gas, Inc.	OGS	4.30%	0.85	0.83	0.84	15.07%	12.04%	9.25%	12.07%
Southwest Gas Holdings, Inc.	SWX	4.30%	0.90	0.92	0.91	15.07%	12.04%	9.25%	12.70%
Spire, Inc.	SR	4.30%	0.85	0.84	0.85	15.07%	12.04%	9.25%	12.13%
Ameren Corporation	AEE	4.30%	0.90	0.82	0.86	15.07%	12.04%	9.25%	12.28%
Avista Corporation	AVA	4.30%	0.95	0.82	0.89	15.07%	12.04%	9.25%	12.51%
Black Hills Corporation	BKH	4.30%	1.05	1.01	1.03	15.07%	12.04%	9.25%	13.85%
CMS Energy Corporation	CMS	4.30%	0.85	0.83	0.84	15.07%	12.04%	9.25%	12.09%
Consolidated Edison, Inc.	ED	4.30%	0.80	0.69	0.74	15.07%	12.04%	9.25%	11.19%
DTE Energy Company	DTE	4.30%	1.00	0.93	0.96	15.07%	12.04%	9.25%	13.22%
Public Service Enterprise Group Inc.	PEG	4.30%	0.95	0.94	0.95	15.07%	12.04%	9.25%	13.06%
The Southern Company	SO	4.30%	0.95	0.88	0.92	15.07%	12.04%	9.25%	12.77%
WEC Energy Group, Inc.	WEC	4.30%	0.85	0.82	0.83	15.07%	12.04%	9.25%	12.01%
Gas Proxy Group Mean					0.88				12.42%
Combined Proxy Group Mean					0.89				12.50%

Notes:
[1] Source: Bloomberg Professional, as of October 31, 2024
[2] Source: Value Line, as of October 31, 2024
[3] Source: Bloomberg Professional, as of October 31, 2024
[4] Equals Average of [2], [3]
[5] Equals Value Line expected market return
[6] Source: Kroll, arithmetic average Market Return 1926-2023
[7] Equals Average ([5],[6]) - [1]
[8] Equals [1] + [4] x [7]

CAPITAL ASSET PRICING MODEL -- PROJECTED RISK-FREE RATE, BLENDED MRP

$K = Rf + \beta\ (Rm - Rf)$

		[1]		[2]		[3]		[4]	[5]
Company	Ticker	Projected 30-Year U.S. Treasury Bond Yield	Value Line Beta (β)	Bloomberg Beta (β)	Average Beta (β)	Forward Market Return (Rm)	Long Term Historical Market Return (Rm)	Average Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.28%	0.85	0.83	0.84	15.07%	12.04%	9.27%	12.05%
New Jersey Resources Corporation	NJR	4.28%	1.00	0.84	0.92	15.07%	12.04%	9.27%	12.81%
NiSource Inc.	NI	4.28%	0.95	0.88	0.91	15.07%	12.04%	9.27%	12.74%
ONE Gas, Inc.	OGS	4.28%	0.85	0.83	0.84	15.07%	12.04%	9.27%	12.07%
Southwest Gas Holdings, Inc.	SWX	4.28%	0.90	0.92	0.91	15.07%	12.04%	9.27%	12.70%
Spire, Inc.	SR	4.28%	0.85	0.84	0.85	15.07%	12.04%	9.27%	12.12%
Ameren Corporation	AEE	4.28%	0.90	0.82	0.86	15.07%	12.04%	9.27%	12.27%
Avista Corporation	AVA	4.28%	0.95	0.82	0.89	15.07%	12.04%	9.27%	12.50%
Black Hills Corporation	BKH	4.28%	1.05	1.01	1.03	15.07%	12.04%	9.27%	13.85%
CMS Energy Corporation	CMS	4.28%	0.85	0.83	0.84	15.07%	12.04%	9.27%	12.08%
Consolidated Edison, Inc.	ED	4.28%	0.80	0.69	0.74	15.07%	12.04%	9.27%	11.19%
DTE Energy Company	DTE	4.28%	1.00	0.93	0.96	15.07%	12.04%	9.27%	13.22%
Public Service Enterprise Group Inc.	PEG	4.28%	0.95	0.94	0.95	15.07%	12.04%	9.27%	13.06%
The Southern Company	SO	4.28%	0.95	0.88	0.92	15.07%	12.04%	9.27%	12.77%
WEC Energy Group, Inc.	WEC	4.28%	0.85	0.82	0.83	15.07%	12.04%	9.27%	12.01%
Gas Proxy Group Mean					0.88				12.42%
Combined Proxy Group Mean					0.89				12.50%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, at 2; Blue Chip Financial Forecasts, Vol. 43, No. 6, at 14.
[2] Source: Value Line, as of October 31, 2024
[3] Source: Bloomberg Professional, as of October 31, 2024
[4] Equals Average of [2], [3]
[5] Equals Value Line expected market return
[6] Source: Kroll, arithmetic average Market Return 1926-2023
[7] Equals Average ([5],[6]) - [1]
[8] Equals [1] + [4] x [7]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE, HISTORICAL MARKET RETURN

$K = Rf + \beta\ (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	30-day average of 30-year U.S. Treasury bond yield	Value Line Beta (β)	Bloomberg Beta (β)	Average Beta (β)	Long Term Historical Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
Atmos Energy Corporation	ATO	4.30%	0.85	0.83	0.84	12.04%	7.74%	10.79%
New Jersey Resources Corporation	NJR	4.30%	1.00	0.84	0.92	12.04%	7.74%	11.42%
NiSource Inc.	NI	4.30%	0.95	0.88	0.91	12.04%	7.74%	11.36%
ONE Gas, Inc.	OGS	4.30%	0.85	0.83	0.84	12.04%	7.74%	10.80%
Southwest Gas Holdings, Inc.	SWX	4.30%	0.90	0.92	0.91	12.04%	7.74%	11.32%
Spire, Inc.	SR	4.30%	0.85	0.84	0.85	12.04%	7.74%	10.85%
Ameren Corporation	AEE	4.30%	0.90	0.82	0.86	12.04%	7.74%	10.97%
Avista Corporation	AVA	4.30%	0.95	0.82	0.89	12.04%	7.74%	11.16%
Black Hills Corporation	BKH	4.30%	1.05	1.01	1.03	12.04%	7.74%	12.29%
CMS Energy Corporation	CMS	4.30%	0.85	0.83	0.84	12.04%	7.74%	10.81%
Consolidated Edison, Inc.	ED	4.30%	0.80	0.69	0.74	12.04%	7.74%	10.07%
DTE Energy Company	DTE	4.30%	1.00	0.93	0.96	12.04%	7.74%	11.76%
Public Service Enterprise Group Inc.	PEG	4.30%	0.95	0.94	0.95	12.04%	7.74%	11.63%
The Southern Company	SO	4.30%	0.95	0.88	0.92	12.04%	7.74%	11.38%
WEC Energy Group, Inc.	WEC	4.30%	0.85	0.82	0.83	12.04%	7.74%	10.75%
Gas Proxy Group Mean					0.88			11.09%
Combined Proxy Group Mean					0.89			11.16%

Notes:
[1] Source: Bloomberg Professional, as of October 31, 2024
[2] Source: Value Line, as of October 31, 2024
[3] Source: Bloomberg Professional, as of October 31, 2024
[4] Equals Average of [2], [3]
[5] Source: Kroll, arithmetic average Market Return 1926-2023
[6] Equals [5] - [1]
[7] Equals [1] + [4] x [6]

CAPITAL ASSET PRICING MODEL -- PROJECTED RISK-FREE RATE, HISTORICAL MARKET RETURN
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-Year U.S. Treasury Bond Yield	[2] Value Line Beta (β)	[3] Bloomberg Beta (β)	[4] Average Beta (β)	[5] Long Term Historical Market Return (Rm)	[6] Market Risk Premium (Rm − Rf)	[7] ROE (K)
Atmos Energy Corporation	ATO	4.28%	0.85	0.83	0.84	12.04%	7.76%	10.78%
New Jersey Resources Corporation	NJR	4.28%	1.00	0.84	0.92	12.04%	7.76%	11.42%
NiSource Inc.	NI	4.28%	0.95	0.88	0.91	12.04%	7.76%	11.36%
ONE Gas, Inc.	OGS	4.28%	0.85	0.83	0.84	12.04%	7.76%	10.80%
Southwest Gas Holdings, Inc.	SWX	4.28%	0.90	0.92	0.91	12.04%	7.76%	11.32%
Spire, Inc.	SR	4.28%	0.85	0.84	0.85	12.04%	7.76%	10.84%
Ameren Corporation	AEE	4.28%	0.90	0.82	0.86	12.04%	7.76%	10.97%
Avista Corporation	AVA	4.28%	0.95	0.82	0.89	12.04%	7.76%	11.16%
Black Hills Corporation	BKH	4.28%	1.05	1.01	1.03	12.04%	7.76%	12.29%
CMS Energy Corporation	CMS	4.28%	0.85	0.83	0.84	12.04%	7.76%	10.81%
Consolidated Edison, Inc.	ED	4.28%	0.80	0.69	0.74	12.04%	7.76%	10.06%
DTE Energy Company	DTE	4.28%	1.00	0.93	0.96	12.04%	7.76%	11.76%
Public Service Enterprise Group Inc.	PEG	4.28%	0.95	0.94	0.95	12.04%	7.76%	11.63%
The Southern Company	SO	4.28%	0.95	0.88	0.92	12.04%	7.76%	11.38%
WEC Energy Group, Inc.	WEC	4.28%	0.85	0.82	0.83	12.04%	7.76%	10.74%
Gas Proxy Group Mean					0.88			11.09%
Combined Proxy Group Mean					0.89			11.15%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 43, No. 11, at 2; Blue Chip Financial Forecasts, Vol. 43, No. 6, at 14.
[2] Source: Value Line, as of October 31, 2024
[3] Source: Bloomberg Professional, as of October 31, 2024
[4] Equals Average of [2], [3]
[5] Source: Kroll, arithmetic average Market Return 1926-2023
[6] Equals [5] - [1]
[7] Equals [1] + [4] x [6]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 408

December 30, 2024

MARKET RISK PREMIUM DERIVED FROM S&P EARNINGS AND ESTIMATE REPORT

[1] S&P's estimate of the S&P 500 Dividend Yield	1.31%
[2] S&P's estimate of the S&P 500 Growth Rate	15.01%
[3] S&P 500 Estimated Required Market Return	16.42%

Notes:
[1] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report,October 31, 2024
[2] Source: S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report, October 31, 2024
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Expected Market Return
Market DCF Based Method - Bloomberg EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.33%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	14.51%
[3] Market Cap. Weighted Estimated Required Market Return	15.93%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$37,442	0.08%	0.72%	5.65%	0.0006%	0.0044%
Apple Inc	AAPL	$3,434,767	7.11%	0.44%	7.80%	0.0315%	0.5543%
AbbVie Inc	ABBV	$360,105	0.75%	3.22%	9.94%	0.0240%	0.0741%
Airbnb Inc	ABNB	$59,308	0.12%	0.00%	19.84%	0.0000%	0.0244%
Abbott Laboratories	ABT	$196,635	0.41%	1.94%	8.15%	0.0079%	0.0332%
Arch Capital Group Ltd	ACGL	$37,064	0.08%	0.00%	7.68%	0.0000%	0.0059%
Accenture PLC	ACN	$215,990	0.45%	1.72%	8.18%	0.0077%	0.0366%
Adobe Inc	ADBE	$210,451	0.44%	0.00%	16.34%	0.0000%	0.0712%
Analog Devices Inc	ADI	$110,773	0.23%	1.65%	-5.82%	0.0038%	-0.0133%
Archer-Daniels-Midland Co	ADM	$26,398	0.05%	3.62%	-4.65%	0.0020%	-0.0025%
Automatic Data Processing Inc	ADP	$117,960	0.24%	1.94%	9.10%	0.0047%	0.0222%
Autodesk Inc	ADSK	$61,017	0.13%	0.00%	23.62%	0.0000%	0.0298%
Ameren Corp	AEE	$23,216	0.05%	3.08%	6.08%	0.0015%	0.0029%
American Electric Power Co Inc	AEP	$52,547	0.11%	3.77%	6.50%	0.0041%	0.0071%
AES Corp/The	AES	n/a	n/a	4.18%	n/a	n/a	n/a
Aflac Inc	AFL	$58,685	0.12%	1.91%	9.37%	0.0023%	0.0114%
American International Group Inc	AIG	$48,863	0.10%	2.11%	11.96%	0.0021%	0.0121%
Assurant Inc	AIZ	$9,929	0.02%	1.50%	6.67%	0.0003%	0.0014%
Arthur J Gallagher & Co	AJG	$61,695	0.13%	0.85%	12.81%	0.0011%	0.0164%
Akamai Technologies Inc	AKAM	$15,316	0.03%	0.00%	6.12%	0.0000%	0.0019%
Albemarle Corp	ALB	$11,134	0.02%	1.71%	34.69%	0.0004%	0.0080%
Align Technology Inc	ALGN	$15,315	0.03%	0.00%	5.19%	0.0000%	0.0016%
Allstate Corp/The	ALL	$49,391	0.10%	1.97%	168.00%	0.0020%	0.1718%
Allegion plc	ALLE	$12,138	0.03%	1.38%	8.33%	0.0003%	0.0021%
Applied Materials Inc	AMAT	$149,695	0.31%	0.88%	8.53%	0.0027%	0.0264%
Amcor PLC	AMCR	$16,087	0.03%	4.58%	4.76%	0.0015%	0.0016%
Advanced Micro Devices Inc	AMD	$233,798	0.48%	0.00%	34.44%	0.0000%	0.1667%
AMETEK Inc	AME	$42,408	0.09%	0.61%	7.34%	0.0005%	0.0064%
Amgen Inc	AMGN	$172,097	0.36%	2.81%	4.81%	0.0100%	0.0171%
Ameriprise Financial Inc	AMP	$50,106	0.10%	1.16%	16.72%	0.0012%	0.0173%
American Tower Corp	AMT	$99,785	0.21%	3.03%	12.68%	0.0063%	0.0262%
Amentum Holdings Inc	AMTM	n/a	n/a	0.00%	n/a	n/a	n/a
Amazon.com Inc	AMZN	$1,956,374	4.05%	0.00%	35.45%	0.0000%	1.4358%
Arista Networks Inc	ANET	$121,401	0.25%	0.00%	17.60%	0.0000%	0.0442%
ANSYS Inc	ANSS	n/a	n/a	0.00%	n/a	n/a	n/a
Aon PLC	AON	$79,342	0.16%	0.74%	11.18%	0.0012%	0.0184%
A O Smith Corp	AOS	n/a	n/a	1.81%	n/a	n/a	n/a
APA Corp	APA	$8,730	0.02%	4.24%	-8.02%	0.0008%	-0.0014%
Air Products and Chemicals Inc	APD	$69,035	0.14%	2.28%	9.54%	0.0033%	0.0136%
Amphenol Corp	APH	$80,800	0.17%	0.98%	18.77%	0.0016%	0.0314%
Aptiv PLC	APTV	$13,357	0.03%	0.00%	17.02%	0.0000%	0.0047%
Alexandria Real Estate Equities Inc	ARE	$19,495	0.04%	4.66%	2.82%	0.0019%	0.0011%
Atmos Energy Corp	ATO	n/a	n/a	2.32%	n/a	n/a	n/a
AvalonBay Communities Inc	AVB	$31,517	0.07%	3.07%	4.93%	0.0020%	0.0032%
Broadcom Inc	AVGO	$792,924	1.64%	1.25%	16.94%	0.0205%	0.2781%
Avery Dennison Corp	AVY	$16,634	0.03%	1.70%	13.82%	0.0006%	0.0048%
American Water Works Co Inc	AWK	$26,917	0.06%	2.22%	7.89%	0.0012%	0.0044%
Axon Enterprise Inc	AXON	$32,006	0.07%	0.00%	21.90%	0.0000%	0.0145%
American Express Co	AXP	$190,257	0.39%	1.04%	15.54%	0.0041%	0.0612%
AutoZone Inc	AZO	$50,865	0.11%	0.00%	13.50%	0.0000%	0.0142%
Boeing Co/The	BA	$109,040	0.23%	0.00%	34.61%	0.0000%	0.0781%
Bank of America Corp	BAC	$320,880	0.66%	2.49%	5.00%	0.0165%	0.0332%
Ball Corp	BALL	$17,682	0.04%	1.35%	12.66%	0.0005%	0.0046%
Baxter International Inc	BAX	$18,213	0.04%	3.25%	3.50%	0.0012%	0.0013%
Best Buy Co Inc	BBY	$19,418	0.04%	4.16%	4.17%	0.0017%	0.0017%
Becton Dickinson & Co	BDX	$67,517	0.14%	1.63%	8.34%	0.0023%	0.0117%
Franklin Resources Inc	BEN	$10,863	0.02%	5.97%	1.00%	0.0013%	0.0002%
Brown-Forman Corp	BF/B	$13,365	0.03%	1.98%	-2.38%	0.0005%	-0.0007%
Bunge Global SA	BG	$11,731	0.02%	3.24%	-8.59%	0.0008%	-0.0021%
Biogen Inc	BIIB	$25,355	0.05%	0.00%	5.62%	0.0000%	0.0030%
Bank of New York Mellon Corp/The	BK	$55,612	0.12%	2.49%	12.10%	0.0029%	0.0139%
Booking Holdings Inc	BKNG	$154,768	0.32%	0.75%	15.98%	0.0024%	0.0512%
Baker Hughes Co	BKR	$37,681	0.08%	2.21%	25.86%	0.0017%	0.0202%
Builders FirstSource Inc	BLDR	$19,960	0.04%	0.00%	1.45%	0.0000%	0.0006%
Blackrock Inc	BLK	$145,318	0.30%	2.08%	12.51%	0.0063%	0.0376%
Bristol-Myers Squibb Co	BMY	$113,111	0.23%	4.30%	-0.51%	0.0101%	-0.0012%
Broadridge Financial Solutions Inc	BR	n/a	n/a	1.67%	n/a	n/a	n/a
Berkshire Hathaway Inc	BRK/B	n/a	n/a	0.00%	n/a	n/a	n/a
Brown & Brown Inc	BRO	$29,923	0.06%	0.57%	11.31%	0.0004%	0.0070%
Boston Scientific Corp	BSX	$123,730	0.26%	0.00%	12.64%	0.0000%	0.0324%
BorgWarner Inc	BWA	$7,355	0.02%	1.31%	5.11%	0.0002%	0.0008%
Blackstone Inc	BX	$120,793	0.25%	2.05%	22.49%	0.0051%	0.0562%
BXP Inc	BXP	$12,723	0.03%	4.87%	0.90%	0.0013%	0.0002%
Citigroup Inc	C	$122,423	0.25%	3.49%	26.39%	0.0088%	0.0669%
Conagra Brands Inc	CAG	$13,812	0.03%	4.84%	0.62%	0.0014%	0.0002%
Cardinal Health Inc	CAH	$26,258	0.05%	1.86%	9.84%	0.0010%	0.0053%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Carrier Global Corp	CARR	$65,246	0.14%	1.05%	12.25%	0.0014%	0.0165%
Caterpillar Inc	CAT	$182,419	0.38%	1.50%	7.02%	0.0057%	0.0265%
Chubb Ltd	CB	$113,851	0.24%	1.29%	1.99%	0.0030%	0.0047%
Cboe Global Markets Inc	CBOE	$22,347	0.05%	1.18%	13.91%	0.0005%	0.0064%
CBRE Group Inc	CBRE	n/a	n/a	0.00%	n/a	n/a	n/a
Crown Castle Inc	CCI	$46,715	0.10%	5.82%	2.22%	0.0056%	0.0021%
Carnival Corp	CCL	n/a	n/a	0.00%	n/a	n/a	n/a
Cadence Design Systems Inc	CDNS	$75,729	0.16%	0.00%	15.52%	0.0000%	0.0243%
CDW Corp/DE	CDW	$25,084	0.05%	1.33%	3.96%	0.0007%	0.0021%
Celanese Corp	CE	$13,764	0.03%	2.22%	-0.12%	0.0006%	0.0000%
Constellation Energy Corp	CEG	$82,864	0.17%	0.54%	24.61%	0.0009%	0.0422%
CF Industries Holdings Inc	CF	$14,310	0.03%	2.43%	-9.54%	0.0007%	-0.0028%
Citizens Financial Group Inc	CFG	n/a	n/a	3.99%	n/a	n/a	n/a
Church & Dwight Co Inc	CHD	$24,459	0.05%	1.14%	7.35%	0.0006%	0.0037%
CH Robinson Worldwide Inc	CHRW	$12,085	0.03%	2.41%	18.95%	0.0006%	0.0047%
Charter Communications Inc	CHTR	$46,763	0.10%	0.00%	7.07%	0.0000%	0.0068%
Cigna Group/The	CI	$87,565	0.18%	1.78%	11.65%	0.0032%	0.0211%
Cincinnati Financial Corp	CINF	$22,014	0.05%	2.30%	8.30%	0.0010%	0.0038%
Colgate-Palmolive Co	CL	$76,562	0.16%	2.13%	8.23%	0.0034%	0.0130%
Clorox Co/The	CLX	$19,625	0.04%	3.08%	10.56%	0.0013%	0.0043%
Comcast Corp	CMCSA	$166,693	0.35%	2.84%	8.31%	0.0098%	0.0287%
CME Group Inc	CME	$81,151	0.17%	2.04%	3.55%	0.0034%	0.0060%
Chipotle Mexican Grill Inc	CMG	$75,992	0.16%	0.00%	22.88%	0.0000%	0.0360%
Cummins Inc	CMI	$45,086	0.09%	2.21%	8.28%	0.0021%	0.0077%
CMS Energy Corp	CMS	$20,798	0.04%	2.96%	7.41%	0.0013%	0.0032%
Centene Corp	CNC	$31,433	0.07%	0.00%	4.18%	0.0000%	0.0027%
CenterPoint Energy Inc	CNP	$19,245	0.04%	2.84%	8.01%	0.0011%	0.0032%
Capital One Financial Corp	COF	$62,106	0.13%	1.47%	14.01%	0.0019%	0.0180%
Cooper Cos Inc/The	COO	$20,848	0.04%	0.00%	12.43%	0.0000%	0.0054%
ConocoPhillips	COP	$126,071	0.26%	2.85%	5.43%	0.0074%	0.0142%
Cencora Inc	COR	$44,706	0.09%	0.89%	9.84%	0.0008%	0.0091%
Costco Wholesale Corp	COST	$387,326	0.80%	0.53%	9.88%	0.0043%	0.0792%
Corpay Inc	CPAY	$22,893	0.05%	0.00%	14.77%	0.0000%	0.0070%
Campbell Soup Co	CPB	$13,884	0.03%	3.17%	5.71%	0.0009%	0.0016%
Copart Inc	CPRT	n/a	n/a	0.00%	n/a	n/a	n/a
Camden Property Trust	CPT	$12,347	0.03%	3.56%	1.87%	0.0009%	0.0005%
Charles River Laboratories Internation	CRL	$9,220	0.02%	0.00%	2.59%	0.0000%	0.0005%
Salesforce Inc	CRM	$278,550	0.58%	0.55%	17.52%	0.0032%	0.1010%
Crowdstrike Holdings Inc	CRWD	$69,087	0.14%	0.00%	35.70%	0.0000%	0.0511%
Cisco Systems Inc	CSCO	$218,314	0.45%	2.92%	3.40%	0.0132%	0.0153%
CoStar Group Inc	CSGP	n/a	n/a	0.00%	n/a	n/a	n/a
CSX Corp	CSX	$64,872	0.13%	1.43%	7.56%	0.0019%	0.0101%
Cintas Corp	CTAS	$83,003	0.17%	0.76%	12.00%	0.0013%	0.0206%
Catalent Inc	CTLT	n/a	n/a	0.00%	n/a	n/a	n/a
Coterra Energy Inc	CTRA	$17,683	0.04%	3.51%	7.68%	0.0013%	0.0028%
Cognizant Technology Solutions Corp	CTSH	$36,984	0.08%	1.61%	6.40%	0.0012%	0.0049%
Corteva Inc	CTVA	$42,172	0.09%	1.12%	10.33%	0.0010%	0.0090%
CVS Health Corp	CVS	$71,025	0.15%	4.71%	1.82%	0.0069%	0.0027%
Chevron Corp	CVX	$272,179	0.56%	4.38%	5.22%	0.0247%	0.0294%
Caesars Entertainment Inc	CZR	n/a	n/a	0.00%	n/a	n/a	n/a
Dominion Energy Inc	D	$49,942	0.10%	4.49%	26.86%	0.0046%	0.0278%
Delta Air Lines Inc	DAL	$36,923	0.08%	1.05%	8.76%	0.0008%	0.0067%
Dayforce Inc	DAY	n/a	n/a	0.00%	n/a	n/a	n/a
DuPont de Nemours Inc	DD	$34,648	0.07%	1.83%	2.50%	0.0013%	0.0018%
Deere & Co	DE	n/a	n/a	1.45%	n/a	n/a	n/a
Deckers Outdoor Corp	DECK	$24,443	0.05%	0.00%	10.50%	0.0000%	0.0053%
Dell Technologies Inc	DELL	$41,277	0.09%	1.44%	9.83%	0.0012%	0.0084%
Discover Financial Services	DFS	$37,267	0.08%	1.89%	11.69%	0.0015%	0.0090%
Dollar General Corp	DG	$17,602	0.04%	2.95%	-7.74%	0.0011%	-0.0028%
Quest Diagnostics Inc	DGX	$17,281	0.04%	1.94%	6.56%	0.0007%	0.0023%
DR Horton Inc	DHI	$55,101	0.11%	0.95%	9.24%	0.0011%	0.0105%
Danaher Corp	DHR	$177,434	0.37%	0.44%	0.85%	0.0016%	0.0031%
Walt Disney Co/The	DIS	$174,467	0.36%	0.94%	17.39%	0.0034%	0.0628%
Digital Realty Trust Inc	DLR	$58,354	0.12%	2.74%	3.14%	0.0033%	0.0038%
Dollar Tree Inc	DLTR	$13,897	0.03%	0.00%	6.86%	0.0000%	0.0020%
Healthpeak Properties Inc	DOC	$15,702	0.03%	5.35%	4.99%	0.0017%	0.0016%
Dover Corp	DOV	$25,975	0.05%	1.09%	9.23%	0.0006%	0.0050%
Dow Inc	DOW	$34,571	0.07%	5.67%	-4.83%	0.0041%	-0.0035%
Domino's Pizza Inc	DPZ	$14,287	0.03%	1.46%	11.05%	0.0004%	0.0033%
Darden Restaurants Inc	DRI	$18,802	0.04%	3.50%	9.75%	0.0014%	0.0038%
DTE Energy Co	DTE	$25,704	0.05%	3.28%	10.65%	0.0017%	0.0057%
Duke Energy Corp	DUK	$88,873	0.18%	3.63%	6.70%	0.0067%	0.0123%
DaVita Inc	DVA	$11,464	0.02%	0.00%	17.90%	0.0000%	0.0042%
Devon Energy Corp	DVN	$24,221	0.05%	2.28%	6.60%	0.0011%	0.0033%
Dexcom Inc	DXCM	$27,529	0.06%	0.00%	20.11%	0.0000%	0.0115%
Electronic Arts Inc	EA	$39,855	0.08%	0.50%	12.85%	0.0004%	0.0106%
eBay Inc	EBAY	$27,547	0.06%	1.88%	9.96%	0.0011%	0.0057%
Ecolab Inc	ECL	$69,581	0.14%	0.93%	15.97%	0.0013%	0.0230%
Consolidated Edison Inc	ED	$35,196	0.07%	3.27%	4.79%	0.0024%	0.0035%
Equifax Inc	EFX	$32,850	0.07%	0.59%	22.00%	0.0004%	0.0150%
Everest Group Ltd	EG	$15,389	0.03%	2.25%	-1.39%	0.0007%	-0.0004%
Edison International	EIX	$31,901	0.07%	3.79%	7.90%	0.0025%	0.0052%
Estee Lauder Cos Inc/The	EL	$16,093	0.03%	2.03%	14.58%	0.0007%	0.0049%
Elevance Health Inc	ELV	$94,105	0.19%	1.61%	11.90%	0.0031%	0.0232%
Eastman Chemical Co	EMN	$12,281	0.03%	3.08%	6.10%	0.0008%	0.0015%
Emerson Electric Co	EMR	$62,006	0.13%	1.94%	14.81%	0.0025%	0.0190%
Enphase Energy Inc	ENPH	$11,219	0.02%	0.00%	4.56%	0.0000%	0.0011%
EOG Resources Inc	EOG	$69,346	0.14%	2.98%	6.14%	0.0043%	0.0088%
EPAM Systems Inc	EPAM	$10,741	0.02%	0.00%	5.29%	0.0000%	0.0012%
Equinix Inc	EQIX	$87,619	0.18%	1.88%	14.22%	0.0034%	0.0258%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Equity Residential	EQR	$26,680	0.06%	3.84%	2.83%	0.0021%	0.0016%
EQT Corp	EQT	$21,803	0.05%	1.72%	5.06%	0.0008%	0.0023%
Erie Indemnity Co	ERIE	n/a	n/a	1.14%	n/a	n/a	n/a
Eversource Energy	ES	$23,534	0.05%	4.34%	5.73%	0.0021%	0.0028%
Essex Property Trust Inc	ESS	$18,243	0.04%	3.45%	3.49%	0.0013%	0.0013%
Eaton Corp PLC	ETN	$131,040	0.27%	1.13%	14.60%	0.0031%	0.0396%
Entergy Corp	ETR	$33,097	0.07%	3.10%	6.67%	0.0021%	0.0046%
Evergy Inc	EVRG	$13,886	0.03%	4.25%	5.35%	0.0012%	0.0015%
Edwards Lifesciences Corp	EW	$40,367	0.08%	0.00%	6.86%	0.0000%	0.0057%
Exelon Corp	EXC	$39,490	0.08%	3.87%	5.48%	0.0032%	0.0045%
Expeditors International of Washingtor	EXPD	$16,794	0.03%	1.23%	4.70%	0.0004%	0.0016%
Expedia Group Inc	EXPE	$19,485	0.04%	0.00%	22.44%	0.0000%	0.0091%
Extra Space Storage Inc	EXR	$34,608	0.07%	3.97%	-0.20%	0.0028%	-0.0001%
Ford Motor Co	F	$40,166	0.08%	5.83%	-2.97%	0.0048%	-0.0025%
Diamondback Energy Inc	FANG	$52,270	0.11%	5.30%	8.34%	0.0057%	0.0090%
Fastenal Co	FAST	$44,788	0.09%	2.00%	7.79%	0.0019%	0.0072%
Freeport-McMoRan Inc	FCX	$64,687	0.13%	1.33%	15.37%	0.0018%	0.0206%
FactSet Research Systems Inc	FDS	$17,249	0.04%	0.92%	9.00%	0.0003%	0.0032%
FedEx Corp	FDX	$66,908	0.14%	2.02%	12.33%	0.0028%	0.0171%
FirstEnergy Corp	FE	$24,107	0.05%	4.06%	6.11%	0.0020%	0.0030%
F5 Inc	FFIV	$13,632	0.03%	0.00%	6.72%	0.0000%	0.0019%
Fiserv Inc	FI	$112,589	0.23%	0.00%	11.99%	0.0000%	0.0279%
Fair Isaac Corp	FICO	$48,869	0.10%	0.00%	27.00%	0.0000%	0.0273%
Fidelity National Information Services I	FIS	$48,954	0.10%	1.60%	22.20%	0.0016%	0.0225%
Fifth Third Bancorp	FITB	$29,563	0.06%	3.39%	25.00%	0.0021%	0.0153%
FMC Corp	FMC	$8,113	0.02%	3.57%	14.67%	0.0006%	0.0025%
Fox Corp	FOX	$9,178	0.02%	1.39%	8.68%	0.0003%	0.0016%
Fox Corp	FOXA	$9,435	0.02%	1.29%	8.68%	0.0003%	0.0017%
Federal Realty Investment Trust	FRT	$9,417	0.02%	3.97%	4.97%	0.0008%	0.0010%
First Solar Inc	FSLR	$20,821	0.04%	0.00%	41.38%	0.0000%	0.0178%
Fortinet Inc	FTNT	$60,168	0.12%	0.00%	8.66%	0.0000%	0.0108%
Fortive Corp	FTV	$24,783	0.05%	0.45%	10.74%	0.0002%	0.0055%
General Dynamics Corp	GD	$80,184	0.17%	1.95%	14.58%	0.0032%	0.0242%
GoDaddy Inc	GDDY	n/a	n/a	0.00%	n/a	n/a	n/a
General Electric Co	GE	$185,916	0.38%	0.65%	30.30%	0.0025%	0.1166%
GE HealthCare Technologies Inc	GEHC	$39,908	0.08%	0.14%	10.24%	0.0001%	0.0085%
Gen Digital Inc	GEN	$17,938	0.04%	1.72%	6.77%	0.0006%	0.0025%
GE Vernova Inc	GEV	$83,153	0.17%	0.00%	81.12%	0.0000%	0.1396%
Gilead Sciences Inc	GILD	$110,580	0.23%	3.47%	18.59%	0.0079%	0.0426%
General Mills Inc	GIS	$37,762	0.08%	3.53%	2.45%	0.0028%	0.0019%
Globe Life Inc	GL	$9,485	0.02%	0.91%	6.00%	0.0002%	0.0012%
Corning Inc	GLW	$40,723	0.08%	2.35%	16.38%	0.0020%	0.0138%
General Motors Co	GM	$55,815	0.12%	0.95%	7.21%	0.0011%	0.0083%
Generac Holdings Inc	GNRC	$9,958	0.02%	0.00%	7.00%	0.0000%	0.0014%
Alphabet Inc	GOOG	$955,666	1.98%	0.46%	16.07%	0.0092%	0.3179%
Alphabet Inc	GOOGL	$999,796	2.07%	0.47%	16.07%	0.0097%	0.3326%
Genuine Parts Co	GPC	n/a	n/a	3.49%	n/a	n/a	n/a
Global Payments Inc	GPN	$26,394	0.05%	0.96%	9.02%	0.0005%	0.0049%
Garmin Ltd	GRMN	$38,088	0.08%	1.51%	9.55%	0.0012%	0.0075%
Goldman Sachs Group Inc/The	GS	$163,518	0.34%	2.32%	14.95%	0.0078%	0.0506%
WW Grainger Inc	GWW	$54,020	0.11%	0.74%	5.52%	0.0008%	0.0062%
Halliburton Co	HAL	$24,490	0.05%	2.45%	5.94%	0.0012%	0.0030%
Hasbro Inc	HAS	$9,155	0.02%	4.27%	27.48%	0.0008%	0.0052%
Huntington Bancshares Inc/OH	HBAN	$22,649	0.05%	3.98%	3.45%	0.0019%	0.0016%
HCA Healthcare Inc	HCA	$90,868	0.19%	0.74%	10.84%	0.0014%	0.0204%
Home Depot Inc/The	HD	$391,109	0.81%	2.29%	3.87%	0.0185%	0.0313%
Hess Corp	HES	$41,435	0.09%	1.49%	24.00%	0.0013%	0.0206%
Hartford Financial Services Group Inc/	HIG	$32,016	0.07%	1.88%	12.07%	0.0012%	0.0080%
Huntington Ingalls Industries Inc	HII	$7,237	0.01%	2.92%	7.62%	0.0004%	0.0011%
Hilton Worldwide Holdings Inc	HLT	$57,252	0.12%	0.26%	12.62%	0.0003%	0.0150%
Hologic Inc	HOLX	$18,784	0.04%	0.00%	8.17%	0.0000%	0.0032%
Honeywell International Inc	HON	$133,743	0.28%	2.20%	7.58%	0.0061%	0.0210%
Hewlett Packard Enterprise Co	HPE	$25,311	0.05%	2.67%	4.21%	0.0014%	0.0022%
HP Inc	HPQ	$34,231	0.07%	3.10%	1.05%	0.0022%	0.0007%
Hormel Foods Corp	HRL	$16,753	0.03%	3.70%	6.23%	0.0013%	0.0022%
Henry Schein Inc	HSIC	$8,899	0.02%	0.00%	8.51%	0.0000%	0.0016%
Host Hotels & Resorts Inc	HST	$12,110	0.03%	4.64%	-2.34%	0.0012%	-0.0006%
Hershey Co/The	HSY	$26,224	0.05%	3.09%	-2.09%	0.0017%	-0.0011%
Hubbell Inc	HUBB	$22,919	0.05%	1.24%	18.00%	0.0006%	0.0085%
Humana Inc	HUM	$31,046	0.06%	1.37%	-8.82%	0.0009%	-0.0057%
Howmet Aerospace Inc	HWM	$40,700	0.08%	0.32%	22.11%	0.0003%	0.0186%
International Business Machines Corp	IBM	$191,143	0.40%	3.23%	3.80%	0.0128%	0.0150%
Intercontinental Exchange Inc	ICE	$89,497	0.19%	1.15%	11.26%	0.0021%	0.0209%
IDEXX Laboratories Inc	IDXX	$33,321	0.07%	0.00%	9.75%	0.0000%	0.0067%
IDEX Corp	IEX	n/a	n/a	1.29%	n/a	n/a	n/a
International Flavors & Fragrances Inc	IFF	$25,420	0.05%	1.61%	2.12%	0.0008%	0.0011%
Incyte Corp	INCY	$14,279	0.03%	0.00%	39.79%	0.0000%	0.0118%
Intel Corp	INTC	$92,020	0.19%	0.00%	4.26%	0.0000%	0.0081%
Intuit Inc	INTU	$171,062	0.35%	0.68%	18.79%	0.0024%	0.0665%
Invitation Homes Inc	INVH	$19,242	0.04%	3.57%	4.16%	0.0014%	0.0017%
International Paper Co	IP	$19,293	0.04%	3.33%	-2.00%	0.0013%	-0.0008%
Interpublic Group of Cos Inc/The	IPG	$10,952	0.02%	4.49%	2.12%	0.0010%	0.0005%
IQVIA Holdings Inc	IQV	$37,356	0.08%	0.00%	10.03%	0.0000%	0.0078%
Ingersoll Rand Inc	IR	n/a	n/a	0.08%	n/a	n/a	n/a
Iron Mountain Inc	IRM	n/a	n/a	2.31%	n/a	n/a	n/a
Intuitive Surgical Inc	ISRG	$179,457	0.37%	0.00%	18.85%	0.0000%	0.0700%
Gartner Inc	IT	$38,723	0.08%	0.00%	7.00%	0.0000%	0.0056%
Illinois Tool Works Inc	ITW	$77,112	0.16%	2.30%	7.08%	0.0037%	0.0113%
Invesco Ltd	IVZ	$7,793	0.02%	4.73%	12.44%	0.0008%	0.0020%
Jacobs Solutions Inc	J	n/a	n/a	0.83%	n/a	n/a	n/a

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
JB Hunt Transport Services Inc	JBHT	$18,212	0.04%	0.95%	10.25%	0.0004%	0.0039%
Jabil Inc	JBL	$13,890	0.03%	0.26%	10.82%	0.0001%	0.0031%
Johnson Controls International plc	JCI	$50,468	0.10%	1.96%	9.26%	0.0020%	0.0097%
Jack Henry & Associates Inc	JKHY	$13,266	0.03%	1.21%	9.73%	0.0003%	0.0027%
Johnson & Johnson	JNJ	$384,883	0.80%	3.10%	3.67%	0.0247%	0.0292%
Juniper Networks Inc	JNPR	$12,879	0.03%	2.26%	4.78%	0.0006%	0.0013%
JPMorgan Chase & Co	JPM	$624,780	1.29%	2.25%	2.80%	0.0291%	0.0362%
Kellanova	K	$27,800	0.06%	2.83%	9.21%	0.0016%	0.0053%
Keurig Dr Pepper Inc	KDP	$44,695	0.09%	2.79%	6.73%	0.0026%	0.0062%
KeyCorp	KEY	$17,099	0.04%	4.75%	20.00%	0.0017%	0.0071%
Keysight Technologies Inc	KEYS	$25,860	0.05%	0.00%	-1.19%	0.0000%	-0.0006%
Kraft Heinz Co/The	KHC	$40,459	0.08%	4.78%	1.87%	0.0040%	0.0016%
Kimco Realty Corp	KIM	$15,990	0.03%	4.22%	2.82%	0.0014%	0.0009%
KKR & Co Inc	KKR	$122,680	0.25%	0.51%	29.00%	0.0013%	0.0737%
KLA Corp	KLAC	$89,115	0.18%	0.87%	13.36%	0.0016%	0.0246%
Kimberly-Clark Corp	KMB	$44,747	0.09%	3.64%	8.06%	0.0034%	0.0075%
Kinder Morgan Inc	KMI	$54,452	0.11%	4.69%	7.29%	0.0053%	0.0082%
CarMax Inc	KMX	$11,213	0.02%	0.00%	17.91%	0.0000%	0.0042%
Coca-Cola Co/The	KO	$281,342	0.58%	2.97%	5.98%	0.0173%	0.0348%
Kroger Co/The	KR	$40,349	0.08%	2.30%	3.11%	0.0019%	0.0026%
Kenvue Inc	KVUE	$43,915	0.09%	3.58%	13.28%	0.0033%	0.0121%
Loews Corp	L	n/a	n/a	0.32%	n/a	n/a	n/a
Leidos Holdings Inc	LDOS	$24,440	0.05%	0.87%	14.26%	0.0004%	0.0072%
Lennar Corp	LEN	$40,669	0.08%	1.17%	9.07%	0.0010%	0.0076%
Labcorp Holdings Inc	LH	$19,092	0.04%	1.26%	8.61%	0.0005%	0.0034%
L3Harris Technologies Inc	LHX	$46,937	0.10%	1.87%	9.00%	0.0018%	0.0087%
Linde PLC	LIN	$217,199	0.45%	1.22%	11.60%	0.0055%	0.0521%
LKQ Corp	LKQ	n/a	n/a	3.26%	n/a	n/a	n/a
Eli Lilly & Co	LLY	$787,685	1.63%	0.63%	31.00%	0.0102%	0.5055%
Lockheed Martin Corp	LMT	$129,433	0.27%	2.42%	2.61%	0.0065%	0.0070%
Alliant Energy Corp	LNT	$15,390	0.03%	3.20%	7.99%	0.0010%	0.0025%
Lowe's Cos Inc	LOW	$148,535	0.31%	1.76%	-0.19%	0.0054%	-0.0006%
Lam Research Corp	LRCX	$95,665	0.20%	1.24%	15.78%	0.0025%	0.0313%
Lululemon Athletica Inc	LULU	$35,051	0.07%	0.00%	7.00%	0.0000%	0.0051%
Southwest Airlines Co	LUV	n/a	n/a	2.35%	n/a	n/a	n/a
Las Vegas Sands Corp	LVS	n/a	n/a	1.54%	n/a	n/a	n/a
Lamb Weston Holdings Inc	LW	$11,078	0.02%	1.85%	0.57%	0.0004%	0.0001%
LyondellBasell Industries NV	LYB	$28,234	0.06%	6.17%	7.76%	0.0036%	0.005%
Live Nation Entertainment Inc	LYV	$27,190	0.06%	0.00%	32.54%	0.0000%	0.0183%
Mastercard Inc	MA	$455,011	0.94%	0.53%	14.76%	0.0050%	0.1390%
Mid-America Apartment Communities I	MAA	$17,689	0.04%	3.89%	0.65%	0.0014%	0.0002%
Marriott International Inc/MD	MAR	$73,202	0.15%	0.97%	4.07%	0.0015%	0.0062%
Masco Corp	MAS	$17,240	0.04%	1.45%	7.54%	0.0005%	0.0027%
McDonald's Corp	MCD	$209,543	0.43%	2.42%	4.77%	0.0105%	0.0207%
Microchip Technology Inc	MCHP	$39,363	0.08%	2.48%	-10.99%	0.0020%	-0.0090%
McKesson Corp	MCK	$64,915	0.13%	0.57%	11.18%	0.0008%	0.0150%
Moody's Corp	MCO	n/a	n/a	0.75%	n/a	n/a	n/a
Mondelez International Inc	MDLZ	$91,571	0.19%	2.75%	6.01%	0.0052%	0.0114%
Medtronic PLC	MDT	$114,460	0.24%	3.14%	5.66%	0.0074%	0.0134%
MetLife Inc	MET	$54,919	0.11%	2.78%	13.14%	0.0032%	0.0149%
Meta Platforms Inc	META	$1,237,325	2.56%	0.35%	21.60%	0.0090%	0.5533%
MGM Resorts International	MGM	$10,978	0.02%	0.00%	5.61%	0.0000%	0.0013%
Mohawk Industries Inc	MHK	$8,475	0.02%	0.00%	2.71%	0.0000%	0.0005%
McCormick & Co Inc/MD	MKC	$19,731	0.04%	2.15%	6.92%	0.0009%	0.0028%
MarketAxess Holdings Inc	MKTX	$10,926	0.02%	1.02%	4.38%	0.0002%	0.0010%
Martin Marietta Materials Inc	MLM	$36,203	0.07%	0.53%	8.39%	0.0004%	0.0063%
Marsh & McLennan Cos Inc	MMC	$107,182	0.22%	1.49%	7.87%	0.0033%	0.0175%
3M Co	MMM	$69,959	0.14%	2.18%	2.03%	0.0032%	0.0029%
Monster Beverage Corp	MNST	$51,602	0.11%	0.00%	10.44%	0.0000%	0.0111%
Altria Group Inc	MO	$92,300	0.19%	7.49%	4.20%	0.0143%	0.0080%
Molina Healthcare Inc	MOH	$18,374	0.04%	0.00%	11.73%	0.0000%	0.0045%
Mosaic Co/The	MOS	$8,527	0.02%	3.14%	-21.74%	0.0006%	-0.0038%
Marathon Petroleum Corp	MPC	$48,686	0.10%	2.50%	-13.72%	0.0025%	-0.0138%
Monolithic Power Systems Inc	MPWR	n/a	n/a	0.66%	n/a	n/a	n/a
Merck & Co Inc	MRK	$259,362	0.54%	3.01%	52.54%	0.0162%	0.2821%
Moderna Inc	MRNA	$20,896	0.04%	0.00%	16.57%	0.0000%	0.0072%
Marathon Oil Corp	MRO	$15,495	0.03%	1.59%	-3.00%	0.0005%	-0.0010%
Morgan Stanley	MS	$188,428	0.39%	3.18%	10.16%	0.0124%	0.0396%
MSCI Inc	MSCI	$44,766	0.09%	1.12%	12.00%	0.0010%	0.0111%
Microsoft Corp	MSFT	$3,021,164	6.25%	0.82%	15.35%	0.0511%	0.9601%
Motorola Solutions Inc	MSI	$74,970	0.16%	0.87%	9.36%	0.0014%	0.0145%
M&T Bank Corp	MTB	$32,512	0.07%	2.77%	5.10%	0.0019%	0.0034%
Match Group Inc	MTCH	$9,292	0.02%	0.00%	36.15%	0.0000%	0.0070%
Mettler-Toledo International Inc	MTD	$27,588	0.06%	0.00%	8.74%	0.0000%	0.0050%
Micron Technology Inc	MU	$110,486	0.23%	0.46%	53.55%	0.0011%	0.1225%
Norwegian Cruise Line Holdings Ltd	NCLH	$11,142	0.02%	0.00%	56.01%	0.0000%	0.0129%
Nasdaq Inc	NDAQ	$42,486	0.09%	1.30%	9.60%	0.0011%	0.0084%
Nordson Corp	NDSN	n/a	n/a	1.26%	n/a	n/a	n/a
NextEra Energy Inc	NEE	$162,970	0.34%	2.60%	8.26%	0.0088%	0.0279%
Newmont Corp	NEM	$51,731	0.11%	2.20%	38.67%	0.0024%	0.0414%
Netflix Inc	NFLX	$323,171	0.67%	0.00%	35.22%	0.0000%	0.2356%
NiSource Inc	NI	$16,412	0.03%	3.01%	7.95%	0.0010%	0.0027%
NIKE Inc	NKE	$91,831	0.19%	1.92%	-1.83%	0.0036%	-0.0035%
Northrop Grumman Corp	NOC	$74,162	0.15%	1.62%	19.22%	0.0025%	0.0295%
ServiceNow Inc	NOW	$192,196	0.40%	0.00%	25.00%	0.0000%	0.0995%
NRG Energy Inc	NRG	$18,657	0.04%	1.80%	5.00%	0.0007%	0.0019%
Norfolk Southern Corp	NSC	$56,657	0.12%	2.16%	9.92%	0.0025%	0.0116%
NetApp Inc	NTAP	$23,613	0.05%	1.80%	5.34%	0.0009%	0.0026%
Northern Trust Corp	NTRS	$19,925	0.04%	2.98%	12.04%	0.0012%	0.0050%
Nucor Corp	NUE	$33,664	0.07%	1.52%	-4.98%	0.0011%	-0.0035%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
NVIDIA Corp	NVDA	$3,256,603	6.74%	0.03%	35.00%	0.0020%	2.3597%
NVR Inc	NVR	$28,169	0.06%	0.00%	9.43%	0.0000%	0.0055%
News Corp	NWS	n/a	n/a	0.69%	n/a	n/a	n/a
News Corp	NWSA	n/a	n/a	0.73%	n/a	n/a	n/a
NXP Semiconductors NV	NXPI	$59,735	0.12%	1.73%	5.89%	0.0021%	0.0073%
Realty Income Corp	O	$51,703	0.11%	5.33%	3.85%	0.0057%	0.0041%
Old Dominion Freight Line Inc	ODFL	$43,142	0.09%	0.52%	6.50%	0.0005%	0.0058%
ONEOK Inc	OKE	$56,596	0.12%	4.09%	4.09%	0.0048%	0.0048%
Omnicom Group Inc	OMC	$19,704	0.04%	2.77%	5.61%	0.0011%	0.0023%
ON Semiconductor Corp	ON	$30,014	0.06%	0.00%	-1.44%	0.0000%	-0.0009%
Oracle Corp	ORCL	$465,095	0.96%	0.95%	11.95%	0.0092%	0.1151%
O'Reilly Automotive Inc	ORLY	$66,889	0.14%	0.00%	9.11%	0.0000%	0.0126%
Otis Worldwide Corp	OTIS	$39,227	0.08%	1.59%	10.00%	0.0013%	0.0081%
Occidental Petroleum Corp	OXY	$45,911	0.10%	1.76%	14.00%	0.0017%	0.0133%
Palo Alto Networks Inc	PANW	$117,829	0.24%	0.00%	11.52%	0.0000%	0.0281%
Paramount Global	PARA	$6,849	0.01%	1.83%	49.00%	0.0003%	0.0069%
Paycom Software Inc	PAYC	$12,053	0.02%	0.72%	10.23%	0.0002%	0.0026%
Paychex Inc	PAYX	$50,145	0.10%	2.81%	6.99%	0.0029%	0.0073%
PACCAR Inc	PCAR	$54,674	0.11%	1.15%	0.48%	0.0013%	0.0005%
PG&E Corp	PCG	$43,219	0.09%	0.20%	9.84%	0.0002%	0.0088%
Public Service Enterprise Group Inc	PEG	$44,541	0.09%	2.68%	6.70%	0.0025%	0.0062%
PepsiCo Inc	PEP	$227,860	0.47%	3.26%	6.26%	0.0154%	0.0295%
Pfizer Inc	PFE	$160,367	0.33%	5.94%	5.68%	0.0197%	0.0188%
Principal Financial Group Inc	PFG	$18,847	0.04%	3.54%	12.60%	0.0014%	0.0049%
Procter & Gamble Co/The	PG	$389,006	0.81%	2.44%	7.37%	0.0196%	0.0593%
Progressive Corp/The	PGR	$142,217	0.29%	0.16%	39.99%	0.0005%	0.1177%
Parker-Hannifin Corp	PH	$81,586	0.17%	1.03%	7.90%	0.0017%	0.0133%
PulteGroup Inc	PHM	$26,564	0.05%	0.62%	8.48%	0.0003%	0.0047%
Packaging Corp of America	PKG	$20,562	0.04%	2.18%	7.85%	0.0009%	0.0033%
Prologis Inc	PLD	$104,572	0.22%	3.40%	4.99%	0.0074%	0.0108%
Palantir Technologies Inc	PLTR	$89,035	0.18%	0.00%	30.06%	0.0000%	0.0554%
Philip Morris International Inc	PM	$206,326	0.43%	4.07%	10.00%	0.0174%	0.0427%
PNC Financial Services Group Inc/The	PNC	$74,837	0.15%	3.40%	18.19%	0.0053%	0.0282%
Pentair PLC	PNR	$16,378	0.03%	0.93%	12.71%	0.0003%	0.0043%
Pinnacle West Capital Corp	PNW	$9,976	0.02%	4.08%	8.22%	0.0008%	0.0017%
Insulet Corp	PODD	$16,234	0.03%	0.00%	20.81%	0.0000%	0.0070%
Pool Corp	POOL	$13,762	0.03%	1.33%	0.20%	0.0004%	0.0001%
PPG Industries Inc	PPG	$28,886	0.06%	2.18%	6.89%	0.0013%	0.0041%
PPL Corp	PPL	$24,022	0.05%	3.16%	7.01%	0.0016%	0.0035%
Prudential Financial Inc	PRU	$43,603	0.09%	4.25%	10.55%	0.0038%	0.0095%
Public Storage	PSA	$57,817	0.12%	3.65%	2.48%	0.0044%	0.0030%
Phillips 66	PSX	$50,310	0.10%	3.78%	-8.14%	0.0039%	-0.0085%
PTC Inc	PTC	$22,265	0.05%	0.00%	14.76%	0.0000%	0.0068%
Quanta Services Inc	PWR	n/a	n/a	0.12%	n/a	n/a	n/a
PayPal Holdings Inc	PYPL	$79,501	0.16%	0.00%	14.76%	0.0000%	0.0243%
QUALCOMM Inc	QCOM	$181,326	0.38%	2.09%	10.64%	0.0078%	0.0399%
Qorvo Inc	QRVO	$6,736	0.01%	0.00%	3.70%	0.0000%	0.0005%
Royal Caribbean Cruises Ltd	RCL	$55,482	0.11%	0.78%	32.53%	0.0009%	0.0374%
Regency Centers Corp	REG	$12,966	0.03%	3.75%	3.79%	0.0010%	0.0010%
Regeneron Pharmaceuticals Inc	REGN	$90,586	0.19%	0.00%	8.67%	0.0000%	0.0163%
Regions Financial Corp	RF	$21,844	0.05%	4.19%	5.52%	0.0019%	0.0025%
Raymond James Financial Inc	RJF	$30,525	0.06%	1.21%	12.11%	0.0008%	0.0077%
Ralph Lauren Corp	RL	$7,929	0.02%	1.67%	11.05%	0.0003%	0.0018%
ResMed Inc	RMD	$35,594	0.07%	0.87%	12.61%	0.0006%	0.0093%
Rockwell Automation Inc	ROK	$30,263	0.06%	1.96%	1.34%	0.0012%	0.0008%
Rollins Inc	ROL	$22,830	0.05%	1.40%	14.00%	0.0007%	0.0066%
Roper Technologies Inc	ROP	n/a	n/a	0.56%	n/a	n/a	n/a
Ross Stores Inc	ROST	$46,354	0.10%	1.05%	8.90%	0.0010%	0.0085%
Republic Services Inc	RSG	$62,004	0.13%	1.17%	11.44%	0.0015%	0.0147%
RTX Corp	RTX	$161,040	0.33%	2.08%	10.62%	0.0069%	0.0354%
Revvity Inc	RVTY	$14,627	0.03%	0.24%	8.82%	0.0001%	0.0027%
SBA Communications Corp	SBAC	$24,662	0.05%	1.71%	23.92%	0.0009%	0.0122%
Starbucks Corp	SBUX	$110,714	0.23%	2.50%	8.81%	0.0057%	0.0202%
Charles Schwab Corp/The	SCHW	$125,967	0.26%	1.41%	8.94%	0.0037%	0.0233%
Sherwin-Williams Co/The	SHW	$90,357	0.19%	0.80%	10.29%	0.0015%	0.0192%
J M Smucker Co/The	SJM	$12,078	0.03%	3.81%	6.07%	0.0010%	0.0015%
Schlumberger NV	SLB	$56,585	0.12%	2.75%	9.17%	0.0032%	0.0107%
Super Micro Computer Inc	SMCI	n/a	n/a	0.00%	n/a	n/a	n/a
Snap-on Inc	SNA	$17,334	0.04%	2.25%	4.81%	0.0008%	0.0017%
Synopsys Inc	SNPS	$78,898	0.16%	0.00%	14.64%	0.0000%	0.0239%
Southern Co/The	SO	$99,644	0.21%	3.16%	8.42%	0.0065%	0.0174%
Solventum Corp	SOLV	$12,535	0.03%	0.00%	-6.20%	0.0000%	-0.0016%
Simon Property Group Inc	SPG	$55,139	0.11%	4.85%	1.37%	0.0055%	0.0016%
S&P Global Inc	SPGI	$152,514	0.32%	0.76%	14.00%	0.0024%	0.0442%
Sempra	SRE	$52,785	0.11%	2.97%	5.35%	0.0033%	0.0058%
STERIS PLC	STE	n/a	n/a	1.03%	n/a	n/a	n/a
Steel Dynamics Inc	STLD	$20,137	0.04%	1.41%	-4.89%	0.0006%	-0.0020%
State Street Corp	STT	$27,204	0.06%	3.28%	10.37%	0.0018%	0.0058%
Seagate Technology Holdings PLC	STX	$21,231	0.04%	2.87%	-11.00%	0.0013%	-0.0048%
Constellation Brands Inc	STZ	$42,178	0.09%	1.74%	10.88%	0.0015%	0.0095%
Smurfit WestRock PLC	SW	$26,783	0.06%	2.35%	1.65%	0.0013%	0.0009%
Stanley Black & Decker Inc	SWK	n/a	n/a	3.53%	n/a	n/a	n/a
Skyworks Solutions Inc	SWKS	$13,988	0.03%	3.20%	-2.57%	0.0009%	-0.0007%
Synchrony Financial	SYF	$21,468	0.04%	1.81%	39.62%	0.0008%	0.0176%
Stryker Corp	SYK	$135,820	0.28%	0.90%	8.61%	0.0025%	0.0242%
Sysco Corp	SYY	$36,817	0.08%	2.72%	7.00%	0.0021%	0.0053%
AT&T Inc	T	$161,731	0.33%	4.92%	1.16%	0.0165%	0.0039%
Molson Coors Beverage Co	TAP	$10,490	0.02%	3.23%	5.29%	0.0007%	0.0011%
TransDigm Group Inc	TDG	$73,074	0.15%	0.00%	19.57%	0.0000%	0.0296%
Teledyne Technologies Inc	TDY	$21,219	0.04%	0.00%	7.34%	0.0000%	0.0032%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Bio-Techne Corp	TECH	$11,702	0.02%	0.43%	5.00%	0.0001%	0.0012%
TE Connectivity PLC	TEL	$44,804	0.09%	1.76%	7.00%	0.0016%	0.0065%
Teradyne Inc	TER	$17,331	0.04%	0.45%	14.60%	0.0002%	0.0052%
Truist Financial Corp	TFC	$57,650	0.12%	4.83%	11.51%	0.0058%	0.0137%
Teleflex Inc	TFX	$9,338	0.02%	0.68%	7.95%	0.0001%	0.0015%
Target Corp	TGT	$69,120	0.14%	2.99%	14.38%	0.0043%	0.0206%
TJX Cos Inc/The	TJX	$127,483	0.26%	1.33%	8.20%	0.0035%	0.0216%
Thermo Fisher Scientific Inc	TMO	$208,692	0.43%	0.29%	8.37%	0.0012%	0.0361%
T-Mobile US Inc	TMUS	$258,974	0.54%	1.58%	5.00%	0.0085%	0.0268%
Tapestry Inc	TPR	$11,037	0.02%	2.95%	5.52%	0.0007%	0.0013%
Targa Resources Corp	TRGP	$36,578	0.08%	1.80%	16.86%	0.0014%	0.0128%
Trimble Inc	TRMB	n/a	n/a	0.00%	n/a	n/a	n/a
T Rowe Price Group Inc	TROW	$24,455	0.05%	4.51%	7.85%	0.0023%	0.0040%
Travelers Cos Inc/The	TRV	$55,833	0.12%	1.71%	18.71%	0.0020%	0.0216%
Tractor Supply Co	TSCO	$28,640	0.06%	1.66%	6.20%	0.0010%	0.0037%
Tesla Inc	TSLA	$802,033	1.66%	0.00%	-9.00%	0.0000%	-0.1494%
Tyson Foods Inc	TSN	$16,746	0.03%	3.35%	47.87%	0.0012%	0.0166%
Trane Technologies PLC	TT	$83,295	0.17%	0.91%	16.94%	0.0016%	0.0292%
Take-Two Interactive Software Inc	TTWO	$28,347	0.06%	0.00%	60.49%	0.0000%	0.0355%
Texas Instruments Inc	TXN	$185,326	0.38%	2.68%	-2.81%	0.0103%	-0.0108%
Textron Inc	TXT	n/a	n/a	0.10%	n/a	n/a	n/a
Tyler Technologies Inc	TYL	n/a	n/a	0.00%	n/a	n/a	n/a
United Airlines Holdings Inc	UAL	$25,732	0.05%	0.00%	9.00%	0.0000%	0.0048%
Uber Technologies Inc	UBER	$151,716	0.31%	0.00%	61.51%	0.0000%	0.1932%
UDR Inc	UDR	$13,921	0.03%	4.03%	1.85%	0.0012%	0.0005%
Universal Health Services Inc	UHS	$12,149	0.03%	0.39%	16.65%	0.0001%	0.0042%
Ulta Beauty Inc	ULTA	$17,384	0.04%	0.00%	-0.44%	0.0000%	-0.0002%
UnitedHealth Group Inc	UNH	$521,269	1.08%	1.49%	9.76%	0.0161%	0.1053%
Union Pacific Corp	UNP	$140,694	0.29%	2.31%	9.24%	0.0067%	0.0269%
United Parcel Service Inc	UPS	$98,200	0.20%	4.86%	1.72%	0.0099%	0.0035%
United Rentals Inc	URI	$53,338	0.11%	0.80%	7.62%	0.0009%	0.0084%
US Bancorp	USB	$75,388	0.16%	4.14%	8.51%	0.0065%	0.0133%
Visa Inc	V	$484,178	1.00%	0.81%	12.50%	0.0082%	0.1253%
VICI Properties Inc	VICI	$33,130	0.07%	5.45%	1.83%	0.0037%	0.0013%
Valero Energy Corp	VLO	$41,080	0.09%	3.30%	-19.92%	0.0028%	-0.0169%
Veralto Corp	VLTO	n/a	n/a	0.35%	n/a	n/a	n/a
Vulcan Materials Co	VMC	$36,175	0.07%	0.67%	16.73%	0.0005%	0.0125%
Verisk Analytics Inc	VRSK	$38,793	0.08%	0.57%	12.00%	0.0005%	0.0096%
VeriSign Inc	VRSN	n/a	n/a	0.00%	n/a	n/a	n/a
Vertex Pharmaceuticals Inc	VRTX	$122,851	0.25%	0.00%	12.49%	0.0000%	0.0318%
Vistra Corp	VST	n/a	n/a	0.71%	n/a	n/a	n/a
Ventas Inc	VTR	$27,464	0.06%	2.75%	8.22%	0.0016%	0.0047%
Viatris Inc	VTRS	$13,846	0.03%	4.14%	-3.41%	0.0012%	-0.0010%
Verizon Communications Inc	VZ	$177,352	0.37%	6.43%	2.98%	0.0236%	0.0109%
Westinghouse Air Brake Technologies	WAB	$32,312	0.07%	0.43%	16.94%	0.0003%	0.0113%
Waters Corp	WAT	$19,180	0.04%	0.00%	7.74%	0.0000%	0.0031%
Walgreens Boots Alliance Inc	WBA	$8,179	0.02%	10.57%	-21.19%	0.0018%	-0.0036%
Warner Bros Discovery Inc	WBD	$19,934	0.04%	0.00%	29.63%	0.0000%	0.0122%
Western Digital Corp	WDC	$22,578	0.05%	0.00%	-10.00%	0.0000%	-0.0047%
WEC Energy Group Inc	WEC	$30,195	0.06%	3.50%	7.19%	0.0022%	0.0045%
Welltower Inc	WELL	$83,988	0.17%	1.99%	16.33%	0.0035%	0.0284%
Wells Fargo & Co	WFC	$216,151	0.45%	2.46%	8.94%	0.0110%	0.0400%
Waste Management Inc	WM	$86,635	0.18%	1.39%	14.57%	0.0025%	0.0261%
Williams Cos Inc/The	WMB	$63,835	0.13%	3.63%	5.18%	0.0048%	0.0068%
Walmart Inc	WMT	$658,735	1.36%	1.01%	9.24%	0.0138%	0.1260%
W R Berkley Corp	WRB	$21,756	0.05%	0.56%	12.87%	0.0003%	0.0058%
West Pharmaceutical Services Inc	WST	$22,301	0.05%	0.27%	2.49%	0.0001%	0.0011%
Willis Towers Watson PLC	WTW	$30,438	0.06%	1.16%	10.81%	0.0007%	0.0068%
Weyerhaeuser Co	WY	$22,640	0.05%	2.57%	-13.66%	0.0012%	-0.0064%
Wynn Resorts Ltd	WYNN	$10,657	0.02%	1.04%	-12.84%	0.0002%	-0.0028%
Xcel Energy Inc	XEL	$38,365	0.08%	3.28%	7.10%	0.0026%	0.0056%
Exxon Mobil Corp	XOM	$518,833	1.07%	3.25%	1.34%	0.0350%	0.0143%
Xylem Inc/NY	XYL	n/a	n/a	1.18%	n/a	n/a	n/a
Yum! Brands Inc	YUM	$36,878	0.08%	2.04%	11.00%	0.0016%	0.0084%
Zimmer Biomet Holdings Inc	ZBH	$21,285	0.04%	0.90%	6.50%	0.0004%	0.0029%
Zebra Technologies Corp	ZBRA	n/a	n/a	0.00%	n/a	n/a	n/a
Zoetis Inc	ZTS	$80,996	0.17%	0.97%	10.10%	0.0016%	0.0169%
		$48,303,551					

[4] Source: Bloomberg Professional as of 10/31/2024
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of 10/31/2024
[7] Source: Bloomberg Professional as of 10/31/2024
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.34%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	13.63%
[3] Market Cap. Weighted Estimated Required Market Return	15.07%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

		[4]	[5]	[6]	n/a [7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$37,442	0.08%	0.72%	8.00%	0.0006%	0.0063%
Apple Inc	AAPL	$3,434,767	7.22%	0.44%	8.00%	0.0319%	0.5774%
AbbVie Inc	ABBV	$360,105	0.76%	3.22%	4.00%	0.0243%	0.0303%
Airbnb Inc	ABNB	$59,308	0.12%	0.00%	23.00%	0.0000%	0.0287%
Abbott Laboratories	ABT	$196,635	0.41%	1.94%	4.00%	0.0080%	0.0165%
Arch Capital Group Ltd	ACGL	$37,064	0.08%	0.00%	17.00%	0.0000%	0.0132%
Accenture PLC	ACN	$215,990	0.45%	1.72%	12.50%	0.0078%	0.0567%
Adobe Inc	ADBE	$210,451	0.44%	0.00%	13.50%	0.0000%	0.0597%
Analog Devices Inc	ADI	$110,773	0.23%	1.65%	7.50%	0.0038%	0.0175%
Archer-Daniels-Midland Co	ADM	$26,398	0.06%	3.62%	3.50%	0.0020%	0.0019%
Automatic Data Processing Inc	ADP	$117,960	0.25%	1.94%	10.50%	0.0048%	0.0260%
Autodesk Inc	ADSK	$61,017	0.13%	0.00%	14.00%	0.0000%	0.0180%
Ameren Corp	AEE	$23,216	0.05%	3.08%	6.50%	0.0015%	0.0032%
American Electric Power Co Inc	AEP	$52,547	0.11%	3.77%	6.50%	0.0042%	0.0072%
AES Corp/The	AES	$11,725	0.02%	4.18%	14.00%	0.0010%	0.0034%
Aflac Inc	AFL	$58,685	0.12%	1.91%	7.50%	0.0024%	0.0092%
American International Group Inc	AIG	$48,863	0.10%	2.11%	13.00%	0.0022%	0.0133%
Assurant Inc	AIZ	$9,929	0.02%	1.50%	9.50%	0.0003%	0.0020%
Arthur J Gallagher & Co	AJG	$61,695	0.13%	0.85%	14.00%	0.0011%	0.0182%
Akamai Technologies Inc	AKAM	$15,316	0.03%	0.00%	6.00%	0.0000%	0.0019%
Albemarle Corp	ALB	$11,134	0.02%	1.71%	-3.50%	0.0004%	-0.0008%
Align Technology Inc	ALGN	$15,315	0.03%	0.00%	17.00%	0.0000%	0.0055%
Allstate Corp/The	ALL	$49,391	0.10%	1.97%	30.00%	0.0020%	0.0311%
Allegion plc	ALLE	$12,138	0.03%	1.38%	8.50%	0.0004%	0.0022%
Applied Materials Inc	AMAT	$149,695	0.31%	0.88%	9.50%	0.0028%	0.0299%
Amcor PLC	AMCR	$16,087	0.03%	4.58%	11.50%	0.0015%	0.0039%
Advanced Micro Devices Inc	AMD	$233,798	0.49%	0.00%	17.00%	0.0000%	0.0835%
AMETEK Inc	AME	$42,408	0.09%	0.61%	10.00%	0.0005%	0.0089%
Amgen Inc	AMGN	$172,097	0.36%	2.81%	4.50%	0.0102%	0.0163%
Ameriprise Financial Inc	AMP	$50,106	0.11%	1.16%	10.00%	0.0012%	0.0105%
American Tower Corp	AMT	$99,785	0.21%	3.03%	11.00%	0.0064%	0.0231%
Amentum Holdings Inc	AMTM	n/a	n/a	0.00%	n/a	n/a	n/a
Amazon.com Inc	AMZN	$1,956,374	4.11%	0.00%	24.50%	0.0000%	1.0072%
Arista Networks Inc	ANET	$121,401	0.26%	0.00%	19.50%	0.0000%	0.0497%
ANSYS Inc	ANSS	$28,000	0.06%	0.00%	9.50%	0.0000%	0.0056%
Aon PLC	AON	$79,342	0.17%	0.74%	12.50%	0.0012%	0.0208%
A O Smith Corp	AOS	$8,945	0.02%	1.81%	9.00%	0.0003%	0.0017%
APA Corp	APA	$8,730	0.02%	4.24%	6.00%	0.0008%	0.0011%
Air Products and Chemicals Inc	APD	$69,035	0.15%	2.28%	10.50%	0.0033%	0.0152%
Amphenol Corp	APH	$80,800	0.17%	0.98%	13.50%	0.0017%	0.0229%
Aptiv PLC	APTV	$13,357	0.03%	0.00%	28.50%	0.0000%	0.0080%
Alexandria Real Estate Equities Inc	ARE	$19,495	0.04%	4.66%	9.50%	0.0019%	0.0039%
Atmos Energy Corp	ATO	$21,543	0.05%	2.32%	7.00%	0.0011%	0.0032%
AvalonBay Communities Inc	AVB	$31,517	0.07%	3.07%	5.50%	0.0020%	0.0036%
Broadcom Inc	AVGO	$792,924	1.67%	1.25%	30.00%	0.0208%	0.4999%
Avery Dennison Corp	AVY	$16,634	0.03%	1.70%	2.00%	0.0006%	0.0007%
American Water Works Co Inc	AWK	$26,917	0.06%	2.22%	4.50%	0.0013%	0.0025%
Axon Enterprise Inc	AXON	$32,006	0.07%	0.00%	25.00%	0.0000%	0.0168%
American Express Co	AXP	$190,257	0.40%	1.04%	9.00%	0.0041%	0.0360%
AutoZone Inc	AZO	$50,865	0.11%	0.00%	12.50%	0.0000%	0.0134%
Boeing Co/The	BA	n/a	n/a	0.00%	n/a	n/a	n/a
Bank of America Corp	BAC	$320,880	0.67%	2.49%	7.00%	0.0168%	0.0472%
Ball Corp	BALL	$17,682	0.04%	1.35%	10.50%	0.0005%	0.0039%
Baxter International Inc	BAX	$18,213	0.04%	3.25%	3.00%	0.0012%	0.0011%
Best Buy Co Inc	BBY	$19,418	0.04%	4.16%	1.00%	0.0017%	0.0004%
Becton Dickinson & Co	BDX	$67,517	0.14%	1.63%	6.00%	0.0023%	0.0085%
Franklin Resources Inc	BEN	$10,863	0.02%	5.97%	4.00%	0.0014%	0.0009%
Brown-Forman Corp	BF/B	$13,365	0.03%	1.98%	15.00%	0.0006%	0.0042%
Bunge Global SA	BG	$11,731	0.02%	3.24%	0.00%	0.0008%	0.0000%
Biogen Inc	BIIB	$25,355	0.05%	0.00%	0.50%	0.0000%	0.0003%
Bank of New York Mellon Corp/The	BK	$55,612	0.12%	2.49%	15.00%	0.0029%	0.0175%
Booking Holdings Inc	BKNG	$154,768	0.33%	0.75%	22.00%	0.0024%	0.0715%
Baker Hughes Co	BKR	$37,681	0.08%	2.21%	29.50%	0.0017%	0.0234%
Builders FirstSource Inc	BLDR	$19,960	0.04%	0.00%	6.50%	0.0000%	0.0027%
Blackrock Inc	BLK	$145,318	0.31%	2.08%	9.50%	0.0063%	0.0290%
Bristol-Myers Squibb Co	BMY	$113,111	0.24%	4.30%	1.00%	0.0102%	0.0024%
Broadridge Financial Solutions Inc	BR	$24,647	0.05%	1.67%	9.50%	0.0009%	0.0049%
Berkshire Hathaway Inc	BRK/B	$597,556	1.26%	0.00%	9.00%	0.0000%	0.1130%
Brown & Brown Inc	BRO	$29,923	0.06%	0.57%	12.50%	0.0004%	0.0079%
Boston Scientific Corp	BSX	$123,730	0.26%	0.00%	13.00%	0.0000%	0.0338%
BorgWarner Inc	BWA	$7,355	0.02%	1.31%	5.50%	0.0002%	0.0009%
Blackstone Inc	BX	$120,793	0.25%	2.05%	16.00%	0.0052%	0.0406%
BXP Inc	BXP	$12,723	0.03%	4.87%	0.50%	0.0013%	0.0001%
Citigroup Inc	C	$122,423	0.26%	3.49%	3.00%	0.0090%	0.0077%
Conagra Brands Inc	CAG	$13,812	0.03%	4.84%	3.00%	0.0014%	0.0009%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Cardinal Health Inc	CAH	$26,258	0.06%	1.86%	6.50%	0.0010%	0.0036%
Carrier Global Corp	CARR	$65,246	0.14%	1.05%	12.00%	0.0014%	0.0165%
Caterpillar Inc	CAT	$182,419	0.38%	1.50%	11.50%	0.0057%	0.0441%
Chubb Ltd	CB	$113,851	0.24%	1.29%	13.00%	0.0031%	0.0311%
Cboe Global Markets Inc	CBOE	$22,347	0.05%	1.18%	14.00%	0.0006%	0.0066%
CBRE Group Inc	CBRE	$40,079	0.08%	0.00%	5.00%	0.0000%	0.0042%
Crown Castle Inc	CCI	$46,715	0.10%	5.82%	-0.50%	0.0057%	-0.0005%
Carnival Corp	CCL	n/a	n/a	0.00%	n/a	n/a	n/a
Cadence Design Systems Inc	CDNS	$75,729	0.16%	0.00%	12.00%	0.0000%	0.0191%
CDW Corp/DE	CDW	$25,084	0.05%	1.33%	7.00%	0.0007%	0.0037%
Celanese Corp	CE	$13,764	0.03%	2.22%	4.50%	0.0006%	0.0013%
Constellation Energy Corp	CEG	n/a	n/a	0.54%	n/a	n/a	n/a
CF Industries Holdings Inc	CF	$14,310	0.03%	2.43%	-1.50%	0.0007%	-0.0005%
Citizens Financial Group Inc	CFG	$18,882	0.04%	3.99%	7.50%	0.0016%	0.0030%
Church & Dwight Co Inc	CHD	$24,459	0.05%	1.14%	6.50%	0.0006%	0.0033%
CH Robinson Worldwide Inc	CHRW	$12,085	0.03%	2.41%	5.50%	0.0006%	0.0014%
Charter Communications Inc	CHTR	$46,763	0.10%	0.00%	6.50%	0.0000%	0.0064%
Cigna Group/The	CI	$87,565	0.18%	1.78%	12.00%	0.0033%	0.0221%
Cincinnati Financial Corp	CINF	$22,014	0.05%	2.30%	10.50%	0.0011%	0.0049%
Colgate-Palmolive Co	CL	$76,562	0.16%	2.13%	11.50%	0.0034%	0.0185%
Clorox Co/The	CLX	$19,625	0.04%	3.08%	7.00%	0.0013%	0.0029%
Comcast Corp	CMCSA	$166,693	0.35%	2.84%	7.50%	0.0099%	0.0263%
CME Group Inc	CME	$81,151	0.17%	2.04%	5.50%	0.0035%	0.0094%
Chipotle Mexican Grill Inc	CMG	$75,992	0.16%	0.00%	20.00%	0.0000%	0.0319%
Cummins Inc	CMI	$45,086	0.09%	2.21%	6.00%	0.0021%	0.0057%
CMS Energy Corp	CMS	$20,798	0.04%	2.96%	6.00%	0.0013%	0.0026%
Centene Corp	CNC	$31,433	0.07%	0.00%	10.00%	0.0000%	0.0066%
CenterPoint Energy Inc	CNP	$19,245	0.04%	2.84%	6.50%	0.0012%	0.0026%
Capital One Financial Corp	COF	$62,106	0.13%	1.47%	2.50%	0.0019%	0.0033%
Cooper Cos Inc/The	COO	$20,848	0.04%	0.00%	7.50%	0.0000%	0.0033%
ConocoPhillips	COP	$126,071	0.26%	2.85%	4.00%	0.0075%	0.0106%
Cencora Inc	COR	$44,706	0.09%	0.89%	6.50%	0.0008%	0.0061%
Costco Wholesale Corp	COST	$387,326	0.81%	0.53%	10.00%	0.0043%	0.0814%
Corpay Inc	CPAY	$22,893	0.05%	0.00%	15.50%	0.0000%	0.0075%
Campbell Soup Co	CPB	$13,884	0.03%	3.17%	5.00%	0.0009%	0.0015%
Copart Inc	CPRT	$49,585	0.10%	0.00%	9.00%	0.0000%	0.0094%
Camden Property Trust	CPT	$12,347	0.03%	3.56%	-6.50%	0.0009%	-0.0017%
Charles River Laboratories Internation	CRL	$9,220	0.02%	0.00%	7.00%	0.0000%	0.0014%
Salesforce Inc	CRM	$278,550	0.59%	0.55%	24.00%	0.0032%	0.1405%
Crowdstrike Holdings Inc	CRWD	n/a	n/a	0.00%	n/a	n/a	n/a
Cisco Systems Inc	CSCO	$218,314	0.46%	2.92%	3.50%	0.0134%	0.0161%
CoStar Group Inc	CSGP	$29,841	0.06%	0.00%	16.50%	0.0000%	0.0103%
CSX Corp	CSX	$64,872	0.14%	1.43%	9.00%	0.0019%	0.0123%
Cintas Corp	CTAS	$83,003	0.17%	0.76%	14.00%	0.0013%	0.0244%
Catalent Inc	CTLT	$10,634	0.02%	0.00%	21.00%	0.0000%	0.0047%
Coterra Energy Inc	CTRA	$17,683	0.04%	3.51%	4.50%	0.0013%	0.0017%
Cognizant Technology Solutions Corp	CTSH	$36,984	0.08%	1.61%	8.00%	0.0013%	0.0062%
Corteva Inc	CTVA	$42,172	0.09%	1.12%	9.50%	0.0010%	0.0084%
CVS Health Corp	CVS	$71,025	0.15%	4.71%	2.50%	0.0070%	0.0037%
Chevron Corp	CVX	$272,179	0.57%	4.38%	5.00%	0.0251%	0.0286%
Caesars Entertainment Inc	CZR	n/a	n/a	0.00%	n/a	n/a	n/a
Dominion Energy Inc	D	$49,942	0.10%	4.49%	3.00%	0.0047%	0.0031%
Delta Air Lines Inc	DAL	n/a	n/a	1.05%	n/a	n/a	n/a
Dayforce Inc	DAY	n/a	n/a	0.00%	n/a	n/a	n/a
DuPont de Nemours Inc	DD	$34,648	0.07%	1.83%	9.00%	0.0013%	0.0066%
Deere & Co	DE	$110,723	0.23%	1.45%	4.00%	0.0034%	0.0093%
Deckers Outdoor Corp	DECK	$24,443	0.05%	0.00%	16.00%	0.0000%	0.0082%
Dell Technologies Inc	DELL	$41,277	0.09%	1.44%	2.50%	0.0012%	0.0022%
Discover Financial Services	DFS	$37,267	0.08%	1.89%	4.00%	0.0015%	0.0031%
Dollar General Corp	DG	$17,602	0.04%	2.95%	-0.50%	0.0011%	-0.0002%
Quest Diagnostics Inc	DGX	$17,281	0.04%	1.94%	3.00%	0.0007%	0.0011%
DR Horton Inc	DHI	$55,101	0.12%	0.95%	5.00%	0.0011%	0.0058%
Danaher Corp	DHR	$177,434	0.37%	0.44%	5.50%	0.0016%	0.0205%
Walt Disney Co/The	DIS	$174,467	0.37%	0.94%	31.50%	0.0034%	0.1155%
Digital Realty Trust Inc	DLR	$58,354	0.12%	2.74%	-5.00%	0.0034%	-0.0061%
Dollar Tree Inc	DLTR	$13,897	0.03%	0.00%	20.00%	0.0000%	0.0058%
Healthpeak Properties Inc	DOC	$15,702	0.03%	5.35%	7.00%	0.0018%	0.0023%
Dover Corp	DOV	$25,975	0.05%	1.09%	6.00%	0.0006%	0.0033%
Dow Inc	DOW	$34,571	0.07%	5.67%	0.50%	0.0041%	0.0004%
Domino's Pizza Inc	DPZ	$14,287	0.03%	1.46%	12.50%	0.0004%	0.0038%
Darden Restaurants Inc	DRI	$18,802	0.04%	3.50%	10.00%	0.0014%	0.0040%
DTE Energy Co	DTE	$25,704	0.05%	3.28%	4.50%	0.0018%	0.0024%
Duke Energy Corp	DUK	$88,873	0.19%	3.63%	5.00%	0.0068%	0.0093%
DaVita Inc	DVA	$11,464	0.02%	0.00%	9.50%	0.0000%	0.0023%
Devon Energy Corp	DVN	$24,221	0.05%	2.28%	3.00%	0.0012%	0.0015%
Dexcom Inc	DXCM	n/a	n/a	0.00%	n/a	n/a	n/a
Electronic Arts Inc	EA	$39,855	0.08%	0.50%	14.00%	0.0004%	0.0117%
eBay Inc	EBAY	$27,547	0.06%	1.88%	9.50%	0.0011%	0.0055%
Ecolab Inc	ECL	$69,581	0.15%	0.93%	11.00%	0.0014%	0.0161%
Consolidated Edison Inc	ED	$35,196	0.07%	3.27%	6.00%	0.0024%	0.0044%
Equifax Inc	EFX	$32,850	0.07%	0.59%	7.00%	0.0004%	0.0048%
Everest Group Ltd	EG	$15,389	0.03%	2.25%	10.50%	0.0007%	0.0034%
Edison International	EIX	$31,901	0.07%	3.79%	6.50%	0.0025%	0.0044%
Estee Lauder Cos Inc/The	EL	$16,093	0.03%	2.03%	3.50%	0.0007%	0.0012%
Elevance Health Inc	ELV	$94,105	0.20%	1.61%	11.00%	0.0032%	0.0218%
Eastman Chemical Co	EMN	$12,281	0.03%	3.08%	3.50%	0.0008%	0.0009%
Emerson Electric Co	EMR	$62,006	0.13%	1.94%	7.00%	0.0025%	0.0091%
Enphase Energy Inc	ENPH	$11,219	0.02%	0.00%	14.00%	0.0000%	0.0033%
EOG Resources Inc	EOG	$69,346	0.15%	2.98%	8.00%	0.0043%	0.0117%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
EPAM Systems Inc	EPAM	$10,741	0.02%	0.00%	20.50%	0.0000%	0.0046%
Equinix Inc	EQIX	$87,619	0.18%	1.88%	15.00%	0.0035%	0.0276%
Equity Residential	EQR	$26,680	0.06%	3.84%	-4.00%	0.0022%	-0.0022%
EQT Corp	EQT	n/a	n/a	1.72%	n/a	n/a	n/a
Erie Indemnity Co	ERIE	$20,731	0.04%	1.14%	20.00%	0.0005%	0.0087%
Eversource Energy	ES	$23,534	0.05%	4.34%	6.00%	0.0021%	0.0030%
Essex Property Trust Inc	ESS	$18,243	0.04%	3.45%	4.50%	0.0013%	0.0017%
Eaton Corp PLC	ETN	$131,040	0.28%	1.13%	11.00%	0.0031%	0.0303%
Entergy Corp	ETR	$33,097	0.07%	3.10%	0.50%	0.0022%	0.0003%
Evergy Inc	EVRG	$13,886	0.03%	4.25%	7.50%	0.0012%	0.0022%
Edwards Lifesciences Corp	EW	$40,367	0.08%	0.00%	10.00%	0.0000%	0.0085%
Exelon Corp	EXC	n/a	n/a	3.87%	n/a	n/a	n/a
Expeditors International of Washingtor	EXPD	$16,794	0.04%	1.23%	-1.00%	0.0004%	-0.0004%
Expedia Group Inc	EXPE	$19,485	0.04%	0.00%	39.00%	0.0000%	0.0160%
Extra Space Storage Inc	EXR	$34,608	0.07%	3.97%	5.00%	0.0029%	0.0036%
Ford Motor Co	F	$40,166	0.08%	5.83%	35.00%	0.0049%	0.0295%
Diamondback Energy Inc	FANG	$52,270	0.11%	5.30%	2.50%	0.0058%	0.0027%
Fastenal Co	FAST	$44,788	0.09%	2.00%	9.00%	0.0019%	0.0085%
Freeport-McMoRan Inc	FCX	$64,687	0.14%	1.33%	11.00%	0.0018%	0.0150%
FactSet Research Systems Inc	FDS	$17,249	0.04%	0.92%	11.00%	0.0003%	0.0040%
FedEx Corp	FDX	$66,908	0.14%	2.02%	3.50%	0.0028%	0.0049%
FirstEnergy Corp	FE	$24,107	0.05%	4.06%	5.50%	0.0021%	0.0028%
F5 Inc	FFIV	$13,632	0.03%	0.00%	10.00%	0.0000%	0.0029%
Fiserv Inc	FI	$112,589	0.24%	0.00%	9.50%	0.0000%	0.0225%
Fair Isaac Corp	FICO	$48,869	0.10%	0.00%	16.50%	0.0000%	0.0169%
Fidelity National Information Services I	FIS	$48,954	0.10%	1.60%	4.00%	0.0017%	0.0041%
Fifth Third Bancorp	FITB	$29,563	0.06%	3.39%	4.50%	0.0021%	0.0028%
FMC Corp	FMC	$8,113	0.02%	3.57%	4.00%	0.0006%	0.0007%
Fox Corp	FOX	n/a	n/a	1.39%	n/a	n/a	n/a
Fox Corp	FOXA	$9,435	0.02%	1.29%	8.00%	0.0003%	0.0016%
Federal Realty Investment Trust	FRT	$9,417	0.02%	3.97%	2.50%	0.0008%	0.0005%
First Solar Inc	FSLR	$20,821	0.04%	0.00%	34.50%	0.0000%	0.0151%
Fortinet Inc	FTNT	$60,168	0.13%	0.00%	24.00%	0.0000%	0.0303%
Fortive Corp	FTV	$24,783	0.05%	0.45%	15.00%	0.0002%	0.0078%
General Dynamics Corp	GD	$80,184	0.17%	1.95%	10.00%	0.0033%	0.0168%
GoDaddy Inc	GDDY	$23,417	0.05%	0.00%	27.00%	0.0000%	0.0133%
General Electric Co	GE	$185,916	0.39%	0.65%	22.00%	0.0025%	0.0859%
GE HealthCare Technologies Inc	GEHC	n/a	n/a	0.14%	n/a	n/a	n/a
Gen Digital Inc	GEN	$17,938	0.04%	1.72%	10.50%	0.0006%	0.0040%
GE Vernova Inc	GEV	n/a	n/a	0.00%	n/a	n/a	n/a
Gilead Sciences Inc	GILD	$110,580	0.23%	3.47%	2.50%	0.0081%	0.0058%
General Mills Inc	GIS	$37,762	0.08%	3.53%	5.00%	0.0028%	0.0040%
Globe Life Inc	GL	$9,485	0.02%	0.91%	8.50%	0.0002%	0.0017%
Corning Inc	GLW	$40,723	0.09%	2.35%	17.50%	0.0020%	0.0150%
General Motors Co	GM	$55,815	0.12%	0.95%	6.50%	0.0011%	0.0076%
Generac Holdings Inc	GNRC	$9,958	0.02%	0.00%	12.50%	0.0000%	0.0026%
Alphabet Inc	GOOG	$955,666	2.01%	0.46%	13.50%	0.0093%	0.2711%
Alphabet Inc	GOOGL	n/a	n/a	0.47%	n/a	n/a	n/a
Genuine Parts Co	GPC	$15,947	0.03%	3.49%	8.50%	0.0012%	0.0028%
Global Payments Inc	GPN	$26,394	0.06%	0.96%	13.50%	0.0005%	0.0075%
Garmin Ltd	GRMN	$38,088	0.08%	1.51%	5.00%	0.0012%	0.0040%
Goldman Sachs Group Inc/The	GS	$163,518	0.34%	2.32%	7.50%	0.0080%	0.0258%
WW Grainger Inc	GWW	$54,020	0.11%	0.74%	7.00%	0.0008%	0.0079%
Halliburton Co	HAL	$24,490	0.05%	2.45%	18.00%	0.0013%	0.0093%
Hasbro Inc	HAS	$9,155	0.02%	4.27%	8.50%	0.0008%	0.0016%
Huntington Bancshares Inc/OH	HBAN	$22,649	0.05%	3.98%	7.50%	0.0019%	0.0036%
HCA Healthcare Inc	HCA	$90,868	0.19%	0.74%	10.50%	0.0014%	0.0200%
Home Depot Inc/The	HD	$391,109	0.82%	2.29%	6.50%	0.0188%	0.0534%
Hess Corp	HES	$41,435	0.09%	1.49%	8.00%	0.0013%	0.0070%
Hartford Financial Services Group Inc/	HIG	$32,016	0.07%	1.88%	7.00%	0.0013%	0.0047%
Huntington Ingalls Industries Inc	HII	$7,237	0.02%	2.92%	10.00%	0.0004%	0.0015%
Hilton Worldwide Holdings Inc	HLT	n/a	n/a	0.26%	n/a	n/a	n/a
Hologic Inc	HOLX	$18,784	0.04%	0.00%	-2.00%	0.0000%	-0.0008%
Honeywell International Inc	HON	$133,743	0.28%	2.20%	10.00%	0.0062%	0.0281%
Hewlett Packard Enterprise Co	HPE	$25,311	0.05%	2.67%	7.50%	0.0014%	0.0040%
HP Inc	HPQ	$34,231	0.07%	3.10%	12.50%	0.0022%	0.0090%
Hormel Foods Corp	HRL	$16,753	0.04%	3.70%	7.50%	0.0013%	0.0026%
Henry Schein Inc	HSIC	$8,899	0.02%	0.00%	8.50%	0.0000%	0.0016%
Host Hotels & Resorts Inc	HST	$12,110	0.03%	4.64%	51.00%	0.0012%	0.0130%
Hershey Co/The	HSY	$26,224	0.06%	3.09%	7.00%	0.0017%	0.0039%
Hubbell Inc	HUBB	$22,919	0.05%	1.24%	9.00%	0.0006%	0.0043%
Humana Inc	HUM	$31,046	0.07%	1.37%	4.50%	0.0009%	0.0029%
Howmet Aerospace Inc	HWM	$40,700	0.09%	0.32%	12.00%	0.0003%	0.0103%
International Business Machines Corp	IBM	$191,143	0.40%	3.23%	3.00%	0.0130%	0.0120%
Intercontinental Exchange Inc	ICE	$89,497	0.19%	1.15%	7.50%	0.0022%	0.0141%
IDEXX Laboratories Inc	IDXX	$33,321	0.07%	0.00%	10.50%	0.0000%	0.0074%
IDEX Corp	IEX	$16,253	0.03%	1.29%	5.00%	0.0004%	0.0017%
International Flavors & Fragrances Inc	IFF	$25,420	0.05%	1.61%	0.50%	0.0009%	0.0003%
Incyte Corp	INCY	$14,279	0.03%	0.00%	18.50%	0.0000%	0.0056%
Intel Corp	INTC	$92,020	0.19%	0.00%	-2.00%	0.0000%	-0.0039%
Intuit Inc	INTU	$171,062	0.36%	0.68%	13.50%	0.0025%	0.0485%
Invitation Homes Inc	INVH	$19,242	0.04%	3.57%	13.50%	0.0014%	0.0055%
International Paper Co	IP	$19,293	0.04%	3.33%	5.50%	0.0014%	0.0022%
Interpublic Group of Cos Inc/The	IPG	$10,952	0.02%	4.49%	8.50%	0.0010%	0.0020%
IQVIA Holdings Inc	IQV	$37,356	0.08%	0.00%	11.00%	0.0000%	0.0086%
Ingersoll Rand Inc	IR	$38,734	0.08%	0.08%	10.50%	0.0001%	0.0085%
Iron Mountain Inc	IRM	$36,294	0.08%	2.31%	5.50%	0.0018%	0.0042%
Intuitive Surgical Inc	ISRG	$179,457	0.38%	0.00%	13.50%	0.0000%	0.0509%
Gartner Inc	IT	$38,723	0.08%	0.00%	8.00%	0.0000%	0.0065%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Illinois Tool Works Inc	ITW	$77,112	0.16%	2.30%	9.00%	0.0037%	0.0146%
Invesco Ltd	IVZ	$7,793	0.02%	4.73%	10.00%	0.0008%	0.0016%
Jacobs Solutions Inc	J	$17,467	0.04%	0.83%	11.00%	0.0003%	0.0040%
JB Hunt Transport Services Inc	JBHT	$18,212	0.04%	0.95%	7.50%	0.0004%	0.0029%
Jabil Inc	JBL	$13,890	0.03%	0.26%	13.50%	0.0001%	0.0039%
Johnson Controls International plc	JCI	$50,468	0.11%	1.96%	9.50%	0.0021%	0.0101%
Jack Henry & Associates Inc	JKHY	$13,266	0.03%	1.21%	6.50%	0.0003%	0.0018%
Johnson & Johnson	JNJ	$384,883	0.81%	3.10%	3.00%	0.0251%	0.0243%
Juniper Networks Inc	JNPR	$12,879	0.03%	2.26%	7.50%	0.0006%	0.0020%
JPMorgan Chase & Co	JPM	$624,780	1.31%	2.25%	7.00%	0.0296%	0.0919%
Kellanova	K	$27,800	0.06%	2.83%	3.00%	0.0017%	0.0018%
Keurig Dr Pepper Inc	KDP	$44,695	0.09%	2.79%	10.00%	0.0026%	0.0094%
KeyCorp	KEY	$17,099	0.04%	4.75%	-2.00%	0.0017%	-0.0007%
Keysight Technologies Inc	KEYS	$25,860	0.05%	0.00%	8.00%	0.0000%	0.0043%
Kraft Heinz Co/The	KHC	$40,459	0.09%	4.78%	4.50%	0.0041%	0.0038%
Kimco Realty Corp	KIM	$15,990	0.03%	4.22%	18.00%	0.0014%	0.0060%
KKR & Co Inc	KKR	$122,680	0.26%	0.51%	5.00%	0.0013%	0.0129%
KLA Corp	KLAC	$89,115	0.19%	0.87%	13.00%	0.0016%	0.0243%
Kimberly-Clark Corp	KMB	$44,747	0.09%	3.64%	7.50%	0.0034%	0.0071%
Kinder Morgan Inc	KMI	$54,452	0.11%	4.69%	10.00%	0.0054%	0.0114%
CarMax Inc	KMX	$11,213	0.02%	0.00%	3.50%	0.0000%	0.0008%
Coca-Cola Co/The	KO	$281,342	0.59%	2.97%	7.00%	0.0176%	0.0414%
Kroger Co/The	KR	$40,349	0.08%	2.30%	5.00%	0.0019%	0.0042%
Kenvue Inc	KVUE	n/a	n/a	3.58%	n/a	n/a	n/a
Loews Corp	L	$17,333	0.04%	0.32%	14.50%	0.0001%	0.0053%
Leidos Holdings Inc	LDOS	$24,440	0.05%	0.87%	9.50%	0.0004%	0.0049%
Lennar Corp	LEN	$40,669	0.09%	1.17%	6.00%	0.0010%	0.0051%
Labcorp Holdings Inc	LH	$19,092	0.04%	1.26%	1.00%	0.0005%	0.0004%
L3Harris Technologies Inc	LHX	$46,937	0.10%	1.87%	11.50%	0.0018%	0.0113%
Linde PLC	LIN	$217,199	0.46%	1.22%	7.00%	0.0056%	0.0319%
LKQ Corp	LKQ	$9,564	0.02%	3.26%	7.00%	0.0007%	0.0014%
Eli Lilly & Co	LLY	$787,685	1.66%	0.63%	28.50%	0.0104%	0.4717%
Lockheed Martin Corp	LMT	$129,433	0.27%	2.42%	9.50%	0.0066%	0.0258%
Alliant Energy Corp	LNT	$15,390	0.03%	3.20%	6.00%	0.0010%	0.0019%
Lowe's Cos Inc	LOW	$148,535	0.31%	1.76%	5.50%	0.0055%	0.0172%
Lam Research Corp	LRCX	$95,665	0.20%	1.24%	12.50%	0.0025%	0.0251%
Lululemon Athletica Inc	LULU	$35,051	0.07%	0.00%	13.00%	0.0000%	0.0096%
Southwest Airlines Co	LUV	n/a	n/a	2.35%	n/a	n/a	n/a
Las Vegas Sands Corp	LVS	n/a	n/a	1.54%	n/a	n/a	n/a
Lamb Weston Holdings Inc	LW	$11,078	0.02%	1.85%	10.50%	0.0004%	0.0024%
LyondellBasell Industries NV	LYB	$28,234	0.06%	6.17%	-1.00%	0.0037%	-0.0006%
Live Nation Entertainment Inc	LYV	n/a	n/a	0.00%	n/a	n/a	n/a
Mastercard Inc	MA	$455,011	0.96%	0.53%	14.50%	0.0051%	0.1386%
Mid-America Apartment Communities I	MAA	$17,689	0.04%	3.89%	-15.00%	0.0014%	-0.0056%
Marriott International Inc/MD	MAR	$73,202	0.15%	0.97%	11.00%	0.0015%	0.0169%
Masco Corp	MAS	$17,240	0.04%	1.45%	9.50%	0.0005%	0.0034%
McDonald's Corp	MCD	$209,543	0.44%	2.42%	8.00%	0.0107%	0.0352%
Microchip Technology Inc	MCHP	$39,363	0.08%	2.48%	6.00%	0.0020%	0.0050%
McKesson Corp	MCK	$64,915	0.14%	0.57%	10.00%	0.0008%	0.0136%
Moody's Corp	MCO	$82,272	0.17%	0.75%	9.00%	0.0013%	0.0156%
Mondelez International Inc	MDLZ	$91,571	0.19%	2.75%	7.50%	0.0053%	0.0144%
Medtronic PLC	MDT	$114,460	0.24%	3.14%	6.50%	0.0075%	0.0156%
MetLife Inc	MET	$54,919	0.12%	2.78%	7.50%	0.0032%	0.0087%
Meta Platforms Inc	META	$1,237,325	2.60%	0.35%	17.50%	0.0092%	0.4550%
MGM Resorts International	MGM	$10,978	0.02%	0.00%	25.00%	0.0000%	0.0058%
Mohawk Industries Inc	MHK	$8,475	0.02%	0.00%	1.00%	0.0000%	0.0002%
McCormick & Co Inc/MD	MKC	$19,731	0.04%	2.15%	4.50%	0.0009%	0.0019%
MarketAxess Holdings Inc	MKTX	$10,926	0.02%	1.02%	9.00%	0.0002%	0.0021%
Martin Marietta Materials Inc	MLM	$36,203	0.08%	0.53%	11.00%	0.0004%	0.0084%
Marsh & McLennan Cos Inc	MMC	$107,182	0.23%	1.49%	12.00%	0.0034%	0.0270%
3M Co	MMM	$69,959	0.15%	2.18%	30.50%	0.0032%	0.0448%
Monster Beverage Corp	MNST	$51,602	0.11%	0.00%	12.00%	0.0000%	0.0130%
Altria Group Inc	MO	$92,300	0.19%	7.49%	6.00%	0.0145%	0.0116%
Molina Healthcare Inc	MOH	$18,374	0.04%	0.00%	11.50%	0.0000%	0.0044%
Mosaic Co/The	MOS	$8,527	0.02%	3.14%	-9.50%	0.0006%	-0.0017%
Marathon Petroleum Corp	MPC	$48,686	0.10%	2.50%	-6.50%	0.0026%	-0.0066%
Monolithic Power Systems Inc	MPWR	$37,017	0.08%	0.66%	10.50%	0.0005%	0.0082%
Merck & Co Inc	MRK	$259,362	0.55%	3.01%	15.50%	0.0164%	0.0845%
Moderna Inc	MRNA	$20,896	0.04%	0.00%	-18.50%	0.0000%	-0.0081%
Marathon Oil Corp	MRO	$15,495	0.03%	1.59%	12.50%	0.0005%	0.0041%
Morgan Stanley	MS	$188,428	0.40%	3.18%	9.50%	0.0126%	0.0376%
MSCI Inc	MSCI	$44,766	0.09%	1.12%	9.50%	0.0011%	0.0089%
Microsoft Corp	MSFT	$3,021,164	6.35%	0.82%	14.00%	0.0519%	0.8888%
Motorola Solutions Inc	MSI	$74,970	0.16%	0.87%	10.00%	0.0014%	0.0158%
M&T Bank Corp	MTB	n/a	n/a	2.77%	n/a	n/a	n/a
Match Group Inc	MTCH	$9,292	0.02%	0.00%	12.00%	0.0000%	0.0023%
Mettler-Toledo International Inc	MTD	$27,588	0.06%	0.00%	8.50%	0.0000%	0.0049%
Micron Technology Inc	MU	$110,486	0.23%	0.46%	24.00%	0.0011%	0.0557%
Norwegian Cruise Line Holdings Ltd	NCLH	n/a	n/a	0.00%	n/a	n/a	n/a
Nasdaq Inc	NDAQ	$42,486	0.09%	1.30%	3.50%	0.0012%	0.0031%
Nordson Corp	NDSN	$14,175	0.03%	1.26%	10.00%	0.0004%	0.0030%
NextEra Energy Inc	NEE	$162,970	0.34%	2.60%	8.00%	0.0089%	0.0274%
Newmont Corp	NEM	$51,731	0.11%	2.20%	13.00%	0.0024%	0.0141%
Netflix Inc	NFLX	$323,171	0.68%	0.00%	16.50%	0.0000%	0.1121%
NiSource Inc	NI	$16,412	0.03%	3.01%	9.50%	0.0010%	0.0033%
NIKE Inc	NKE	$91,831	0.19%	1.92%	10.50%	0.0037%	0.0203%
Northrop Grumman Corp	NOC	$74,162	0.16%	1.62%	8.00%	0.0025%	0.0125%
ServiceNow Inc	NOW	$192,196	0.40%	0.00%	32.50%	0.0000%	0.1313%
NRG Energy Inc	NRG	$18,657	0.04%	1.80%	11.00%	0.0007%	0.0043%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Norfolk Southern Corp	NSC	$56,657	0.12%	2.16%	9.50%	0.0026%	0.0113%
NetApp Inc	NTAP	$23,613	0.05%	1.80%	7.50%	0.0009%	0.0037%
Northern Trust Corp	NTRS	$19,925	0.04%	2.98%	4.00%	0.0012%	0.0017%
Nucor Corp	NUE	n/a	n/a	1.52%	n/a	n/a	n/a
NVIDIA Corp	NVDA	$3,256,603	6.84%	0.03%	41.00%	0.0021%	2.8057%
NVR Inc	NVR	$28,169	0.06%	0.00%	1.50%	0.0000%	0.0009%
News Corp	NWS	n/a	n/a	0.69%	n/a	n/a	n/a
News Corp	NWSA	$10,338	0.02%	0.73%	14.50%	0.0002%	0.0031%
NXP Semiconductors NV	NXPI	$59,735	0.13%	1.73%	7.50%	0.0022%	0.0094%
Realty Income Corp	O	$51,703	0.11%	5.33%	5.00%	0.0058%	0.0054%
Old Dominion Freight Line Inc	ODFL	$43,142	0.09%	0.52%	7.50%	0.0005%	0.0068%
ONEOK Inc	OKE	$56,596	0.12%	4.09%	12.00%	0.0049%	0.0143%
Omnicom Group Inc	OMC	$19,704	0.04%	2.77%	7.00%	0.0011%	0.0029%
ON Semiconductor Corp	ON	$30,014	0.06%	0.00%	8.00%	0.0000%	0.0050%
Oracle Corp	ORCL	$465,095	0.98%	0.95%	10.00%	0.0093%	0.0977%
O'Reilly Automotive Inc	ORLY	$66,889	0.14%	0.00%	10.50%	0.0000%	0.0148%
Otis Worldwide Corp	OTIS	$39,227	0.08%	1.59%	11.00%	0.0013%	0.0091%
Occidental Petroleum Corp	OXY	$45,911	0.10%	1.76%	6.00%	0.0017%	0.0058%
Palo Alto Networks Inc	PANW	n/a	n/a	0.00%	n/a	n/a	n/a
Paramount Global	PARA	$6,849	0.01%	1.83%	3.00%	0.0003%	0.0004%
Paycom Software Inc	PAYC	$12,053	0.03%	0.72%	21.00%	0.0002%	0.0053%
Paychex Inc	PAYX	$50,145	0.11%	2.81%	8.00%	0.0030%	0.0084%
PACCAR Inc	PCAR	$54,674	0.11%	1.15%	14.50%	0.0013%	0.0167%
PG&E Corp	PCG	$43,219	0.09%	0.20%	9.00%	0.0002%	0.0082%
Public Service Enterprise Group Inc	PEG	$44,541	0.09%	2.68%	5.00%	0.0025%	0.0047%
PepsiCo Inc	PEP	$227,860	0.48%	3.26%	7.50%	0.0156%	0.0359%
Pfizer Inc	PFE	$160,367	0.34%	5.94%	2.50%	0.0200%	0.0084%
Principal Financial Group Inc	PFG	$18,847	0.04%	3.54%	4.00%	0.0014%	0.0016%
Procter & Gamble Co/The	PG	$389,006	0.82%	2.44%	5.00%	0.0199%	0.0409%
Progressive Corp/The	PGR	$142,217	0.30%	0.16%	22.50%	0.0005%	0.0672%
Parker-Hannifin Corp	PH	$81,586	0.17%	1.03%	12.50%	0.0018%	0.0214%
PulteGroup Inc	PHM	$26,564	0.06%	0.62%	8.00%	0.0003%	0.0045%
Packaging Corp of America	PKG	$20,562	0.04%	2.18%	9.00%	0.0009%	0.0039%
Prologis Inc	PLD	$104,572	0.22%	3.40%	0.50%	0.0075%	0.0011%
Palantir Technologies Inc	PLTR	n/a	n/a	0.00%	n/a	n/a	n/a
Philip Morris International Inc	PM	$206,326	0.43%	4.07%	5.00%	0.0176%	0.0217%
PNC Financial Services Group Inc/The	PNC	$74,837	0.16%	3.40%	11.50%	0.0053%	0.0181%
Pentair PLC	PNR	$16,378	0.03%	0.93%	12.00%	0.0003%	0.0041%
Pinnacle West Capital Corp	PNW	$9,976	0.02%	4.08%	4.50%	0.0009%	0.0009%
Insulet Corp	PODD	n/a	n/a	0.00%	n/a	n/a	n/a
Pool Corp	POOL	$13,762	0.03%	1.33%	14.00%	0.0004%	0.0040%
PPG Industries Inc	PPG	$28,886	0.06%	2.18%	7.00%	0.0013%	0.0042%
PPL Corp	PPL	$24,022	0.05%	3.16%	7.50%	0.0016%	0.0038%
Prudential Financial Inc	PRU	$43,603	0.09%	4.25%	4.00%	0.0039%	0.0037%
Public Storage	PSA	$57,817	0.12%	3.65%	7.00%	0.0044%	0.0085%
Phillips 66	PSX	$50,310	0.11%	3.78%	0.50%	0.0040%	0.0005%
PTC Inc	PTC	$22,265	0.05%	0.00%	29.00%	0.0000%	0.0136%
Quanta Services Inc	PWR	$44,524	0.09%	0.12%	16.50%	0.0001%	0.0154%
PayPal Holdings Inc	PYPL	$79,501	0.17%	0.00%	11.50%	0.0000%	0.0192%
QUALCOMM Inc	QCOM	$181,326	0.38%	2.09%	6.00%	0.0080%	0.0229%
Qorvo Inc	QRVO	$6,736	0.01%	0.00%	5.50%	0.0000%	0.0008%
Royal Caribbean Cruises Ltd	RCL	n/a	n/a	0.78%	n/a	n/a	n/a
Regency Centers Corp	REG	$12,966	0.03%	3.75%	11.50%	0.0010%	0.0031%
Regeneron Pharmaceuticals Inc	REGN	$90,586	0.19%	0.00%	1.50%	0.0000%	0.0029%
Regions Financial Corp	RF	$21,844	0.05%	4.19%	4.50%	0.0019%	0.0021%
Raymond James Financial Inc	RJF	$30,525	0.06%	1.21%	10.00%	0.0008%	0.0064%
Ralph Lauren Corp	RL	$7,929	0.02%	1.67%	11.00%	0.0003%	0.0018%
ResMed Inc	RMD	$35,594	0.07%	0.87%	10.00%	0.0007%	0.0075%
Rockwell Automation Inc	ROK	$30,263	0.06%	1.96%	9.50%	0.0012%	0.0060%
Rollins Inc	ROL	$22,830	0.05%	1.40%	9.00%	0.0007%	0.0043%
Roper Technologies Inc	ROP	$57,644	0.12%	0.56%	9.00%	0.0007%	0.0109%
Ross Stores Inc	ROST	$46,354	0.10%	1.05%	14.00%	0.0010%	0.0136%
Republic Services Inc	RSG	$62,004	0.13%	1.17%	11.00%	0.0015%	0.0143%
RTX Corp	RTX	$161,040	0.34%	2.08%	12.00%	0.0070%	0.0406%
Revvity Inc	RVTY	$14,627	0.03%	0.24%	-2.50%	0.0001%	-0.0008%
SBA Communications Corp	SBAC	$24,662	0.05%	1.71%	16.50%	0.0009%	0.0086%
Starbucks Corp	SBUX	$110,714	0.23%	2.50%	9.00%	0.0058%	0.0209%
Charles Schwab Corp/The	SCHW	$125,967	0.26%	1.41%	10.50%	0.0037%	0.0278%
Sherwin-Williams Co/The	SHW	$90,357	0.19%	0.80%	11.00%	0.0015%	0.0209%
J M Smucker Co/The	SJM	$12,078	0.03%	3.81%	7.00%	0.0010%	0.0018%
Schlumberger NV	SLB	$56,585	0.12%	2.75%	22.00%	0.0033%	0.0262%
Super Micro Computer Inc	SMCI	$17,046	0.04%	0.00%	39.00%	0.0000%	0.0140%
Snap-on Inc	SNA	$17,334	0.04%	2.25%	5.50%	0.0008%	0.0020%
Synopsys Inc	SNPS	$78,898	0.17%	0.00%	12.50%	0.0000%	0.0207%
Southern Co/The	SO	$99,644	0.21%	3.16%	6.50%	0.0066%	0.0136%
Solventum Corp	SOLV	n/a	n/a	0.00%	n/a	n/a	n/a
Simon Property Group Inc	SPG	$55,139	0.12%	4.85%	3.50%	0.0056%	0.0041%
S&P Global Inc	SPGI	$152,514	0.32%	0.76%	8.00%	0.0024%	0.0256%
Sempra	SRE	$52,785	0.11%	2.97%	7.00%	0.0033%	0.0078%
STERIS PLC	STE	$21,878	0.05%	1.03%	8.00%	0.0005%	0.0037%
Steel Dynamics Inc	STLD	$20,137	0.04%	1.41%	2.00%	0.0006%	0.0008%
State Street Corp	STT	n/a	n/a	3.28%	n/a	n/a	n/a
Seagate Technology Holdings PLC	STX	$21,231	0.04%	2.87%	32.00%	0.0013%	0.0143%
Constellation Brands Inc	STZ	$42,178	0.09%	1.74%	6.00%	0.0015%	0.0053%
Smurfit WestRock PLC	SW	n/a	n/a	2.35%	n/a	n/a	n/a
Stanley Black & Decker Inc	SWK	$14,328	0.03%	3.53%	11.00%	0.0011%	0.0033%
Skyworks Solutions Inc	SWKS	n/a	n/a	3.20%	n/a	n/a	n/a
Synchrony Financial	SYF	$21,468	0.05%	1.81%	47.00%	0.0008%	0.0212%
Stryker Corp	SYK	$135,820	0.29%	0.90%	9.50%	0.0026%	0.0271%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Sysco Corp	SYY	$36,817	0.08%	2.72%	13.50%	0.0021%	0.0104%
AT&T Inc	T	$161,731	0.34%	4.92%	4.00%	0.0167%	0.0136%
Molson Coors Beverage Co	TAP	$10,490	0.02%	3.23%	11.50%	0.0007%	0.0025%
TransDigm Group Inc	TDG	$73,074	0.15%	0.00%	22.00%	0.0000%	0.0338%
Teledyne Technologies Inc	TDY	$21,219	0.04%	0.00%	7.00%	0.0000%	0.0031%
Bio-Techne Corp	TECH	$11,702	0.02%	0.43%	10.00%	0.0001%	0.0025%
TE Connectivity PLC	TEL	$44,804	0.09%	1.76%	10.50%	0.0017%	0.0099%
Teradyne Inc	TER	$17,331	0.04%	0.45%	9.50%	0.0002%	0.0035%
Truist Financial Corp	TFC	$57,650	0.12%	4.83%	1.50%	0.0059%	0.0018%
Teleflex Inc	TFX	$9,338	0.02%	0.68%	8.50%	0.0001%	0.0017%
Target Corp	TGT	$69,120	0.15%	2.99%	9.50%	0.0043%	0.0138%
TJX Cos Inc/The	TJX	$127,483	0.27%	1.33%	17.00%	0.0036%	0.0455%
Thermo Fisher Scientific Inc	TMO	$208,692	0.44%	0.29%	6.00%	0.0013%	0.0263%
T-Mobile US Inc	TMUS	$258,974	0.54%	1.58%	20.00%	0.0086%	0.1088%
Tapestry Inc	TPR	$11,037	0.02%	2.95%	9.00%	0.0007%	0.0021%
Targa Resources Corp	TRGP	$36,578	0.08%	1.80%	20.00%	0.0014%	0.0154%
Trimble Inc	TRMB	$14,775	0.03%	0.00%	5.50%	0.0000%	0.0017%
T Rowe Price Group Inc	TROW	$24,455	0.05%	4.51%	5.50%	0.0023%	0.0028%
Travelers Cos Inc/The	TRV	$55,833	0.12%	1.71%	12.00%	0.0020%	0.0141%
Tractor Supply Co	TSCO	$28,640	0.06%	1.66%	11.50%	0.0010%	0.0069%
Tesla Inc	TSLA	$802,033	1.69%	0.00%	19.00%	0.0000%	0.3202%
Tyson Foods Inc	TSN	$16,746	0.04%	3.35%	6.00%	0.0012%	0.0021%
Trane Technologies PLC	TT	$83,295	0.18%	0.91%	14.00%	0.0016%	0.0245%
Take-Two Interactive Software Inc	TTWO	n/a	n/a	0.00%	n/a	n/a	n/a
Texas Instruments Inc	TXN	$185,326	0.39%	2.68%	3.00%	0.0104%	0.0117%
Textron Inc	TXT	$14,919	0.03%	0.10%	13.00%	0.0000%	0.0041%
Tyler Technologies Inc	TYL	$25,918	0.05%	0.00%	8.00%	0.0000%	0.0044%
United Airlines Holdings Inc	UAL	n/a	n/a	0.00%	n/a	n/a	n/a
Uber Technologies Inc	UBER	n/a	n/a	0.00%	n/a	n/a	n/a
UDR Inc	UDR	$13,921	0.03%	4.03%	2.50%	0.0012%	0.0007%
Universal Health Services Inc	UHS	$12,149	0.03%	0.39%	9.00%	0.0001%	0.0023%
Ulta Beauty Inc	ULTA	$17,384	0.04%	0.00%	6.50%	0.0000%	0.0024%
UnitedHealth Group Inc	UNH	$521,269	1.10%	1.49%	12.00%	0.0163%	0.1314%
Union Pacific Corp	UNP	$140,694	0.30%	2.31%	8.00%	0.0068%	0.0237%
United Parcel Service Inc	UPS	$98,200	0.21%	4.86%	3.50%	0.0100%	0.0072%
United Rentals Inc	URI	$53,338	0.11%	0.80%	19.00%	0.0009%	0.0213%
US Bancorp	USB	$75,388	0.16%	4.14%	4.00%	0.0066%	0.0063%
Visa Inc	V	$484,178	1.02%	0.81%	13.50%	0.0083%	0.1374%
VICI Properties Inc	VICI	$33,130	0.07%	5.45%	10.50%	0.0038%	0.0073%
Valero Energy Corp	VLO	$41,080	0.09%	3.30%	9.50%	0.0028%	0.0082%
Veralto Corp	VLTO	$25,272	0.05%	0.35%	6.00%	0.0002%	0.0032%
Vulcan Materials Co	VMC	$36,175	0.08%	0.67%	8.00%	0.0005%	0.0061%
Verisk Analytics Inc	VRSK	$38,793	0.08%	0.57%	8.50%	0.0005%	0.0069%
VeriSign Inc	VRSN	$16,994	0.04%	0.00%	12.00%	0.0000%	0.0043%
Vertex Pharmaceuticals Inc	VRTX	$122,851	0.26%	0.00%	11.00%	0.0000%	0.0284%
Vistra Corp	VST	n/a	n/a	0.71%	n/a	n/a	n/a
Ventas Inc	VTR	$27,464	0.06%	2.75%	23.00%	0.0016%	0.0133%
Viatris Inc	VTRS	$13,846	0.03%	4.14%	-1.50%	0.0012%	-0.0004%
Verizon Communications Inc	VZ	$177,352	0.37%	6.43%	0.50%	0.0240%	0.0019%
Westinghouse Air Brake Technologies	WAB	$32,312	0.07%	0.43%	16.00%	0.0003%	0.0109%
Waters Corp	WAT	$19,180	0.04%	0.00%	6.50%	0.0000%	0.0026%
Walgreens Boots Alliance Inc	WBA	$8,179	0.02%	10.57%	-7.00%	0.0018%	-0.0012%
Warner Bros Discovery Inc	WBD	n/a	n/a	0.00%	n/a	n/a	n/a
Western Digital Corp	WDC	$22,578	0.05%	0.00%	22.50%	0.0000%	0.0107%
WEC Energy Group Inc	WEC	$30,195	0.06%	3.50%	6.00%	0.0022%	0.0038%
Welltower Inc	WELL	$83,988	0.18%	1.99%	26.50%	0.0035%	0.0468%
Wells Fargo & Co	WFC	$216,151	0.45%	2.46%	9.50%	0.0112%	0.0431%
Waste Management Inc	WM	$86,635	0.18%	1.39%	6.00%	0.0025%	0.0109%
Williams Cos Inc/The	WMB	$63,835	0.13%	3.63%	11.00%	0.0049%	0.0148%
Walmart Inc	WMT	$658,735	1.38%	1.01%	9.50%	0.0140%	0.1315%
W R Berkley Corp	WRB	$21,756	0.05%	0.56%	13.00%	0.0003%	0.0059%
West Pharmaceutical Services Inc	WST	$22,301	0.05%	0.27%	7.50%	0.0001%	0.0035%
Willis Towers Watson PLC	WTW	$30,438	0.06%	1.16%	9.50%	0.0007%	0.0061%
Weyerhaeuser Co	WY	$22,640	0.05%	2.57%	-2.00%	0.0012%	-0.0010%
Wynn Resorts Ltd	WYNN	$10,657	0.02%	1.04%	27.00%	0.0002%	0.0060%
Xcel Energy Inc	XEL	$38,365	0.08%	3.28%	6.00%	0.0026%	0.0048%
Exxon Mobil Corp	XOM	$518,833	1.09%	3.25%	-3.00%	0.0355%	-0.0327%
Xylem Inc/NY	XYL	$29,586	0.06%	1.18%	12.00%	0.0007%	0.0075%
Yum! Brands Inc	YUM	$36,878	0.08%	2.04%	10.00%	0.0016%	0.0077%
Zimmer Biomet Holdings Inc	ZBH	$21,285	0.04%	0.90%	6.50%	0.0004%	0.0029%
Zebra Technologies Corp	ZBRA	$19,702	0.04%	0.00%	1.00%	0.0000%	0.0004%
Zoetis Inc	ZTS	$80,996	0.17%	0.97%	7.50%	0.0016%	0.0128%
		$47,588,577					

[4] Source: Value Line as of 10/31/2024
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of 10/31/2024
[7] Source: Value Line as of 10/31/2024
[8] Equals [5] x [6]
[9] Equals [5] x [7]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

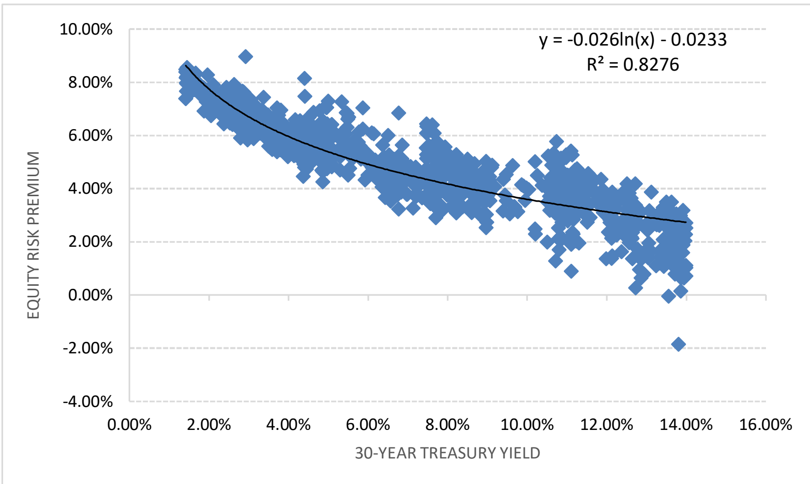
Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 409

December 30, 2024

Bond Yield Plus Risk Premium (Gas)

[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
-2.335%	-2.577%			
Current 30-Year Treasury		4.30%	5.77%	10.07%
Projected 30-Year Treasury		4.28%	5.78%	10.07%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield; Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024, at 2; Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Exhibit JEN-8
[7] Equals [5] + [6]
[8] Source: S&P Capital IQ
[9] Source: S&P Capital IQ
[10] Source: Bloomberg Professional, equals 187-trading day average (i.e. lag period)
[11] Equals [9] - [10]

Bond Yield Plus Risk Premium (Gas)

[8]	[9]	[10]	[11]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.86%	4.14%
3/5/1980	14.00%	9.91%	4.09%
3/7/1980	13.50%	9.95%	3.55%
3/14/1980	14.00%	10.04%	3.96%
3/27/1980	12.69%	10.20%	2.49%
4/1/1980	14.75%	10.26%	4.49%
4/29/1980	12.50%	10.51%	1.99%
5/7/1980	14.27%	10.56%	3.71%
5/8/1980	13.75%	10.56%	3.19%
5/19/1980	15.50%	10.62%	4.88%
5/27/1980	14.60%	10.65%	3.95%
5/29/1980	16.00%	10.67%	5.33%
6/10/1980	13.78%	10.71%	3.07%
6/25/1980	14.25%	10.74%	3.51%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.79%	2.11%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	14.00%	10.87%	3.13%
8/28/1980	13.61%	10.87%	2.74%
9/4/1980	14.00%	10.90%	3.10%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	13.00%	11.10%	1.90%
10/28/1980	12.00%	11.10%	0.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.12%	3.88%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.14%	2.36%
12/5/1980	14.60%	11.13%	3.47%
12/8/1980	16.40%	11.13%	5.27%
12/12/1980	15.45%	11.15%	4.30%
12/17/1980	14.40%	11.16%	3.24%
12/17/1980	14.20%	11.16%	3.04%
12/18/1980	14.00%	11.16%	2.84%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.14%	3.36%
12/31/1980	14.56%	11.14%	3.42%
1/7/1981	14.30%	11.13%	3.17%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.40%	3.10%
3/12/1981	15.65%	11.60%	4.05%
3/25/1981	15.30%	11.74%	3.56%
4/1/1981	15.30%	11.82%	3.48%
4/9/1981	15.00%	11.91%	3.09%
4/29/1981	13.50%	12.12%	1.38%
4/29/1981	14.25%	12.12%	2.13%
4/30/1981	15.00%	12.14%	2.86%
4/30/1981	13.60%	12.14%	1.46%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.46%	2.21%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.60%	2.15%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.69%	3.31%
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.78%	3.00%
7/27/1981	15.50%	12.82%	2.68%
7/27/1981	13.77%	12.82%	0.95%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.02%	2.43%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.24%	1.10%
9/24/1981	16.25%	13.26%	2.99%
9/29/1981	14.50%	13.31%	1.19%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.36%	1.44%
10/12/1981	16.25%	13.43%	2.82%
10/20/1981	16.50%	13.50%	3.00%
10/20/1981	17.00%	13.50%	3.50%
10/20/1981	15.25%	13.50%	1.75%
10/23/1981	15.50%	13.54%	1.96%
10/26/1981	13.50%	13.56%	-0.06%
10/29/1981	16.50%	13.60%	2.90%
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.66%	3.09%
12/1/1981	16.00%	13.66%	2.34%
12/1/1981	15.70%	13.66%	2.04%
12/15/1981	15.81%	13.69%	2.12%
12/17/1981	14.75%	13.70%	1.05%
12/22/1981	15.70%	13.72%	1.98%
12/22/1981	16.00%	13.72%	2.28%
12/30/1981	16.25%	13.74%	2.51%
12/30/1981	16.00%	13.74%	2.26%
1/4/1982	15.50%	13.75%	1.75%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.86%	0.14%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.92%	3.18%
3/26/1982	16.00%	13.97%	2.03%
3/31/1982	16.25%	13.98%	2.27%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.99%	1.01%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.99%	1.11%
4/12/1982	16.70%	13.99%	2.71%
4/18/1982	14.70%	13.99%	0.71%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.85%	2.15%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	16.00%	13.79%	2.21%
7/1/1982	15.55%	13.79%	1.76%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.75%	3.05%
7/22/1982	14.50%	13.71%	0.79%
7/28/1982	16.10%	13.68%	2.42%
7/30/1982	14.82%	13.66%	1.16%
8/4/1982	15.58%	13.64%	1.94%
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.59%	2.41%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.57%	1.93%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	14.74%	13.42%	1.32%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.70%	13.42%	3.28%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.33%	1.67%
10/15/1982	15.90%	13.26%	2.64%
10/19/1982	15.90%	13.22%	2.68%
10/27/1982	17.00%	13.12%	3.88%
10/28/1982	14.75%	13.11%	1.64%
11/2/1982	16.25%	13.07%	3.18%
11/4/1982	15.75%	13.03%	2.72%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
11/5/1982	14.73%	13.01%	1.72%
11/17/1982	16.00%	12.86%	3.14%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	14.50%	12.77%	1.73%
11/24/1982	16.02%	12.77%	3.25%
11/30/1982	15.65%	12.72%	2.93%
11/30/1982	16.10%	12.72%	3.38%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	16.00%	12.72%	3.28%
11/30/1982	12.98%	12.72%	0.26%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.63%	3.12%
12/13/1982	16.00%	12.58%	3.42%
12/14/1982	16.40%	12.57%	3.83%
12/17/1982	16.25%	12.52%	3.73%
12/20/1982	15.00%	12.51%	2.49%
12/21/1982	15.70%	12.49%	3.21%
12/28/1982	15.25%	12.42%	2.83%
12/28/1982	15.25%	12.42%	2.83%
12/29/1982	16.25%	12.41%	3.84%
12/29/1982	16.25%	12.41%	3.84%
1/11/1983	15.90%	12.26%	3.64%
1/12/1983	15.50%	12.24%	3.26%
1/18/1983	15.00%	12.18%	2.82%
1/24/1983	15.50%	12.13%	3.37%
1/24/1983	16.00%	12.13%	3.87%
1/28/1983	14.90%	12.08%	2.82%
1/31/1983	15.00%	12.07%	2.93%
2/10/1983	15.00%	11.97%	3.03%
2/25/1983	15.70%	11.84%	3.86%
3/2/1983	15.25%	11.79%	3.46%
3/16/1983	16.00%	11.62%	4.38%
3/21/1983	14.96%	11.57%	3.39%
3/23/1983	15.40%	11.53%	3.87%
3/23/1983	16.10%	11.53%	4.57%
3/24/1983	15.00%	11.51%	3.49%
4/12/1983	13.25%	11.30%	1.95%
4/29/1983	15.05%	11.09%	3.96%
5/3/1983	15.40%	11.06%	4.34%
5/9/1983	15.50%	11.00%	4.50%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.84%	3.16%
6/2/1983	14.50%	10.82%	3.68%
6/7/1983	14.50%	10.80%	3.70%
6/9/1983	14.85%	10.79%	4.06%
6/20/1983	14.15%	10.74%	3.41%
6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.71%	3.79%
6/30/1983	14.80%	10.70%	4.10%
6/30/1983	15.90%	10.70%	5.20%
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.69%	4.31%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.70%	4.30%
7/19/1983	15.10%	10.70%	4.40%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
8/31/1983	14.75%	10.87%	3.88%
8/31/1983	15.25%	10.87%	4.38%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	16.00%	11.26%	4.74%
12/20/1983	15.40%	11.26%	4.14%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.30%	3.70%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.42%	4.48%
2/14/1984	14.25%	11.51%	2.74%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.70%	4.30%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.86%	4.34%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.04%	2.36%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.37%	3.63%
8/7/1984	16.69%	12.51%	4.18%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.54%	2.28%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.57%	2.18%
8/30/1984	15.60%	12.58%	3.02%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.65%	2.35%
10/24/1984	15.50%	12.65%	2.85%
11/7/1984	15.00%	12.64%	2.36%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
11/20/1984	15.92%	12.63%	3.29%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.27%	2.73%
2/20/1985	14.50%	12.25%	2.25%
2/22/1985	14.86%	12.25%	2.61%
3/14/1985	15.50%	12.16%	3.34%
3/28/1985	14.80%	12.08%	2.72%
4/9/1985	15.50%	12.02%	3.48%
4/16/1985	15.70%	11.96%	3.74%
6/10/1985	15.75%	11.58%	4.17%
6/26/1985	14.82%	11.46%	3.36%
7/9/1985	15.00%	11.38%	3.62%
7/26/1985	14.50%	11.26%	3.24%
8/29/1985	14.50%	11.11%	3.39%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.03%	4.27%
9/25/1985	14.50%	11.02%	3.48%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.91%	4.34%
11/8/1985	12.94%	10.85%	2.09%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.71%	1.29%
12/11/1985	14.90%	10.68%	4.22%
12/20/1985	15.00%	10.59%	4.41%
12/20/1985	14.88%	10.59%	4.29%
12/20/1985	15.00%	10.59%	4.41%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.51%	3.49%
12/31/1985	14.50%	10.51%	3.99%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.20%	2.30%
2/12/1986	15.20%	10.19%	5.01%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.76%	3.14%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.18%	4.07%
5/28/1986	14.00%	9.12%	4.88%
5/29/1986	13.90%	9.10%	4.80%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.97%	5.03%
6/13/1986	13.55%	8.94%	4.61%
6/27/1986	11.88%	8.77%	3.11%
7/14/1986	12.60%	8.59%	4.01%
7/30/1986	13.30%	8.38%	4.92%
8/14/1986	13.50%	8.22%	5.28%
9/5/1986	13.30%	8.02%	5.28%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.67%	5.33%
10/31/1986	13.75%	7.66%	6.09%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
11/10/1986	14.00%	7.61%	6.39%
11/19/1986	13.75%	7.56%	6.19%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.47%	6.33%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.47%	5.53%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.73%	5.77%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.09%	3.31%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.98%	8.55%	4.43%
10/20/1987	12.60%	8.55%	4.05%
11/12/1987	12.75%	8.68%	4.07%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	13.25%	8.94%	4.31%
12/31/1987	12.85%	8.94%	3.91%
1/15/1988	13.15%	8.99%	4.16%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.95%	4.05%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.93%	3.07%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.94%	3.86%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%
10/28/1988	13.00%	8.95%	4.05%
11/15/1988	12.00%	8.98%	3.02%
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.81%	4.19%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.72%	4.18%
9/21/1989	12.10%	8.62%	3.48%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	13.00%	8.45%	4.55%
11/9/1989	12.60%	8.45%	4.15%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.32%	4.93%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.90%	8.25%	4.65%
12/21/1989	12.80%	8.25%	4.55%
12/27/1989	12.50%	8.23%	4.27%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.16%	4.34%
1/26/1990	12.10%	8.14%	3.96%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.35%	4.90%
7/6/1990	12.10%	8.36%	3.74%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.53%	3.97%
8/31/1990	12.50%	8.53%	3.97%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.50%	8.70%	3.80%
11/21/1990	12.10%	8.70%	3.40%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/21/1990	13.60%	8.67%	4.93%
12/21/1990	12.50%	8.67%	3.83%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.63%	4.62%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.80%	8.56%	4.24%
2/15/1991	12.70%	8.56%	4.14%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.34%	3.36%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.30%	4.60%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.15%	3.60%
12/19/1991	12.80%	8.14%	4.66%
12/19/1991	12.60%	8.14%	4.46%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.98%	3.77%
3/18/1992	12.50%	7.94%	4.56%
5/15/1992	12.75%	7.86%	4.89%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.70%	5.05%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.40%	7.62%	4.78%
12/22/1992	12.30%	7.62%	4.68%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.75%	7.25%	4.50%
5/3/1993	11.50%	7.25%	4.25%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.06%	4.72%
7/21/1993	11.90%	7.06%	4.84%
7/23/1993	11.50%	7.05%	4.45%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.97%	3.78%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.47%	6.87%	4.60%
9/1/1993	11.25%	6.87%	4.38%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.72%	4.28%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.67%	4.83%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.64%	5.11%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.20%	6.57%	3.63%
10/29/1993	10.10%	6.57%	3.53%
10/29/1993	11.25%	6.57%	4.68%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.45%	4.15%
12/16/1993	11.20%	6.45%	4.75%
12/21/1993	11.30%	6.44%	4.86%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	11.00%	7.20%	3.80%
9/29/1994	10.90%	7.20%	3.70%
10/7/1994	11.87%	7.26%	4.61%
10/18/1994	11.50%	7.32%	4.18%
10/18/1994	11.50%	7.32%	4.18%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.72%	3.28%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.98%	3.78%
11/7/1995	12.50%	6.86%	5.64%
11/8/1995	11.30%	6.85%	4.45%
11/8/1995	11.10%	6.85%	4.25%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.45%	4.85%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.40%	4.37%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.40%	4.60%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.86%	4.14%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.00%	5.25%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.86%	6.24%
2/5/2001	11.50%	5.75%	5.75%
3/15/2001	11.25%	5.66%	5.59%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	11.00%	5.54%	5.46%
10/24/2001	10.30%	5.54%	4.76%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.48%	6.82%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.50%	5.30%	5.20%
11/20/2002	10.00%	5.30%	4.70%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.16%	6.09%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.92%	7.08%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.81%	5.39%
9/17/2003	9.90%	4.85%	5.05%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.75%	4.88%	5.87%
10/31/2003	10.20%	4.88%	5.32%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.53%	5.47%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.52%	5.88%
12/21/2005	11.00%	4.52%	6.48%
12/22/2005	10.20%	4.52%	5.68%
12/22/2005	11.00%	4.52%	6.48%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	10.00%	4.87%	5.13%
7/24/2006	9.60%	4.87%	4.73%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.97%	4.74%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.84%	5.41%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.92%	4.78%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.48%	5.82%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.41%	6.09%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.89%	6.41%
3/25/2009	10.17%	3.84%	6.33%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.12%	6.03%
10/28/2009	10.15%	4.12%	6.03%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.26%	6.04%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%
12/18/2009	10.40%	4.26%	6.14%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.30%	6.08%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.33%	4.37%	5.96%
1/21/2010	10.23%	4.37%	5.86%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.46%	5.54%
6/18/2010	10.30%	4.46%	5.84%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.17%	5.58%
11/2/2010	9.75%	4.17%	5.58%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	10.09%	4.12%	5.97%
12/6/2010	9.56%	4.12%	5.44%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.11%	6.22%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.10%	5.82%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.32%	6.18%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.38%	4.45%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.06%	3.59%	5.47%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.75%	3.16%	6.59%
4/24/2012	9.50%	3.16%	6.34%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	10.00%	2.92%	7.08%
10/31/2012	9.30%	2.92%	6.38%
11/1/2012	9.45%	2.91%	6.54%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.90%	7.40%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.50%	2.87%	7.63%
12/4/2012	10.00%	2.87%	7.13%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.50%	2.84%	7.66%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.25%	2.84%	7.41%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.92%	6.88%
4/23/2013	9.80%	2.96%	6.84%
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.33%	6.27%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.53%	6.20%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.55%	6.17%
12/30/2013	10.00%	3.57%	6.43%
1/21/2014	9.65%	3.66%	5.99%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.72%	6.13%
2/28/2014	9.55%	3.73%	5.82%
3/16/2014	9.72%	3.74%	5.98%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
9/4/2014	9.10%	3.50%	5.60%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.44%	6.31%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.30%	6.90%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.84%	6.16%
10/30/2015	9.80%	2.87%	6.93%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.94%	6.56%
1/6/2016	9.50%	2.97%	6.53%
1/6/2016	9.50%	2.97%	6.53%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.56%	6.94%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%
10/13/2016	10.20%	2.48%	7.72%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.47%	7.33%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.51%	7.59%
12/15/2016	9.00%	2.53%	6.47%
12/15/2016	9.00%	2.53%	6.47%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.77%	6.73%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.81%	6.69%
5/23/2017	9.60%	2.88%	6.72%
6/6/2017	9.70%	2.91%	6.79%
6/22/2017	9.70%	2.93%	6.77%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
6/30/2017	9.60%	2.94%	6.66%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%
10/30/2017	10.05%	2.90%	7.15%
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.86%	6.94%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%
1/31/2018	9.80%	2.83%	6.97%
2/21/2018	9.80%	2.84%	6.96%
2/21/2018	9.80%	2.84%	6.96%
2/28/2018	9.50%	2.85%	6.65%
3/15/2018	9.00%	2.87%	6.13%
3/26/2018	10.19%	2.88%	7.31%
4/26/2018	9.50%	2.91%	6.59%
4/27/2018	9.30%	2.91%	6.39%
5/2/2018	9.50%	2.91%	6.59%
5/3/2018	9.70%	2.91%	6.79%
5/29/2018	9.40%	2.95%	6.45%
6/6/2018	9.80%	2.96%	6.84%
6/14/2018	8.80%	2.97%	5.83%
7/16/2018	9.60%	2.98%	6.62%
7/20/2018	9.40%	2.99%	6.41%
8/24/2018	9.28%	3.02%	6.26%
8/28/2018	10.00%	3.03%	6.97%
9/13/2018	10.00%	3.04%	6.96%
9/14/2018	10.00%	3.05%	6.95%
9/19/2018	9.85%	3.05%	6.80%
9/20/2018	9.80%	3.05%	6.75%
9/26/2018	9.40%	3.06%	6.34%
9/26/2018	10.20%	3.06%	7.14%
9/28/2018	9.50%	3.07%	6.43%
9/28/2018	9.50%	3.07%	6.43%
10/5/2018	9.61%	3.08%	6.53%
10/15/2018	9.80%	3.09%	6.71%
10/26/2018	9.40%	3.11%	6.29%
10/29/2018	9.60%	3.11%	6.49%
11/1/2018	9.87%	3.11%	6.76%
11/8/2018	9.70%	3.12%	6.58%
11/8/2018	9.70%	3.12%	6.58%
12/11/2018	9.70%	3.14%	6.56%
12/12/2018	9.30%	3.14%	6.16%
12/13/2018	9.60%	3.14%	6.46%
12/19/2018	9.30%	3.14%	6.16%
12/21/2018	9.35%	3.14%	6.21%
12/24/2018	9.25%	3.14%	6.11%
12/24/2018	9.25%	3.14%	6.11%
1/4/2019	9.80%	3.14%	6.66%
1/18/2019	9.70%	3.14%	6.56%
3/14/2019	9.00%	3.12%	5.88%
3/27/2019	9.70%	3.12%	6.58%
4/30/2019	9.73%	3.11%	6.62%
5/7/2019	9.65%	3.10%	6.55%

[8]	[9]	[10]	[11]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/21/2019	9.80%	3.10%	6.70%
9/4/2019	10.00%	2.76%	7.24%
9/26/2019	9.90%	2.69%	7.21%
10/2/2019	9.73%	2.67%	7.06%
10/2/2019	9.90%	2.67%	7.23%
10/8/2019	9.40%	2.64%	6.76%
10/15/2019	9.70%	2.62%	7.08%
10/21/2019	9.40%	2.60%	6.80%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	10.20%	2.57%	7.63%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	9.70%	2.57%	7.13%
11/7/2019	9.35%	2.55%	6.80%
11/13/2019	9.60%	2.54%	7.06%
11/13/2019	9.60%	2.54%	7.06%
12/6/2019	9.87%	2.47%	7.40%
12/11/2019	9.40%	2.46%	6.94%
12/17/2019	9.75%	2.44%	7.31%
12/18/2019	9.60%	2.44%	7.16%
12/18/2019	9.60%	2.44%	7.16%
12/19/2019	10.20%	2.44%	7.76%
12/19/2019	10.05%	2.44%	7.61%
12/19/2019	10.25%	2.44%	7.81%
12/20/2019	9.20%	2.44%	6.76%
12/26/2019	9.75%	2.42%	7.33%
1/15/2020	9.35%	2.37%	6.98%
1/16/2020	8.80%	2.37%	6.43%
1/24/2020	9.44%	2.35%	7.09%
2/3/2020	9.40%	2.32%	7.08%
2/24/2020	9.10%	2.27%	6.83%
2/25/2020	9.50%	2.27%	7.23%
2/28/2020	9.70%	2.25%	7.45%
3/25/2020	9.40%	2.15%	7.25%
3/26/2020	9.48%	2.14%	7.34%
4/21/2020	9.80%	2.02%	7.78%
5/19/2020	9.20%	1.94%	7.26%
6/16/2020	9.65%	1.86%	7.79%
7/8/2020	9.40%	1.80%	7.60%
8/4/2020	9.50%	1.70%	7.80%
8/20/2020	9.90%	1.64%	8.26%
8/21/2020	9.35%	1.64%	7.71%
9/10/2020	9.90%	1.57%	8.33%
9/23/2020	9.60%	1.53%	8.07%
9/25/2020	9.25%	1.52%	7.73%
9/25/2020	9.25%	1.52%	7.73%
10/4/2020	9.80%	1.50%	8.30%
10/7/2020	9.70%	1.49%	8.21%
10/12/2020	9.20%	1.48%	7.72%
10/16/2020	9.40%	1.46%	7.94%
10/30/2020	9.90%	1.44%	8.46%
11/7/2020	9.60%	1.43%	8.17%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	9.90%	1.42%	8.48%
11/24/2020	9.80%	1.42%	8.38%
12/9/2020	9.10%	1.43%	7.67%
12/10/2020	9.40%	1.43%	7.97%
12/16/2020	9.38%	1.44%	7.94%
12/16/2020	9.65%	1.44%	8.21%

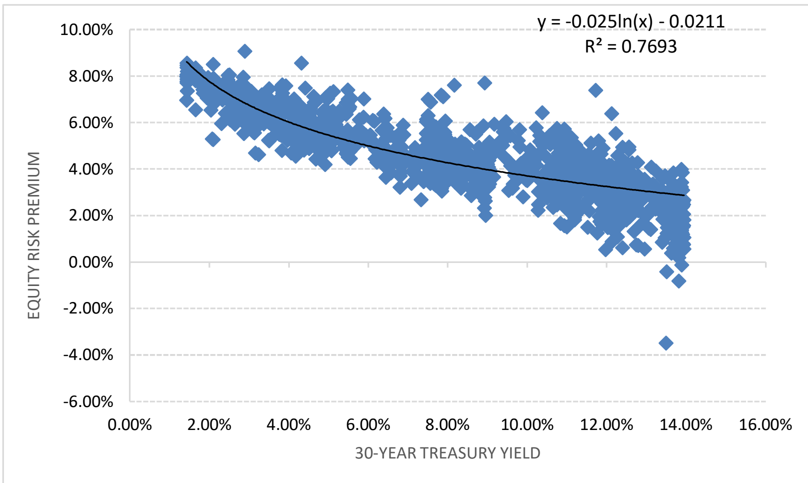
[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/23/2020	10.00%	1.45%	8.55%
1/6/2021	9.60%	1.47%	8.13%
1/6/2021	9.40%	1.47%	7.93%
1/13/2021	9.67%	1.49%	8.18%
1/26/2021	9.50%	1.51%	7.99%
2/16/2021	9.80%	1.56%	8.24%
2/19/2021	9.86%	1.57%	8.29%
2/24/2021	9.25%	1.57%	7.68%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
4/9/2021	9.70%	1.73%	7.97%
5/5/2021	9.30%	1.83%	7.47%
5/18/2021	9.40%	1.87%	7.53%
5/19/2021	8.80%	1.88%	6.92%
6/17/2021	10.24%	1.97%	8.27%
6/30/2021	9.43%	2.00%	7.43%
7/27/2021	9.54%	2.03%	7.51%
7/30/2021	9.30%	2.04%	7.26%
8/12/2021	8.80%	2.05%	6.75%
8/12/2021	8.80%	2.05%	6.75%
9/1/2021	9.40%	2.07%	7.33%
9/8/2021	9.67%	2.08%	7.59%
9/9/2021	9.85%	2.08%	7.77%
9/14/2021	9.50%	2.08%	7.42%
9/27/2021	9.40%	2.09%	7.31%
9/29/2021	9.80%	2.10%	7.70%
9/30/2021	9.70%	2.10%	7.60%
10/6/2021	9.70%	2.10%	7.60%
10/27/2021	9.37%	2.12%	7.25%
11/17/2021	9.80%	2.11%	7.69%
11/17/2021	9.60%	2.11%	7.49%
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.75%	2.11%	7.64%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.10%	7.70%
11/30/2021	9.40%	2.09%	7.31%
12/3/2021	9.65%	2.08%	7.57%
12/9/2021	9.90%	2.07%	7.83%
12/13/2021	9.20%	2.06%	7.14%
12/28/2021	9.35%	2.03%	7.32%
12/28/2021	9.60%	2.03%	7.57%
12/28/2021	9.38%	2.03%	7.35%
1/3/2022	9.25%	2.03%	7.22%
1/6/2022	9.60%	2.02%	7.58%
1/20/2022	9.00%	2.01%	6.99%
1/21/2022	9.60%	2.01%	7.59%
3/22/2022	9.40%	2.02%	7.38%
3/22/2022	9.40%	2.02%	7.38%
4/14/2022	9.20%	2.08%	7.12%
5/19/2022	9.23%	2.23%	7.00%
6/16/2022	9.25%	2.36%	6.89%
7/7/2022	9.90%	2.45%	7.45%
7/20/2022	9.30%	2.50%	6.80%
7/27/2022	9.85%	2.53%	7.32%
8/2/2022	9.40%	2.56%	6.84%
8/17/2022	9.60%	2.62%	6.98%
8/18/2022	9.39%	2.63%	6.76%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
8/23/2022	9.40%	2.65%	6.75%
9/15/2022	9.30%	2.79%	6.51%
10/10/2022	9.60%	2.94%	6.66%
10/12/2022	9.60%	2.96%	6.64%
10/24/2022	9.40%	3.04%	6.36%
10/25/2022	9.20%	3.05%	6.15%
10/27/2022	9.80%	3.07%	6.73%
10/27/2022	9.70%	3.07%	6.63%
11/3/2022	10.20%	3.12%	7.08%
11/17/2022	9.65%	3.22%	6.43%
11/30/2022	9.38%	3.29%	6.09%
12/15/2022	9.80%	3.35%	6.45%
12/21/2022	9.60%	3.38%	6.22%
12/22/2022	9.40%	3.39%	6.01%
12/22/2022	9.80%	3.39%	6.41%
12/23/2022	9.60%	3.39%	6.21%
12/29/2022	9.80%	3.42%	6.38%
12/29/2022	9.80%	3.42%	6.38%
1/19/2023	9.60%	3.48%	6.12%
1/23/2023	9.30%	3.49%	5.81%
1/24/2023	10.25%	3.49%	6.76%
1/26/2023	9.60%	3.49%	6.11%
3/23/2023	9.57%	3.63%	5.94%
3/28/2023	9.50%	3.64%	5.86%
5/4/2023	9.30%	3.73%	5.57%
6/30/2023	9.50%	3.81%	5.69%
7/20/2023	9.25%	3.79%	5.46%
8/30/2023	9.90%	3.85%	6.05%
8/30/2023	9.80%	3.85%	5.95%
8/31/2023	9.40%	3.85%	5.55%
9/20/2023	9.49%	3.90%	5.59%
9/20/2023	9.35%	3.90%	5.45%
10/5/2023	9.30%	3.96%	5.34%
10/6/2023	9.80%	3.97%	5.83%
10/12/2023	9.20%	3.99%	5.21%
10/12/2023	9.20%	3.99%	5.21%
10/25/2023	9.55%	4.06%	5.49%
10/26/2023	9.65%	4.06%	5.59%
10/26/2023	9.50%	4.06%	5.44%
11/1/2023	9.60%	4.09%	5.51%
11/3/2023	9.70%	4.10%	5.60%
11/7/2023	9.65%	4.11%	5.54%
11/9/2023	10.15%	4.12%	6.03%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	9.80%	4.12%	5.68%
11/16/2023	9.51%	4.14%	5.37%
11/16/2023	9.44%	4.14%	5.30%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.38%	4.14%	5.24%
12/4/2023	9.80%	4.18%	5.62%
12/14/2023	9.45%	4.21%	5.24%
12/14/2023	9.50%	4.21%	5.29%
12/15/2023	9.65%	4.21%	5.44%
12/21/2023	9.75%	4.22%	5.53%
12/22/2023	10.50%	4.22%	6.28%
1/17/2024	9.85%	4.26%	5.59%
1/31/2024	9.70%	4.29%	5.41%
3/24/2024	9.30%	4.38%	4.92%
4/8/2024	11.88%	4.41%	7.47%

[8] Date of Gas Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	9.50%	4.41%	5.09%
4/17/2024	9.75%	4.44%	5.31%
6/26/2024	9.80%	4.48%	5.32%
6/28/2024	9.40%	4.48%	4.92%
7/18/2024	9.50%	4.44%	5.06%
7/23/2024	9.90%	4.43%	5.47%
7/25/2024	9.38%	4.43%	4.95%
7/31/2024	9.75%	4.42%	5.33%
8/15/2024	9.35%	4.40%	4.95%
8/15/2024	9.35%	4.40%	4.95%
9/17/2024	9.65%	4.38%	5.27%
9/18/2024	9.51%	4.38%	5.13%
9/26/2024	9.86%	4.38%	5.48%
10/1/2024	9.85%	4.38%	5.47%
10/9/2024	9.60%	4.38%	5.22%
10/17/2024	10.08%	4.38%	5.70%
10/25/2024	9.35%	4.39%	4.96%
10/25/2024	9.40%	4.39%	5.01%
10/31/2024	9.90%	4.39%	5.51%
		# of Cases:	1,317

Bond Yield Plus Risk Premium (Electric)

[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
-2.108%	-2.525%			
Current 30-Year Treasury		4.30%	5.84%	10.14%
Projected 30-Year Treasury		4.28%	5.85%	10.13%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield; Blue Chip Financial Forecasts, Vol. 43, No. 11, November 1, 2024, at 2; Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Exhibit JEN-8
[7] Equals [5] + [6]
[8] Source: S&P Capital IQ
[9] Source: S&P Capital IQ
[10] Source: Bloomberg Professional, equals 199-trading day average (i.e. lag period)
[11] Equals [9] - [10]

Bond Yield Plus Risk Premium (Electric)

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.39%	5.00%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.64%	3.16%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.90%	2.80%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.11%	4.05%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.14%	4.36%
4/11/1980	12.75%	10.28%	2.47%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.32%	5.18%
4/22/1980	13.25%	10.36%	2.89%
4/22/1980	13.90%	10.36%	3.54%
4/24/1980	16.80%	10.38%	6.42%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.46%	4.54%
5/8/1980	13.75%	10.47%	3.28%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.49%	3.11%
5/15/1980	13.25%	10.50%	2.75%
5/19/1980	13.75%	10.52%	3.23%
5/27/1980	13.62%	10.55%	3.07%
5/27/1980	14.60%	10.55%	4.05%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.57%	3.23%
6/2/1980	15.63%	10.58%	5.05%
6/9/1980	15.90%	10.61%	5.29%
6/10/1980	13.78%	10.61%	3.17%
6/12/1980	14.25%	10.62%	3.63%
6/19/1980	13.40%	10.63%	2.77%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.68%	4.07%
7/10/1980	15.00%	10.69%	4.31%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.72%	3.08%
7/22/1980	14.10%	10.73%	3.37%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.74%	2.74%
7/31/1980	14.58%	10.76%	3.82%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	15.80%	10.88%	4.92%
9/15/1980	13.93%	10.88%	3.05%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.95%	2.80%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.99%	4.51%
10/7/1980	12.50%	11.00%	1.50%
10/9/1980	13.25%	11.01%	2.24%
10/9/1980	14.50%	11.01%	3.49%
10/9/1980	14.50%	11.01%	3.49%
10/16/1980	16.10%	11.03%	5.07%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	14.00%	11.13%	2.87%
11/5/1980	13.75%	11.13%	2.62%
11/8/1980	13.75%	11.15%	2.60%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.20%	2.80%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.22%	4.23%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.22%	2.23%
12/22/1980	15.00%	11.22%	3.78%
12/30/1980	14.95%	11.21%	3.74%
12/30/1980	14.50%	11.21%	3.29%
12/31/1980	13.39%	11.21%	2.18%
1/2/1981	15.25%	11.21%	4.04%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.19%	4.06%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.20%	3.80%
1/31/1981	13.47%	11.21%	2.26%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.34%	3.91%
3/11/1981	15.40%	11.50%	3.90%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
3/12/1981	14.51%	11.51%	3.00%
3/12/1981	16.00%	11.51%	4.49%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.61%	3.69%
4/1/1981	14.53%	11.69%	2.84%
4/3/1981	19.10%	11.72%	7.38%
4/9/1981	15.00%	11.79%	3.21%
4/9/1981	15.30%	11.79%	3.51%
4/9/1981	17.00%	11.79%	5.21%
4/9/1981	16.50%	11.79%	4.71%
4/10/1981	13.75%	11.81%	1.94%
4/13/1981	13.57%	11.83%	1.74%
4/15/1981	15.30%	11.86%	3.44%
4/16/1981	13.50%	11.88%	1.62%
4/17/1981	14.10%	11.88%	2.22%
4/21/1981	14.00%	11.91%	2.09%
4/21/1981	16.80%	11.91%	4.89%
4/24/1981	16.00%	11.96%	4.04%
4/27/1981	12.50%	11.98%	0.52%
4/27/1981	13.61%	11.98%	1.63%
4/29/1981	13.65%	12.01%	1.64%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.06%	4.16%
5/5/1981	14.40%	12.08%	2.32%
5/7/1981	16.25%	12.12%	4.13%
5/7/1981	16.27%	12.12%	4.15%
5/8/1981	13.00%	12.14%	0.86%
5/8/1981	16.00%	12.14%	3.86%
5/12/1981	13.50%	12.17%	1.33%
5/15/1981	15.75%	12.23%	3.52%
5/18/1981	14.88%	12.24%	2.64%
5/20/1981	16.00%	12.27%	3.73%
5/21/1981	14.00%	12.28%	1.72%
5/26/1981	14.90%	12.31%	2.59%
5/27/1981	15.00%	12.32%	2.68%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.38%	2.29%
6/5/1981	13.00%	12.40%	0.60%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.52%	2.23%
6/26/1981	16.00%	12.53%	3.47%
6/30/1981	15.25%	12.55%	2.70%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.75%	0.73%
7/31/1981	13.50%	12.79%	0.71%
7/31/1981	15.00%	12.79%	2.21%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
7/31/1981	16.00%	12.79%	3.21%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.06%	1.44%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.34%	2.41%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.39%	2.11%
10/16/1981	16.50%	13.39%	3.11%
10/19/1981	14.25%	13.40%	0.85%
10/20/1981	17.00%	13.41%	3.59%
10/20/1981	15.25%	13.41%	1.84%
10/23/1981	16.00%	13.46%	2.54%
10/27/1981	10.00%	13.49%	-3.49%
10/29/1981	16.50%	13.52%	2.98%
10/29/1981	14.75%	13.52%	1.23%
11/3/1981	15.17%	13.54%	1.63%
11/5/1981	16.60%	13.56%	3.04%
11/6/1981	15.17%	13.57%	1.60%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	15.70%	13.61%	2.09%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.64%	2.86%
12/18/1981	15.45%	13.64%	1.81%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.25%	13.67%	2.58%
12/30/1981	16.00%	13.67%	2.33%
12/31/1981	16.15%	13.68%	2.47%
1/4/1982	15.50%	13.68%	1.82%
1/11/1982	17.00%	13.73%	3.27%
1/11/1982	14.50%	13.73%	0.77%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	16.50%	13.76%	2.74%
1/15/1982	15.00%	13.76%	1.24%
1/22/1982	16.25%	13.80%	2.45%
1/27/1982	16.84%	13.81%	3.03%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/28/1982	13.00%	13.82%	-0.82%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.83%	2.02%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.90%	1.50%
3/30/1982	15.50%	13.91%	1.59%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.92%	0.78%
4/1/1982	16.50%	13.92%	2.58%
4/2/1982	15.50%	13.92%	1.58%
4/5/1982	15.50%	13.93%	1.57%
4/8/1982	16.40%	13.94%	2.46%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	17.00%	13.89%	3.11%
5/28/1982	15.50%	13.89%	1.61%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.87%	0.98%
6/18/1982	15.50%	13.86%	1.64%
6/21/1982	14.90%	13.86%	1.04%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.85%	0.85%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.83%	1.79%
7/2/1982	17.00%	13.83%	3.17%
7/13/1982	16.80%	13.82%	2.98%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
7/13/1982	14.00%	13.82%	0.18%
7/14/1982	15.76%	13.81%	1.95%
7/14/1982	16.02%	13.81%	2.21%
7/19/1982	16.50%	13.79%	2.71%
7/22/1982	17.00%	13.76%	3.24%
7/22/1982	14.50%	13.76%	0.74%
7/27/1982	16.75%	13.74%	3.01%
7/29/1982	16.50%	13.73%	2.77%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.62%	3.45%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	16.25%	13.51%	2.74%
9/15/1982	13.08%	13.51%	-0.43%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.47%	1.03%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.14%	2.36%
11/3/1982	17.20%	13.12%	4.08%
11/4/1982	16.25%	13.10%	3.15%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.88%	2.62%
11/23/1982	15.85%	12.88%	2.97%
11/30/1982	16.50%	12.80%	3.70%
12/1/1982	17.04%	12.78%	4.26%
12/6/1982	15.00%	12.72%	2.28%
12/6/1982	16.35%	12.72%	3.63%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.64%	3.36%
12/14/1982	15.30%	12.62%	2.68%
12/14/1982	16.40%	12.62%	3.78%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.55%	2.20%
12/21/1982	15.85%	12.55%	3.30%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.75%	12.54%	4.21%
12/22/1982	16.25%	12.54%	3.71%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.35%	12.46%	3.89%
12/30/1982	16.00%	12.46%	3.54%
12/30/1982	16.77%	12.46%	4.31%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	15.50%	12.32%	3.18%
1/12/1983	14.63%	12.32%	2.31%
1/20/1983	17.75%	12.23%	5.52%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/21/1983	15.00%	12.21%	2.79%
1/24/1983	15.50%	12.20%	3.30%
1/24/1983	14.50%	12.20%	2.30%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.16%	3.98%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.09%	1.91%
2/10/1983	15.00%	12.05%	2.95%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.96%	3.54%
2/23/1983	16.00%	11.95%	4.05%
2/23/1983	15.10%	11.95%	3.15%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.76%	1.24%
3/18/1983	15.25%	11.72%	3.53%
3/23/1983	15.40%	11.68%	3.72%
3/24/1983	15.00%	11.66%	3.34%
3/29/1983	15.50%	11.62%	3.88%
3/30/1983	16.71%	11.60%	5.11%
3/31/1983	15.00%	11.58%	3.42%
4/4/1983	15.20%	11.57%	3.63%
4/8/1983	15.50%	11.49%	4.01%
4/11/1983	14.81%	11.48%	3.33%
4/19/1983	14.50%	11.36%	3.14%
4/20/1983	16.00%	11.35%	4.65%
4/29/1983	16.00%	11.23%	4.77%
5/1/1983	14.50%	11.23%	3.27%
5/9/1983	15.50%	11.14%	4.36%
5/11/1983	16.46%	11.11%	5.35%
5/12/1983	14.14%	11.10%	3.04%
5/18/1983	15.00%	11.04%	3.96%
5/23/1983	14.90%	11.00%	3.90%
5/23/1983	15.50%	11.00%	4.50%
5/25/1983	15.50%	10.97%	4.53%
5/27/1983	15.00%	10.95%	4.05%
5/31/1983	14.00%	10.94%	3.06%
5/31/1983	15.50%	10.94%	4.56%
6/2/1983	14.50%	10.92%	3.58%
6/17/1983	15.03%	10.83%	4.20%
7/1/1983	14.90%	10.77%	4.13%
7/1/1983	14.80%	10.77%	4.03%
7/8/1983	16.25%	10.75%	5.50%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.85%	3.90%
9/7/1983	15.00%	10.87%	4.13%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.01%	5.49%
10/19/1983	16.25%	11.01%	5.24%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.15%	11.13%	5.02%
11/23/1983	16.00%	11.13%	4.87%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.16%	3.91%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.18%	3.32%
12/15/1983	15.56%	11.20%	4.36%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.22%	4.78%
12/20/1983	14.69%	11.22%	3.47%
12/20/1983	16.25%	11.22%	5.03%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.27%	3.48%
1/10/1984	15.90%	11.30%	4.60%
1/12/1984	15.60%	11.31%	4.29%
1/18/1984	13.75%	11.33%	2.42%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.38%	3.87%
2/1/1984	14.80%	11.39%	3.41%
2/6/1984	14.75%	11.41%	3.34%
2/6/1984	13.75%	11.41%	2.34%
2/9/1984	15.25%	11.43%	3.82%
2/15/1984	15.70%	11.45%	4.25%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.48%	3.27%
2/28/1984	14.50%	11.52%	2.98%
3/2/1984	14.25%	11.54%	2.71%
3/20/1984	16.00%	11.65%	4.35%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%
4/2/1984	15.50%	11.72%	3.78%
4/6/1984	14.74%	11.76%	2.98%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.88%	2.52%
5/16/1984	14.69%	11.99%	2.70%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
5/16/1984	15.00%	11.99%	3.01%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.16%	3.09%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.33%	4.17%
7/13/1984	16.25%	12.34%	3.91%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.36%	3.14%
7/18/1984	15.30%	12.36%	2.94%
7/19/1984	14.30%	12.37%	1.93%
7/24/1984	16.79%	12.40%	4.39%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.45%	1.80%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.53%	3.02%
9/6/1984	16.00%	12.54%	3.46%
9/10/1984	14.75%	12.55%	2.20%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.56%	4.82%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	15.00%	12.57%	2.43%
9/28/1984	16.25%	12.57%	3.68%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.59%	3.01%
10/22/1984	15.00%	12.59%	2.41%
10/26/1984	16.40%	12.59%	3.81%
10/31/1984	16.25%	12.59%	3.66%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.59%	3.16%
11/20/1984	15.25%	12.58%	2.67%
11/20/1984	15.92%	12.58%	3.34%
11/23/1984	15.00%	12.58%	2.42%
11/28/1984	16.15%	12.57%	3.58%
12/3/1984	15.80%	12.57%	3.23%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.54%	3.86%
12/19/1984	15.00%	12.53%	2.47%
12/19/1984	14.75%	12.53%	2.22%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.30%	1.54%
3/8/1985	16.85%	12.28%	4.57%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.16%	3.46%
4/3/1985	14.60%	12.13%	2.47%
4/9/1985	15.50%	12.10%	3.40%
4/16/1985	15.70%	12.05%	3.65%
4/22/1985	14.00%	12.01%	1.99%
4/26/1985	15.50%	11.97%	3.53%
4/29/1985	15.00%	11.96%	3.04%
5/2/1985	14.68%	11.93%	2.75%
5/8/1985	15.62%	11.88%	3.74%
5/10/1985	16.50%	11.86%	4.64%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.60%	3.90%
7/9/1985	15.00%	11.44%	3.56%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.32%	3.18%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.26%	3.74%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.14%	3.36%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.04%	4.46%
9/27/1985	15.80%	11.04%	4.76%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.91%	3.59%
11/7/1985	15.50%	10.89%	4.61%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	15.00%	10.66%	4.34%
12/20/1985	14.50%	10.66%	3.84%
12/20/1985	14.50%	10.66%	3.84%
1/24/1986	15.40%	10.40%	5.00%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
2/11/1986	12.50%	10.27%	2.23%
2/14/1986	14.40%	10.24%	4.16%
2/18/1986	16.00%	10.22%	5.78%
2/24/1986	14.50%	10.17%	4.33%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.07%	4.83%
3/11/1986	14.50%	10.01%	4.49%
3/12/1986	13.50%	10.00%	3.50%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
3/27/1986	14.10%	9.85%	4.25%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.82%	4.18%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.68%	3.72%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.31%	5.19%
5/16/1986	14.50%	9.31%	5.19%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.17%	5.93%
6/2/1986	12.81%	9.16%	3.65%
6/11/1986	14.00%	9.06%	4.94%
6/24/1986	16.63%	8.93%	7.70%
6/26/1986	14.75%	8.90%	5.85%
6/26/1986	12.00%	8.90%	3.10%
6/30/1986	13.00%	8.86%	4.14%
7/10/1986	14.34%	8.74%	5.60%
7/11/1986	12.75%	8.72%	4.03%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.65%	3.75%
7/25/1986	14.25%	8.56%	5.69%
8/6/1986	13.50%	8.43%	5.07%
8/14/1986	13.50%	8.34%	5.16%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.02%	5.23%
10/1/1986	14.00%	7.94%	6.06%
10/3/1986	13.40%	7.92%	5.48%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.74%	5.26%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.57%	6.87%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.50%	6.30%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.48%	5.52%
1/12/1987	12.40%	7.46%	4.94%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.84%	7.16%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.87%	5.03%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/27/1987	13.00%	7.92%	5.08%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.07%	5.18%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.44%	4.56%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.69%	3.31%
12/3/1987	14.20%	8.71%	5.49%
12/15/1987	13.25%	8.78%	4.47%
12/16/1987	13.72%	8.79%	4.93%
12/16/1987	13.50%	8.79%	4.71%
12/17/1987	11.75%	8.80%	2.95%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.82%	3.18%
12/22/1987	12.75%	8.82%	3.93%
12/22/1987	13.00%	8.82%	4.18%
12/22/1987	12.00%	8.82%	3.18%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.96%	4.94%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.98%	3.93%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	8.99%	3.76%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.91%	3.84%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.06%	3.94%
1/31/1989	13.00%	9.06%	3.94%
2/17/1989	13.00%	9.05%	3.95%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.48%	4.52%
12/15/1989	13.00%	8.33%	4.67%
12/20/1989	12.90%	8.31%	4.59%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	13.00%	8.29%	4.71%
12/27/1989	12.50%	8.29%	4.21%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.23%	4.67%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.19%	3.81%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.34%	4.16%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.63%	4.21%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.66%	4.44%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.65%	4.10%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.57%	4.43%
2/14/1991	12.72%	8.56%	4.16%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.43%	4.32%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.38%	3.32%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.37%	3.63%
7/3/1991	12.50%	8.36%	4.14%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.55%	8.20%	4.35%
10/23/1991	12.50%	8.20%	4.30%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	13.25%	8.18%	5.07%
11/12/1991	12.50%	8.18%	4.32%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.80%	8.15%	4.65%
12/19/1991	12.60%	8.15%	4.45%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.93%	3.52%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.92%	3.58%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	12.46%	7.88%	4.58%
5/12/1992	11.87%	7.88%	3.99%
6/1/1992	12.30%	7.86%	4.44%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
6/12/1992	10.90%	7.85%	3.05%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.71%	4.04%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.71%	5.45%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.40%	7.65%	4.75%
12/22/1992	12.30%	7.65%	4.65%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.62%	4.28%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	12.20%	7.48%	4.72%
2/26/1993	11.80%	7.48%	4.32%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.24%	4.51%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.22%	4.28%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.95%	4.55%
9/21/1993	10.50%	6.80%	3.70%
9/29/1993	11.47%	6.76%	4.71%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.56%	5.44%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	12.00%	6.35%	5.65%
2/25/1994	11.25%	6.35%	4.90%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.34%	4.66%
4/25/1994	11.00%	6.40%	4.60%
5/10/1994	11.75%	6.44%	5.31%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.40%	3.45%
11/9/1994	10.85%	7.40%	3.45%
11/18/1994	11.20%	7.46%	3.74%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.50%	3.56%
12/8/1994	11.50%	7.55%	3.95%
12/8/1994	11.70%	7.55%	4.15%
12/14/1994	10.95%	7.57%	3.38%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.72%	3.78%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.72%	3.38%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.51%	3.59%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.75%	7.12%	4.63%
9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.30%	7.12%	4.18%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	12.36%	6.89%	5.47%
11/9/1995	11.38%	6.89%	4.49%
11/17/1995	11.00%	6.85%	4.15%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.69%	4.91%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.84%	4.91%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.28%	4.97%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	12.30%	5.48%	6.82%
6/20/2002	11.00%	5.48%	5.52%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.04%	7.26%
3/6/2003	10.75%	5.02%	5.73%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.95%	7.05%
4/15/2003	11.15%	4.93%	6.22%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.79%	4.71%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	10.70%	4.94%	5.76%
12/17/2003	9.85%	4.94%	4.91%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.07%	5.18%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.50%	5.07%	6.43%
12/21/2004	11.25%	5.07%	6.18%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.08%	4.77%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.89%	5.41%
4/4/2005	10.00%	4.87%	5.13%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.53%	6.22%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.62%	5.58%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.75%	5.25%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.87%	5.18%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.96%	5.29%
12/1/2006	10.50%	4.96%	5.54%
12/7/2006	10.75%	4.96%	5.79%
12/21/2006	11.25%	4.95%	6.30%
12/21/2006	10.90%	4.95%	5.95%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.90%	4.95%	5.95%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.86%	6.49%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.80%	5.45%
5/17/2007	10.25%	4.80%	5.45%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.80%	4.86%	5.94%
12/14/2007	10.70%	4.86%	5.84%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.86%	5.34%
12/20/2007	11.00%	4.86%	6.14%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.58%	6.12%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	11.04%	4.54%	6.50%
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.51%	4.89%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.50%	5.75%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.47%	5.73%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.39%	5.86%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.07%	6.43%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.78%	6.22%
4/30/2009	11.25%	3.77%	7.48%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.76%	7.04%
7/8/2009	10.63%	3.76%	6.87%
7/17/2009	10.50%	3.77%	6.73%
8/21/2009	10.25%	3.80%	6.45%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.02%	6.68%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.10%	6.60%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.16%	6.09%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.19%	6.51%
12/16/2009	11.00%	4.22%	6.78%
12/16/2009	10.90%	4.22%	6.68%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.31%	6.69%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.70%	4.36%	6.34%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.32%	5.68%
9/16/2010	10.00%	4.32%	5.68%
9/30/2010	9.75%	4.28%	5.47%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.19%	6.51%
11/19/2010	10.20%	4.17%	6.03%
11/22/2010	10.00%	4.17%	5.83%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.14%	5.86%
12/20/2010	10.60%	4.14%	6.46%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.11%	5.49%
2/3/2011	10.00%	4.11%	5.89%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.24%	5.43%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.25%	5.75%
5/4/2011	10.00%	4.25%	5.75%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.37%	5.83%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.38%	5.97%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.79%	6.21%
12/14/2011	10.30%	3.79%	6.51%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.75%	6.45%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.55%	6.95%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.43%	6.47%
2/27/2012	10.25%	3.42%	6.83%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.31%	7.06%
4/4/2012	10.00%	3.29%	6.71%
4/26/2012	10.00%	3.20%	6.80%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.16%	6.64%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.07%	7.23%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.05%	6.55%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.89%	6.86%
11/29/2012	9.88%	2.89%	6.99%
12/5/2012	10.40%	2.89%	7.51%
12/5/2012	9.71%	2.89%	6.82%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.08%	6.28%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.27%	6.93%
9/11/2013	10.25%	3.27%	6.98%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	9.75%	3.49%	6.26%
12/9/2013	8.72%	3.49%	5.23%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	9.80%	3.51%	6.29%
12/18/2013	8.72%	3.51%	5.21%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.69%	5.51%
2/26/2014	9.75%	3.70%	6.05%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.96%	3.73%	6.23%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
3/26/2014	9.40%	3.73%	5.67%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.56%	6.19%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.44%	6.36%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.32%	6.38%
11/26/2014	10.20%	3.32%	6.88%
12/4/2014	9.68%	3.30%	6.38%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.28%	6.79%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.95%	6.55%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
9/25/2015	9.60%	2.80%	6.80%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.61%	7.14%
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.57%	7.43%
9/28/2016	9.58%	2.53%	7.05%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.00%	2.54%	6.46%
12/19/2016	9.37%	2.54%	6.83%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/24/2017	9.60%	2.64%	6.96%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.72%	7.53%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.60%	2.86%	6.74%
12/14/2017	9.65%	2.86%	6.79%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.85%	6.73%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	10.00%	2.89%	7.11%
4/18/2018	9.25%	2.89%	6.36%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.01%	6.27%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	10.00%	3.05%	6.95%
9/26/2018	9.77%	3.05%	6.72%
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.14%	6.86%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.89%	6.71%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.78%	7.22%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.52%	6.98%
12/4/2019	9.75%	2.51%	7.24%
12/4/2019	8.91%	2.51%	6.40%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	9.70%	2.47%	7.23%
12/17/2019	10.50%	2.47%	8.03%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.65%	2.46%	7.19%
12/20/2019	9.45%	2.46%	6.99%
12/24/2019	9.70%	2.46%	7.24%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.39%	7.11%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.34%	7.66%
2/11/2020	9.30%	2.33%	6.97%
2/14/2020	9.40%	2.32%	7.08%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.29%	7.46%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.17%	7.23%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.02%	7.23%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.84%	7.41%
7/8/2020	9.40%	1.82%	7.58%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.76%	7.74%
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.49%	8.01%
10/28/2020	9.60%	1.48%	8.12%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7.76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.44%	7.71%
12/23/2020	10.00%	1.44%	8.56%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.68%	7.92%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.85%	7.65%
6/4/2021	9.28%	1.90%	7.38%
6/23/2021	9.00%	1.95%	7.05%
6/28/2021	9.55%	1.96%	7.59%
6/30/2021	9.43%	1.97%	7.46%
6/30/2021	9.43%	1.97%	7.46%
7/14/2021	9.60%	1.99%	7.61%
7/15/2021	9.38%	1.99%	7.39%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.02%	7.58%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%
9/1/2021	9.40%	2.05%	7.35%
9/27/2021	9.40%	2.07%	7.33%
10/21/2021	9.95%	2.10%	7.85%
10/26/2021	10.60%	2.10%	8.50%
10/28/2021	9.35%	2.10%	7.25%
11/2/2021	8.90%	2.11%	6.79%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.25%	2.11%	7.14%
11/18/2021	9.35%	2.11%	7.24%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.11%	7.69%
12/1/2021	7.36%	2.10%	5.26%
12/7/2021	9.65%	2.09%	7.56%
12/13/2021	7.36%	2.08%	5.28%
12/15/2021	9.60%	2.08%	7.52%
12/22/2021	9.90%	2.06%	7.84%
12/28/2021	9.40%	2.05%	7.35%
1/20/2022	9.00%	2.03%	6.97%
2/16/2022	9.35%	2.02%	7.33%
2/23/2022	9.70%	2.02%	7.68%
3/16/2022	9.30%	2.02%	7.28%
4/14/2022	9.20%	2.07%	7.13%
4/25/2022	9.50%	2.11%	7.39%
5/12/2022	9.20%	2.18%	7.02%
5/23/2022	9.50%	2.22%	7.28%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.69%	6.81%
9/15/2022	9.35%	2.73%	6.62%
10/4/2022	10.10%	2.85%	7.25%
10/4/2022	10.80%	2.85%	7.95%
10/25/2022	9.50%	3.00%	6.50%
11/3/2022	10.25%	3.07%	7.18%
11/3/2022	10.20%	3.07%	7.13%
11/3/2022	10.30%	3.07%	7.23%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.17%	6.73%
11/30/2022	9.80%	3.23%	6.57%
12/1/2022	7.85%	3.24%	4.61%
12/14/2022	10.00%	3.30%	6.70%
12/14/2022	9.50%	3.30%	6.20%
12/14/2022	9.60%	3.30%	6.30%
12/15/2022	10.00%	3.30%	6.70%
12/15/2022	9.95%	3.30%	6.65%
12/15/2022	10.05%	3.30%	6.75%
12/16/2022	9.50%	3.31%	6.19%
12/20/2022	10.50%	3.32%	7.18%
12/22/2022	9.40%	3.33%	6.07%
12/22/2022	9.80%	3.33%	6.47%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.37%	5.93%
12/29/2022	9.80%	3.37%	6.43%
1/19/2023	9.90%	3.45%	6.45%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.47%	6.28%
2/9/2023	9.60%	3.50%	6.10%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.61%	6.29%
4/27/2023	10.00%	3.67%	6.33%
5/31/2023	9.35%	3.76%	5.59%
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.75%	3.77%	5.98%
6/6/2023	9.35%	3.77%	5.58%
7/20/2023	9.25%	3.82%	5.43%
8/2/2023	9.80%	3.81%	5.99%
8/3/2023	9.57%	3.81%	5.76%
8/18/2023	9.80%	3.82%	5.98%
8/23/2023	9.58%	3.82%	5.76%
8/25/2023	9.55%	3.83%	5.72%
8/25/2023	8.63%	3.83%	4.80%
8/31/2023	11.45%	3.84%	7.61%
8/31/2023	9.40%	3.84%	5.56%
9/6/2023	9.30%	3.85%	5.45%
9/21/2023	9.65%	3.90%	5.75%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.75%	3.97%	5.78%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.03%	5.62%
11/3/2023	9.30%	4.08%	5.22%
11/3/2023	9.70%	4.08%	5.62%
11/9/2023	9.80%	4.10%	5.70%
11/9/2023	9.80%	4.10%	5.70%
11/17/2023	9.60%	4.13%	5.47%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.17%	5.53%
12/14/2023	8.91%	4.18%	4.73%
12/14/2023	8.72%	4.18%	4.54%
12/14/2023	10.00%	4.18%	5.82%
12/14/2023	9.50%	4.18%	5.32%
12/15/2023	10.10%	4.18%	5.92%

[8] Date of Electric Rate Case	[9] Return on Equity	[10] 30-Year Treasury Yield	[11] Risk Premium
12/18/2023	9.50%	4.18%	5.32%
12/22/2023	10.70%	4.19%	6.51%
12/22/2023	10.65%	4.19%	6.46%
12/22/2023	10.75%	4.19%	6.56%
12/26/2023	9.52%	4.19%	5.33%
12/28/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.20%	5.06%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.26%	5.49%
2/14/2024	9.60%	4.29%	5.31%
2/28/2024	9.70%	4.31%	5.39%
3/1/2024	9.90%	4.32%	5.58%
3/5/2024	9.55%	4.32%	5.23%
3/26/2024	9.80%	4.36%	5.44%
4/17/2024	9.90%	4.41%	5.49%
4/18/2024	9.60%	4.41%	5.19%
5/8/2024	9.85%	4.46%	5.39%
6/10/2024	9.50%	4.50%	5.00%
6/20/2024	9.94%	4.50%	5.44%
6/28/2024	9.40%	4.50%	4.90%
7/2/2024	9.86%	4.50%	5.36%
7/18/2024	9.50%	4.47%	5.03%
8/8/2024	9.94%	4.43%	5.51%
8/21/2024	10.30%	4.40%	5.90%
8/26/2024	9.97%	4.39%	5.58%
9/17/2024	9.87%	4.36%	5.51%
9/18/2024	9.74%	4.36%	5.38%
9/23/2024	9.50%	4.36%	5.14%
9/26/2024	9.86%	4.37%	5.49%
9/30/2024	9.35%	4.37%	4.98%
10/3/2024	9.76%	4.37%	5.39%
10/9/2024	9.60%	4.37%	5.23%
10/10/2024	9.86%	4.37%	5.49%
10/17/2024	10.28%	4.38%	5.90%
10/17/2024	10.23%	4.38%	5.85%
10/17/2024	10.33%	4.38%	5.95%
10/24/2024	9.78%	4.38%	5.40%
		# of Cases	1,806

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 410

December 30, 2024

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Value Line ROE 2027-2029	Value Line Total Capital 2023	Value Line Common Equity Ratio 2023	Total Equity 2023	Value Line Total Capital 2027-2029	Value Line Common Equity Ratio 2027-2029	Total Equity 2027-2029	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Atmos Energy Corporation	ATO	9.50%	17,509	62.10%	10,873	26,000	60.00%	15,600	7.49%	1.036	9.84%
New Jersey Resources Corporation	NJR	12.50%	4,759	41.80%	1,989	6,300	45.00%	2,835	7.34%	1.035	12.94%
NiSource Inc.	NI	8.00%	21,192	45.50%	9,642	27,500	45.00%	12,375	5.12%	1.025	8.20%
ONE Gas, Inc.	OGS	8.50%	4,926	56.20%	2,769	7,000	49.00%	3,430	4.38%	1.021	8.68%
Southwest Gas Holdings, Inc.	SWX	7.00%	8,025	42.60%	3,418	10,000	44.00%	4,400	5.18%	1.025	7.18%
Spire, Inc.	SR	8.50%	6,471	41.30%	2,673	9,100	45.00%	4,095	8.91%	1.043	8.86%
Ameren Corporation	AEE	10.00%	24,847	43.80%	10,883	29,500	48.50%	14,308	5.62%	1.027	10.27%
Avista Corporation	AVA	8.50%	5,091	48.80%	2,485	5,900	51.50%	3,039	4.11%	1.020	8.67%
Black Hills Corporation	BKH	8.50%	7,017	45.80%	3,214	9,550	44.00%	4,202	5.51%	1.027	8.73%
CMS Energy Corporation	CMS	12.50%	22,114	33.10%	7,320	25,300	38.00%	9,614	5.60%	1.027	12.84%
Consolidated Edison, Inc.	ED	9.00%	43,085	49.10%	21,155	55,000	48.00%	26,400	4.53%	1.022	9.20%
DTE Energy Company	DTE	12.50%	26,282	38.00%	9,987	32,200	39.00%	12,558	4.69%	1.023	12.79%
Public Service Enterprise Group Inc.	PEG	12.00%	33,261	46.50%	15,466	47,500	41.50%	19,713	4.97%	1.024	12.29%
The Southern Company	SO	14.50%	83,654	37.60%	31,454	93,500	37.00%	34,595	1.92%	1.010	14.64%
WEC Energy Group, Inc.	WEC	13.00%	26,279	44.50%	11,694	29,800	44.50%	13,261	2.55%	1.013	13.16%
Gas Proxy Group Mean											9.28%
Combined Proxy Group Mean											10.55%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 411

December 30, 2024

FLOTATION COST ADJUSTMENT

Company	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
Atmos Energy Corporation	11/28/2018	8,059	$ 92.75	$ 0.98	1000	$ 91.65	$ 8,873	$ 747,500	$ 738,627	1.187%
Atmos Energy Corporation	11/28/2017	4,558	$ 88.56	$ 1.77	NA	$ 86.79	$ 8,068	$ 403,692	$ 395,624	1.999%
New Jersey Resources Corporation	12/4/2019	6,545	$ 41.25	$ 1.24	500	$ 39.94	$ 8,600	$ 270,000	$ 261,400	3.185%
NiSource Inc.	9/8/2010	24,265	$ 16.50	$ 0.54	400	$ 15.95	$ 13,411	$ 400,373	$ 386,962	3.350%
NiSource Inc.	11/6/2002	41,400	$ 18.30	$ 0.55	300	$ 17.74	$ 23,029	$ 757,620	$ 734,591	3.040%
ONE Gas, Inc.	3/8/2023	2,300	$ 76.90	$ 0.72	135	$ 76.12	$ 1,791	$ 176,870	$ 175,079	1.013%
Southwest Gas Holdings, Inc.	3/8/2023	4,113	$ 60.12	$ 2.03	538	$ 57.96	$ 8,883	$ 247,250	$ 238,367	3.593%
Southwest Gas Holdings, Inc.	3/29/2022	6,325	$ 74.00	$ 2.50	730	$ 71.39	$ 16,527	$ 468,050	$ 451,523	3.531%
Spire Inc.	6/13/2023	1,745	$ 64.20	$ 0.60	450	$ 63.34	$ 1,497	$ 112,000	$ 110,503	1.336%
Spire Inc.	5/7/2018	2,300	$ 68.75	$ 2.11	325	$ 66.50	$ 5,177	$ 158,125	$ 152,948	3.274%
Total							$ 95,854.88	$ 3,741,479.79	$ 3,645,624.91	
							WEIGHTED AVERAGE FLOTATION COSTS			2.562% [10]

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9744, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[11] Annualized Dividend	[12] Stock Price	[13] Dividend Yield	[14] Expected Dividend Yield	[15] Expected Dividend Yield Adjusted for Flotation Costs	[16] Value Line Earnings Growth	[17] S&P Earnings Growth	[18] Zacks Earnings Growth	[19] Average Earnings Growth	[20] ROE	[21] ROE Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$3.22	$139.77	2.30%	2.38%	2.45%	7.00%	7.00%	7.00%	7.00%	9.38%	9.45%
New Jersey Resources Corporation	NJR	$1.80	$46.44	3.88%	4.00%	4.10%	5.00%	7.60%	n/a	6.30%	10.30%	10.40%
NiSource Inc.	NI	$1.06	$34.58	3.07%	3.19%	3.27%	9.50%	7.95%	7.00%	8.15%	11.34%	11.42%
ONE Gas, Inc.	OGS	$2.64	$73.19	3.61%	3.67%	3.77%	3.50%	2.00%	5.00%	3.50%	7.17%	7.27%
Southwest Gas Holdings, Inc.	SWX	$2.48	$74.03	3.35%	3.48%	3.58%	10.00%	n/a	6.00%	8.00%	11.48%	11.58%
Spire, Inc.	SR	$3.02	$65.54	4.61%	4.73%	4.85%	4.50%	6.00%	5.00%	5.17%	9.89%	10.02%
Mean											9.93%	10.02%
Flotation Cost Adjustment											[22]	0.09%

Notes:
[1] - [4] Source: SEC Form 424B2 (Prospectus)
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Equals average [6] / average [7]
[11] Source: Bloomberg Professional
[12] Source: Bloomberg Professional, equals 30-day average
[13] Equals [11] / [12]
[14] Equals [13] x (1 + 0.5 x [19])
[15] Equals [14] / (1 − Flotation Cost)
[16] Source: Zacks
[17] Source: S&P Capital IQ
[18] Source: Value Line
[19] Equals Average ([16], [17], [18])
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals Average ([21]) − Average ([20])

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 412

December 30, 2024

Small Size Premium

	[1] ($Mil)
NW Natural Gas Equity	$1,232.08
Median Market to Book for Proxy Group	1.63
NW Natural's Implied Market Capitalization	$2,009.45

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corporation	ATO	$ 21,696.84	1.78
New Jersey Resources Corporation	NJR	$ 4,605.08	2.15
NiSource Inc.	NI	$ 15,552.57	1.91
ONE Gas, Inc.	OGS	$ 4,146.40	1.42
Southwest Gas Holdings, Inc.	SWX	$ 5,308.68	1.48
Spire, Inc.	SR	$ 3,785.20	1.23
MEDIAN		$4,956.88	1.63
MEAN		$9,182	1.66

	Market Capitalization ($Mil) [4]		
Decile	Low	High	Size Premium
2	$ 14,910.719	$ 36,391.110	0.46%
3	$ 7,493.607	$ 14,820.050	0.61%
4	$ 4,622.261	$ 7,461.280	0.64%
5	$ 3,011.224	$ 4,621.790	0.95%
6	$ 1,864.293	$ 3,010.810	1.21%
7	$ 1,050.083	$ 1,862.490	1.39%
8	$ 555.880	$ 1,046.040	1.14%
9	$ 213.039	$ 554.520	1.99%
10	$ 1.576	$ 212.640	4.70%
Proxy Group Median		$ 4,956.879	0.64%
6th Decile Size Premium		$ 2,009.450	1.21%
Difference from Proxy Group Median			0.57%

Notes:
[1] Source: NW Natural's total company equity as of 12/31/2023 as reported on the Annual LDC Report to the Oregon
[2] Source: S&P Capital IQ, 30-day average as of 10/31/2024
[3] Source: S&P Capital IQ, 30-day average as of 10/31/2024
[4] Source: Duff & Phelps Cost of Capital Navigator as of December 31, 2023

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 413

December 30, 2024

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
New Jersey Resources Corporation	NJR	55.15%	53.98%	55.19%	54.77%
NiSource Inc.	NI	55.44%	54.17%	54.85%	54.82%
ONE Gas, Inc.	OGS	60.41%	58.24%	61.09%	59.92%
Southwest Gas Holdings, Inc.	SWX	47.45%	43.96%	50.70%	47.37%
Spire, Inc.	SR	51.91%	57.15%	55.30%	54.79%
Ameren Corporation	AEE	53.66%	53.36%	53.39%	53.47%
Avista Corporation	AVA	50.24%	51.06%	50.77%	50.69%
Black Hills Corporation	BKH	49.38%	46.79%	46.48%	47.55%
CMS Energy Corporation	CMS	49.01%	49.69%	52.17%	50.29%
Consolidated Edison, Inc.	ED	47.50%	46.73%	46.87%	47.03%
DTE Energy Company	DTE	50.11%	50.49%	50.25%	50.29%
Public Service Enterprise Group Inc.	PEG	55.40%	55.16%	55.17%	55.24%
The Southern Company	SO	54.90%	54.98%	54.42%	54.77%
WEC Energy Group, Inc.	WEC	57.34%	55.15%	56.19%	56.23%
GAS PROXY GROUP MEAN		55.09%	54.59%	56.17%	55.28%
COMBINED PROXY GROUP MEAN		53.21%	52.73%	53.52%	53.15%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
New Jersey Natural Gas Company	NJR	55.15%	53.98%	55.19%	54.77%
Columbia Gas of Kentucky, Incorporated	NI	53.66%	54.91%	53.87%	54.15%
Columbia Gas of Maryland, Incorporated	NI	52.00%	51.96%	55.26%	53.07%
Columbia Gas of Ohio, Inc.	NI	50.50%	50.67%	50.79%	50.65%
Columbia Gas of Pennsylvania, Inc.	NI	55.88%	56.64%	56.05%	56.19%
Columbia Gas of Virginia, Incorporated	NI	45.25%	44.25%	44.52%	44.67%
Northern Indiana Public Service Company, LLC	NI	59.26%	56.92%	58.59%	58.26%
Kansas Gas Service Company, Inc.	OGS	60.44%	58.37%	61.37%	60.06%
Oklahoma Natural Gas Company	OGS	60.46%	58.26%	60.99%	59.90%
Texas Gas Service Company, Inc.	OGS	60.35%	58.13%	60.98%	59.82%
Spire Alabama Inc.	SR	55.31%	61.18%	58.51%	58.33%
Spire Gulf Inc.	SR	46.42%	51.61%	49.48%	49.17%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	50.66%	55.55%	53.96%	53.39%
Southwest Gas Corporation	SWX	47.45%	43.96%	50.70%	47.37%
Ameren Illinois Company	AEE	55.98%	55.39%	55.51%	55.63%
Union Electric Company	AEE	51.56%	51.54%	51.50%	51.53%
Alaska Electric Light and Power Company	AVA	62.52%	60.89%	60.49%	61.30%
Avista Corporation	AVA	49.74%	50.65%	50.34%	50.25%
Black Hills Colorado Electric, Inc.	BKH	49.15%	47.92%	46.55%	47.87%
Black Hills Energy Arkansas, Inc.	BKH	48.05%	43.30%	41.39%	44.25%
Black Hills Power, Inc.	BKH	52.58%	50.13%	49.96%	50.89%
Black Hills Wyoming Gas, LLC	BKH	49.89%	48.27%	47.36%	48.51%
Cheyenne Light, Fuel and Power Company	BKH	45.41%	42.85%	46.37%	44.88%
Consumers Energy Company	CMS	49.01%	49.69%	52.17%	50.29%
Consolidated Edison Company of New York, Inc.	ED	47.44%	46.75%	46.82%	47.00%
Orange and Rockland Utilities, Inc.	ED	48.57%	46.44%	47.69%	47.57%
Rockland Electric Co.	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	49.72%	50.41%	49.83%	49.99%
DTE Gas Company	DTE	51.67%	50.82%	51.99%	51.49%
Public Service Electric and Gas Company	PEG	55.40%	55.16%	55.17%	55.24%
Alabama Power Company	SO	52.36%	52.22%	51.60%	52.06%
Georgia Power Company	SO	56.32%	56.05%	55.60%	55.99%
Mississippi Power Company	SO	55.01%	55.67%	55.40%	55.36%
Atlanta Gas Light Company	SO	58.95%	59.05%	59.17%	59.06%
Chattanooga Gas Company	SO	52.54%	52.54%	52.54%	52.54%
Northern Illinois Gas Company	SO	53.45%	56.35%	54.68%	54.83%
Virginia Natural Gas, Inc.	SO	52.16%	55.37%	54.17%	53.90%
Michigan Gas Utilities Corporation	WEC	59.38%	57.89%	55.30%	57.52%
North Shore Gas Company	WEC	54.68%	55.36%	55.15%	55.06%
The Peoples Gas Light and Coke Company	WEC	50.27%	52.04%	52.34%	51.55%
Upper Michigan Energy Resources Corporation	WEC	53.92%	54.50%	54.72%	54.38%
Wisconsin Electric Power Company	WEC	60.51%	55.65%	58.33%	58.16%
Wisconsin Gas LLC	WEC	61.44%	60.13%	57.18%	59.58%
Wisconsin Public Service Corporation	WEC	56.45%	54.77%	56.24%	55.82%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital and long-term debt of Operating Subsidiaries.

[2] Spire Mississippi, Rockland Electric Co., and Citizens Gas Fuel Company are financed with >90% equity and are excluded from the analysis.

[3] Utility operating companies that do not have data reported by S&P Capital IQ are excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
New Jersey Resources Corporation	NJR	44.85%	46.02%	44.81%	45.23%
NiSource Inc.	NI	44.56%	45.83%	45.15%	45.18%
ONE Gas, Inc.	OGS	39.59%	41.76%	38.91%	40.08%
Southwest Gas Holdings, Inc.	SWX	52.55%	56.04%	49.30%	52.63%
Spire, Inc.	SR	48.09%	42.85%	44.70%	45.21%
Ameren Corporation	AEE	45.83%	46.09%	46.00%	45.97%
Avista Corporation	AVA	49.76%	48.94%	49.23%	49.31%
Black Hills Corporation	BKH	50.62%	53.21%	53.52%	52.45%
CMS Energy Corporation	CMS	50.82%	50.13%	47.62%	49.52%
Consolidated Edison, Inc.	ED	52.50%	53.27%	53.13%	52.97%
DTE Energy Company	DTE	49.89%	49.51%	49.75%	49.71%
Public Service Enterprise Group Inc.	PEG	44.60%	44.84%	44.83%	44.76%
The Southern Company	SO	45.10%	45.02%	45.12%	45.08%
WEC Energy Group, Inc.	WEC	42.51%	44.69%	43.63%	43.61%
GAS PROXY GROUP MEAN		44.91%	45.41%	43.83%	44.72%
COMBINED PROXY GROUP MEAN		46.74%	47.21%	46.39%	46.78%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
New Jersey Natural Gas Company	NJR	44.85%	46.02%	44.81%	45.23%
Columbia Gas of Kentucky, Incorporated	NI	46.34%	45.09%	46.13%	45.85%
Columbia Gas of Maryland, Incorporated	NI	48.00%	48.04%	44.74%	46.93%
Columbia Gas of Ohio, Inc.	NI	49.50%	49.33%	49.21%	49.35%
Columbia Gas of Pennsylvania, Inc.	NI	44.12%	43.36%	43.95%	43.81%
Columbia Gas of Virginia, Incorporated	NI	54.75%	55.75%	55.48%	55.33%
Northern Indiana Public Service Company, LLC	NI	40.74%	43.08%	41.41%	41.74%
Kansas Gas Service Company, Inc.	OGS	39.56%	41.63%	38.63%	39.94%
Oklahoma Natural Gas Company	OGS	39.54%	41.74%	39.01%	40.10%
Texas Gas Service Company, Inc.	OGS	39.65%	41.87%	39.02%	40.18%
Spire Alabama Inc.	SR	44.69%	38.82%	41.49%	41.67%
Spire Gulf Inc.	SR	53.58%	48.39%	50.52%	50.83%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	49.34%	44.45%	46.04%	46.61%
Southwest Gas Corporation	SWX	52.55%	56.04%	49.30%	52.63%
Ameren Illinois Company	AEE	43.61%	44.17%	44.00%	43.93%
Union Electric Company	AEE	47.84%	47.80%	47.78%	47.81%
Alaska Electric Light and Power Company	AVA	37.48%	39.11%	39.51%	38.70%
Avista Corporation	AVA	50.26%	49.35%	49.66%	49.75%
Black Hills Colorado Electric, Inc.	BKH	50.85%	52.08%	53.45%	52.13%
Black Hills Energy Arkansas, Inc.	BKH	51.95%	56.70%	58.61%	55.75%
Black Hills Power, Inc.	BKH	47.42%	49.87%	50.04%	49.11%
Black Hills Wyoming Gas, LLC	BKH	50.11%	51.73%	52.64%	51.49%
Cheyenne Light, Fuel and Power Company	BKH	54.59%	57.15%	53.63%	55.12%
Consumers Energy Company	CMS	50.82%	50.13%	47.62%	49.52%
Consolidated Edison Company of New York, Inc.	ED	52.56%	53.25%	53.18%	53.00%
Orange and Rockland Utilities, Inc.	ED	51.43%	53.56%	52.31%	52.43%
Rockland Electric Co.	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	50.28%	49.59%	50.17%	50.01%
DTE Gas Company	DTE	48.33%	49.18%	48.01%	48.51%
Public Service Electric and Gas Company	PEG	44.60%	44.84%	44.83%	44.76%
Alabama Power Company	SO	47.64%	47.78%	46.96%	47.46%
Georgia Power Company	SO	43.68%	43.95%	44.40%	44.01%
Mississippi Power Company	SO	44.99%	44.33%	44.60%	44.64%
Atlanta Gas Light Company	SO	41.05%	40.95%	40.83%	40.94%
Chattanooga Gas Company	SO	47.46%	47.46%	47.46%	47.46%
Northern Illinois Gas Company	SO	46.55%	43.65%	45.32%	45.17%
Virginia Natural Gas, Inc.	SO	47.84%	44.63%	45.83%	46.10%
Michigan Gas Utilities Corporation	WEC	40.62%	42.11%	44.70%	42.48%
North Shore Gas Company	WEC	45.32%	44.64%	44.85%	44.94%
The Peoples Gas Light and Coke Company	WEC	49.73%	47.96%	47.66%	48.45%
Upper Michigan Energy Resources Corporation	WEC	46.08%	45.50%	45.28%	45.62%
Wisconsin Electric Power Company	WEC	39.12%	43.94%	41.22%	41.43%
Wisconsin Gas LLC	WEC	38.56%	39.87%	42.82%	40.42%
Wisconsin Public Service Corporation	WEC	43.55%	45.23%	43.76%	44.18%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital and long-term debt of Operating Subsidiaries.

[2] Spire Mississippi, Rockland Electric Co., and Citizens Gas Fuel Company are financed with >90% equity and are excluded from the analysis.

[3] Utility operating companies that do not have data reported by S&P Capital IQ are excluded from the analysis.

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Holdings, Inc.	SWX	0.00%	0.00%	0.00%	0.00%
Spire, Inc.	SR	0.00%	0.00%	0.00%	0.00%
Ameren Corporation	AEE	0.51%	0.55%	0.61%	0.56%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%
Black Hills Corporation	BKH	0.00%	0.00%	0.00%	0.00%
CMS Energy Corporation	CMS	0.17%	0.18%	0.21%	0.19%
Consolidated Edison, Inc.	ED	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%
Public Service Enterprise Group Inc.	PEG	0.00%	0.00%	0.00%	0.00%
The Southern Company	SO	0.00%	0.00%	0.46%	0.15%
WEC Energy Group, Inc.	WEC	0.15%	0.16%	0.18%	0.16%
GAS PROXY GROUP MEAN		0.00%	0.00%	0.00%	0.00%
COMBINED PROXY GROUP MEAN		0.06%	0.06%	0.10%	0.07%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company, LLC	NI	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%	0.00%
Ameren Illinois Company	AEE	0.40%	0.44%	0.48%	0.44%
Union Electric Company	AEE	0.60%	0.66%	0.71%	0.66%
Alaska Electric Light and Power Company	AVA	0.00%	0.00%	0.00%	0.00%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%
Black Hills Colorado Electric, Inc.	BKH	0.00%	0.00%	0.00%	0.00%
Black Hills Energy Arkansas, Inc.	BKH	0.00%	0.00%	0.00%	0.00%
Black Hills Power, Inc.	BKH	0.00%	0.00%	0.00%	0.00%
Black Hills Wyoming Gas, LLC	BKH	0.00%	0.00%	0.00%	0.00%
Cheyenne Light, Fuel and Power Company	BKH	0.00%	0.00%	0.00%	0.00%
Consumers Energy Company	CMS	0.17%	0.18%	0.21%	0.19%
Consolidated Edison Company of New York, Inc.	ED	0.00%	0.00%	0.00%	0.00%
Orange and Rockland Utilities, Inc.	ED	0.00%	0.00%	0.00%	0.00%
Rockland Electric Co.	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	0.00%	0.00%	0.00%	0.00%
DTE Gas Company	DTE	0.00%	0.00%	0.00%	0.00%
Public Service Electric and Gas Company	PEG	0.00%	0.00%	0.00%	0.00%
Alabama Power Company	SO	0.00%	0.00%	1.43%	0.48%
Georgia Power Company	SO	0.00%	0.00%	0.00%	0.00%
Mississippi Power Company	SO	0.00%	0.00%	0.00%	0.00%
Atlanta Gas Light Company	SO	0.00%	0.00%	0.00%	0.00%
Chattanooga Gas Company	SO	0.00%	0.00%	0.00%	0.00%
Northern Illinois Gas Company	SO	0.00%	0.00%	0.00%	0.00%
Virginia Natural Gas, Inc.	SO	0.00%	0.00%	0.00%	0.00%
Michigan Gas Utilities Corporation	WEC	0.00%	0.00%	0.00%	0.00%
North Shore Gas Company	WEC	0.00%	0.00%	0.00%	0.00%
The Peoples Gas Light and Coke Company	WEC	0.00%	0.00%	0.00%	0.00%
Upper Michigan Energy Resources Corporation	WEC	0.00%	0.00%	0.00%	0.00%
Wisconsin Electric Power Company	WEC	0.36%	0.41%	0.45%	0.41%
Wisconsin Gas LLC	WEC	0.00%	0.00%	0.00%	0.00%
Wisconsin Public Service Corporation	WEC	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital and long-term debt of Operating Subsidiaries.

[2] Spire Mississippi, Rockland Electric Co., and Citizens Gas Fuel Company are financed with >90% equity and are excluded from the analysis.

[3] Utility operating companies that do not have data reported by S&P Capital IQ are excluded from the analys

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 414

December 30, 2024

Proxy Group Current Authorized Equity Ratio by Jurisdiction

Ticker	Company Name	Docket Number	Jurisdiction	Date Authorized	Current Authorized Equity Ratio	
ATO	Atmos Energy Corporation					
	Colorado Division	D-22AL-0348G	CO	5/4/2023	58.00%	
	Kansas Division	D-23-ATMG-359-RTS	KS	5/9/2023	NA	
	Kansas Division	D-19-ATMG-525-RTS	KS	2/24/2020	56.32%	
	Kentucky Division	C-2021-00214	KY	5/19/2022	54.50%	
	Louisiana Division	D-U-36658	LA	5/13/2024	58.00%	
	Mississippi Division	C-2005-UN-503	MS	7/1/2024	60.79%	
	Tennessee Division	D-24-00006	TN	7/29/2024	62.38%	
	West Texas (Environs)	D-GUD-10743	TX RRC	6/1/2024	60.00%	
	Mid-Tex Division	D-GUD-10779	TX RRC	5/21/2019	60.18%	
	West Texas (Cities)	[1]	TX RRC	10/1/2023	58.00%	
	Mid-Tex (Cities)	[1]	TX RRC	10/1/2023	58.00%	
	West Texas Triangle	D-GUD-10900	TX RRC	4/21/2020	60.12%	
	West Texas (ALDC)	[1]	TX RRC	6/7/2024	59.00%	
	Mid-Tex (Environs)	[1]	TX RRC	6/1/2024	60.00%	
	Mid-Tex (Dallas)	[1]	TX RRC	6/1/2024	60.00%	
	Virginia Division	PUR-2018-00014	VA	3/11/2019	58.21%	
NI	NiSource Inc.					
	Columbia Gas of Kentucky, Incorporated	C-2021-00183	KY	12/28/2021	52.64%	
	Columbia Gas of Maryland, Incorporated	C-9701	MD	10/26/2023	NA	
	Columbia Gas of Maryland, Incorporated	C-9680	MD	11/17/2022	52.97%	
	Columbia Gas of Ohio, Inc.	C-21-0637-GA-AIR	OH	1/26/2023	50.60%	
	Columbia Gas of Pennsylvania, Inc.	D-R-2024-3046519	PA	11/21/2024	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2022-3031211	PA	12/8/2022	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2021-3024296	PA	12/16/2021	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2020-3018835	PA	2/19/2021	54.19%	
	Columbia Gas of Virginia, Incorporated	C-PUR-2022-00036	VA	5/15/2023	NA	
	Columbia Gas of Virginia, Incorporated	C-PUR-2018-00131	VA	6/12/2019	NA	
	Northern Indiana Public Service Company	Ca-45967	IN	7/31/2024	58.51%	[2]
NJR	New Jersey Resources Corporation					
	New Jersey Natural Gas Company	D-GR24010071	NJ	11/21/2024	54.00%	
OGS	ONE Gas, Inc.					
	Kansas Gas Service Company, Inc.	D-24-KGSG-610-RTS	KS	10/3/2024	NA	
	Kansas Gas Service Company, Inc.	D-18-KGSG-560-RTS	KS	2/5/2019	NA	
	Oklahoma Natural Gas Company	Ca-PUD2024-000010	OK	8/27/2024	NA	
	Oklahoma Natural Gas Company	Ca-PUD2023-000012	OK	7/11/2023	NA	
	Oklahoma Natural Gas Company	Ca-PUD202200023	OK	11/29/2022	NA	
	Oklahoma Natural Gas Company	Ca-PUD202100063	OK	11/30/2021	58.55%	
	Texas Gas Service Company, Inc.	D-OS-24-00017471(Central-Gulf)	TX RRC	11/20/2024	59.58%	
	Texas Gas Service Company, Inc.	D-OSS-23-00014399	TX RRC	1/31/2024	59.07%	
SR	Spire Inc.					
	Spire Alabama Inc.	D-18328	AL	9/30/2024	55.50%	[3]
	Spire Missouri Inc.	C-GR-2022-0179	MO	11/30/2022	NA	
	Spire Missouri Inc.	C-GR-2021-0108	MO	10/27/2021	49.86%	
	Spire Mississippi	D-2015-UN-109	MS	11/26/2024	50.00%	
	Spire Gulf Inc.	D-28101	AL	9/30/2024	55.50%	[3]
SWX	Southwest Gas Corp.					
	Arizona Division	D-G-01551A-21-0368	AZ	1/23/2023	50.00%	
	California Division (SoCal)	A-19-08-015 (SoCal)	CA	3/25/2021	52.00%	
	California Division (NoCal)	A-19-08-015 (NoCal)	CA	3/25/2021	52.00%	
	California Division (LkTah)	A-19-08-015 (LkTah)	CA	3/25/2021	52.00%	
	Nevada Division (Northern)	D-23-09012 (Northern)	NV	9/11/2023	50.00%	
	Nevada Division (Southern)	D-23-09012 (Southern)	NV	9/11/2023	50.00%	
	Average				55.90%	
	Median				57.16%	
	High				62.38%	
	Low				49.86%	
	Count >55%; % of Total				20	58.82%
	Total Count				34	

Source: Regulatory Research Associates; SEC Form 10-K for ATO and SR
If the capital structure was not determined in the most recent rate proceeding, the authorized equity ratio determined in the next most recent proceeding with a determination in the last five years was used.

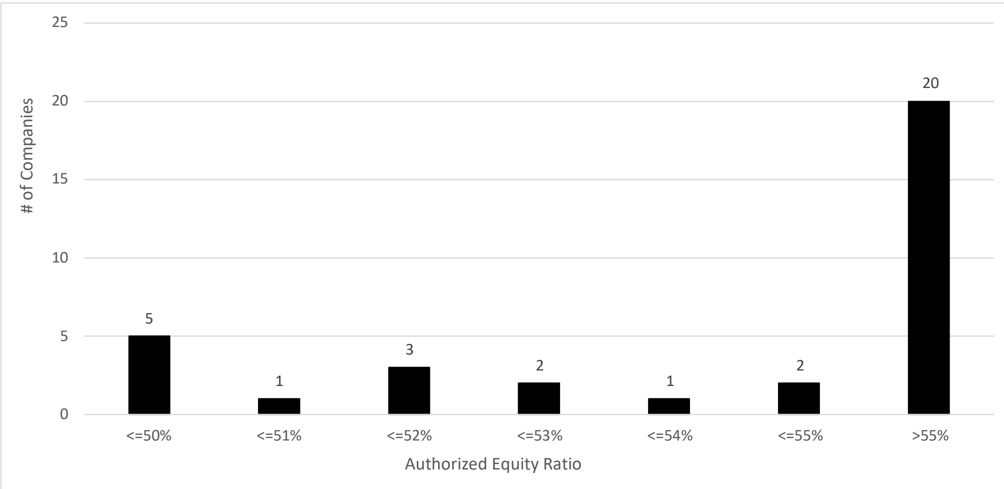
Notes:

[1] Gas utilities regulated by the Texas Rail Road Commission (RRC) have a general rate case only if they are unable to reach a settlement with the cities and unincorporated areas ("environs") within their service territories. Current authorized equity ratio for Atmos Texas' territories is published in ATO's 2024 10-K.

[2] Calculated using investor-supplied capital sources only. Indiana includes non-investor supplied capital in the ratemaking capital structure reported by RRA. Including non-investor supplied capital, NIPSCO's authorized equity ratio is 52.39%

[3] Source: Spire, Inc. 2024 10-K; authorized in Spire's RSE proceedings, not a general rate case

Equity Ratio	Count
<=50%	5
<=51%	1
<=52%	3
<=53%	2
<=54%	1
<=55%	2
>55%	20



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 500

December 30, 2024

EXHIBIT 500 – DIRECT TESTIMONY – DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Mr. Kizer, please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Daniel B. Kizer. I am the Engineering Senior Director at NW Natural. I am responsible for design, construction, operation, and maintenance of the gas transmission and distribution system (collectively herein, the "distribution system") and utility gas storage plants, and operations support services including work management functions, mapping and compliance.

Q. Mr. Kizer, please describe your education and employment background.

A. I graduated from Oregon State University with a Bachelor of Science in Civil Engineering, and I am a registered Professional Engineer in the State of Oregon. Before being promoted to my current position at NW Natural in June 2021, I was an Engineering Manager for the Company beginning January 2018. Prior to holding that position, I was a Field Engineer for the Company beginning May 2012. Before joining NW Natural, I worked as a Project Manager at Westech Engineering, Inc. from 1993 until 2012.

Q. Mr. Johnson, please state your name and position with NW Natural.

A. My name is Scott S. Johnson and I am Director of Gas Supply at NW Natural.

Q. Mr. Johnson, please describe your education and employment background.

A. I have a bachelor's degree in accounting and started my career working at a public accounting firm where I focused on auditing utilities. I have worked at NW Natural for 14 years in various roles including financial reporting, gas and regulatory accounting and gas supply. I have worked in gas supply for about 10 years.

Q. Which sections of this Direct Testimony are each of you sponsoring?

A. We are jointly sponsoring Sections II.B.2.a and b (Major Storage Facility Projects: Background of the Company's Storage Facilities, and Detailed Information about the Mist Storage Facility and the Natural Gas Market in the Pacific Northwest), and Mr. Kizer is individually sponsoring the remainder of this Direct Testimony.

Q. What is the purpose of your testimony?

A. The primary purpose of our testimony is to describe major distribution system projects (sponsored by Mr. Kizer) and storage facility projects (sponsored by Mr. Kizer and in part by Mr. Johnson) serving Oregon customers that are included in this rate case. Before we do so, Mr. Kizer discusses aspects of the Company's long-term system planning and the Company's recent improvements to its system modeling. Mr. Kizer also discusses the Company's ongoing plans for safety-driven system projects and programs. These projects are discussed in the Company's 2025 Safety Project Plan ("SPP"), filed in docket UM 1900. The Company's safety-related projects and programs address the Company's In-Line Inspection ("ILI") Conversion Projects, Proactive Excess Flow Valve ("EFV") Installation Program, Probabilistic Distribution Risk Model Project, Sewer Cross-Bores and Other Safety Projects and Programs.

II. MAJOR DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

A. Long-Term System Planning

Q. Before addressing the major distribution system and storage facility projects included in this rate case, are there any aspects of the Company's long-term system planning that you wish to discuss here?

A. Yes. Distribution system planning has historically been conducted as just-in-time planning, where traditional pipeline solutions were not developed until areas of the system became constrained. While this type of planning has long benefited customers, it does not allow for the lead time needed for non-pipeline alternative ("NPA") solutions. Forward-looking planning is necessary to evaluate and implement NPAs. NW Natural is in the process of expanding its suite of NPA solutions such as Geographically Targeted Energy Efficiency ("GeoTEE") and Geographically Targeted Demand Response ("GeoDR"), as well as a system-wide demand response program. Using updated, more sophisticated modeling, NW Natural has identified several areas on the system that have the potential for early NPA solutions, as they do not currently violate system reinforcement criteria but are areas where the gas distribution system is either approaching these thresholds and/or is showing evidence of growth in demand that drive the need for a system reinforcement.[1] In addition to GeoTEE and GeoDR, the Company has hired an

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[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, NW Natural's 2022 Integrated Resource Plan Update, at 14 (Table 3 lists these areas for investigation as: Dallas Feeder, Creswell Feeder, Lebanon Feeder, Hillsboro Industrial District Feeder and McMinnville Feeder; the areas are discussed in detail in Appendix C) (Aug. 2, 2024).

outside consultant to prepare a compressed natural gas ("CNG") or liquefied natural gas ("LNG") trucking study to help determine when CNG or LNG gas supplies may be a viable alternative to a pipeline solution for a peak weather event. The Company intends to evaluate and pursue as many of these opportunities as possible and will document those for which it is not feasible and why. The Company is conducting all of these efforts and analysis concurrently and expects them to be available for alternatives planning purposes in the next Integrated Resource Plan ("IRP") to be filed in August 2025.[2]

Q. Has the Company made any improvements to its system modeling?

A. Yes. The Company recently completed implementation of its Customer Management Module ("CMM") into the Company's pressure system modeling software, Synergi™. CMM provides a link between NW Natural's Geographical Information System ("GIS"), Customer Information System ("CIS") and Synergi™.

Q. How is CMM different from past system modeling software?

A. CMM provides NW Natural with the ability to import each customer's recent historical billing data from CIS and calculate a per customer demand based on daily temperature, as well as update customer information such as rate schedule, customer status (active or inactive) and changes in forecasted consumption. CMM ties individual customer demands to their specific geographic location in the model. Previous modeling methods utilized area-specific averages for residential and

[2] *See In the Matter of Northwest Natural Gas Company, dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, NW Natural's 2022 Integrated Resource Plan Update No. 2, at 3 (Aug. 21, 2024).

small commercial customers, whereas CMM allows for customer-specific average usages per customer in the model based on recent historical consumption. The overall benefit of CMM is that it more accurately models local system pressures on historical customer usage, rather than local average customer usages.

Q. Did the transition to CMM change the Company's understanding of the adequacy of the distribution system during design peak cold weather conditions?

A. Yes. The differences in customer usage became apparent when the transition to CMM was completed. After the implementation of CMM, our system modeling revealed that our distribution pressures for the design cold weather planning event, and for less-than-peak cold weather events in some locations, fell below our minimum system planning threshold in areas where customer demands were higher than previously modeled, and that customers would experience loss of gas service during a peak cold weather event. Likewise, in areas where customer demands were less than previously modeled, our system modeling showed better system pressures during the peak cold weather planning event.

Q. Are these newly revealed areas that fail the minimum system planning criteria isolated or extensive throughout the Company's distribution system?

A. In general, the areas are isolated and limited to geographical areas within our distribution system where customers exhibit higher-than-previously-assumed average demands.

Q. Has the Company validated the results of the CMM modeling?

A. Yes. The Company employed electronic portable pressure recorders ("EPPRs") in locations where CMM showed NW Natural's system pressures to be weak. Most recently, the EPPRs provided continuous pressure and temperature data during the January 2024 cold weather event (i.e., from Friday, January 12, 2024 through Thursday, January 18, 2024), and that data were used to validate CMM system modeling for the temperature conditions experienced during this cold weather event. The pressure and temperature data collected for the 2024 cold weather event also validated the Company's CMM modeling findings that, in areas of its system where customer demands were higher than previously modeled, the Company can expect to see a loss of service to customers during a peak cold weather event, and in some cases, at temperatures similar to what the area experienced during the January 2024 ice storm event.

Q. How is the Company addressing these areas that CMM shows currently fail the minimum system planning threshold?

A. The Company has identified multiple reinforcement projects to improve supply to areas where CMM modeling predicts a loss of service for customers where gas demands were higher than previously modeled. The Company determined that NPA solutions cannot be employed fast enough and are not likely cost effective to address the immediate need for improved gas supply to these areas recently identified by CMM. NW Natural is conducting additional modeling to forecast future constraints where load growth might be expected to occur over the next five years.

B. Discussion of Major Distribution System and Storage Facility Projects

Q. Has the Company previously sought cost recovery for any major distribution system and storage facility projects that have been completed since the Company's 2024 rate case (docket UG 490)?

A. Yes. In its last rate case, the Company sought cost recovery for the P30 Willis Creek Horizontal Directional Drilling ("HDD") Project, the Wilsonville Day Road Grading Project, the Happy Valley 172nd and Armstrong Grading Project, and the SE 76th and Morrison DR Replacement Project. As part of the Second Partial Stipulation in docket UG 490, NW Natural agreed to remove these projects from its request because the projects were not scheduled to be placed in-service by October 31, 2024. By its Order Nos. 24-359 and 24-363, entered respectively on October 25 and 30, 2024, the Public Utility Commission of Oregon ("Commission") approved and adopted the Second Partial Stipulation that removed the costs of these projects from revenue requirement for purposes of calculating rates as set forth in the Company's attestations filed in docket UG 490 on October 4 and 25, 2024.

Q. Please provide an update of these four projects.

A. The Company completed and placed in service the SE 76th and Morrison DR Replacement Project in November 2024. The P30 Willis Creek HDD Project, Wilsonville Day Road Grading Project and Happy Valley 172nd and Armstrong Grading Project are scheduled to be completed and in-service by the rate effective date in this case and are discussed in this testimony.

Q. Please identify the significant distribution system and storage facility projects that are included for recovery in this case.

A. The Company is requesting recovery for the following significant distribution system and storage facility projects:

- North Coast Feeder Uprate Project – Phase B;
- P30 Willis Creek HDD Install Project;
- Wilsonville Day Road Grading Project;
- Happy Valley 172nd and Armstrong Grading Project;
- Turner Grading Mill Creek Road Bridge Grading Project;
- P20 Highway 212 12-Inch Pipeline Reroute Project; and
- Turner Gate Station Metering Project.
- Major Storage Facility Projects. The projects listed below are designed to replace equipment and facilities that reached the end of their useful life and to promote the integrity and reliability of the Mist Storage Facility ("Mist") or the Company's Portland LNG or Newport LNG storage facilities.
    - Mist GC500 Turbine Compressor Replacement Project and Mist GC600 Turbine Compressor Replacement Project; and
    - Newport LNG Pretreatment Improvements Project and Newport LNG Cold Box Replacement Project.

1. Major Distribution System Projects

a. North Coast Feeder Uprate Project – Section B

Q. Please generally describe the North Coast Feeder Uprate Project.

A. The Company presented the North Coast Feeder Uprate Project for acknowledgement in its 2018 IRP Update 3 filed in docket LC 71 on March 1, 2021. In 2018, the Company identified, via system modeling, a potential pressure drop in the northwest area of its service territory in violation of the Company's system reinforcement standards. In November 2019, the Company verified these violations by collecting data from its Cannon Beach District Regulator, via one of its EPPRs. Data revealed significant pressure drop violations, such that the Company determined the violations posed an unacceptable risk to safety and reliability. The Company again gathered pressure data in January 2021 via a second EPPR and again observed high pressure drops. These pressure drops occurred on non-peak times in NW Natural's heating season. Modeling also indicated that, if left unmitigated, pressure drops could potentially reach zero pounds per square inch gauge ("psig"). To mitigate these observed and potential drops in pressure, the Company proposed: (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 (2) uprating another 22.2 miles of high-pressure gas main on another section of its system from Warrenton to Cannon Beach from a MAOP of 175 psig to a MAOP of 390 psig ("Section B").

Q. Did NW Natural assess alternatives to the North Coast Feeder Uprate Project in its 2018 IRP Update 3?

A. Yes. The Company timely and diligently completed alternatives analyses, including NPA solutions, of both targeted interruptible agreements and the siting of a satellite LNG facility and presented its findings on pages 19 and 28-29 of its 2018 IRP Update 3. The Company determined that potential interruptible schedule agreements with the limited number of large customers in this region would be insufficient to avoid the need for additional capacity in the area, and cost estimates for a satellite LNG facility far exceeded the cost of the selected uprate project.

Q. Did Staff of the Commission ("Staff") support acknowledgment of the North Coast Feeder Uprate Project?

A. Yes. In its Opening Comments filed in docket LC 71 on May 14, 2021, Staff stated that it reviewed the project information provided by the Company and found the action item to be reasonable. Staff explained on page 6 of its Opening Comments that the "ongoing replacement of infrastructure for safety purposes is part of the Company's basic obligation to provide safe and reliable service" and noted that the Company "supported its acknowledgment request with relevant data and verification of system modeling." On the same page, Staff mentioned that it had reviewed the Company's standards utilized to determine when a transmission, high pressure distribution, or certain parts of the distribution system need to be reinforced, and found those standards "prudent and normal for operations and workflow, with no apparent impacts or conflicts with maintaining compliance with safety standards."

Q. Did the Commission acknowledge the North Coast Feeder Uprate Project?

A. Yes. The Commission acknowledged the North Coast Feeder Uprate Project in Order No. 21-274, entered September 8, 2021.

Q. Does the North Coast Feeder Uprate Project continue to be the least-cost, least-risk alternative for continuing to serve current customers safely and reliably?

A. Yes. Through proactive and extensive system modeling and data verification from 2018 through 2021, the Company determined that a situation existed in the northwest area of its service territory that posed an unacceptable risk to safety and reliability to then-current customers. Staff agreed, finding that the Company's "high-quality data" supported the North Coast Feeder Uprate Project "for safety purposes" as "part of the Company's basic obligation to provide safe and reliable service."[3] The North Coast Feeder Uprate Project had nothing to do with load growth or the Company's management of load growth, and nothing has changed since that time. As stated earlier, the Company appropriately analyzed alternatives (including NPA solutions) and determined that they far exceeded the cost and risk of the North Coast Feeder Uprate Project, and the same holds true today. Simply stated, there have been no material changes in the facts, circumstances, and

[3] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2018 Integrated Resource Plan*, Docket No. LC 71, Staff's Opening Comments, at 6 (May 14, 2021).

assumptions that supported IRP acknowledgement of the North Coast Feeder Uprate Project and the Company's execution of the North Coast Feeder Uprate Project has remained prudent and reasonable. The North Coast Feeder Uprate Project continues to be the least-cost, least-risk alternative for continuing to serve current customers safely and reliably.

Q. What is the timing and status of the North Coast Feeder Uprate Project – Section A?

A. The North Coast Feeder Uprate Project – Section A, included in the Company's last general rate case (UG 490), was placed in service in September 2024.

Q. What is the timing and status of the North Coast Feeder Uprate Project – Section B?

A. Section B of the North Coast Feeder Uprate Project is expected to be completed by October 2025. The design to remediate the existing facilities in advance of the uprate is substantially complete and permitting activities have proceeded in the fourth quarter of 2024 and will continue in the first quarter of 2025. The Company expects construction to commence in Spring 2025, with completion by October 2025.

Q. What is the estimated cost to complete the North Coast Feeder Uprate Project – Section B?

A. The total cost to complete the North Coast Feeder Uprate Project – Section B is expected to be approximately $7.3 million.

b. P30 Willis Creek HDD Install Project

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 Wills Creek area. Specifically, NW Natural has been monitoring a landslide movement known as the Willis Creek Landslide that was identified along the P30 12-inch 600 psig MAOP transmission pipeline alignment in 2001. The area was relatively inactive until 2022, when the landslide was reactivated and moved materially by approximately 1.6 inches, representing the largest incremental displacement observed throughout the 20-year monitoring period. Since the slide plain is located a few feet above the P30 transmission pipeline and additional movement could adversely affect the pipeline, NW Natural is mitigating the risk by relocating and lowering the pipeline via an HDD installation.

Q. What is the status of the P30 Willis Creek HDD Install Project?

A. The Company submitted this project to bid in August 2023. The bid process resulted in feedback from the contractors that the proposed solution was not constructable due to the steep terrain and accessibility issues to mobilize equipment to the site. Based on this feedback, the project was redesigned with a scheduled construction timeframe of Summer 2024. The Company also needed to work with a landowner on a revised easement agreement, which extended the commencement of construction to 2025. As a result, the Company removed this project from its request for cost recovery in docket UG 490 for rates that became effective on November 1, 2024. The Company expects the P30 Willis Creek HDD install Project to be completed by October 2025.

Q. What is the estimated total cost of the P30 Willis Creek HDD Install Project?

A. The total cost to complete the P30 Willis Creek HDD Install Project is expected to be approximately $4.9 million.

c. Wilsonville Day Road Grading Project

Q. Please describe the Wilsonville Day Road Grading Project.

A. The City of Wilsonville is repairing sections of Day Road between SW Boones Ferry Road and SW Grahams Ferry Road. The city is requiring the relocation of approximately 2,100 feet of Class D six-inch main and approximately 1,700 feet of Class B two-inch main that otherwise would conflict with this public works project.

Q. Did the Company include the Wilsonville Day Road Grading Project in its last rate case (UG 490)?

A. Yes. The Company included the Wilsonville Day Road Grading Project in UG 490. In its attestation filed in docket UG 490 on October 25, 2024, the Company removed $2,269,605 of capital cost from rate base for purposes of calculating rates in that case because the project was not expected to be completed by October 31, 2024.

Q. Why was the Wilsonville Day Road Grading Project not completed by October 31, 2024?

A. The Company expected to begin the Wilsonville Day Road Grading Project in August 2024, but construction did not begin until November 2024 because of delays in obtaining the necessary permits.

Q. What is the expected timing of the Wilsonville Day Road Grading Project?

A. The Company expects that the Wilsonville Day Road Grading Project will be completed and placed in service by October 2025.

Q. Has the scope of the Wilsonville Day Road Grading Project changed since the Company included it for recovery in docket UG 490?

A. Yes. The Company discovered rocky soils in the affected area that are expected to result in a longer construction period, requiring more time and resources. Another entity has uncovered shallow bedrock in an adjacent construction site that needs to be excavated, and if this condition is also discovered around the Wilsonville Day Road Grading Project, it may require the Company to expend even more time and resources to address. The Company also found an old culvert in the affected area that could prolong pipeline installation. Additionally, the City of Wilsonville now is requiring the Company to remove its conflicted pipeline, rather than retire it in place, and restore the pavement.

Q. What is the Company's most recent cost estimate for the Wilsonville Day Road Grading Project?

A. The Company's most recent total cost estimate for the Wilsonville Day Road Grading Project is approximately $7.8 million.

d. Happy Valley 172nd and Armstrong Grading Project

Q. Please describe the Happy Valley 172nd and Armstrong Grading Project.

A. The City of Happy Valley is regrading sections of SE Armstrong Circle from SE 172nd Avenue. The city is requiring the relocation of approximately 450 feet of Class D 12-inch main that otherwise would conflict with this public works project.

Q. Did the Company include the Happy Valley 172nd and Armstrong Grading Project in its last rate case (UG 490)?

A. Yes. The Company included the Happy Valley 172nd and Armstrong Grading Project in UG 490. In its attestation filed in docket UG 490 on October 25, 2024, the Company removed $1,033,713 of capital cost from rate base for purposes of calculating rates in that case because the project was not expected to be completed by October 31, 2024.

Q. Why was the Happy Valley 172nd and Armstrong Grading Project not completed by October 31, 2024?

A. With the approaching 2024-25 winter heating season, the Company needed to prioritize its limited resources, and the City of Happy Valley allowed the Company to complete the project in 2025.

Q. What is the expected timing of the Happy Valley 172nd and Armstrong Grading Project?

A. The Company expects that the Happy Valley 172nd and Armstrong Grading Project will be completed and placed in service by October 2025.

Q. Has the scope of the Happy Valley 172nd and Armstrong Grading Project changed since the Company included it for recovery in docket UG 490?

A. Yes. The project was in early planning phase at the time of the previous submittal, and the scope of work has been further developed. The length of pipe to be relocated has approximately doubled in length, due to the identification of additional shallow pipe. Also, the Company has experienced increased construction costs for this large-diameter pipe, lower production expected due to rock excavation, and increased restoration costs.

Q. What is the Company's most recent cost estimate for the Happy Valley 172nd and Armstrong Grading Project?

A. The Company's most recent total cost estimate for the Happy Valley 172nd and Armstrong Grading Project is approximately $2.4 million.

e. Turner Grading Mill Creek Road Bridge Grading Project

Q. Please describe the Turner Grading Mill Creek Road Bridge Grading Project.

A. In October 2022, NW Natural received notice that Marion County will replace the old bridge over the Mill River at Mill Creek Road and construction on the project will begin in early 2025. The Company is relocating a section of the six-inch high-pressure pipeline that would otherwise conflict with this public works project.

Q. What is the status and timing of the Turner Grading Mill Creek Road Bridge Grading Project?

A. The design for the pipe relocation is substantially complete, and permit activities are in progress. The construction work is dependent on Marion County construction that is scheduled to start in March 2025. The Company expects the project to be completed and in-service by October 2025.

Q. What is the estimated total cost to complete the Turner Grading Mill Creek Road Bridge Grading Project?

A. The total cost to complete the Turner Grading Mill Creek Road Bridge Grading Project is expected to be approximately $2.4 million.

f. P20 Highway 212 12-Inch Pipeline Reroute Project

Q. Please describe the P20 Highway 212 12-inch transmission pipeline between SE 142nd Avenue and SE 152nd Avenue.

A. According to the GIS pipeline alignment data available, the existing P20 Highway 212 12-inch transmission pipeline follows the north side of Highway 212 from SE 152nd Avenue to about 385 feet west of SE 152nd Avenue, where it crosses Highway 212 at an obtuse angle. After crossing to the south side of Highway 212, the pipeline generally parallels it to the west of SE 142nd Avenue. During routine pipeline patrols in 2023, the Company discovered that increased flow in the Clackamas River adjacent to the P20 Highway 212 12-inch transmission main had caused an active landside process to the bluff on the northern bank of the river near the pipeline on the south side of Highway 212, approximately 800 feet east of SE 142nd Avenue. Further monitoring through the winter of 2023-24 resulted in an increased observation of this active landside process posing a high risk of exposure and potential failure to the existing pipeline, such that relocation was recommended.

Q. Please describe the P20 Highway 212 12-Inch Pipeline Reroute Project.

A. The P20 Highway 212 12-Inch Pipeline Reroute Project involves the relocation of approximately 2,500 feet of 12-inch transmission main located on the south side of Highway 212 in Clackamas.

Q. What is the status of the P20 Highway 212 12-Inch Pipeline Reroute Project?

A. The project planning phase started in the fourth quarter of 2024 and will continue during the first quarter of 2025. Work on this project is expected to begin in the second quarter of 2025, with completion expected by October 2025.

Q. What is the estimated total cost of the P20 Highway 212 12-Inch Pipeline Reroute Project?

A. The total cost to complete the P20 Highway 212 12-Inch Pipeline Reroute Project is expected to be approximately $4.6 million.

g. Turner Gate Station Metering Project

Q. Please describe the Turner Gate Station.

A. The Turner Gate Station is missing original pressure test records for certain pipe segments and does not currently utilize check metering or gas flow metering to Salem. In addition, a vehicle protection study in 2023 concluded that the Turner

Gate Station is at high risk of potential disruptions to gas supply should a vehicle from the neighboring highway impact the station.[4]

Q. Please describe the Turner Gate Station Metering Project.

A. The Turner Gate Station Metering Project is a project to install flow metering and improve gate station resiliency. First, the Company will install a new ultrasonic flow meter, install isolation valves for gas flowing east and west out of the station, bury above-ground pipe and tie into the existing remote terminal unit (RTU) panel. Second, to better protect the critical site infrastructure, the Company will install vehicle protection along the highway and fencing will be improved.

Q. Did the Company consider alternatives to performing the Turner Gate Station Metering Project?

A. Yes. The Company considered doing nothing, but that approach would not remedy any of the operational, safety, or efficiency concerns referenced above.

Q. What is the timing of the Turner Gate Station Metering Project?

A. The Company expects to complete the Turner Gate Station Metering Project by October 2025.

[4] Recall the Williams Pipeline Outage on December 20, 2020, when a vehicle traveling northbound at a high rate of speed across the Hood River bridge failed to stop at the stop sign at the T-intersection with Washington State Route 14 located at the north end of the bridge, continued through the stop sign, left the roadway and continued some distance until it impacted the gate station operated by Williams Pipeline. The vehicle came to rest on top of the pipe station components causing significant damage to the facility. This gate station is a custody transfer station where Williams Pipeline provides service to NW Natural and its local distribution system and customers throughout the central Columbia River Gorge area. The damage to the station was significant. The final resting location of the vehicle and presence of blowing natural gas due to the damage required a complete shut-in of the gate station to make the area safe and safely remove the vehicle and its driver. The shut-in of the gate station caused NW Natural to lose supply to the entirety of our system that serves the communities of White Salmon, Washington and Hood River/Odell, Oregon. As a result, NW Natural lost service to nearly 5,600 customers in those communities, and the restoration process took nearly one week.

Q. What is the estimated total cost of the Turner Gate Station Metering Project?

A. The total cost of the Turner Gate Station Metering Project is expected to be approximately $2.4 million.

2. Major Storage Facility Projects

a. Background of the Company's Storage Facilities

Q. Please identify the Company's storage facilities.

A. The Company has three storage facilities: Portland LNG, Newport LNG and Mist.

Q. Please describe the Company's Portland LNG facility.

A. The Portland LNG facility is a peak shaving facility located in Portland, Oregon and consists of a 600,000 Dth capacity storage tank, liquefaction facilities capable of processing about 2,150 Dth/day, and vaporization capacity of up to 130,800 Dth/day. This facility was constructed by Chicago Bridge and Iron and commissioned in 1969.

Q. Please describe the Company's Newport LNG facility.

A. The Newport LNG facility is a peak shaving facility located in Newport, Oregon and consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth/day, and vaporization capacity of up to 100,000 Dth/day.[5] This facility was constructed by Chicago Bridge and Iron and commissioned in 1977.

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[5] Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 100,000 Dth/day vaporization rate is not achievable. Instead, 60,000 Dth/day is the effective limit on vaporization at Newport.

Q. Please describe the Mist Storage Facility.

A. NW Natural's Mist Storage Facility, located in Mist, Oregon, began operations in 1989. It features a natural gas storage field consisting of seven different underground reservoirs, 21 injection/withdrawal wells, gathering lines, an operational hub called Miller Station,[6] and other related facilities. In all, the Mist Storage Facility is a 17.5 Bcf facility with 12.8 Bcf used to provide gas storage for core customers. We will provide much more detail about the Mist Storage Facility later in our testimony.

Q. Are the Company's storage facility projects allocated to both Oregon and Washington?

A. Yes. The Company allocates storage facility projects to both states. Gas acquisition, including both capacity and commodity costs, has historically been accomplished on a system basis, with customers in both states providing recovery of pipeline capacity and storage costs proportionally, even though gas from the storage facilities in Oregon is not physically deliverable to Washington. In that sense, storage is considered as a substitute for pipeline capacity, and the lower cost of storage as compared to pipeline demand, is shared among the customers in both states.

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[6] Miller Station, with peak certificated injection and withdrawal capacities of 335 million standard cubic feet per day ("MMscfd") and 515 MMscfd, respectively, is the compressor station within the Mist Storage Facility that contains the operations and controls facility as well as the process equipment for conveying natural gas between the wells and utility pipelines, including the natural gas compression and dehydration systems.

Q. Please describe further how the storage facility projects affect the Company's Oregon operations.

A. For its gas supply portfolio, NW Natural operates its three storage facilities in Oregon – Mist, Newport LNG, and Portland LNG – on an integrated basis with Washington. That is, gas supplies from those facilities work in tandem with supplies delivered by Northwest Pipeline ("NWP") to serve the requirements of customers in Oregon as well as in Washington. For example, withdrawals from the Mist Storage Facility flow directly to Oregon customers in and around the Portland area, which in turn allows the Company to divert an equivalent volume of NWP deliveries from interconnection points (gate stations) serving Oregon to gate stations serving Washington customers. Thus, while not physically connected or delivered to Washington, in this way, i.e., via displacement, Washington customers receive storage gas from the Company's storage facilities.

The gas supplies used to fill the three storage facilities come through NWP and other upstream pipelines during the spring/summer/fall months when customer usage is low and the Company's agreements with NWP are not fully utilized. Withdrawals from storage avoid the need for additional upstream pipeline capacity – and associated demand charges – during the winter months when customer usage is high. The costs of the Company's upstream pipeline agreements flow to Oregon and Washington customers through the purchased gas adjustment ("PGA") process. In the PGA, upstream pipeline demand charges are allocated between Oregon and Washington customers based on sales volumes.

This allows the benefits created by storage through the reduction of upstream pipeline demand charges to flow to both states.

The treatment of storage on an integrated basis between Oregon and Washington is also reflected in the resource acquisition decisions determined in the Company's IRP process.

Q. How are the Company's storage facility projects allocated to Oregon customers?

A. The Company's storage facility projects are allocated to Oregon and Washington customers on the basis of firm sales volumes. The Oregon allocation factor for firm sales volumes is currently 88.96 percent. The Direct Testimony of Kyle T. Walker (NW Natural/1500, Walker) addresses the topic of allocation factors and their associated methodology.

b. Detailed Information about the Mist Storage Facility and the Natural Gas Market in the Pacific Northwest

Q. Please describe how the Mist Storage Facility operates, especially during the winter heating season and even more particularly during peak system demand.

A. The Mist Storage Facility's gas storage for core customers is about 16 percent of the gas the Company distributes through its gas sales in an average calendar year, and a higher percentage when focusing on just the winter months when the facility is actively withdrawing. The remaining 4.7 Bcf of the facility is currently contracted with other utilities, third-party marketers, and electric generators through the Company's interstate storage service ("ISS"); however, core customers have the right to recall this storage capacity. Mist recall is typically identified as the least cost/risk option to serve customer needs in the IRP. The actual energy stored at the Mist Storage Facility depends on the energy content of the gas. In recent years, NW Natural has seen an uplift of between 6 percent to 8 percent with more energy-dense gas being shipped there on the pipeline system. This means the 17.5 Bcf Mist Storage Facility can store between 18.5 million Dth and 18.9 million Dth of natural gas. Exhibit NW Natural/501, Kizer-Johnson, are charts that outline the growth of the Mist Storage Facility over time and highlight its allocation between core customers (including recall capacity) and ISS.

NW Natural's gas supply portfolio provides about 1 million Dth on a peak day. About one-third of this supply comes from the core utility service at the Mist Storage Facility. NW Natural's two LNG facilities contribute another 18 percent of that supply, bringing the total on-system supply to just over half of our peak day. Our resource planning assumes all resources are available at their maximum output, so they need to be reliable. Utility peak day Mist Storage Facility supply of 325,000 Dth/day could serve over 440,000 average residential customers. The rest of the Mist Storage Facility, which is contracted through ISS, is also physically delivered onto the NW Natural system and those supplies could serve another 250,000 average residential customers.

Q. To what extent, if any, are upstream pipeline options available to replace the Company's reliance on the Mist Storage Facility?

A. NW Natural is connected exclusively to NWP at all of our city gates. NWP is fully subscribed, and no existing pipeline capacity is available to serve winter season or peak day needs. In fact, the existing pipeline system has been strained past its design capacity during recent cold weather events. If NW Natural had to increase pipeline deliveries, it would need to participate in a pipeline expansion on NWP. Such an expansion would require new pipe to be constructed either through the Columbia River Gorge or down the I-5 corridor between Canada and the NW Natural service territory. Pipeline capacity, while available 365 days a year, is not the best fit resource to satisfy the Company's needs that are currently met through use of the Mist Storage Facility. And when comparing the cost of such a pipeline expansion to costs of maintaining the Mist Storage Facility, the pipeline option would be orders of magnitude more expensive. The Company would also expect that permitting an interstate pipeline expansion would be a difficult process.

Exhibit NW Natural/502, Kizer-Johnson, is a map that shows the existing upstream pipeline and natural gas storage infrastructure in the Pacific Northwest. The Mist Storage Facility is designated as a tan star and noted as having 656,000 Dth/day of deliverability. This figure includes North Mist which is contracted exclusively to Portland General Electric. NWP is shown in dark blue and runs down the I-5 corridor and through the Columbia River Gorge. The Woodfibre LNG facility is being constructed not far from the green triangle in southwestern British Columbia.

Q. How is the Woodfibre LNG facility expected to impact the gas market in the Pacific Northwest?

A. Pacific Northwest natural gas system infrastructure is highly utilized and operates past its design capacity on peak days. This system will become further constrained in 2027 when the Woodfibre LNG facility goes into service. Woodfibre is an LNG export terminal which is currently under construction in southern British Columbia and will liquefy 0.3 Bcf/day. Woodfibre LNG has already secured the pipeline capacity needed to supply the facility. This pipeline capacity is currently available in the broader market, but when the facility comes online it will be used solely by Woodfibre LNG. When the Woodfibre LNG facility comes online in 2027, it will have the impact of removing about 16 percent of the supply from the Sumas market.

Forward prices are up for the 2027-28 winter due to these fundamental market risks. An example of a similar energy constrained time period was in 2018 when the pipeline serving the Sumas market ruptured and flows from British Columbia were limited throughout the 2018/19 winter. Flows initially dropped by about one-third in November and December 2018, and then rebounded to a decrease of around 17 percent in January through March 2019. While the 2018/19 winter started out warmer than normal, February 2019 was quite cold and by early

March 2019, regional storage was low and Sumas prices rose to approximately $200/Dth during a cold event.

We have seen growth in natural gas demand in the Pacific Northwest since 2018 and during this prior event certain industries shut down due to inadequate and/or prohibitively high-priced gas supplies. There is a chance we will see demand destruction beginning in 2027 when the Woodfibre LNG facility comes online, especially if it is a cold winter.

Q. Is NW Natural doing anything with its gas supply portfolio to prepare for the expected impact of the Woodfibre LNG facility on the Pacific Northwest gas market?

A. At this time, NW Natural relies on 60,700 Dth/day of segmented pipeline capacity on NWP as a peak day resource. Two things must happen for segmented capacity to be an effective resource. First, the path on NWP cannot be constrained. Segmented capacity is not primary firm capacity, so constraints in the shipping path would not allow supplies to flow. Through analysis in its IRP, the Company notes that cold weather in the Pacific Northwest has historically caused pipeline dynamics that allow enough pipeline space for these supplies to flow. NW Natural is not expecting this dynamic to change when the Woodfibre LNG facility comes online in 2027.

Second, NW Natural needs to have sufficient liquidity in the Sumas spot (next day) market to purchase the 60,700 Dth/day of supplies. The Sumas market is already tight, and it can be difficult to procure this volume of supply in the current environment. When the Woodfibre LNG facility comes online, the Company expects liquidity to deteriorate past the level it would be comfortable relying on making purchases for a peak day.

Accordingly, NW Natural is planning to cease peak day reliance on segmented pipeline capacity, when the Woodfibre LNG facility comes online in 2027. As a result, our IRP currently indicates the need to recall Mist capacity in place of this segmented capacity resource. A Mist recall of 60,000 Dth/day would shift this deliverability (and the related capacity) from its ISS customers to NW Natural's core customers. Assuming no other recalls in the interim, this would increase the core customer Mist Storage Facility portfolio from 325,000 Dth/day of deliverability to 385,000 Dth/day. In percentage terms, this would shift about 6 percent of our peak day supply from pipeline resources to the Mist Storage Facility, thereby increasing our reliance on the Mist Storage Facility to almost 39 percent of our portfolio on a peak day.

Q. Are there any other LNG export projects that could impact gas supplies in the West?

A. Yes. Construction is approximately 85% complete on the Costa Azul LNG facility, which is another LNG export facility on the West Coast. The Costa Azul LNG facility is located in Baja California, Mexico and will liquefy 0.4 Bcf/day in phase one which is expected to be in service in early 2026. Phase two would add 1.6 Bcf/day, but it has not reached final investment decision. An outage on the El Paso pipeline in 2022/23 decreased flows into California and this, plus cold weather, drove prices up to approximately $50/Dth in the West. The Costa Azul LNG facility could have a similar impact. Exhibit NW Natural/503, Kizer-Johnson, is a map showing how Costa Azul LNG connects to the natural gas system in the Southwest. Exhibit NW Natural/504, Kizer-Johnson, is a spot market price map from December 9, 2022, that shows the impact of constrained infrastructure due to the outage on El Paso pipeline in 2022/23 in the West. Pricing in markets that NW Natural participates in, such as Sumas and Opal, are directly impacted by regional markets in California, while abundant gas supplies in Canada cannot be accessed in adequate quantities due to existing pipeline constraints.

c. Mist GC500 Turbine Compressor Replacement Project and Mist GC600 Turbine Compressor Replacement Project

Q. Has the Company studied the Mist Storage Facility to identify areas of concern and needed improvements?

A. Yes. In June 2016, the Company completed an engineering facility assessment of the Mist Storage Facility ("2016 Mist Storage Facility Assessment") and identified a number of needed improvements to the facility to improve site reliability, resulting in the Mist Reliability Program.[7] The Company also completed a study of the compressor units in June 2020 ("2020 AECOM Compressor Study")[8] and a focused turbine compressor study in December 2022 ("2022 Burns and McDonnell Turbine Compressor Study" or "2022 Turbine Compressor Study").[9]

[7] Confidential Exhibit NW Natural/505, Kizer-Johnson, is the 2016 Mist Storage Facility Assessment.

[8] Confidential Exhibit NW Natural/506, Kizer-Johnson, is the 2020 AECOM Compressor Study.

[9] Confidential NW Natural/507, Kizer-Johnson, is the 2022 Burns and McDonnell Turbine Compressor Study.

Q. Please describe the GC500 and GC600 compressor units at Miller Station of the Mist Storage Facility.

A. The GC500 (5,500 hp) and GC600 units (7,200 hp), installed in 1998 and 2001-2002, respectively, perform the bulk of the compressive work for withdrawal and injection activities when they are available for operation. Although each turbine compressor unit has the same three major components (i.e., a gas generator, a power turbine and a centrifugal compressor), they are not identical and have different operational strengths. The GC600 unit is more effective operating in lower compression ratios, such as early in the withdrawal season when gas reservoir pressures are higher. The GC600 unit also is used in connection with the Company's ISS; about one-third of its costs are allocated to core utility service and the other two-thirds of its costs are allocated to ISS. The GC500 unit is more effective operating in high compression ratios, such as later in the withdrawal season when the gas reservoir pressures are lower. The 2016 Mist Storage Facility Assessment recommended that the Company replace over a period of time the four compressor units at Miller Station, all of which have exceeded their expected compressor core lifetime, in order to right-size the units for the facility's ongoing and future operations.

Q. How did the GC500 and GC600 compressor units perform after the Company completed the 2016 Mist Storage Facility Assessment?

A. The compressor units experienced multiple failures each year from the start of the 2018-2019 withdrawal season to present. The GC500 unit experienced several turbine engine failures, requiring complete removal of the unit for repair due to turbine blade fractures, oil leaks, gear failures and valve malfunctions and taking it out of operation for significant periods of time between Summer 2018 and the 2023-2024 heating season. The GC600 unit experienced several turbine engine failures as well. A combustion chamber failure was found during an outage inspection in April 2019, resulting in a repair outage lasting 16 months. In order to meet operational needs for two heating seasons, a leased turbine from Fortis BC was needed. Additionally, the GC600 unit had to be taken out of operation several times to address cracked vanes, failed combustion air seals, bleed valve failures, and oil leaks.

Q. What caused those failures and outages?

A. The 2020 AECOM Compressor Study and the 2022 Burns and McDonnell Turbine Compressor Study found that the issues with the compressor units were caused by age, outdated and unsupported systems, mechanical fatigue, and non-ideal operation. The 2022 AECOM Compressor Study recommended modifying the GC500 turbine compressor and purchasing a GC600 turbine driver with upgrades to the latest service bulletins to be used as a cold spare. With three more years of operational experience with continued outages and reliance of the turbine compressor original equipment manufacturer ("OEM"), NW Natural became much more informed about the vulnerability associated with operating the existing turbine compressor units to supply storage gas to its customers. Based on that additional operational experience, the 2022 Turbine Compressor Study recommended replacing the end-of-life GC500 and GC600 turbines all together.

Q. Do you anticipate that the GC500 and GC600 turbine compressor units will continue to experience failures and outages without corrective action?

A. Yes. As both units have exceeded their useful life expectancy -- the GC500 unit currently has over 57,000 hours of operation and has been in service for over 26 years and the GC600 unit has over 45,000 hours of operation over and has been in service for over 22 years – frequent failures and outages are expected to continue until corrective action is taken as many of the major core components are original and the OEM support for the two-shaft series turbine continues to diminish.

Q. What typically happens when the GC500 or GC600 units fail?

A. Failures commonly require the return of the turbine compressor core to the Maintenance Repair and Overhaul Center (“MROC”) in Houston, Texas, consuming three to six months or more before it can be returned to service. The manufacturer, Siemens, does not offer any cores or core exchange program for the specific turbine configuration used at NW Natural, so during repair times there is no replacement compression at Miller Station. The absence of a core exchange program from Siemens became apparent in April 2019 when a combustion chamber failure was discovered resulting in a repair outage of 16 months. To ensure operational continuity for two heating seasons, NW Natural leased a turbine from Fortis BC. Miller Station does not operate with a backup turbine compressor, so the failure of one or both turbine compressors disrupts the supply of storage gas to our utility customers (e.g., the loss of one turbine compressor unit leads to a 35-50 percent reduction of gas throughput). Siemens also does not carry substantial inventory to support the GC500 or GC600 turbine series. Parts are commonly made to order as needed, resulting in long lead times for parts and components. The make-to-order strategy can extend outages out past two years as seen with other operators of the same series turbines found on NW Natural's GC500 and GC600 compressors. Due to the uniqueness of the GC500 and GC600 and make-to-order strategy, an existing supply chain does not exist.

Q. As a result of those continuing failures and outages, did the Company reevaluate and update the 2020 AECOM Compressor Study?

A. Yes. In December 2022, the Company completed the 2022 Turbine Compressor Study. Through the 2022 Turbine Compressor Study, NW Natural became much more informed about the vulnerability of operating the existing turbine compressor units to supply storage gas to its customers. As a result of the 2022 Turbine Compressor Study, the Company implemented the Mist GC500 Turbine Compressor Cold Spare Project and the Mist GC600 Turbine Compressor Cold Spare Project.

Q. Please describe the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects.

A. The Company completed the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects in 2024 during docket UG 490, and the rates that went into effect on November 1, 2024, included the cost of those two projects. Through those projects, the Company acquired a gas generator, a power turbine and standby spare parts from Siemens for each of the GC500 and GC600 turbine compressor units. The gas generator and power turbine operate at extreme conditions, such as high temperatures and speeds, which make those two components most at risk of major downtime. Acquiring these critical cold standby spares has mitigated the risk of prolonged outages down to less than a month (from a previous average downtime of three to six months) and has improved resiliency at the Miller Station, and it has been the most cost-effective and viable option for the most recent and upcoming winter seasons. Because many of the components are not new and consist of multiple used out-of-service turbine packages to assemble a single serviceable cold spare, the acquisition of spare compressor components is a short-term, risk mitigation plan to extend the life of the GC500 and GC600 compressor units until the Mist GC500 and GC600 Turbine Compressors Replacement Projects are completed.

Q. Are the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects a long-term solution for reliability at the Mist Storage Facility?

A. No. The Mist GC500 and GC600 Turbine Compressors Cold Spare Projects are necessary to ensure the immediate reliability of Mist only for the near term. This is evident as operational issues persist even with the GC500 and GC600 cold spares. For example, during an outage in Spring 2024, damage was found on the GC500 unit's gas generator that exceeded operating limits. Continued operation of the GC500 unit would have resulted in significant damage to the turbine end.

Additionally at this time, it was identified that the GC600 unit was due for an overhaul of the cold section of its gas generator. Due to the historical frequency and lengthy outages of the GC500 unit, the utilization of the GC600 unit had increased significantly. With these discoveries during the Spring 2024 outage, the GC500 and GC600 units had their gas generator cold spares installed to allow operations to continue into the injection season. Without these cold spares, 82 percent of the compression horsepower would not have been available at the start of the injection season.

Within the first half of the injection season, the removed original GC500 gas generator was field-repaired, and the removed original GC600 gas generator was sent to the MROC for an overhaul. In the latter half of the injection season, both gas generator cold spares installed during the Spring 2024 outage also experienced failures.

The cold spare GC500 unit failed in August 2024 and with the repaired original GC500 gas generator available, it was reinstalled, enabling operations to complete the injection season. Although the GC600 unit was operational at this time, it is a high-flow, low-compression-ratio compressor and was not ideal for operation.

The cold spare GC600 unit was found to have failures during an outage in October 2024, as substantial damage was discovered in the combustion section of the cold spare GC600 unit's gas generator. The original GC600 gas generator removed in the Spring 2024 outage and sent for overhaul was still undergoing rework. To return the GC600 unit to service quickly, parts were taken from the original GC600 gas generator undergoing overhaul to field-repair the cold spare gas generator that is currently installed.

With continued operational failures, the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects do not address the long-term viability of the GC500 and GC600 units. Namely, complete overall compressor skids have exceeded their operational lives, and failures and outages have already occurred and continue to occur. The existing turbine compressors are not supported by the OEM and there are several core components that are no longer able to be sourced globally even with the OEM's support.

Q. Has NW Natural's service territory recently experienced severe winter weather that highlights the importance of reliable operations at the Mist Storage Facility?

A. Yes. In mid-January 2024, NW Natural's service territory experienced severe winter weather, highlighting the importance of reliable operations at the Mist Storage Facility. On January 13, 2024, as temperatures dropped to 15°F in the Portland area, NW Natural delivered 9 million therms of natural gas to homes and businesses throughout our service territory, virtually matching our previous record set in December 2022 for a single gas day, and approximately doubling our average daily winter send out. NW Natural delivered approximately 8 million therms of natural gas for each of the following three days. In addition to matching a single gas day delivery record and sustaining high volumes of natural gas delivery to our customers, NW Natural also broke previous Mist Storage Facility send out records for five consecutive days and delivered over 4.5 million therms (421 MMscfd) of stored natural gas on January 13, 2024. During these types of cold weather events, the importance of the Mist Storage Facility cannot be overstated. It is absolutely crucial to ensuring that NW Natural can provide safe and reliable service to our customers throughout the winter months.

Q. What would be the impact on NW Natural customers if the GC500 unit or GC600 unit were to fail during such cold weather events?

A. During cold weather events, such as those we experienced in January 2024, NW Natural has estimated that the loss of the GC500 unit or GC 600 unit would lead to a loss of gas service to approximately 200,000 customers (25 percent of our current customer count). Once NW Natural loses gas pressure to a customer, gas restoration is a three-step process, with the third step of restoration only possible when system gas pressure is assured. The January 2024 cold weather would have caused repeated, daily low-pressure outages in our distribution system and loss of service due to lack of pressure. It is estimated that the recent, January 2024 cold weather would have prohibited the start of service restoration for six days, should NW Natural have experienced failure of the GC500 unit or the GC600 unit at the beginning of the recent cold weather that we experienced.

The estimated time and resources required to complete service restoration for 200,000 customers, once weather warmed and system pressures were stabilized, is beyond any scale we have experienced. For reference, as we noted earlier, NW Natural has recent experience resourcing a smaller, large system outage. In that situation, after a Williams gate station was damaged by a motor vehicle in White Salmon, Washington in December 2020, NW Natural lost service to nearly 5,600 customers in White Salmon and in Hood River and Odell, Oregon, and the restoration process took nearly one week with the mutual assistance of staff from neighboring utilities.

Q. Do the Mist GC500 and GC600 Turbine Compressors Replacement Projects address the long-term viability of the GC500 and GC600 units?

A. Yes.

Q. Please describe the Mist GC500 and GC600 Turbine Compressors Replacement Projects.

A. NW Natural is replacing the existing GC500 and GC600 compressors with two new turbine compressors with an established and active supply chain, with parts readily available to support the operational needs of NW Natural and the needs of our customers. Removal of the existing GC 500 and GC600 compressors also requires removal of their existing foundation, associated oil coolers, lube oil systems, gas coolers, gas scrubbers, piping and valves, intake filters, exhaust silencers, fuel gas filter, regulation and measurement equipment, electrical distribution and control panels and other associated items. As a replacement, NW Natural is installing a Solar Turbine ("Solar") Taurus 60 with two new turbine-driven compressors of approximately 15,400 BHP (7,700 BHP each). The replacement work will include installing foundations for the new turbine/compressor packages, installing associated oil coolers, gas coolers, gas scrubbers, piping and valves, intake filters, exhaust silencers, electrical distribution and control panels, and other associated minor items.

NW Natural plans to replace the GC500 turbine compressor unit by October 2025 and the GC600 turbine compressor unit after the Test Year of this rate case. The Company will replace the GC500 unit first because it is the older unit and will use the GC600 unit to support injection operations during this time. During the next injection season (2026), the Company will replace the GC600 unit and will use the replacement GC500 unit to support operations during this time.

Q. Did the Company assess alternatives to the Mist GC 500 and GC600 Turbine Compressors Replacement Projects?

A. Yes. The Company considered a variety of Solar turbine options; electric compression; and the 2020 AECOM Compressor Study's recommendation of modifying the GC500 turbine compressor package, installing the repaired original GC600 gas generator, and purchasing an identical GC600 Gas Generator with upgrades to the latest service bulletins to be used as a cold spare. The lack of available space for an expansion and the wide range of operating pressures and flows drove careful consideration of all the design cases and space requirements for each alternative. NW Natural immediately disqualified replacing the GC500 and/or GC600 with reciprocating compressors due to the lack of market availability of the needed unit size of reciprocating engines. The Company also disqualified using other turbine manufacturers such as Vericor, who offers lower horsepower one-off turbine packages that would have put the Company in the same predicament that it is trying to fix now, or Baker Hughes/GE, which offers well supported turbine package solutions in a much higher horsepower range that would have been oversized for NW Natural's needs.

Q. What Solar turbine options did the Company consider?

A. Solar originally suggested a Taurus 60 with a single compressor unit, but the maximum flow rate offered by a single compressor unit would have been below the flow rate required for multiple design cases and it would not have been able to achieve the necessary minimum flow rate.

The next option Solar turbine considered was a Taurus 70 with a singular compressor unit. The Taurus 70 solution faced similar constraints to that of the Taurus 60 when using a single compressor unit. Though the maximum flowrates could be met, it would have been oversized for the needed applications. Multiple minimum flow rate scenarios would not have been covered in the full range of design cases needed and would have required a new compressor building or an extension to the existing building.

Solar then proposed a tandem option using two compressors attached to a single gas turbine. This allowed the two compressors to operate in parallel or series greatly expanding the operational range meeting the full range of design case requirements. This became the selected option described above.

Q. Please explain why the Company did not select an electric compression option.

A. Although electric driven compressors were evaluated as a potential option, it was not considered feasible for several reasons. First, power onsite would not be reliable, in that any power outage would cause a complete shutdown of the units. Second, two power feeds from different sources would have likely been required to maintain availability and reliability of the units during the peak seasons. Third, the cost of the electric driven compressor unit project at the needed size would have been comparable to the gas turbines. Fourth, to be able to maintain the electric driven compressor units running, a full-size back up power generator would have needed to be installed. Fifth, electric power rates in the area are some of the highest in the country.

Q. Why did the Company not select the 2020 AECOM Compressor Study recommendation of modifying the GC500 turbine compressor and purchasing a GC600 turbine driver with upgrades to the latest service bulletins to be used as a cold spare?

A. Simply stated, there were many notable disadvantages that far outweighed any interim and minimal improvement offered by the 2020 AECOM Compressor Study recommendation to replace the GC500 gas generator with a new Siemens SGT100 gas generator, rewheel the GC500 compressor for more efficiency and swap out the Fortis-owned gas generator of the GC600 unit with a NW Natural gas generator.

First, replacing the GC500's gas generator with a new Siemens SGT100 gas generator with the compressor rewheeled would have several long-term disadvantages. Similar to the existing GC500's gas generator and overall package, a SGT100 gas generator installed in the GC500 package would be a one-of-a-kind solution. SGT100 gas generator fleets in the North/South American market do not exist. There are no field subject matter experts in the United States. SGT100 specific parts and cold spares do not have inventory in the North/South American market. Additionally, the rewheeling would not have any significant benefit to operations, the remainder of the skid would continue to be non-standard and supported poorly, and failure issues of auxiliary items would continue to occur.

Second, replacing the Fortis owned gas generator with the same newly repaired original NW Natural GC600 gas generator would have similar disadvantages to the SGT100 solution. This turbine compressor package is one of a kind, with only a few remaining units in operation in the world. NW Natural and the two other operators of this type of unit with the same model gas generator have had the same experiences with the lack of spare parts, reliability, support, and turnaround times of those units. The NW Natural gas generator for the GC600 unit has proven to be unreliable, and continued operations is unsustainable. Additionally, with the repeated failures of the GC500, the GC600 has been relied on more heavily. The GC600's run hours are approaching the same hours as the GC500. Based on the similarities of the two units and the track record of the GC500 unit, the same failures and reliability issues of the GC500 unit were expected and are being realized as the GC600 unit approaches the operating hours of the GC500 unit.

Third, the 2020 AECOM Compressor Study's recommendations rely on the existing turbine compressor vendor for support. The existing turbine compressor vendor is a conglomeration of companies with no standards or asset management plan for legacy turbine compressor packages. This has proven to be a challenge for lifecycle support of the equipment, as every solution is a research and development exercise. This has led to more costly one-off experimental solutions and repeated failures to identify to the true root cause corrective action.

Q. What is the status of the Mist GC500 and GC600 Turbine Compressors Replacement Projects?

A. On March 15, 2024, NW Natural filed an application with the Oregon Department of Energy's Energy Facility Siting Council ("EFSC") to amend the Company's current site certificate to allow for the replacement of the compressor units. Due to NW Natural's commitment to expediting this project and the need to complete this project as expeditiously as possible, NW Natural has already procured the GC500 compressor replacement and performed the final engineering in advance of site certificate approval. On August 15, 2024, EFSC issued a draft proposed order finding that NW Natural's application should be approved. A public comment period ensued through September 19, 2024, on which date EFSC held a public hearing. On November 21, 2024, EFSC issued a proposed order finding that NW Natural's application should be approved. EFSC expects to issue a final decision in January 2025. The GC500 unit is expected to be installed, in service and used and useful by October 2025, and the GC600 unit is expected to be installed, in service and used and useful by October 2026.

Q. What is the estimated total cost of the Mist GC500 and GC600 Turbine Compressors Replacement Projects?

A. The GC500 Replacement Project is a 100 percent utility asset. The total cost of the Mist GC500 Turbine Replacement Project is expected to be approximately $45.6 million or approximately $40.1 million on an Oregon-allocated basis. The GC600 Replacement Project is a 33 percent utility asset. The total utility cost of the Mist GC600 Turbine Replacement Project is expected to be approximately $12.3 million, which is approximately $10.9 million on an Oregon-allocated basis.

d. Newport LNG Pretreatment Improvements Project

Q. Please describe the Newport LNG Pretreatment Improvements Project.

A. The Newport LNG Pretreatment Improvements Project includes two changes to the gas pretreatment system at Newport LNG. The first change is a new thermal oxidizer system, in order to improve the efficiency of the existing regeneration gas system. The second change is the replacement of the molecular sieve media in the dehydration and carbon dioxide removal systems, as the molecular sieve is at end of life. In addition, small valve and piping changes were made to add safety features during the installation of the molecular sieve.

Q. What is the purpose of the Newport LNG Pretreatment Improvements Project?

A. During the front-end engineering design phase of the Newport LNG Cold Box Replacement Project (which we will discuss next), the design contractor, Sanborn, Head & Associates, recommended two modifications to the existing gas pretreatment system, prior to installing the new cold box. The recommendations were provided in a project memo, to ensure the quality of the natural gas being processed by the new cold box equipment was within parameters of the new cold box. Ensuring the gas quality is within specifications reduces variability in contractor bids, reduces performance risk for the new cold box system, and will allow the Company to secure a performance guarantee by the cold box vendor. The Newport LNG Pretreatment Improvements Project was designed to accomplish these recommendations by optimizing dehydration and carbon dioxide removal from the liquefaction gas stream. The existing gas pretreatment system uses a molecular sieve media to remove water and carbon dioxide from natural gas. This media has a finite lifetime and must be replaced when it is no longer effective. This project replaces the media with new media that will allow the system to perform to the specifications of the new cold box.

During liquefaction operations, the molecular sieve media also must be regenerated with high-temperature natural gas. The successful operation of the regeneration system is a key concern in the design of the new cold box, as inadequate regeneration of the molecular sieve media will result in break-through of carbon dioxide or water, resulting in freezing and plugging in the new cold box. By installing the thermal oxidizer, the regeneration gas system increases flow through the gas pretreatment system, which enhances the regeneration capabilities. In addition, this system will allow for regeneration of the media while the liquefaction process is offline, an ability that will allow the plant to test systems, perform additional molecular sieve regeneration, and increase reliability without running the entire liquefaction process.

Q. What is the status of the Newport LNG Pretreatment Improvements Project?

A. The Newport LNG Pretreatment Improvements Project is expected to be completed by the end of December 2024.

Q. What is the estimated total cost of the Newport LNG Pretreatment Improvements Project?

A. The total cost of the Newport LNG Pretreatment Improvements Project is expected to be approximately $6.0 million, or $5.3 million on an Oregon allocated basis.

e. Newport LNG Cold Box Replacement Project

Q. Please describe the purpose of the Newport LNG Cold Box.

A. The Newport LNG Cold Box is an essential component in the Newport LNG liquefaction plant, as it is where natural gas is cooled to cryogenic temperatures to convert the gas to liquid. Once liquefied, it is pumped from the Newport LNG Cold Box to the onsite insulated storage tank where it can later be used as wintertime peaking supply and also a source of supply for emergency situations and pipeline maintenance.

Q. What is the current status of the Newport LNG Cold Box?

A. The Cold Box at Newport LNG is more than 47 years old. This places it well past its nominal 25- to 30-year design life, and it is currently showing signs of its age through performance problems. In particular, contamination has fouled the interior of the heat exchangers, causing differential pressure in the system that is higher than design limits, reducing production capacity.

Q. Please describe the operation of the Newport LNG Cold Box leading up to its current performance problems.

A. While an initial consultant recommended replacing the Newport LNG Cold Box in a 2014 study, it was later determined the estimate they provided for the cost of replacement was drastically low. Additionally, in 2016 NW Natural installed a new pretreatment system to address high CO_2 in the supply of gas, which was making it through the liquefier and into the LNG tank. The new pretreatment process dramatically improved the quality of gas entering the Newport LNG Cold Box. However, the original pretreatment design required additives such as methanol to be injected ahead of the Newport LNG Cold Box to absorb moisture. The methanol was then removed after liquefaction. Although that was no longer required with the new pretreatment process, without the additive, contaminants were able to easily foul the Newport LNG Cold Box causing increased differential pressure in the system and reducing production. Inspections to understand this issue revealed contaminants on the interior surfaces within the Newport LNG Cold Box heat exchangers, which compound flow restriction issues caused by poor gas quality entering the system. The differential pressure is higher than design allows in the first two exchangers within the Newport LNG Cold Box. This is believed to be due to several issues, including internal contamination upon inspection. The Newport LNG Cold Box itself is not the only contributor to operational issues, as higher levels of heavy hydrocarbons are contained within the gas stream than were present at the time of the original design of the facility. Heavier hydrocarbons tend to freeze at higher temperatures and can create blockages in the system, which also contribute to higher operating pressures within the Newport LNG Cold Box.

Q. Please generally describe the Newport LNG Cold Box Replacement Project.

A. The Company is replacing the Newport LNG Cold Box at the Newport LNG facility. NW Natural presented the Newport LNG Cold Box Replacement Project for acknowledgement in its 2018 IRP Update 3 filed in docket LC 71 on March 1, 2021.

Q. Why is the Newport LNG Cold Box Replacement Project necessary?

A. The Newport LNG Cold Box Replacement Project is necessary to be able to continue to rely upon Newport LNG as a firm resource to serve NW Natural's current needs. Should the Newport LNG Cold Box fail, the ramifications to the plant would be significant. A replacement unit would require approximately two years to install. Repairs to this type of equipment can be very costly or even impractical. If a failure were to occur at the beginning of the production season, this would leave the facility without a reasonable means to refill the storage tank. As a result, all remaining LNG may boil off prior to equipment replacement (depending on the tank level at the time of failure), which in turn, would allow the large LNG tank to warm significantly, inducing stress on the tank due to thermal expansion. Customers would also be left without the benefit of backup storage to support periods of peak demand during cold weather or other supply constraints.

Q. Did NW Natural assess alternatives to the Newport LNG Cold Box Replacement Project in its 2018 IRP Update 3?

A. Yes. The Company assessed two alternatives: (A) Contract with NWP for additional pipeline capacity from Sumas south to city gates on NWP's Grants Pass Lateral ("Alternative A"); and (B) Construct a 25-mile-high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall ("Alternative B"). As stated in its 2018 IRP Update 3, the Company determined that even the lower end of the *annual* costs of Alternative A was higher than the *total* capital costs of the Newport LNG Cold Box Replacement Project. The Company also determined that the total cost of the Newport LNG Cold Box Replacement Project was *multiple times less than* Alternative B from the perspective of the present value of revenue requirement of portfolios over the planning horizon.

Q. Did Staff support acknowledgement of the Newport LNG Cold Box Replacement Project?

A. Yes. In its Opening Comments filed in docket LC 71 on May 14, 2021, Staff stated (on page 5) that it "finds this action item, replacing the Newport [LNG] Cold Box, is a reasonable step in order to meet the Company's obligation to provide safe and reliable service and, based on the information provided by the Company, is the lowest cost option available." In its July 12, 2021 Staff Report to the Commission, Staff stated (on page 3) that "[a]fter reviewing stakeholder comments, Staff continues to find the Newport Cold Box to be a reasonable investment and recommends acknowledgement."

Q. Did the Commission acknowledge the Newport LNG Cold Box Replacement Project?

A. Yes. The Commission acknowledged the Newport LNG Cold Box Replacement Project in Order No. 21-274, entered September 8, 2021.

Q. What is the timing of the Newport LNG Cold Box Replacement Project?

A. The Company expects to complete the Newport LNG Cold Box Replacement Project by October 2026.

Q. What is the estimated total cost of the Newport LNG Cold Box Replacement Project?

A. The total cost of the Newport LNG Cold Box Replacement Project is expected to be approximately $25.4 million, or $22.6 million on an Oregon-allocated basis.

III. SAFETY-RELATED PROJECTS AND PROGRAMS

Q. Is the Company performing safety-related projects on its distribution system and at its storage facilities?

A. Yes. NW Natural currently is performing several safety-related projects on its transmission and distribution systems and at its storage facilities. These projects are also discussed in the Company's 2025 SPP,[10] filed in docket UM 1900 on September 23, 2024. NW Natural estimates for 2025 that it will invest approximately $18.8 million in capital to comply with United States Department of Transportation Pipeline and Hazardous Materials Safety Administration's ("PHMSA's") Transmission Integrity Management Program ("TIMP"), Distribution Integrity Management Program ("DIMP") and other federal and state regulations.[11] For discussion in this testimony, significant projects and programs include:

- ILI Conversion Projects;
- Proactive EFV Installation Program;
- Probabilistic Distribution Risk Model Project;
- Sewer Crossbore Program; and
- Other Safety Projects and Programs

Q. Will the Company provide additional information to the Commission about these safety-related projects as they move forward?

A. Yes, the Company will keep the Commission and interested stakeholders informed through its SPPs filed in UM 1900.

[10] The dollar amounts stated in this section of the testimony (III. Safety-Related Projects) are project costs before construction overhead costs are added.

[11] The Company also expects to incur approximately $6.4 million of expenses to address and comply with DIMP, TIMP, damage prevention and public awareness.

A. ILI Conversion Projects

Q. Please describe NW Natural's ILI Conversion Projects.

A. PHMSA requires transmission lines to be assessed at seven-year intervals, using one of three methodologies: ILI, External Corrosion Direct Assessment ("ECDA"), or pressure testing. On balance, ILI represents the least risk option needed to meet PHMSA transmission line safety testing requirements. NW Natural has been proactively upgrading its transmission facilities in a planful way to allow for the use of ILI for integrity assessment. For many of our transmission pipelines, NW Natural will need to invest in pipeline facilities such as pig launchers and receivers and removal of reduced port fittings that prevent passage of cleaning, sizing and inspection pigs for inline assessment. This is a one-time investment to upgrade these facilities to allow for inline inspection. Inline inspection tools have the advantage over direct assessment and pressure testing because they assess the entire pipeline segment, between the pig launcher and pig receiver, maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation, corrosion, bad pipe seams and metal loss. As such, ILI is a more complete assessment of the pipeline, is able to detect more threats to the pipeline and provides a greater level of safety to the public as this assessment gives NW Natural a better view of the pipeline and the potential defects. Also, with the advancements in ILI technology, NW Natural is utilizing inspection tools that allow NW Natural a greater understanding of the material properties of the transmission pipeline system, which assures NW Natural that the transmission pipeline system is in alignment with original design records.

In contrast, ECDA as utilized per Code is performed only in High Consequence Areas ("HCAs"), Moderate Consequence Areas ("MCAs") and identified sites, thus limiting the assessment to only certain sections of the pipeline. The threats identified by ECDA are limited to threats that are associated with coating damage. Therefore, ECDA assessment can miss defects such as third-party damage or natural forces damage where the coating was not disturbed, and does not identify any threats outside of the HCAs, MCAs and identified sites.

NW Natural believes that its ILI conversion projects allow it to have a better understanding of the transmission pipeline system, which results in a safer and more reliable natural gas system.

Q. Can you provide an example showing the enhanced safety value of ILI conversion projects compared with ECDA?

A. Yes. In the past, the Company's S22 Albany to Corvallis ten-inch transmission pipeline had been inspected by ECDA. No anomalies were found from the ECDA inspections. In August 2024, the Company changed the ECDA assessment methodology to ILI for the approximately 12 miles of pipeline from the Albany Gate Station to the Corvallis Granger Regional Station (described in the Company's last rate case, docket UG 490), and then conducted an ILI inspection after that conversion. In September 2024, NW Natural received the preliminary report from the smart tool vendor stating the pipeline had five immediate anomalies (four dents with metal loss and one 77 percent metal loss anomaly). The Company quickly mobilized crews to repair the anomalies within a few days, making that pipeline much safer than had been possible in the past with ECDA inspections.

Q. Which ILI Conversion Project are you addressing in your testimony?

A. In 2025, NW Natural expects to change the assessment methodology of the following S03 Salem Bypass Transmission pipeline to ILI to continue to comply with PHMSA's seven-year inspection requirement.

Q. Please describe the S03 Salem Bypass Trans ILI Project.

A. The S03 Salem Bypass Trans ILI Project changes the ECDA assessment methodology to ILI for this approximately 5.5 miles of 8-inch pipeline in Salem that starts at Highway 99E and Blossom Drive and ends at Center Street Regional Station. The Company expects to complete this project and place it in service by October 2025, at an estimated total cost of $9.2 million.

B. Proactive EFV Installation Program

Q. What are EFVs and how do they work?

A. An EFV is a device installed in a service line near the point of connection to the gas main. EFVs will "trip" and stop the flow of gas if there is a full line failure, such as a damaged or severed service line.

Q. Why is the installation of EFVs important to increase safety?

A. In the event of a damaged or severed service line, EFVs are effective in mitigating the escape of gas.

Q. How has NW Natural approached the installation of EFVs?

A. Consistent with federal pipeline safety requirements, NW Natural includes EFVs on all newly installed and fully replaced service lines to single family residences. In addition, the Company installs EFVs for multifamily residences and small commercial customers served by a single service line with a known customer load not exceeding 5,000 standard cubic feet/hour (50 therms/hour). To date, the Company has installed more than 310,000 EFVs on residential and commercial services. For customers with larger known loads, a shut-off valve, instead of an EFV, is installed on the service. Additionally, NW Natural provides notice to its customers of their right to request EFV installation, and they are currently installed at the requesting customer's cost. The Company provides this notice to customers via its website, annual safety notifications, and new customer welcome packets.

Q. Please describe the Company's program to proactively install EFVs on existing service lines.

A. Starting in 2020, as part of our DIMP, NW Natural has been installing EFV retrofits on service lines based on the likelihood and potential consequence of a damage. Factors included in its analysis are population density, service pipe diameter, service material, business districts, and special buildings. In 2025, we expect to invest approximately $2.1 million, or approximately $1.8 million on an Oregon-allocated basis, as part of our DIMP budget on EFV retrofits in high consequence areas.

C. Probabilistic Distribution Risk Model Project

Q. What is a probabilistic risk model, and why is the Company undertaking this project for its distribution system?

A. A probabilistic risk model is a model that determines the probability of failure in the system and quantifies the consequences of a failure per threat. In 2023, NW Natural initiated a project to partner with a data analysis consultant, JANA, to implement a probabilistic risk model to assess the NW Natural distribution system. Probabilistic risk models have been identified by PHMSA as a best practice to proactively manage threats to the natural gas distribution system. The Direct Testimony of Brian E. Fellon (NW Natural/700, Fellon) describes the Company's JANA Probabilistic Risk Model Project, provides its status and quantifies its estimated cost.

D. Sewer Crossbore Program

Q. Please describe the Company's Sewer Crossbore Program.

A. The Sewer Crossbore Program involves the visual inspection of sanitary sewers in Oregon for incidences of gas line crossbores. In installations where trenchless technology was used to install polyethylene pipe, there exists the possibility the gas line was bored through a sewer main or lateral. NW Natural's policy is to expose all foreign line crossings when performing trenchless work. Sewer crossbores typically occur when facility owners fail to locate their pipe, creating a situation where NW Natural is unable to expose facilities during construction. This is an industry-wide threat. Although sewer crossbores are not isolated to gas operators, the consequence when gas lines are involved can be high. This program identifies existing trenchless polyethylene installations and inspects the sewers in the vicinity to identify crossbores.

Q. When does the Company expect to conduct the Sewer Crossbore Program for 2025?

A. The Company expects to conduct the Sewer Crossbore Program for 2025 through October 2025.

Q. What is the Company's most recent cost estimate for the Sewer Crossbore Program for 2025?

A. The Company's most recent total cost estimate for the Sewer Crossbore Program in Oregon for 2025 is approximately $1.0 million.

E. Other Safety Projects and Programs

Q. Please provide a few examples of NW Natural's other safety projects and programs that are addressed in the Company's 2025 SPP.

A. Other safety projects and programs undertaken by NW Natural include non-seismic natural forces, non-hazardous leakage projects and removal of Class A services. In 2025, we expect to invest in the range of $2-5 million, or in the range of $1.8-4.4 million on an Oregon-allocated basis, on our other safety projects and programs.

1. Non-Seismic Natural Forces

Q. Is the Company assessing the impact of non-seismic natural forces on its system?

A. Yes. Portions of NW Natural's transmission and distribution system also cross through landslide faults, sensitive areas, and waterways. Due to significant weather events or the passage of time, the integrity of these pipelines may become at risk. When identified during patrols or routine maintenance, or by other stakeholders, the Company develops plans to remediate these at-risk pipelines as they are identified.

Where the threat of natural forces can be mitigated without pipe replacement or rerouting, NW Natural may choose to address the threat through site work funded by operating expenses. This option is necessary in situations where a reroute is not feasible due to environmental restrictions or where a pipeline serves a critical customer or provides a single feed to a distribution system. Work may include armoring of slopes, re-grading of sites, culvert improvements, and retaining structures to address land movement and drainage issues.

2. Non-Hazardous Leakage Projects

Q. Please describe the Company's Non-Hazardous Leakage Projects.

A. As part of NW Natural's continued efforts to reduce fugitive methane emissions, an approach has been taken to proactively replace facilities that have been identified as producing non-hazardous leaks. Per NW Natural Standard Practices, these facilities previously could be reevaluated on a more frequent basis until the leak classification changes or the facility is repaired or replaced. In order to address these frequent revaluations and reduce fugitive methane emissions, a more proactive approach is being taken towards these facilities and projects are being developed to accelerate replacements.

Q. Are there any recent developments that may affect the scope of the Company's Non-Hazardous Leakage Projects?

A. Yes. In May 2023, PHMSA issued a proposed Gas Pipeline Leak Detection and Repair ("LDAR") rule which among many things established timelines to eliminate leaks classified as "C" leaks ("'C' Leaks"). To date, PHMSA has not defined 'C' Leaks in the federal regulations, but the Company, consistent with industry best practices, has defined 'C' Leaks as the least severe leaks that have a very low level of emissions and present no risk to people or property with timelines to monitor these leaks, but no timeline requirements regarding repair.[12] Currently this rule going through the rulemaking process to potentially become part of PHMSA's federal regulations. The proposed LDAR rule will provide classification definitions and assign a timeline to repair 'C' Leaks when in the past we were allowed to monitor them. If the rule is enacted as currently proposed, this 'C' Leak repair timeline will cause the need for increased spend. As a prudent operator, the Company is expanding work on 'C' Leaks now as the proposed LDAR rule works its way through PHMSA's process.

[12] An 'A' leak is the highest risk leak which requires immediate attention. A 'B' leak presents less of a risk, but the Company does still have a timeframe to eliminate those leaks.

3. Removal of Class A Services

Q. Please describe the safety value of removing Class A services.

A. NW Natural in recent history performed work to eliminate a low-pressure system and transition to a full distribution system. During this transition to eliminate the low-pressure system a small number of Class A services still exist in the system. These Class A services have an MAOP of 12 inches of water column (0.43 psig) and are a legacy from the low-pressure system. NW Natural has identified approximately 32 such services and has taken on a DIMP project to eliminate or upgrade these services such that it is scheduled to eliminate Class A pipe from the NW Natural system by the end of 2026.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBITS 501 – 507

December 30, 2024

EXHIBITS 501-507 – DISTRIBUTION SYSTEM & STORAGE FACILITY PROJECTS

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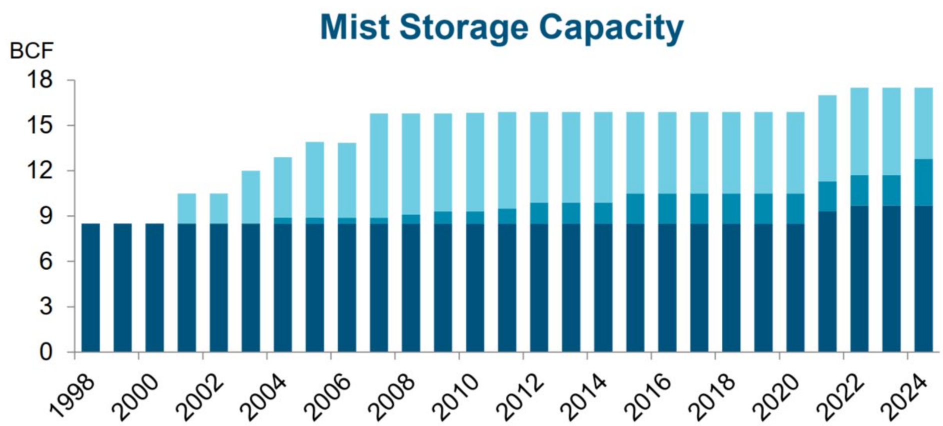
December 30, 2024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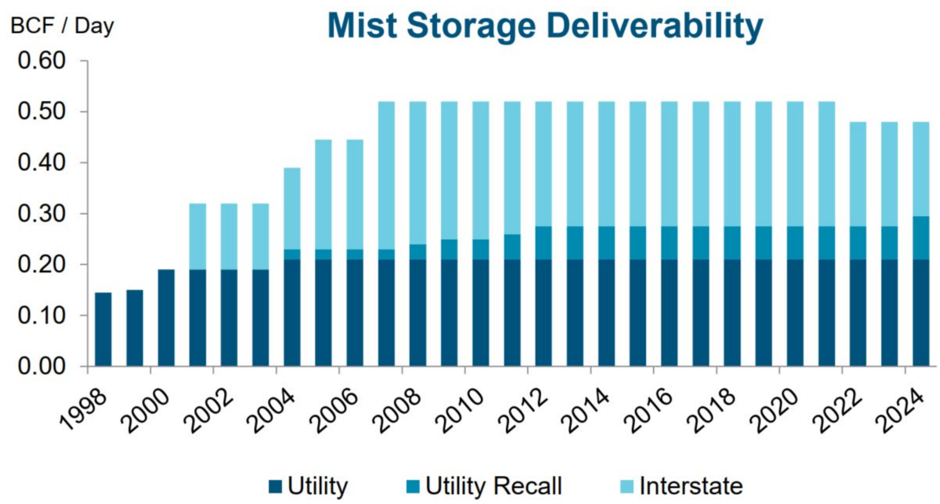
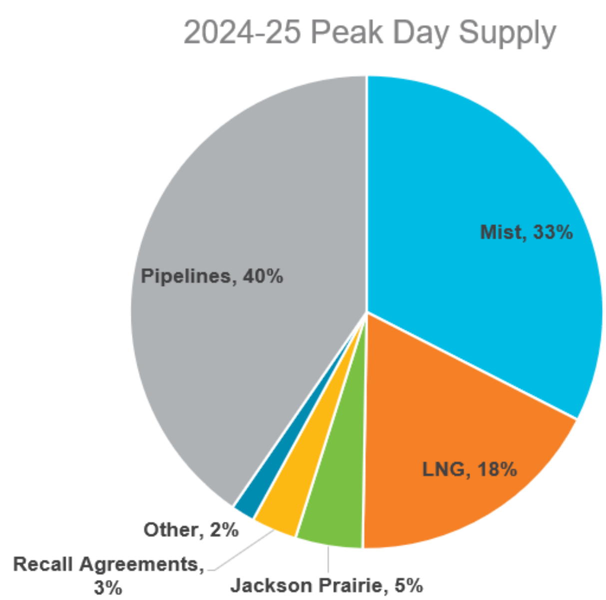

BCF / Day
Mist Storage Deliverability
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
Utility
Utility Recall
Interstate


2024-25 Peak Day Supply
Mist, 33%
LNG, 18%
Jackson Prairie, 5%
Recall Agreements, 3%
Other, 2%
Pipelines, 40%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

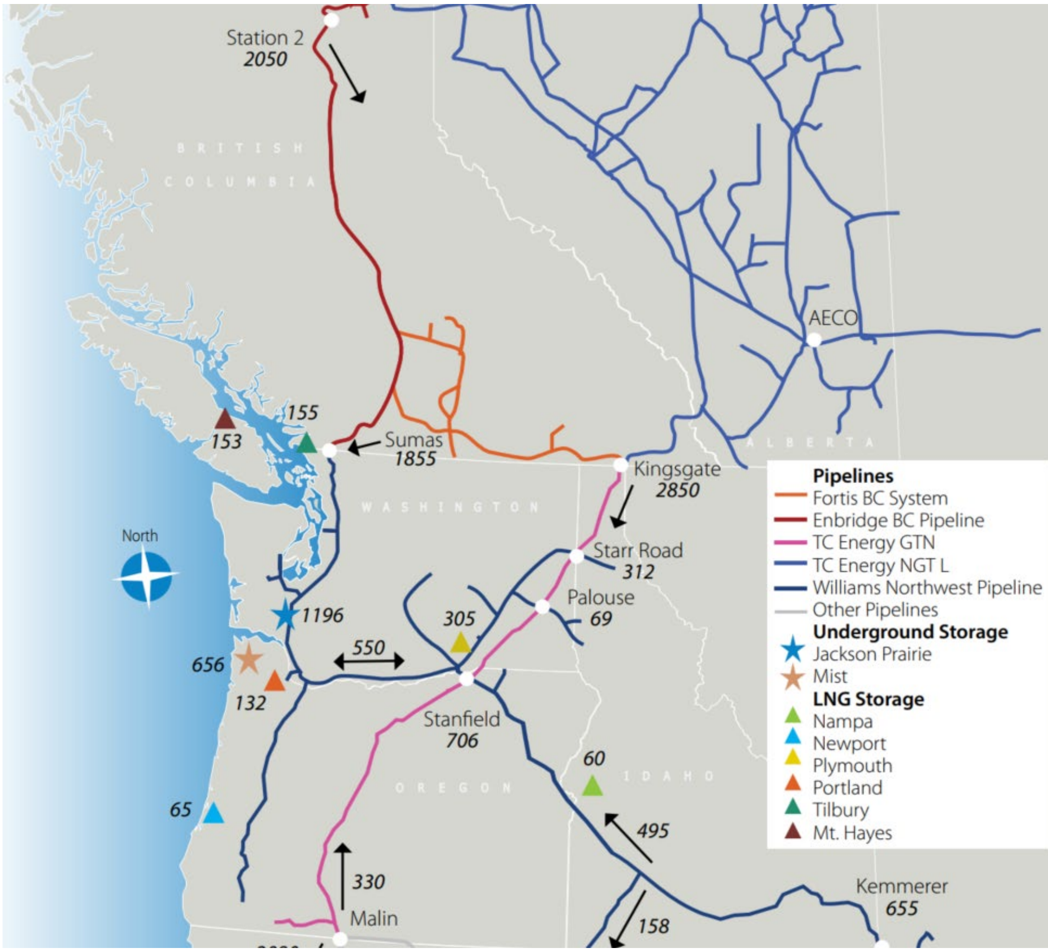
UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 502

December 30, 2024


Station 2
2050
BRITISH
COLUMBIA
AECO
ALBERTA
155
153
Sumas
1855
Kingsgate
2850
WASHINGTON
North
Starr Road
312
Palouse
69
1196
305
550
656
132
Stanfield
706
OREGON
60
IDAHO
65
495
330
Malin
158
Kemmerer
655
Pipelines
Fortis BC System
Enbridge BC Pipeline
TC Energy GTN
TC Energy NGT L
Williams Northwest Pipeline
Other Pipelines
Underground Storage
Jackson Prairie
Mist
LNG Storage
Nampa
Newport
Plymouth
Portland
Tilbury
Mt. Hayes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

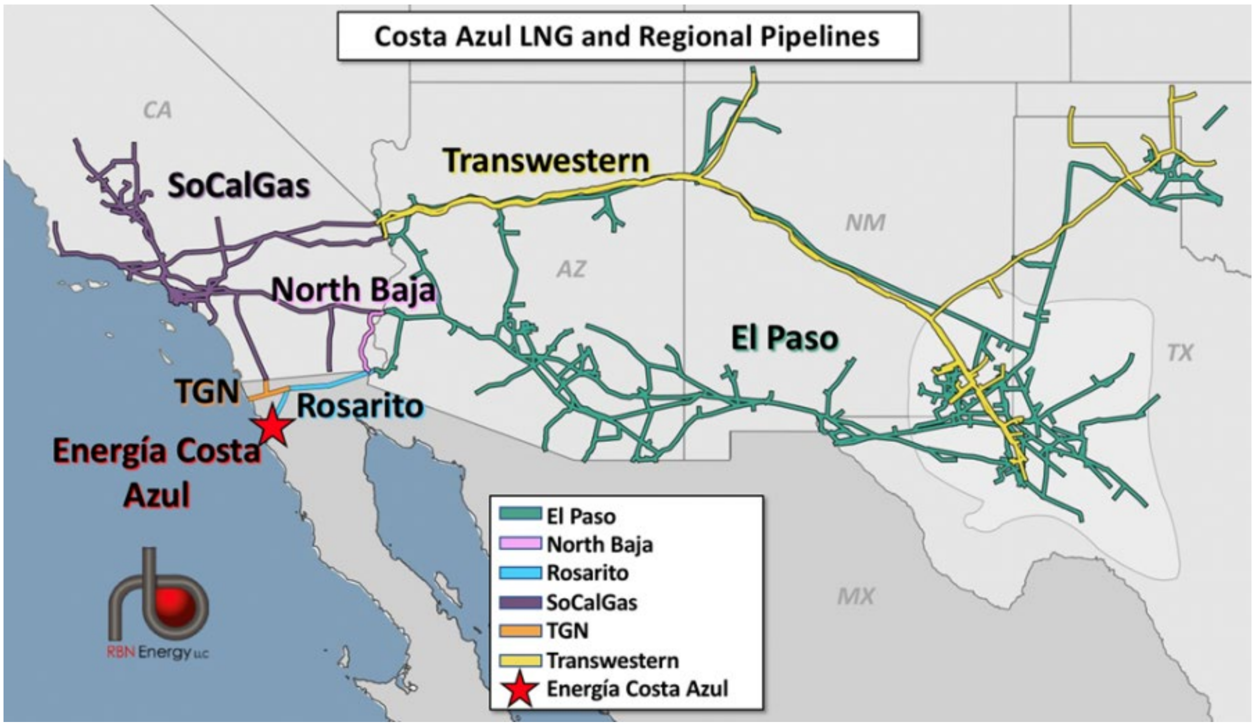
UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 503

December 30, 2024


Costa Azul LNG and Regional Pipelines
CA
SoCalGas
Transwestern
North Baja
AZ
NM
El Paso
TX
TGN
Rosarito
Energía Costa Azul
MX
El Paso
North Baja
Rosarito
SoCalGas
TGN
Transwestern
Energía Costa Azul
RBN Energy LLC

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

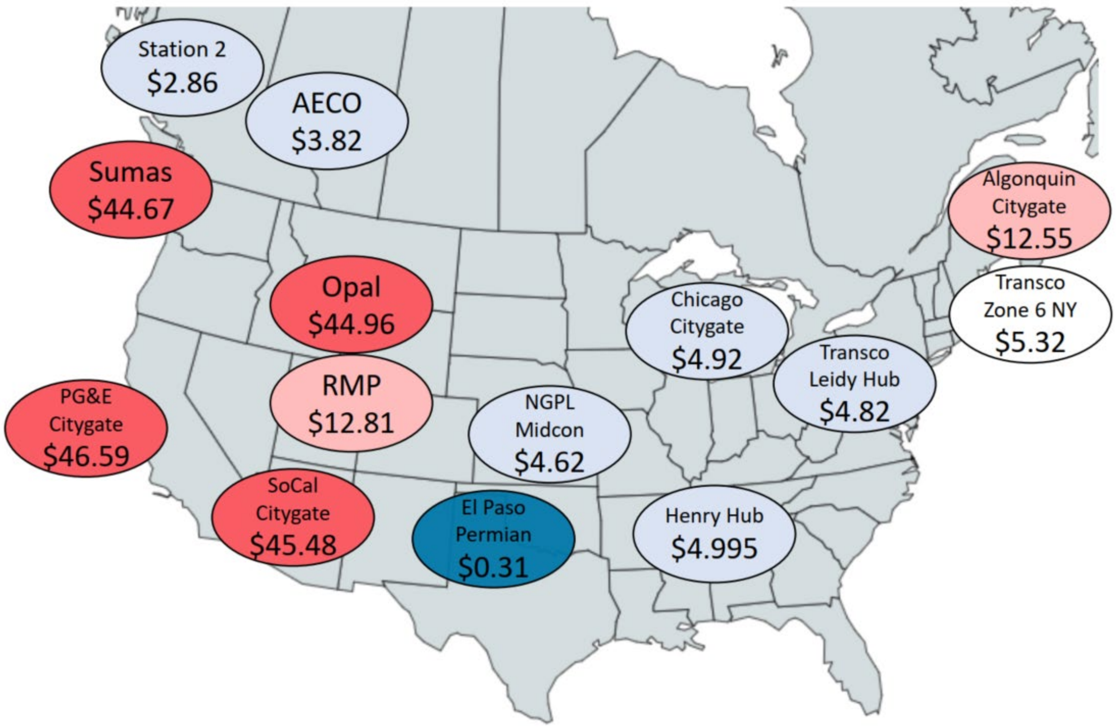
UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 504

December 30, 2024


Station 2
$2.86
AECO
$3.82
Sumas
$44.67
Algonquin
Citygate
$12.55
Opal
$44.96
Transco
Zone 6 NY
$5.32
Chicago
Citygate
$4.92
Transco
Leidy Hub
$4.82
RMP
$12.81
PG&E
Citygate
$46.59
NGPL
Midcon
$4.62
SoCal
Citygate
$45.48
El Paso
Permian
$0.31
Henry Hub
$4.995

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 505

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 506

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 507

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Wayne K. Pipes

FACILITIES
EXHIBIT 600

December 30, 2024

EXHIBIT 600 – DIRECT TESTIMONY – FACILITIES

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Wayne K. Pipes. I am the Director of Facilities, Security and Emergency Management for NW Natural. In this role I am responsible for facilities, planning, and management of real estate, construction, capital projects, maintenance, security, and emergency management activities for NW Natural.

Q. Please describe your education and employment background.

A. I have over 40 years of Facilities Management and Construction experience. I have been employed at NW Natural since 2014. Prior to assuming my current position at NW Natural, I worked for New Seasons for a year as Director of Design, Construction, and Facilities Management. I also worked for Knowledge Universe for 15 years as Vice President of Facilities and Development, and for Red Lion Hotels for 17 years as Senior Director of Facilities Management.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to describe facilities projects that are included in this rate case, specifically, the The Dalles Resource Center ("RC") and our continuing progress on physical security upgrades.

Q. Please summarize your testimony.

A. I will discuss the major facilities projects included in this case. These projects will enhance security and improve The Dalles RC, which will increase functionality and support ongoing safe and efficient operations. A summary of the projects is below:

- The Dalles Resource Center – As part of our on-going facilities strategy, NW Natural will be relocating its The Dalles RC to a new location in The Dalles. I give an overview of The Dalles RC project and why we are replacing the current facility (i.e., the current facility/site is too small and does not include the NW Natural standard equipment and functionality that is required for efficient and safe operations). I also discuss the purchase of a new piece of land to build the new facility. The land purchase will occur in 2025, and The Dalles RC Project will be complete in October 2026.
- Security Enhancements - NW Natural is continuing physical security enhancements at its facilities and field infrastructure through a multi-year effort. Enhanced physical security is necessary in response to increasing threats to facilities and direction from the United States Department of Homeland Security's Transportation Security Administration ("TSA") about those threats. These annual enhancements will continue and should be completed in 2028.

Q. Prior to your discussion of The Dalles RC and Security Enhancements, can you please provide an update on the Company's Facilities roadmap?

A. Yes. In 2008, NW Natural developed a facilities strategy as a flexible roadmap to guide the Company's facilities decisions and investments. Work at NW Natural facilities has been ongoing since then and is nearing completion. The planned relocation of The Dalles RC scheduled for 2026, followed by the Coos Bay and Albany Yard enhancement projects in 2027 and 2028, respectively, are the last large projects currently remaining on the roadmap. A few smaller projects will be completed by 2030.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. The following exhibit accompanies my testimony:

- Exhibit NW Natural/601, Pipes – KPFF Report – The Dalles Resource Center

II. MAJOR FACILITIES PROJECTS

A. The Dalles Resource Center Project

Q. Please provide an overview of The Dalles Resource Center.

A. NW Natural operates a resource center in The Dalles, Oregon, which is essential for supporting the delivery of safe and reliable service across northern Hood River and Wasco Counties in Oregon, as well as Klickitat and Skamania Counties in Washington. The services provided out of this location include customer field services, construction, transmission maintenance, leakage inspection, system operations, and field engineering. The facility also provides materials and equipment storage. The facility is small, leased, and the lease expires at the end of 2026. The leased area is one-half acre and includes a prefabricated steel building. The building consists of a single-story 65-foot by 40-foot garage, a 19-foot by 40-foot ground-floor office, and a 19-foot by 40-foot mezzanine office above the ground floor, totaling about 4,100 square feet. Ten employees work from this site, representing Customer Field Services, Construction, Emergency Response, and Community Affairs. In 2016, a seismic assessment was completed by KPFF Engineering (Exhibit NW Natural/601, Pipes) and concluded that the building does not meet current life-safety building codes, raising concerns about employee safety. Additionally, the lack of onsite fueling could hinder NW Natural's response capabilities during a major natural disaster.

Q. Why is The Dalles Resource Center Project necessary?

A. The office building lacks standard NW Natural functionality. It does not have a conference room, a write-up room (where the crews meet each morning to get their assignments for the day and close out their day), a drying room, or changing room and showers, and the kitchen is inadequate. In addition, the existing site is too small to support current operational needs like a vehicle fueling system, pipe storage, and a decant system. The site lacks and cannot accommodate sufficient indoor covered storage for Company tools and materials, or enclosed parking for specialty equipment, to protect it from the environment. The site also lacks space to accommodate adequately sized storage bins for rocks and sand. The absence of a decant system means employees must drive 23 miles one way (1.5-hour round trip) to dispose of wet spoils. Similarly, the lack of a covered spoils bin requires employees to drive five miles one way (20-minute round trip) to dispose of dry spoils. NW Natural must relocate to a new site because it cannot remedy these size constraints at the existing facility.

In sum, The Dalles Resource Center Project is necessary because the existing site and buildings are inadequate and are too small to be upgraded to accommodate required operations functionality and to enhance efficiency and employee safety.

Q. How is The Dalles Resource Center Project important to the Company's business continuity planning?

A. The Dalles Resource Center is the Company's only facility in the Columbia River Gorge, so it is essential to performing basic utility functions and serves as a center for Company regional emergency response. The Dalles Resource Center Project will increase Company emergency response readiness by designing it to be functional following a seismic event. Additionally, NW Natural will install a fueling station that will be available for Company use during emergencies that impact retail fueling stations.

Q. Were there alternative sites the Company considered for The Dalles Resource Center Project?

A. Yes. Given the upcoming lease expiration and size constraints of the current facility, the Company realized that staying at the existing site was not feasible and began evaluating relocation options in 2022. The Company's broker, Cushman & Wakefield, is concluding an extensive two-year search during which it evaluated several properties, and the site of the new The Dalles Resource Center was the only available property that met the Company's requirements for an adequately sized space in an appropriately zoned area. The new property is large enough to accommodate the Company's new purpose-built building and necessary equipment and vehicle storage. The property was also desirable because it was the lowest cost and risk for zoning approval.

Q. Please describe the scope of The Dalles Resource Center Project.

A. After the Company completes the purchase of a new site, the Company will construct and move into a new facility on the new site. The new facility will include an office building and warehouse (both designed to be functional following a seismic event) and various yard support infrastructure. The other structures include a covered pipe storage shed, enclosed specialty equipment storage garage attached to the pipe storage building, a spoils and decant system shed, a fuel tank within a fueling canopy, and a truck wash room that includes a Landa unit for separating oil from water. The scope will also include a truck and heavy equipment scale. The Company will also make general site improvements like landscaping, yard lighting, parking area striping and bollard installation, fencing, and motorized driveway gates.

Q. Please describe the office building and warehouse the Company will construct at The Dalles Resource Center.

A. The Company will construct both an office building and a warehouse designed to be functional following a seismic event. The office building will include offices, a write up room, a non-commercial galley, locker rooms with showers, a drying room, and a data room. NW Natural will construct the building with necessary features like HVAC, plumbing, and mechanical systems and furniture. The Company will utilize the warehouse to store the various tools and equipment necessary to support operations out of this resource center.

Q. Please explain why the Company needs the various outbuildings and equipment at The Dalles Resource Center.

A. NW Natural is adding these features to all its resource centers to support Company operations, safety and resiliency objectives. Below I provide additional detail for each of the site features mentioned above.

Q. Why is the covered pipe storage needed?

A. There is no existing covered storage space at The Dalles RC for pipes and special equipment. Because the Company's pipes require protection from ultraviolet ("UV") light, the Company has had to use tarps to provide UV protection, which may increase the risk of injury to NW Natural personnel when removing and tarping polyethylene pipe.

Q. How will the Company use the specialty equipment garage?

A. During freezing weather, critical equipment has been stored in the mechanic garage area at night and then removed in the morning to allow mechanics to utilize the garage. The specialty equipment garage will provide a heated storage space and permanent home for temperature sensitive equipment such as the vacuum truck and vapor extraction unit.

Q. Why did NW Natural decide to install a fueling station?

A. The fueling station will improve productivity by allowing employees to fuel their vehicles and equipment while on site and at the beginning and end of their shifts, and not having to rely on retail gas stations. Additionally, as I discussed above, the fueling station will support the Company's business continuity objectives by providing an independent on-site fuel source in the event of a major disaster limiting access to retail fueling sources.

Q. What is the decant system and why is it important to NW Natural's The Dalles operations?

A. The decant system is used to remove liquids from soils removed during excavation work (also called "spoils") completed by utility operations. The liquids are removed by placing the soil in the decant system, which is a sloped containment bin that enables liquids to separate from the soil by allowing settling of the heavier solid materials and by evaporation and draining of the liquids.

The decant system is important to NW Natural's The Dalles field operations because disposal of spoils is required to support the Company's construction projects—including large capital projects, system reinforcement projects, main extensions, new service installations, customer relocates and cut and abandons—that involve vacuum excavation and horizontal directional drilling operations. Environmental compliance requirements are continuing to reduce the availability for disposal sites, and as a result, sites accepting spoils are overcrowded with too many vehicles and pose safety concerns for our employees when entering sites, during spoil disposal, and exiting sites. Additionally, due to the limited availability of sites accepting spoils, NW Natural has needed to haul spoils offsite, which is an inefficient use of resources in terms of both fuel and employee time. Due to the above issues, NW Natural is installing these systems at all resource centers.

Q. How are the spoils bins used in the Company's operations?

A. The spoils bins are used for storage of sand and gravel, which is used for fill material in construction, and are also used for storage of material removed during excavation activities, which may include soils, asphalt and other materials. These materials are stored on site in the spoils bins on an ongoing basis and are then hauled off to a disposal site in larger quantities for efficiency.

Q. Why is the truck scale needed?

A. The truck scale is a safety measure to ensure that NW Natural's trucks and trailers meet applicable weight limitations to avoid over-loading with equipment and materials.

Q. Why is the truck wash needed?

A. The truck wash system is used for cleaning all vehicles and equipment used at The Dalles Resource Center, which includes dump trucks, backhoes, trailers, specialty equipment, pickup trucks, and service vans. Keeping this equipment clean improves safety by ensuring equipment can be inspected properly prior to use and helps maintain the equipment and extends its life expectancy.

Q. What will the Company do to maintain service between the time it vacates the existing facility and when it starts utilizing the new The Dalles Resource Center?

A. The Company will continue to occupy its existing facilities until the new The Dalles Resource Center is completed; the lease at the existing property expires on December 31, 2026. In addition, the new property will be used for materials and equipment storage once it is purchased and for construction materials and activities as the new facility is being constructed.

Q. What is the Company's current forecasted cost for the land acquisition and the RC project?

A. The Company estimates the costs of the land acquisition to be approximately $1.3 million. The Dalles RC is estimated to cost $16.4 million, or $12.5 million on an Oregon allocated basis.

B. Security Upgrades

Q. Please summarize the security upgrades NW Natural is undertaking.

A. In response to increasing threats and ongoing direction from TSA over the last six years, NW Natural has been undertaking a comprehensive, multi-year effort to enhance the physical security at the Company's facilities and field infrastructure. The initial phase of this effort included a pilot program to complete upgrades at five, high-priority sites in 2023.

After the pilot concluded, NW Natural began implementing security upgrades more broadly in 2024. The Company is completing multiple sites per year over the next several years. Currently, NW Natural anticipates that all security upgrades should be completed by the end of 2028. After that, the Company will turn over annual maintenance/upgrades to NW Natural's Engineering Department as part of the ongoing system infrastructure maintenance and enhancements.

Q. How did NW Natural determine that security upgrades are necessary?

A. A variety of emerging threats and new requirements over the last several years have led NW Natural to evaluate and prioritize physical security upgrades. The

Company began working on a physical security strategy and roadmap in 2017 to address issues of employee and public safety posed by potential security breaches. The first step in this process was to document all physical security apparatuses associated with Company facilities and identify potential risks. To aid in this effort, NW Natural engaged consulting firm CH2M in 2017 to develop a criticality ranking and asset protection recommendations. With input from NW Natural subject matter experts, CH2M completed the criticality ranking of the Company's facilities and field infrastructure in early 2018.

In March 2018, TSA—the federal agency that oversees pipeline safety—issued pipeline security guidelines that contained recommendations regarding assessing the risks of, and implementing site-specific security measures at, both critical and non-critical facilities.[1] The TSA updated these guidelines in 2021, creating a mechanism for designating "critical" facilities to ensure these sites have sufficient security to avoid service disruptions to important infrastructure and to the public at large.[2]

Following the May 2021 ransomware attack on the Colonial Pipeline, TSA issued several directives mandating cybersecurity measures. One way that these directives enhance cybersecurity is by addressing physical security, because TSA recognized that unauthorized access to physical facilities could enable a bad actor to obtain access to cyber systems. Along with the pipeline security guidelines, the

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[1] Transportation Security Administration, *Pipeline Security Guidelines* (March 2018; updated April 2021), *available at* https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.

[2] *Id.*, at 8.

cybersecurity directives related to physical security highlighted the importance of NW Natural's ongoing efforts to strengthen physical security and the need to accelerate and expand those efforts.

In June 2022, TSA conducted an audit of several NW Natural sites classified as "critical" infrastructure, and the TSA audit recommendations also informed the Company's planned upgrades at other sites.

Finally, the United States in general has seen ongoing attacks on the energy system, including intentional destruction of critical infrastructure, unauthorized access to facilities, and instances of individuals using recording devices, taking pictures, and flying drones over refineries and other facilities. The Company has recently experienced break-ins and theft at the Company's resource centers and damage to regulator stations. Because of these continuing activities, it is imperative that NW Natural continue addressing physical security upgrades in a comprehensive way.

Q. Please provide additional detail regarding the pilot program.

A. The Company's facilities and field infrastructure include more than 1,200 sites. It is not feasible to complete every potential upgrade at each site in a single, sweeping project effort. Instead, NW Natural stood up a limited pilot on five key sites, which would eventually be scaled across the Company's facilities and field infrastructure footprint.

NW Natural designed the pilot program to help the Company refine its choice of technology/equipment, procurement strategy, quality assurance, risk management, cost estimates, and efficient execution of security upgrades. In particular, the pilot allowed the Company to learn about costs, supply chain issues, and equipment that could have long lead time issues; test various price breaks for purchasing materials needed in bulk; and identify efficiencies from conducting upgrades at multiple sites or along with unrelated projects at specific sites.

Q. What were some of the lessons learned from the pilot program?

A. From the pilot program, NW Natural:

- Created detailed security enhancement specs based on CH2M's protection tiers;
- Developed cost estimates, lead-times, and installation timeframes for upgrade projects;
- Implemented strong safety practices and coordinated with NW Natural teams;
- Gained experience with surveying sites, navigating easements and permitting work;
- Gained experience in managing complicated purchase orders;
- Estimated costs for site surveys and structural engineering; and
- Established safety practices using gas monitoring equipment.

Q. Has the Company applied the lessons learned from the pilot program to its ongoing security enhancement efforts?

A. Yes. Using the insight gained from the pilot program, NW Natural has planned and executed ongoing security upgrades in an efficient and cost-effective manner.

Q. How will the security upgrades included in this case provide benefits to customers?

A. Security upgrades provide several benefits: they help ensure the Company's system can continue providing safe and reliable service to customers without interruption; they improve employee safety; they protect property, plant and equipment; they improve cyber security at locations that are connected to our gas control system; and they also ensure NW Natural is compliant with requirements from regulators, specifically the TSA.

Q. What is the Company's forecasted cost and timing for these projects?

A. The broader upgrade program is expected to continue through 2028, with annual security upgrades placed in service on a rolling basis as they are completed. Various sites will be completed each year. The current budget for these projects is $2.5 million per year.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Wayne K. Pipes

FACILITIES
EXHIBIT 601

December 30, 2024

EXHIBIT 601 – FACILITIES

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ASCE 41-13 Tier 1 Seismic Evaluation of

NW Natural – The Dalles Service Center

1125 Bargeway Road
The Dalles, OR 97058

August 5, 2016
KPFF Project No. 1600122

NW Natural – The Dalles Service Center
ASCE 41-13 Tier 1 Seismic Evaluation

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Introduction

This report is to summarize the findings of our seismic evaluation of the NW Natural The Dalles Service Center located at 1125 Bargeway Road, The Dalles, OR. The evaluation was performed using the procedures of ASCE 41-13 "Seismic Evaluation and Retrofit of Existing Buildings." Please note that this evaluation only relates to the seismic performance of the structure. It does not address issues related to gravity framing.

Scope and Intent

KPFF Consulting Engineers was contracted to perform a Tier 1 seismic evaluation of the NW Natural The Dalles Service Center located in The Dalles, Oregon. This evaluation is based on a site visit that was completed on May 3, 2016, and upon the procedures of ASCE 41-13 "Seismic Evaluation and Retrofit of Existing Buildings." The intent of the evaluation is to determine if the structure meets the acceptance criteria of the Basic Performance Objective for Existing Buildings (BPOE). For this evaluation, the building was considered a Risk Category II building (i.e. a standard building occupancy) as defined by the International Building Code and the Oregon Structural Specialty Code. Therefore, the BPOE requires meeting the Life Safety Structural Performance level at the BSE-1E seismic hazard level, and the Life Safety Nonstructural Performance level also at the BSE-1E seismic hazard level. The City of Portland, chapter 24.85, stipulates that the BSE-1E seismic hazard level shall not be taken as less than 75 percent of the BSE-1N seismic hazard level. This City of Portland requirement is being applied to all NW Natural evaluations as to provide a consistent evaluation process across all locations. Life Safety, BSE-1E, and BSE-1N are defined as follows:

- Life Safety is a structural performance level in which a structure has significantly damaged components but retains a margin against the onset of partial or total collapse. It is possible that the structure will be damaged to the extent that it is not practical to repair and re-occupy the building.

- BSE-1E is a seismic hazard level that represents an earthquake that has a probability of exceedance of 20% in a 50 year period. This can also be thought of as an earthquake that is not expected to be exceeded in a 225 year return period.

- BSE-1N is two thirds of a seismic hazard level that represents an earthquake that has a probability of exceedance of 2% in a 50 year period multiplied by a risk coefficient. This can also be thought of as two thirds of the ground acceleration of an earthquake that is not expected to be exceeded in a 2,475 year return period.

Site and Building Data

The NW Natural The Dalles Service Center is an existing pre-engineered and prefabricated steel building, located at 1125 Bargeway Road, in The Dalles, Oregon. The original construction date is unknown. The overall building measures approximately 84 feet in the northeast-southwest direction by 40 feet in the northwest-southeast direction. It consists of a single story 65-foot by 40-foot garage, a 19-foot by 40-foot ground floor office, and a 19-foot by 40-foot mezzanine office (above the ground floor office). The combined building is approximately 4,100 square feet.

The roof structure consists of corrugated metal roofing that spans between cold-formed metal joists. The joists span between transverse steel frames, and the frames are bolted to the slab/foundation. The lateral force resisting system in the northeast-southwest direction consists of metal roof decking and diagonal roof bracing, which transfer load to the transverse frames via bolted connections, and bolted connections transfer the load from the frames into wall diagonal bracing, and these diagonals are bolted to the base of the frames that are bolted to the slab/foundation. The lateral force resisting system in the northwest-southeast direction consists of metal roof decking and diagonal roof bracing, which transfer load to the transvers frames, and the frames are bolted to the slab/foundation.

List of Criteria Used for Analysis

A geotechnical investigation was not performed for this evaluation. It was assumed that classification of the soils at the site as Site Class D and the following ground motions were used for the analysis:

Parameter	Value	Comments
$S_{X1,\ BSE\text{-}1E}$	0.157 g	Design spectral response acceleration parameter at 1 second for the BSE-1E seismic hazard level.
$S_{XS,\ BSE\text{-}1N}$	0.458 g	Design short-period (0.2 seconds) spectral response acceleration parameter for the BSE-1N seismic hazard Level.
T	0.217 s	Building fundamental period, as defined in Section 4.5.2.4.
S_a	0.343 g	Response spectral acceleration parameter. S_a = minimum($S_{X1,\ BSE\text{-}1E}$ / T, 0.75$S_{XS,\ BSE\text{-}1N}$)

The Level of Seismicity for the structure is therefore considered to be “High” as defined by Section 2.5 of ASCE 41. Please reference the full summary of the evaluation assumptions listed in the appendix.

Findings

The building was evaluated using the Tier 1 checklists, including the “Life Safety Non-structural Checklist,” as required in Section 4.4 of ASCE 41-13. The building in its existing condition does not meet the requirements of the Basic Performance Objective for Existing Buildings (i.e. Life Safety structural performance at three-quarters of BSE-1N seismic hazard level, as amended by the City of Portland Chapter 24.85). The following table summarizes the deficiencies that were identified for the building per the Tier 1 checklists. Reference Appendix A for the summary data sheet and completed checklists.

Structural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	n/a	n/a	n/a

Note: There were no identified structural noncompliant items. However, the following list of structural unknowns may contain noncompliant items if evaluation was possible.

Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Load Path	A.2.1.1	It is unclear how the mezzanine attaches to the steel frames or if it is self-supported/braced. The metal building alone appears to have a complete load path.
2	Mezzanines	A.2.1.3	It is not clear how the mezzanine is laterally braced. The mezzanine connections to the main steel frame were not exposed to view, and the building structure drawings were not available for review.
3	Liquefaction	A.6.1.1	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, this building site has a "low" earthquake liquefaction hazard.
4	Slope Failure	A.6.1.2	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, this building site has a "high" landslide hazard.
5	Surface Fault Rupture	A.6.1.3	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, there are no identified active faults located within several miles of the site.
6	Ties Between Foundation Elements	A.6.2.3	Without structural drawings, it is not known if foundation ties between columns are present.
7	Brace Axial Stress Check	A.3.3.1.2	Without structural drawings, and the lack of access inside the northern part of the exterior walls, the quantity of diagonal rod bracing bays is not known.
8	Moment-Resisting Connections	A.3.1.3.4	Without structural drawings that describe the frame details, it is not possible to perform this check.

No.	Item	Tier 1 Ref.	Comments
9	Compact Members	A.3.1.3.8	Without structural drawings that describe the frame details, it is not possible to determine the frame member section properties.

Nonstructural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Shut-Off Valves	A.7.13.3	A natural gas shut-off valve was not identified.
2	Flexible Couplings	A.7.15.4	Hazardous material piping (natural gas) does not appear to have flexible couplings (all rigid steel).
3	Tall Narrow Contents	A.7.11.2	Not all cabinets/refrigerators/storage racks/etc. are anchored.
4	Fall-Prone Contents	A.7.11.3	Heavy items on storage racks do not appear to be braced to the racks.

Note: Not all nonstructural checklist items were able to be identified. The following list of nonstructural unknowns may contain noncompliant items if evaluation was possible.

Nonstructural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Suspended Gypsum Board	A.7.2.3	The ceiling attachments were not viewable.
2	Overhead Glazing	A.7.4.8	The type of glazing is not known.
3	Stair Details	A.7.10.2	The stair details were not accessible to view, and structural drawings were not available for review; therefore the condition is not known.

Conceptual Seismic Upgrade Work

No explicit structural deficiencies are identified in the Tier 1 Checklists as noted in the Structural Deficiencies table previously shown in this report. However, there are structural unknowns that may contain noncompliant items if evaluation was possible. These unknowns may be identified as compliant or noncompliant if more extensive investigation, beyond that of a Tier 1 checklist, was performed.

Nonstructural deficiencies are identified in the Tier 1 Checklists, and are listed in the Nonstructural Deficiencies table previously shown in this report. There are also nonstructural unknowns that may contain noncompliant items if evaluation was possible. These unknowns may be identified as compliant or noncompliant if more extensive investigation, beyond that of a Tier 1 checklist, was performed. The following is a list of potential solutions to mitigate the identified deficiencies:

1. Shut-Off Valves: Identify the shut-off valves for natural gas. Add shut-off valve if one is not present.
2. Flexible Couplings: Add flexible couplings to natural gas piping.
3. Tall Narrow Contents: Anchor cabinets/refrigerators/storage racks/etc. that are taller than 6 feet and with a height-to-depth ratio greater than 3-to-1.

No explicit structural deficiencies are identified in the Tier 1 Checklists; however, as previously noted, several structural unknowns may contain noncompliant items if more extensive investigation was performed. Based on our experience with seismic upgrades of similar buildings, the probable cost of an upgrade of this type related to direct structural costs would be approximately $25 - $30 per square foot. This does not include costs associated with nonstructural deficiencies, soft costs, impacts to architectural or M/E/P systems, business interruption, geotechnical ground improvement, etc. It is assumed that an M/E/P designer or contractor would address costs associated with the identified nonstructural deficiencies.

Summary

This ASCE 41-13 Tier 1 seismic evaluation was prepared for the NW Natural – The Dalles Service Center. It was found that the aforementioned building, in its current state, does not achieve the desired seismic performance objective for Life Safety Structural Performance at the BSE-1E seismic hazard or 0.75 x BSE-1N seismic hazard as amended by the City of Portland's Chapter 24.85. It also does not achieve the desired seismic performance objective for Life Safety Nonstructural Performance at the same seismic hazard as stated above.

Since there are no identified structural deficiencies, yet several unknowns, further investigation should be completed to determine compliance of the identified unknowns. If the unknowns were to identify structural deficiencies, in the event of a significant seismic event, it is expected that the building will be damaged, possibly to the point where repair and re-occupancy of the building is not possible. The threat to the life safety of the building occupants, under the seismic hazards and performance objectives mentioned in this report, is higher than it would be compared to a building constructed to modern building codes. Most of the nonstructural seismic upgrade work would relate to bracing and/or restraint of nonstructural components and contents. The nonstructural unknowns should also be further investigated. It is our opinion that conventional seismic upgrade work could be employed to reduce/mitigate this seismic risk.

Appendix

ASCE 41-13 Summary Data Sheet and Checklists

Appendix C: Summary Data Sheet

BUILDING DATA

Building Name: NW Natural - The Dalles Service Center
Date: May 3, 2016
Building Address: 1125 Bargeway Road, The Dalles, OR 97058
Latitude: 45.610616 Longitude: -121.19476 By: IKE

Year Built: Unknown Year(s) Remodeled: Unknown Original Design Code: Unknown
Area (sf): 4,100 Length (ft): 84 (NE-SW) Width (ft): 40 (NW-SE)
No. of Stories: 1 (plus mezzanine) Story Height: 24 ft Total Height: 24 ft

USE ☐ Industrial ☑ Office ☐ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☑ Other: Service Center/Garage

CONSTRUCTION DATA

Gravity Load Structural System: Structural steel
Exterior Transverse Walls: Corrugated metal panels Openings? Yes
Exterior Longitudinal Walls: Corrugated metal panels Openings? Yes
Roof Materials/Framing: Corrugated metals panels over light gauge metal joists supported by structural steel frames
Intermediate Floors/Framing: Mezzanine - plywood sheathing over wood framing
Ground Floor: Concrete slab on grade
Columns: Structural steel Foundation: Spread footings
General Condition of Structure: Good (structural steel appears to be in good condition)
Levels Below Grade? No
Special Features and Comments: None

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	Rod bracing	Rod bracing
Vertical Elements:	Steel columns	Steel columns
Diaphragms:	Rod bracing	Rod bracing
Connections:	Rod bracing bolted to steel columns at top and bottom	Rod bracing bolted to steel columns at top and bottom

EVALUATION DATA

BSE-1N Spectral Response Accelerations: S_{Ds}= 0.458 S_{D1}= 0.290
Soil Factors: Class= Site Class D
BSE-1E Spectral Response Accelerations: S_{XS}= 0.258 S_{X1}= 0.157
Level of Seismicity: High Performance Level: Life Safety
Building Period: T= 0.217 seconds
Spectral Acceleration: S_a= min($S_{X1,\ BSE\text{-}1E}$ / T = 0.724, $S_{X1,\ BSE\text{-}1N}$ = 0.343) = 0.343
Modification Factor: $C_mC_1C_2$= 1.0 (1-story S3) Building Weight: W= 107 kips
Pseudo Lateral Force: $V= C_mC_1C_2S_aW$= 37 kips

BUILDING CLASSIFICATION: S3

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☑	☐
Building Type **S3** Structural Checklist	☑	☐
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: n/a

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.1 Basic Checklist

Very Low Seismicity

Structural Components

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	LOAD PATH: The structure shall contain a complete, well-defined load path, including structural elements and connections, that serves to transfer the inertial forces associated with the mass of all elements of the building to the foundation. (Commentary: Sec. A.2.1.1. Tier 2: Sec. 5.4.1.1)	Unclear how the mezzanine attaches to the steel frames. The metal building alone appears to have a complete load path: metal roof decking and roof diagonal rod bracing, diagonal rod bracing in the N-S direction and moment frames in the E-W direction.
C ☐	NC ☐	N/A ☒	U ☐	WALL ANCHORAGE: Exterior concrete or masonry walls that are dependent on the diaphragm for lateral support are anchored for out-of-plane forces at each diaphragm level with steel anchors, reinforcing dowels, or straps that are developed into the diaphragm. Connections shall have adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.5.3.7. (Commentary: Sec. A.5.1.1. Tier 2: Sec. 5.7.1.1)	There are no concrete or masonry walls.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.1.2LS Life Safety Basic Configuration Checklist

Low Seismicity

Building System

General

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	LOAD PATH: The structure shall contain a complete, well-defined load path, including structural elements and connections, that serves to transfer the inertial forces associated with the mass of all elements of the building to the foundation. (Commentary: Sec. A.2.1.1. Tier 2: Sec. 5.4.1.1)	Unclear how the mezzanine attaches to the steel frames. The metal building alone appears to have a complete load path: metal roof decking and roof diagonal rod bracing, diagonal rod bracing in the N-S direction and moment frames in the E-W direction.
C ☐	NC ☐	N/A ☒	U ☐	ADJACENT BUILDINGS: The clear distance between the building being evaluated and any adjacent building is greater than 4% of the height of the shorter building. This statement need not apply for the following building types: W1, W1A, and W2. (Commentary: Sec. A.2.1.2. Tier 2: Sec. 5.4.1.2)	There are no immediately adjacent buildings.
C ☐	NC ☐	N/A ☐	U ☒	MEZZANINES: Interior mezzanine levels are braced independently from the main structure or are anchored to the seismic-force-resisting elements of the main structure. (Commentary: Sec. A.2.1.3. Tier 2: Sec. 5.4.1.3)	The mezzanine connections to the main steel frame were not exposed to view, and building structure drawings were not available for review. It is not clear how the mezzanine is laterally braced.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

Building Configuration

RATING C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	WEAK STORY: The sum of the shear strengths of the seismic-force-resisting system in any story in each direction is not less than 80% of the strength in the adjacent story above. (Commentary: Sec. A2.2.2. Tier 2: Sec. 5.4.2.1)	This is a one-story building (with the exception of the mezzanine).
☐	☐	☒	☐	SOFT STORY: The stiffness of the seismic-force-resisting system in any story is not less than 70% of the seismic-force-resisting system stiffness in an adjacent story above or less than 80% of the average seismic-force-resisting system stiffness of the three stories above. (Commentary: Sec. A.2.2.3. Tier 2: Sec. 5.4.2.2)	This is a one-story building (with the exception of the mezzanine).
☒	☐	☐	☐	VERTICAL IRREGULARITIES: All vertical elements in the seismic-force-resisting system are continuous to the foundation. (Commentary: Sec. A.2.2.4. Tier 2: Sec. 5.4.2.3)	The steel frames are continuous to the foundation.
☒	☐	☐	☐	GEOMETRY: There are no changes in the net horizontal dimension of the seismic-force-resisting system of more than 30% in a story relative to adjacent stories, excluding one-story penthouses and mezzanines. (Commentary: Sec. A.2.2.5. Tier 2: Sec. 5.4.2.4)	This is a one-story building, and the steel frames appear to be symmetric.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	MASS: There is no change in effective mass more than 50% from one story to the next. Light roofs, penthouses, and mezzanines need not be considered. (Commentary: Sec. A.2.2.6. Tier 2: Sec. 5.4.2.5)	This is a one-story building (with the exception of the mezzanine).
☒	☐	☐	☐	TORSION: The estimated distance between the story center of mass and the story center of rigidity is less than 20% of the building width in either plan dimension. (Commentary: Sec. A.2.2.7. Tier 2: Sec. 5.4.2.6)	

Moderate Seismicity

Geologic Site Hazards

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	LIQUEFACTION: Liquefaction-susceptible, saturated, loose granular soils that could jeopardize the building's seismic performance shall not exist in the foundation soils at depths within 50 ft under the building. (Commentary: Sec. A.6.1.1. Tier 2: 5.4.3.1)	A geotechnical report was not available for review.
C ☐	NC ☐	N/A ☐	U ☒	SLOPE FAILURE: The building site is sufficiently remote from potential earthquake-induced slope failures or rockfalls to be unaffected by such failures or is capable of accommodating any predicted movements without failure. (Commentary: Sec. A.6.1.2. Tier 2: 5.4.3.1)	A geotechnical report was not available for review.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☐	☒	SURFACE FAULT RUPTURE: Surface fault rupture and surface displacement at the building site are not anticipated. (Commentary: Sec. A.6.1.3. Tier 2: 5.4.3.1)	A geotechnical report was not available for report.

High Seismicity

Foundation Configuration

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	OVERTURNING: The ratio of the least horizontal dimension of the seismic-force-resisting system at the foundation level to the building height (base/height) is greater than $0.6S_a$. (Commentary: Sec. A.6.2.1. Tier 2: Sec. 5.4.3.3)	
☐	☐	☐	☒	TIES BETWEEN FOUNDATION ELEMENTS: The foundation has ties adequate to resist seismic forces where footings, piles, and piers are not restrained by beams, slabs, or soils classified as Site Class A, B, or C. (Commentary: Sec. A.6.2.2. Tier 2: Sec. 5.4.3.4)	Without structural drawings, it is not known if foundation ties are present between column footings.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.6LS Life Safety Structural Checklist for Building Type S3: Steel Light Frames

Low and Moderate Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	BRACE AXIAL STRESS CHECK: The axial stress in the diagonals, calculated using the Quick Check procedure of Section 4.5.3.4, is less than $0.50F_y$. (Commentary: Sec. A.3.3.1.2. Tier 2: Sec. 5.5.4.1)	Without structural drawings and visible access to the north end of the building, the quantity of diagonal rod bracing bays is not known. The steel grade for the rod bracing is also unknown.

Connections

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	TRANSFER TO STEEL FRAMES: Diaphragms are connected for transfer of seismic forces to the steel frames. (Commentary: Sec. A.5.2.2. Tier 2: Sec. 5.7.2)	Roof diaphragm rod bracing is connected to the frame columns.
C ☒	NC ☐	N/A ☐	U ☐	STEEL COLUMNS: The columns in seismic-force-resisting frames are anchored to the building foundation. (Commentary: Sec. A.5.3.1. Tier 2: Sec. 5.7.3.1)	The columns are bolted to the concrete slab/foundation.

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

High Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	MOMENT-RESISTING CONNECTIONS: All moment connections are able to develop the elastic moment (F_yS) of the adjoining members. (Commentary: Sec. A.3.1.3.4. Tier 2: Sec. 5.5.2.2.1)	Without structural drawings that describe the frame details, it is not possible to perform this calculation.
C ☐	NC ☐	N/A ☐	U ☒	COMPACT MEMBERS: All frame elements shall meet compact section requirements set forth by AISC 360, Table B4.1. (Commentary: Sec. A.3.1.3.8. Tier 2: Sec. 5.5.2.2.4)	Without structural drawings that describe the frame details, it is not possible to determine section properties.
C ☒	NC ☐	N/A ☐	U ☐	OTHER DIAPHRAGMS: The diaphragm does not consist of a system other than wood, metal deck, concrete, or horizontal bracing. (Commentary: Sec. A.4.7.1. Tier 2: Sec. 5.6.5)	The roof diaphragm has horizontal/diagonal bracing.

Connections

RATING				DESCRIPTION	COMMENTS
C ☒	NC ☐	N/A ☐	U ☐	ROOF PANELS: Metal, plastic, or cementitious roof panels are positively attached to the roof framing to resist seismic forces. (Commentary: Sec. A.5.5.1. Tier 2: Sec. 5.7.5)	The roof panels appear to be fastened to the roof framing.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U		
☒	☐	☐	☐	WALL PANELS: Metal, fiberglass, or cementitious wall panels are positively attached to the framing and foundation to resist seismic forces. (Commentary: Sec. A.5.5.2. Tier 2: Sec. 5.7.5)	The wall panels are fastened to the wall framing, the framing to the main moment frames, and the main frames to the foundation.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.17 Nonstructural Checklist

The Performance Level is designated LS for Life Safety or PR for Position Retention. The level of seismicity is designated as "not required" or by L, M, or H, for Low, Moderate, and High.

All Seismicity Levels

Life Safety Systems

RATING C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	LS-LMH; PR-LMH. FIRE SUPPRESSION PIPING: Fire suppression piping is anchored and braced in accordance with NFPA-13. (Commentary: Sec. A.7.13.1. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
☐	☐	☒	☐	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Fire suppression piping has flexible couplings in accordance with NFPA-13. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
☒	☐	☐	☐	LS-LMH; PR-LMH. EMERGENCY POWER: Equipment used to power or control life safety systems is anchored or braced. (Commentary: Sec. A.7.12.1. Tier 2: Sec. 13.7.7)	The generator is anchored to a concrete slab.
☐	☐	☒	☐	LS-LMH; PR-LMH. STAIR AND SMOKE DUCTS: Stair pressurization and smoke control ducts are braced and have flexible connections at seismic joints. (Commentary: Sec. A.7.14.1. Tier 2: Sec. 13.7.6)	The building does not contain seismic joints.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	LS-MH; PR-MH. SPRINKLER CEILING CLEARANCE: Penetrations through panelized ceilings for fire suppression devices provide clearances in accordance with NFPA-13. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
☐	☐	☒	☐	LS-not required; PR-LMH. EMERGENCY LIGHTING: Emergency and egress lighting equipment is anchored or braced. (Commentary: Sec. A.7.3.1. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.

Hazardous Materials

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL EQUIPMENT: Equipment mounted on vibration isolators and containing hazardous material is equipped with restraints or snubbers. (Commentary: Sec. A.7.12.2. Tier 2: 13.7.1)	This type of equipment, mounted on isolators, does not appear to occur in this building.
☐	☐	☒	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL STORAGE: Breakable containers that hold hazardous material, including gas cylinders, are restrained by latched doors, shelf lips, wires, or other methods. (Commentary: Sec. A.7.15.1. Tier 2: Sec. 13.8.4)	There do not appear to be "breakable" containers that hold hazardous materials.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U	Statement	Comments
☒	☐	☐	☐	LS-MH; PR-MH. HAZARDOUS MATERIAL DISTRIBUTION: Piping or ductwork conveying hazardous materials is braced or otherwise protected from damage that would allow hazardous material release. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	Gas piping appears to be braced to the building.
☐	☒	☐	☐	LS-MH; PR-MH. SHUT-OFF VALVES: Piping containing hazardous material, including natural gas, has shut-off valves or other devices to limit spills or leaks. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.3 and 13.7.5)	A natural shut-off valve was not identified.
☐	☒	☐	☐	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Hazardous material ductwork and piping, including natural gas piping, has flexible couplings. (Commentary: Sec. A.7.15.4, Tier 2: Sec.13.7.3 and 13.7.5)	Couplings all appear to be rigid steel.
☐	☐	☒	☐	LS-MH; PR-MH. PIPING OR DUCTS CROSSING SEISMIC JOINTS: Piping or ductwork carrying hazardous material that either crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.13.6. Tier 2: Sec.13.7.3, 13.7.5, and 13.7.6)	There are no seismic joints.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

Partitions

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY: Unreinforced masonry or hollow-clay tile partitions are braced at a spacing of at most 10 ft in Low or Moderate Seismicity, or at most 6 ft in High Seismicity. (Commentary: Sec. A.7.1.1. Tier 2: Sec. 13.6.2)	There are no masonry walls.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. HEAVY PARTITIONS SUPPORTED BY CEILINGS: The tops of masonry or hollow-clay tile partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	There are no heavy partitions supported by ceilings.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. DRIFT: Rigid cementitious partitions are detailed to accommodate the following drift ratios: in steel moment frame, concrete moment frame, and wood frame buildings, 0.02; in other buildings, 0.005. (Commentary A.7.1.2 Tier 2: Sec. 13.6.2)	There are no rigid cementitious partitions.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-MH. LIGHT PARTITIONS SUPPORTED BY CEILINGS: The tops of gypsum board partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center

Project Number 1600122

C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. STRUCTURAL SEPARATIONS: Partitions that cross structural separations have seismic or control joints. (Commentary: Sec. A.7.1.3. Tier 2. Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-MH. TOPS: The tops of ceiling-high framed or panelized partitions have lateral bracing to the structure at a spacing equal to or less than 6 ft. (Commentary: Sec. A.7.1.4. Tier 2. Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.

Ceilings

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-LMH. SUSPENDED LATH AND PLASTER: Suspended lath and plaster ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	There are no lath and plaster ceilings.
☐	☐	☐	☒	LS-MH; PR-LMH. SUSPENDED GYPSUM BOARD: Suspended gypsum board ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	This was not viewable for gypsum board ceilings.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-MH. INTEGRATED CEILINGS: Integrated suspended ceilings with continuous areas greater than 144 ft^2, and ceilings of smaller areas that are not surrounded by restraining partitions, are laterally restrained at a spacing no greater than 12 ft with members attached to the structure above. Each restraint location has a minimum of four diagonal wires and compression struts, or diagonal members capable of resisting compression. (Commentary: Sec. A.7.2.2. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-MH. EDGE CLEARANCE: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 have clearances from the enclosing wall or partition of at least the following: in Moderate Seismicity, 1/2 in.; in High Seismicity, 3/4 in. (Commentary: Sec. A.7.2.4. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-MH. CONTINUITY ACROSS STRUCTURE JOINTS: The ceiling system does not cross any seismic joint and is not attached to multiple independent structures. (Commentary: Sec. A.7.2.5. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. EDGE SUPPORT: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 are supported by closure angles or channels not less than 2 in. wide. (Commentary: Sec. A.7.2.6. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.

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C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. SEISMIC JOINTS: Acoustical tile or lay-in panel ceilings have seismic separation joints such that each continuous portion of the ceiling is no more than 2500 ft^2 and has a ratio of long-to-short dimension no more than 4-to-1. (Commentary: Sec. A.7.2.7. Tier 2: 13.6.4)	This check is not required for the Life Safety Performance Level.

Light Fixtures

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. INDEPENDENT SUPPORT: Light fixtures that weigh more per square foot than the ceiling they penetrate are supported independent of the grid ceiling suspension system by a minimum of two wires at diagonally opposite corners of each fixture. (Commentary: Sec. A.7.3.2. Tier 2: Sec. 13.6.4 and 13.7.9)	Grid ceilings do not occur. Light fixtures are connected directly to the gypsum board ceilings.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. PENDANT SUPPORTS: Light fixtures on pendant supports are attached at a spacing equal to or less than 6 ft and, if rigidly supported, are free to move with the structure to which they are attached without damaging adjoining components. (Commentary: A.7.3.3. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. LENS COVERS: Lens covers on light fixtures are attached with safety devices. (Commentary: Sec. A.7.3.4. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.

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Cladding and Glazing

C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	LS-MH; PR-MH. CLADDING ANCHORS: Cladding components weighing more than 10 lb/ft^2 are mechanically anchored to the structure at a spacing equal to or less than the following: for Life Safety in Moderate Seismicity, 6 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 ft. (Commentary: Sec. A.7.4.1. Tier 2: Sec. 13.6.1)	The building does not have this type of cladding.
☐	☐	☒	☐	LS-MH; PR-MH. CLADDING ISOLATION: For steel or concrete moment frame buildings, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicity, 0.02. (Commentary: Sec. A.7.4.3. Tier 2: Section 13.6.1)	All walls are metal siding and are "hard-fastened" directly to the structural frame.
☐	☐	☒	☐	LS-MH; PR-MH. MULTI-STORY PANELS: For multi-story panels attached at more than one floor level, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicty, 0.02. (Commentary: Sec. A.7.4.4. Tier 2: Sec. 13.6.1)	There are no multi-story panels.
☐	☐	☒	☐	LS-MH; PR-MH. PANEL CONNECTIONS: Cladding panels are anchored out-of-plane with a minimum number of connections for each wall panel, as follows: for Life Safety in Moderate Seismicity, 2 connections; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 connections. (Commentary: Sec. A.7.4.5. Tier 2: Sec. 13.6.1.4)	There are no cladding panels.

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C ☒	NC ☐	N/A ☐	U ☐	LS-MH; PR-MH. BEARING CONNECTIONS: Where bearing connections are used, there is a minimum of two bearing connections for each cladding panel. (Commentary: Sec. A.7.4.6. Tier 2: Sec. 13.6.1.4)	The metal siding are fastened directly to the wall framing at several locations.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. INSERTS: Where concrete cladding components use inserts, the inserts have positive anchorage or are anchored to reinforcing steel. (Commentary: Sec. A.7.4.7. Tier 2: Sec. 13.6.1.4)	There are no concrete cladding components.
C ☐	NC ☐	N/A ☐	U ☒	LS-MH; PR-MH. OVERHEAD GLAZING: Glazing panes of any size in curtain walls and individual interior or exterior panes over 16 ft^2 in area are laminated annealed or laminated heat-strengthened glass and are detailed to remain in the frame when cracked. (Commentary: Sec. A.7.4.8: Tier 2: Sec. 13.6.1.5)	The type of glazing is not known.

Masonry Veneer

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. TIES: Masonry veneer is connected to the backup with corrosion-resistant ties. There is a minimum of one tie for every 2-2/3 ft^2, and the ties have spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 36 in.; for Life Safety in High Seismicity and for Position Retention in any seismicity, 24 in. (Commentary: Sec. A.7.5.1. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.

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C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. SHELF ANGLES: Masonry veneer is supported by shelf angles or other elements at each floor above the ground floor. (Commentary: Sec. A.7.5.2. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. WEAKENED PLANES: Masonry veneer is anchored to the backup adjacent to weakened planes, such as at the locations of flashing. (Commentary: Sec. A.7.5.3. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY BACKUP: There is no unreinforced masonry backup. (Commentary: Sec. A.7.7.2. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no unreinforced masonry.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. STUD TRACKS: For veneer with metal stud backup, stud tracks are fastened to the structure at a spacing equal to or less than 24 in. on center. (Commentary: Sec. A.7.6.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no masonry veneer.

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-MH; PR-MH. ANCHORAGE: For veneer with concrete block or masonry backup, the backup is positively anchored to the structure at a horizontal spacing equal to or less than 4 ft along the floors and roof. (Commentary: Sec. A.7.7.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no masonry veneer.
☐	☐	☒	☐	LS-not required; PR-MH. WEEP HOLES: In veneer anchored to stud walls, the veneer has functioning weep holes and base flashing. (Commentary: Sec. A.7.5.6. Tier 2: Section 13.6.1.2)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-MH. OPENINGS: For veneer with metal stud backup, steel studs frame window and door openings. (Commentary: Sec. A.7.6.2. Tier 2: Sec. 13.6.1.1 and 13.6.1.2)	This check is not required for the Life Safety Performance Level.

Parapets, Cornices, Ornamentation, and Appendages

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. URM PARAPETS OR CORNICES: Laterally unsupported unreinforced masonry parapets or cornices have height-to-thickness ratios no greater than the following: for Life Safety in Low or Moderate Seismicity, 2.5; for Life Safety in High Seismicity and for Position Retention in any seismicity, 1.5. (Commentary: Sec. A.7.8.1. Tier 2: Sec. 13.6.5)	There are no URM parapets.

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RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. CANOPIES: Canopies at building exits are anchored to the structure at a spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 10 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 6 ft. (Commentary: Sec. A.7.8.2. Tier 2: Sec. 13.6.6)	There are no canopies.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-LMH. CONCRETE PARAPETS: Concrete parapets with height-to-thickness ratios greater than 2.5 have vertical reinforcement. (Commentary: Sec. A.7.8.3. Tier 2: Sec. 13.6.5)	There are no concrete parapets.
C ☒	NC ☐	N/A ☐	U ☐	LS-MH; PR-LMH. APPENDAGES: Cornices, parapets, signs, and other ornamentation or appendages that extend above the highest point of anchorage to the structure or cantilever from components are reinforced and anchored to the structural system at a spacing equal to or less than 6 ft. This checklist item does not apply to parapets or cornices covered by other checklist items. (Commentary: Sec. A.7.8.4. Tier 2: Sec. 13.6.6)	Where these items occur, they are anchored.

Masonry Chimneys

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. URM CHIMNEYS: Unreinforced masonry chimneys extend above the roof surface no more than the following: for Life Safety in Low or Moderate Seismicity, 3 times the least dimension of the chimney; for Life Safety in High Seismicity and for Position Retention in any seismicity, 2 times the least dimension of the chimney. (Commentary: Sec. A.7.9.1. Tier 2: 13.6.7)	There are no URM chimneys.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. ANCHORAGE: Masonry chimneys are anchored at each floor level, at the topmost ceiling level, and at the roof. (Commentary: Sec. A.7.9.2. Tier 2: 13.6.7)	There are no masonry chimneys.

Stairs

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. STAIR ENCLOSURES: Hollow-clay tile or unreinforced masonry walls around stair enclosures are restrained out-of-plane and have height-to-thickness ratios not greater than the following: for Life Safety in Low or Moderate Seismicity, 15-to-1; for Life Safety in High Seismicity and for Position Retention in any seismicity, 12-to-1. (Commentary: Sec. A.7.10.1. Tier 2: Sec. 13.6.2 and 13.6.8)	These types of stair enclosures do not occur in this building.
C	NC	N/A	U		
☐	☐	☐	☒	LS-LMH; PR-LMH. STAIR DETAILS: In moment frame structures, the connection between the stairs and the structure does not rely on shallow anchors in concrete. Alternatively, the stair details are capable of accommodating the drift calculated using the Quick Check procedure of Section 4.5.3.1 without including any lateral stiffness contribution from the stairs. (Commentary: Sec. A.7.10.2. Tier 2: 13.6.8)	The stair details were not accessible to view, and structural drawings were not available for review; therefore, the condition is not known.

Contents and Furnishings

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-MH. INDUSTRIAL STORAGE RACKS: Industrial storage racks or pallet racks more than 12 ft high meet the requirements of ANSI/MH 16.1 as modified by ASCE 7 Chapter 15. (Commentary: Sec. A.7.11.1. Tier 2: Sec. 13.8.1)	There did not appear to be any storage racks more than 12 feet tall.

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C	NC	N/A	U		
☐	☒	☐	☐	LS-H; PR-MH. TALL NARROW CONTENTS: Contents more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 are anchored to the structure or to each other. (Commentary: Sec. A.7.11.2. Tier 2: Sec. 13.8.2)	Not all cabinets/refrigerators/storage racks/etc. are anchored.
☐	☒	☐	☐	LS-H; PR-H. FALL-PRONE CONTENTS: Equipment, stored items, or other contents weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level are braced or otherwise restrained. (Commentary: Sec. A.7.11.3. Tier 2: Sec. 13.8.2)	Heavy items on storage racks do not appear to be braced or anchored to the racks.
☐	☐	☒	☐	LS-not required; PR-MH. ACCESS FLOORS: Access floors more than 9 in. high are braced. (Commentary: Sec. A.7.11.4. Tier 2: Sec. 13.8.3)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-MH. EQUIPMENT ON ACCESS FLOORS: Equipment and other contents supported by access floor systems are anchored or braced to the structure independent of the access floor. (Commentary: Sec. A.7.11.5. Tier 2: Sec. 13.7.7 and 13.8.3)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED CONTENTS: Items suspended without lateral bracing are free to swing from or move with the structure from which they are suspended without damaging themselves or adjoining components. (Commentary. A.7.11.6. Tier 2: Sec. 13.8.2)	This check is not required for the Life Safety Performance Level.

Mechanical and Electrical Equipment

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-H. FALL-PRONE EQUIPMENT: Equipment weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level, and which is not in-line equipment, is braced. (Commentary: A.7.12.4. Tier 2: 13.7.1 and 13.7.7)	Suspended equipment appears to be braced.
☒	☐	☐	☐	LS-H; PR-H. IN-LINE EQUIPMENT: Equipment installed in-line with a duct or piping system, with an operating weight more than 75 lb, is supported and laterally braced independent of the duct or piping system. (Commentary: Sec. A.7.12.5. Tier 2: Sec. 13.7.1)	Suspended equipment appears to be braced.
☒	☐	☐	☐	LS-H; PR-MH. TALL NARROW EQUIPMENT: Equipment more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 is anchored to the floor slab or adjacent structural walls. (Commentary: Sec. A.7.12.6. Tier 2: Sec. 13.7.1 and 13.7.7)	Tall narrow equipment appears to be anchored.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. MECHANICAL DOORS: Mechanically operated doors are detailed to operate at a story drift ratio of 0.01. (Commentary: Sec. A.7.12.7. Tier 2: Sec. 13.6.9)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED EQUIPMENT: Equipment suspended without lateral bracing is free to swing from or move with the structure from which it is suspended without damaging itself or adjoining components. (Commentary: Sec. A.7.12.8. Tier 2: Sec. 13.7.1 and 13.7.7)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. VIBRATION ISOLATORS: Equipment mounted on vibration isolators is equipped with horizontal restraints or snubbers and with vertical restraints to resist overturning. (Commentary: Sec. A.7.12.9. Tier 2: Sec. 13.7.1)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. HEAVY EQUIPMENT: Floor-supported or platform-supported equipment weighing more than 400 lb is anchored to the structure. (Commentary: Sec. A.7.12.10. Tier 2: 13.7.1 and 13.7.7)	This check is not required for the Life Safety Performance Level.

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C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. ELECTRICAL EQUIPMENT: Electrical equipment is laterally braced to the structure. (Commentary: Sec. A.7.12.11. Tier 2: 13.7.7)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. CONDUIT COUPLINGS: Conduit greater than 2.5 in. trade size that is attached to panels, cabinets, or other equipment and is subject to relative seismic displacement has flexible couplings or connections. (Commentary: Sec. A.7.12.12. Tier 2: 13.7.8)	This check is not required for the Life Safety Performance Level.

Piping

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. FLEXIBLE COUPLINGS: Fluid and gas piping has flexible couplings. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. FLUID AND GAS PIPING: Fluid and gas piping is anchored and braced to the structure to limit spills or leaks. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U	Description	Comments
☐	☐	☒	☐	LS-not required; PR-H. C-CLAMPS: One-sided C-clamps that support piping larger than 2.5 in. in diameter are restrained. (Commentary: Sec. A.7.13.5. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. PIPING CROSSING SEISMIC JOINTS: Piping that crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A7.13.6. Tier 2: Sec.13.7.3 and Sec. 13.7.5)	This check is not required for the Life Safety Performance Level.

Ducts

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. DUCT BRACING: Rectangular ductwork larger than 6 ft^2 in cross-sectional area and round ducts larger than 28 in. in diameter are braced. The maximum spacing of transverse bracing does not exceed 30 ft. The maximum spacing of longitudinal bracing does not exceed 60 ft. (Commentary: Sec. A.7.14.2. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. DUCT SUPPORT: Ducts are not supported by piping or electrical conduit. (Commentary: Sec. A.7.14.3. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U	DESCRIPTION	COMMENTS
☐	☐	☒	☐	LS-not required; PR-H. DUCTS CROSSING SEISMIC JOINTS: Ducts that cross seismic joints or isolation planes or are connected to independent structures have couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.14.5. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.

Elevators

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-H; PR-H. RETAINER GUARDS: Sheaves and drums have cable retainer guards. (Commentary: Sec. A.7.16.1. Tier 2: 13.8.6)	There are no elevators.
☐	☐	☒	☐	LS-H; PR-H. RETAINER PLATE: A retainer plate is present at the top and bottom of both car and counterweight. (Commentary: Sec. A.7.16.2. Tier 2: 13.8.6)	There are no elevators.
☐	☐	☒	☐	LS-not required; PR-H. ELEVATOR EQUIPMENT: Equipment, piping, and other components that are part of the elevator system are anchored. (Commentary: Sec. A.7.16.3. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

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C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. SEISMIC SWITCH: Elevators capable of operating at speeds of 150 ft/min or faster are equipped with seismic switches that meet the requirements of ASME A17.1 or have trigger levels set to 20% of the acceleration of gravity at the base of the structure and 50% of the acceleration of gravity in other locations. (Commentary: Sec. A.7.16.4. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. SHAFT WALLS: Elevator shaft walls are anchored and reinforced to prevent toppling into the shaft during strong shaking. (Commentary: Sec. A.7.16.5. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. COUNTERWEIGHT RAILS: All counterweight rails and divider beams are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.6. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-H. BRACKETS: The brackets that tie the car rails and the counterweight rail to the structure are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.7. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SPREADER BRACKET: Spreader brackets are not used to resist seismic forces. (Commentary: Sec. A.7.16.8. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. GO-SLOW ELEVATORS: The building has a go-slow elevator system. (Commentary: Sec. A.7.16.9. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES
EXHIBIT 700

December 30, 2024

EXHIBIT 700 – DIRECT TESTIMONY – INFORMATION TECHNOLOGY & SERVICES

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "Company").

A. My name is Brian E. Fellon. My title is Vice President, Chief Information Officer & Chief Information Security Officer. I am responsible for NW Natural's information technology and services ("IT&S"), including cybersecurity, information technology ("IT"), operational technology ("OT"), service desk, and other technology-related architecture, infrastructure, network, and applications—which together enable NW Natural to support its customers and operate successfully.

Q. Please describe your education and employment background.

A. I hold a bachelor's degree in business administration from the University of Washington and a Master of Business Administration from Seattle University. I have more than 25 years of experience in information technology, and nearly 20 years of information technology leadership at management and executive levels. I joined NW Natural in my current role in 2024. Prior to joining NW Natural, I was Director of Information Technology, Application Services, at Puget Sound Energy in Bellevue, Washington for eight years, and prior to that I held a variety of technical and technology leadership roles in consulting, aerospace, and the retail sectors.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to introduce and describe the IT&S projects for which the Company is seeking recovery in this case. I will therefore provide an overview of NW Natural's strategic vision, provide an update on the

Company's ongoing Horizon Program, and detail the IT&S projects that will be completed prior to the rate effective date of this rate case.

Q. Please summarize your testimony.

A. First, I provide an overview of NW Natural's IT&S environment and the need to migrate to cloud-based software. Second, I provide an update on the second phase of the Company's Horizon projects. As discussed in prior rate cases, NW Natural is modernizing its IT&S systems, including two cornerstone projects: i) replacing an end-of-life enterprise resource planning ("ERP") and ii) replacing a nearly thirty-year-old customer information system ("CIS"). The ERM project, known as Horizon 1, was successfully completed in 2022. The Company recently completed a study to determine the next steps for the second phase, known as H2: Vista. As explained in my testimony, the Company has decided to delay this project to reduce the near-term cost impacts to customers and to provide more time for necessary prerequisite projects. Third, I describe the IT&S projects that we are placing in-service and seeking cost recovery of in this rate case.

II. OVERVIEW OF THE IT&S ENVIRONMENT

Q. Please describe NW Natural's current IT&S environment.

A. IT&S continues to play a critical and ever-evolving role in serving customers, utility operations, and cybersecurity. In this dynamic environment, NW Natural strives to modernize its systems while prudently preserving and extending the useful life of the systems in place. The Company will continue to prioritize IT&S cybersecurity, ensuring that both the new and existing IT&S platforms are safeguarded against potential threats.

Q. Does the Company's IT&S environment continue to include adoption of cloud-based solutions?

A. Yes. Cloud-based solutions are becoming industry standard for large enterprises. Utilities often transition to cloud-based solutions when legacy systems reach end-of-life because these solutions have become the standard offering in the industry, if not the only available offering depending on the system. Legacy systems are increasingly difficult and costly to maintain, lack compatibility with modern technologies, and pose significant cybersecurity risks. Cloud-based platforms provide enhanced scalability with resource demands, real-time data accessibility, and robust support and real-time cybersecurity updates from developers. With on-premises options being phased out, cloud solutions are now the primary avenue for utilities to maintain their operations and ensure reliable service delivery in an evolving energy landscape.

Over the last several years, the Company has successfully migrated an array of IT&S solutions and platforms to Microsoft's Azure cloud platform, which is consistent with NW Natural's overarching goal of simplifying IT&S solutions.

Q. Is NW Natural continuing to experience financial pressures associated with the cloud-based solutions?

A. Yes. While cloud-based solutions are the right choice for the Company and our customers, the accounting rules associated with these solutions create new financial pressures that do not fit neatly into existing ratemaking frameworks. First, unlike on-premises solutions, the utility can only capitalize the implementation costs of cloud-based assets, and the depreciable life of the asset is tied to the duration of the contract for the software service. Typically, in the IT&S field, these contracts are relatively short – between one and five years. As such, the depreciable life of the asset is very fast compared to most of the utilities' long-lived assets. With a five-year asset life, if the utility does not recover a single year of the asset, the utility is foregoing 20 percent of the recovery of that asset.

Additionally, cloud-based assets are a relatively new technology. NW Natural did not have any cloud-based assets prior to 2020. As such, this asset class is a growing asset class, which creates a more urgent financial need to ensure that the Company is routinely recovering this new asset class.

Finally, because cloud-based solutions entail ongoing subscriptions, the accounting rules require that these subscription costs be accounted for as operations and maintenance ("O&M") expense. As noted above, with the system-wide migration to cloud-based solutions, NW Natural is continuing to experience increases in the Company's annual incremental O&M expense as the Company moves to more cloud-based tools.

Q. How do the projects you detail in your testimony align with the Company's overarching strategic goals and cloud-based strategy?

A. The projects I detail in my testimony each support the Company's goal of reducing complexity through a current, secure, and compliant system. These projects ensure the reliability and resilience of NW Natural's operations, enhance operational security, and help streamline NW Natural's portfolio of IT&S solutions using off-the-shelf tools that are effective and vendor-supported. NW Natural has worked closely with software vendors to identify competitive and quality solutions that prioritize quality customer service and reliable business operations. As the Company continues to implement its overarching strategic IT&S transition, the Company will continue to make progress toward consolidating its systems on cloud-based platforms, leveraging the reliability and flexibility benefits described above.

III. MAJOR IT&S PROJECTS

A. Horizon Program

Q. Please briefly describe the Horizon Program.

A. As described in UG 388, UG 435, and UG 490, the Horizon Program is a multi-year, two-phase IT&S initiative to upgrade NW Natural's central technology architecture. Each phase, referred to as Horizon 1 and Horizon 2: Vista ("H2: Vista"), is driven by a significant keystone project to upgrade a major piece of software using modern, industry-standard software tools. NW Natural successfully completed the first phase of the transformational effort ("Horizon 1") in 2022, by upgrading the Company's backbone ERP software. Horizon 1 was implemented on time and within reasonable budget parameters, providing valuable lessons learned for the Horizon Program's second major phase: H2: Vista. H2: Vista will comprehensively update the Company's outdated CIS and other customer-facing functions and related services and is currently in development.

Q. What is the status of the Horizon Program?

A. In 2024, the Company completed the initial planning stage of H2: Vista, which involved a comprehensive framing study to confirm the sequence and scope of various prerequisite and component projects. This careful preliminary analysis was crucial to minimize risk in the larger implementation components of H2: Vista. NW Natural is moving forward with the prerequisite projects identified in the study to prepare for its CIS replacement. These prerequisite activities will ensure that NW Natural has the right foundational technologies in place to support its CIS replacement and will ensure that the Company's legacy CIS is able to provide reliable service to NW Natural customers during the transition.

Q. Please summarize the CIS study approach.

A. The Company completed the 6-month study with third-party consultant support from Ernst & Young ("EY"). EY was selected through a competitive procurement process which included several vendors that are leaders in implementations of this type. EY brought extensive experience in completing recent similar work with other utilities around the country. The study followed a structured approach starting with a current state assessment, followed by the identification of the strategic alternatives, and concluding with a development of the recommendation and a roadmap for the program.

Q. Please summarize the study recommendation.

A. The recommendation is to initiate the implementation of the new CIS in 2030, while dedicating the next five years to completing the prerequisite work. This approach mitigates the risks associated with the upcoming CIS replacement project and establishes a more balanced and steady expenditure pattern in the years leading up to the CIS implementation. The recommendation is based on several compelling reasons:

- **Strategy & Alignment:** This plan prioritizes NW Natural's mission of providing affordable service by minimizing the immediate impact on customer rates.
- **Service Impacts:** By extending the timeline for completing peripheral and prerequisite projects, NW Natural can address more pressing customer needs sooner.
- **Financial Impacts:** Financial management is a cornerstone of this recommendation, focusing on reducing near-term costs. This strategy enables steady investment in the existing technology and the completion of vital prerequisite projects, while deferring major capital expenditures and synchronizing them with the completion of other large capital programs.
- **Implementation Logistics:** This plan acknowledges the current personnel limitations within NW Natural's IT&S and business teams, which are not presently staffed to manage such a large-scale project. There is too great a risk of unknown complexities to move forward with prerequisites and CIS project launch in a single workstream. CIS is a critical business function and a longer timeframe for completion is needed to adequately reduce project risk.
- **Technology Considerations:** Delaying the CIS replacement allows NW Natural to continue use of its existing CIS asset, thereby obtaining additional value from the investment. While the current system meets business needs today, its flexibility and scalability to accommodate growth and evolving customer needs are limited.

The projects included in the CIS Replacement Program can be categorized into three groups:

- **Evolve & Sustain projects:** These are essential to maintain business as usual while preparing for the CIS replacement, including the cutover and stabilization phases.
- **Prerequisite projects:** These projects are necessary to meet core business needs and mitigate risks associated with the CIS Replacement Program, while aligning with the customer lifecycle management roadmap.
- **CIS replacement projects:** These are directly related to the replacement efforts, such as the CIS implementation itself.

Q. What alternatives did the Company consider?

A. NW Natural evaluated three alternatives for CIS replacement to determine which one best aligns with the Company's desired outcomes and objectives. The evaluation involved a thorough examination of each alternative's advantages, disadvantages, and potential impacts:

1. **Near-Term CIS Replacement:** This alternative involves replacing the existing CIS with SAP within the next five years. This approach would require a significant financial investment in the next few years and the simultaneous execution of prerequisite and peripheral projects.
2. **Long-Term CIS Replacement:** This alternative is a gradual approach to replacing the existing CIS, one that balances expenditure and resources utilization over time. It allows for the completion of necessary peripheral projects before transitioning to the new CIS.

3. **Defer CIS Replacement Decision:** This alternative involves improving and strengthening the existing CIS through regular hardware and software refreshes. It also includes redesigning the user interface and reducing its scope to primarily billing functions. The decision on replacing the existing CIS would be deferred indefinitely.

Q. How did NW Natural consider each of these alternatives?

A. Each alternative was developed with a proposed timeline, along with a sequence of activities, which allowed the Company to better understand the broader impact of the sequencing of work outlined in the alternatives. Each of the three CIS alternatives was then scored across a set of criteria and business objectives. These criteria were categorized into key areas of impact, including Strategy and Alignment, Service Impact, Financial Impact, Implementation Logistics, and Technology considerations. For each area, specific criteria such as strategic fit, regulatory compliance, benefits versus risks, customer expectations, and operational excellence were evaluated.

Q. What alternative did NW Natural choose for its CIS system?

A. After completing its formal evaluation process, the Company is pursuing a balancing and blending of the second and third CIS alternatives. A CIS replacement is among the most complex projects a utility can undertake, and because of this NW Natural intends to complete all peripheral and prerequisite work at a manageable pace to account for staffing level dynamics. This work will put the Company on track to replace the CIS on a specific timeline, currently estimated to be 2032. By adopting this deliberate, structured approach to replacing its CIS, NW Natural can ensure a seamless transition to a new system while maintaining customer service quality.

Q. What other considerations were a factor in NW Natural's decision to postpone the replacement of the CIS?

A. NW Natural needs to complete several prerequisite and peripheral projects in advance of replacing the CIS. Completing this work along with preparing to launch a new CIS would be extremely challenging due to the limited size of NW Natural's current CIS support team. The existing CIS system is maintained by a small, experienced team within NW Natural, which includes key employees eligible for retirement over the next four years. These individuals possess detailed working knowledge of the CIS's architecture, operation, customizations, and integrations. Regulatory requirements and business enhancements involving changes to the CIS flow through a very narrow funnel of design and development capacity. By extending the time needed before starting the new CIS implementation from two years to five, NW Natural can build up its CIS staffing, execute the necessary peripheral projects, and prepare for the prerequisite projects.

Q. Were there external factors in the market affecting the decision to not pursue replacing the CIS in the near-term?

A. Yes. System integrator demand is outpacing supply for utilities looking to replace their CIS in the next two years. According to EY, many similarly sized or larger utilities are pursuing CIS replacement projects. There is a finite capacity of quality CIS system integrators, and the current competition for these resources would result in higher costs or lower quality resources for NW Natural.

Q. Were there other factors considered in the decision to not pursue the third alternative of maintaining the current CIS and deferring the CIS replacement decision indefinitely?

A. The Company determined that making significant investments in the existing CIS would not be a viable long-term solution. Long-term support (e.g., over 10 years) of the current CIS and its associated hardware will become increasingly difficult, risky, and costly. While NW Natural plans to take steps over the next several years to evolve and sustain the existing CIS as needed, the underlying CIS technologies (e.g., iSeries hardware and RPG code) are moving toward obsolescence. According to EY, the trajectory for customer-supporting applications will require more nimbleness, modularity, and embedded artificial intelligence to support future needs. Adding these capabilities into the existing CIS is not feasible.

Q. How is NW Natural planning to manage risks associated with the current CIS given the replacement date of 2032?

A. NW Natural is implementing a series of "Evolve & Sustain CIS" projects to ensure the continued stability and performance of the existing CIS leading up to and through its replacement. These projects include activities necessary to maintain business as usual while preparing for the replacement of the CIS and through the cutover and stabilization phases. This work encompasses several key upgrade projects. These include the enhancements to the integration of the CIS with the Clevest field work management system to enhance operational efficiency, the upgrade of the CIS graphical user interface to better support customer service representatives, and lifecycle upgrades scheduled between 2028 and 2030.

These upgrades are strategically planned to keep the CIS components up-to-date and secure, ensuring consistent service reliability for customers within a well-managed budget. The projects are grouped to address different operational needs, including vendor selection and third-party integrations, ensuring that each aspect of the CIS is optimized for performance and security.

Q. Is the Company seeking cost recovery of projects associated with H2: Vista in this rate case?

A. Yes. NW Natural is seeking cost recovery associated with completing several projects that are part of the CIS replacement roadmap. These are essential to maintain business as usual while preparing for the CIS replacement. Although these projects are part of the CIS roadmap, they are also necessary as part of ongoing investment to ensure continued availability, stability, security, technical currency of our existing CIS. The projects are:

- **CIS to Clevest integration hardening and upgrade project:** required to ensure a robust and efficient connection between the current CIS and the Clevest field work management system, which is critical for ensuring stable transfer of work orders between the two systems. The total system amount is $283 thousand in the Test Year with an Oregon allocation of $241 thousand.
- **Application Lifecycle Management – LegaSuite project:** required to update to CIS graphical user interface (GUI) to maintain system technical currency. The total system amount is $172 thousand in the Test Year with an Oregon allocation of $151 thousand.

- **CIS training materials project:** required to evolve current CIS functionalities and capabilities through training, upskilling, and transfer knowledge to new hires. The total system amount is $342 thousand in the Test Year with an Oregon allocation of $300 thousand.

Q. In testimony in docket UG 490, NW Natural indicated that it may file a request for a deferral of expenses associated with H2: Vista in 2024.[1] Did NW Natural ultimately file a deferral application?

A. No. The decision to delay the CIS replacement also delayed some of the large increases in operations and maintenance ("O&M") expense that were expected with the near-term CIS replacement plan. At the outset of our updated longer-term plan, we anticipate managing the incremental O&M expense through rate cases, and we expect that the larger one-time increases to O&M associated with the CIS replacement project will occur closer in time to the CIS replacement. As such, we are not seeking a deferral for costs at this time, but we still expect such a need in the future.

B. Application Lifecyle Management

Q. Please provide some context on what the Company means by Application Lifecycle Management.

A. Application Lifecycle Management encompasses the work effort required to update and maintain key and critical IT&S application platforms. It is necessary to

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a* General *Rate Revision*, Docket No. UG 490, Direct Testimony of Jim R. Downing, NW Natural/700 at 13 (Dec. 29, 2023).

ensure ongoing availability, stability, security, technical currency, and vendor support. By keeping software and equipment at supported levels, NW Natural can continue to receive critical system and security patches, take advantage of the latest technology features, and maintain license compliance as defined by support agreements. The Application Lifecycle Management – SAP Project discussed below is part of this program.

Q. Please describe the Application Lifecycle Management - SAP ("ALM - SAP") Project.

A. The ALM - SAP Project includes an update of NW Natural's SAP S4 platform to the current version. SAP S4 is the Company's key enterprise application used to support its field operations, engineering functions, financial operations, and ability to pay suppliers and vendors.

Q. Why is it necessary to update SAP?

A. It is necessary to update SAP S4 to mitigate risks of technical failures of the Company's essential enterprise operating system. As with other software products, SAP requires periodic updates to address bug fixes, incorporate product improvements, and maintain support services. In this case, NW Natural's current 2020 SAP S4 version will no longer be fully supported by SAP at the end of 2025. An unsupported platform would put the Company's operations at risk, as any security patches or other system issues could not be resolved without SAP's assistance. Therefore, updating SAP S4 to the latest version is critical in ensuring the essential functionality of NW Natural's SAP system.

Q. Did NW Natural consider alternatives to the ALM - SAP Project?

A. The only alternative to an update is remaining on the current SAP S4 version. This would place NW Natural at significant risk as it results in limited vendor support for its critical enterprise application. The reduction in support would prevent the delivery of legal and regulatory changes, support for integrations, and functional enhancements. In addition, there is no guarantee of technical updates including support of new operating systems and database versions, and if available, the updates may include additional fees for problem resolution.

Q. What is the status of the ALM - SAP Project?

A. The project is in planning phase. The Company expects to place the project into service by the end of summer 2025.

Q. What cost recovery is NW Natural requesting for the ALM - SAP Project?

A. NW Natural is requesting a total system amount of $2.3 million with an Oregon allocation of $2.0 million.

C. Field and Web Mapping Program Projects

Q. What is the status of the Company's Field and Web Mapping Program Projects?

A. As explained in UG 490, the Company is in the process of a multi-year program to replace its field and web mapping solutions by phasing out end-of-life software and transitioning to a consolidated set of modern software solutions. NW Natural relies on its field and web mapping tools to view its infrastructure and other assets in a geospatial format and for collecting various types of data related to these assets.

These field and web mapping tools provide field and office personnel with visual representations of NW Natural facilities and assets, which they use for various business purposes including inspection compliance programs. While NW Natural has several related projects planned for the coming years, in the near term the Company is implementing the Field and Web Mapping Phase I Project.

Q. Please describe the Field and Web Mapping Phase I Project.

A. The Field and Web Mapping Phase I Project begins the Company's transition away from an existing end-of-life software system, Visual Fusion, and develops some of the equivalent functionality in the Company's IQGeo platform through creation of the custom user interface. Specifically, this project will replace valve isolation tracing capabilities currently performed in Visual Fusion. A valve isolation trace is performed when there is an emergency, such as damage, to create a map identifying the valves to be closed to isolate an area, and to generate an impacted customer list for outage notification and relight order creation. Valve isolation traces are run by members of the Geographical Information Systems support team Engineering, Gas Control, and the Resource Management Center teams, and additional NW Natural teams use this information as well. For example, the Emergency Contact Center uses trace results and creates work orders to relight gas that was shut off during emergency response.

Q. Why is the Field and Web Mapping Phase I Project necessary?

A. The Field and Web Mapping Phase 1 Project is necessary because the current Visual Fusion software has been in an end-of-life stage since 2021 because it relies on an end-of-life Microsoft technology. The basic support that NW Natural receives does not include application enhancements or break fixes. As a result, transitioning away from this product is important to ensure continuity of NW Natural's operations as well as to mitigate cybersecurity concerns. While there are other uses of Visual Fusion, valve isolation tracing is its most critical functionality, so enabling another application to perform tracing is the highest priority within the Field and Web Mapping Program. This project is a necessary step that will allow NW Natural to eventually decommission the Visual Fusion platform and reduce technical architectural complexity through platform consolidation.

Q. Did NW Natural consider alternatives to the Field and Web Mapping Phase I Project?

A. Yes. NW Natural considered two alternatives to the Field and Web Mapping Phase 1 Project. First, the Company considered implementing IQGeo's tracing module instead of creating a custom user interface. Using the IQGeo tracing module would require NW Natural to leverage a complex and difficult-to-maintain parallel data model to accomplish tracing, meaning NW Natural would have to maintain one data model for Esri GIS information (our system of record for geospatial data) and a second data model for IQGeo. Because of this, it is highly likely that running a trace in each system could provide different results, which is unacceptable for emergency situations. The custom user interface also leverages existing data integrations resulting in lower effort and cost needed to accomplish the work.

Second, NW Natural considered maintaining the existing Visual Fusion solution. This option was not selected because it would undermine the reliability of the Company's mapping functions due to reliance on the software that is end of life as described above.

Q. What is the status of the Field and Web Mapping Phase I Project?

A. The Field and Web Mapping Phase I Project is in the planning stage. The Company expects to place the project into service in the summer of 2025.

Q. What cost recovery is NW Natural requesting for the Field and Web Mapping Phase I Project?

A. NW Natural is requesting a total system amount of $1.2 million with an Oregon allocation of $1.1 million.

D. Identity Governance and Administration Program

Q. What is Identity Governance and Administration ("IGA")?

A. Identity Governance and Administration ("IGA") is the process of granting, updating, reviewing, and revoking access to technology systems for NW Natural employees and contractors, based on job changes or other Company needs.

Q. In docket UG 490, did the Company describe areas for improvement in the Company's IGA procedures?

A. Yes, the Company identified areas for improvement, noting that the procedures in place at the time were manual, inefficient, and inconsistently compliant with regulations for account terminations. As a result, updates to user permissions were not always completed in a timely manner. For example, when users leave the Company or when their job roles change, user permissions were not always updated in a timely manner which can create a security risk.

Q. Did NW Natural identify a solution for this issue?

A. Yes. As the Company explained in docket UG 490, to begin to address this issue, the Company transitioned to an automated IGA software solution to ensure consistent, secure monitoring and control of access and permissions. The software solution is called IdentityNow and is provided by third party-vendor, SailPoint. The initial effort, IGA Phase 1, was focused on selection, installation and configuration of a state-of-the-art IGA solution, establishing connections and data collection for priority systems and establishing foundational functionality. The IGA Phase 2 Project builds on the foundation established in IGA Phase 1 and will focus on extending the base functional capabilities, expanding to additional systems/applications, preparing for and implementing a pilot of granting access based on the person's role, and solidifying the foundation for the IGA systems and processes.

Q. Please describe the IGA Phase 2 Project.

A. The second phase of the IGA Project is part of the evolution of the identity governance roadmap and includes access certifications, process automation, application onboarding, and building the foundation for granting access based on the person's role, including changes to their access as their role changes. This project will complete the analysis and prioritization of the foundation for controlling access to technology systems and integration with physical security devices and systems. These activities are compliance and regulatory control requirements, supporting the Company's safety, security, and operational efficiency. Additionally, this project will create access certifications, which ensures employees and contractors have access to only what they need, and removes unnecessary access. This is particularly important to ensure that offboarded employees or other unauthorized individuals cannot access sensitive information.

Q. Why is the IGA Phase 2 Project necessary?

A. The IGA Phase 2 Project is a planned and required step to build expertise and improve security through centralization of user provisioning and management on the roadmap toward advanced functionality like access based on the person's role. Phase 2 is the next evolution from the foundation established in Phase 1 to expand the reach and functionality of the base automation, refine access management processes, analyze and prioritize roles and functions toward implementation of a pilot of granting access based on the person's role , and improve and incorporate secure access controls as required by the Sarbanes Oxley Act of 2002 (SOX).

Q. Please describe NW Natural's consideration of alternatives to the IGA Phase 2 Project.

A. The Company views IGA as an evolutionary, multi-phased effort to build infrastructure, processes, tools and capabilities to improve IT identity and access management and overall NW Natural IT security, compliance and efficiency; therefore, Phase 2 has always been anticipated. The scope for Phase 2 has been established to pragmatically build on the foundation established in Phase 1 within realistic resource, budget, and timeline constraints, applying lessons learned from Phase 1 and anticipated activities within NW Natural that may pose challenges for resources. Generally, NW Natural expected to continue the evolution of IGA with a Phase 2 effort and evaluated alternatives around items to include in scope, size of budget/resources and what could realistically be delivered in the near-term given competing priorities and ability to absorb change.

Q. What is the status of the IGA Phase 2 Project?

A. The IGA Phase 2 Project was initiated in December 2024 and is expected to be completed by October 2025.

Q. What cost recovery is NW Natural requesting for the IGA Phase 2 Project?

A. NW Natural is requesting recovery for capital costs associated with the IGA Phase 2 Project in the amount of approximately $3.5 million, or $3.1 million on an Oregon allocated basis.

E. Telemetry Refresh Projects

Q. Please describe the Telemetry Refresh Projects.

A. NW Natural manages its natural gas pipeline through an active, central monitoring and control system, known as Supervisory Control and Data Acquisition ("SCADA"). SCADA systems collect, transmit, and measure data from remote sources, using sensors and other devices to collect data through remote communications systems, known as telemetry. These telemetry systems include a range of equipment, such as SCADA Remote Terminal Units / Programmable Logic Controllers, pressure transmitters, flow meters, line heaters, actuators, and communications equipment.

As the Company explained in UG 490, the Telemetry Refresh Projects are on-going and targeted at replacing decades-old SCADA technologies with modern equipment to comply with new security and safety standards. The projects involve surveying, permitting, and deploying new equipment to the Company's remote monitoring and control sites.

Q. Why are the Telemetry Refresh Projects necessary?

A. The Telemetry Refresh projects are crucial to ensure accurate and reliable telemetry regarding the condition and control of NW Natural's pipeline systems. These projects manage the lifecycle of the remote telemetry sites to ensure accurate data for the SCADA system, thus maintaining the Company's safe and reliable operation of its gas pipeline system.

The specific nature of the telemetry equipment varies by location, depending in part on the site's accessibility, and has historically included radio, network circuits, cellular, and satellite connections, and other transmission technologies. Over time, each site's telemetry equipment ages and reaches end-of-life and is no longer reliable. As a site reaches end of life, NW Natural must update the site with current technology to maintain system, regulatory, security, and safety requirements. If NW Natural did not implement the Telemetry Refresh Projects, the Company would risk losing critical functionality of its telemetry system.

Q. What is the status of the Telemetry Refresh Projects?

A. NW Natural initiated the Telemetry Refresh Projects in September 2024. The Company is currently assessing the scope and schedule to upgrade twenty sites for the period between November 1, 2024, to October 31, 2025.

Q. What cost recovery is NW Natural requesting for the project?

A. The Company is requesting $4.3 million on a system basis, or $3.8 million on an Oregon-allocated basis.

F. Resource Scheduling Optimization Project

Q. Please describe the Resource Scheduling Optimization Project.

A. The Resource Scheduling Optimization Project is an incremental new effort to optimize and improve the Workforce software used by NW Natural's Resource Management Center ("RMC") to manage field worker schedules and timesheets. The project scope includes resolution of issues that currently require several manual workarounds and functionality improvements. By optimizing the Workforce software, the Company can ensure that the tool continues to provide the best value for the Company and its customers.

Q. Why is the Resource Scheduling Optimization Project necessary?

A. An optimization effort is needed to ensure Workforce supports business processes to its full capability. It will include improvements to Workforce and associated integrations, systems, and processes to increase the efficiency and effectiveness of RMC schedulers, planners, and timekeepers.

Q. Did NW Natural consider alternatives to the project?

A. Yes. NW Natural considered three alternatives before deciding to proceed with the Resource Scheduling Optimization Project:

1. **Address only mission critical items**. Mission critical items are those needed to ensure system features are used to their fullest potential, enabling the automation of previously manual processes. NW Natural

would not pursue further optimization and enhancements with this alternative.

2. **Address both mission critical and high priority items.** This would include additional work on high priority changes that provide efficiency gains and new features that would improve business processes.

3. **Address mission critical, high priority and fully optimized items.** This would include fully optimizing items that improve user experience, such as on the NW Natural mobile application. These items require little to no development or configuration, and in many cases, simply involve enabling a feature.

Of these alternatives, NW Natural selected the third option.

Q. Why did NW Natural not select the first two options?

A. The Company decided not to restrict the project scope to only mission critical items as it would not resolve important process gaps and would leave several manual workarounds in place. After analyzing options two and three, NW Natural found that there was not a significant difference in total cost for addressing all three items. The fully optimized functionality improvements will result in high-impact new features with little additional cost.

Q. What is the status of the project?

A. The project is currently in the execution phase. The Company expects to place the project into service in the first part of 2025.

Q. What cost recovery is NW Natural requesting for the project?

A. The Company is requesting $1.6 million on a system basis, or $1.4 million on an Oregon-allocated basis.

G. JANA[2] Project

Q. Please describe the JANA Project.

A. The JANA Probabilistic Risk Model is a project within the NW Natural Distribution Integrity Management Program ("DIMP") where a risk model is performed to estimate the risk associated with gas distribution system threats. Risk models are required by Federal Code (CRF 49 Part 192). Refreshing the model and planning mitigation actions is an integral part of the NW Natural DIMP Plan. The current risk model is a relative risk model which measures the likelihood of failure associated with a threat. This project will transition the risk model to a probabilistic risk model which determines the probability of a failure in the system and estimates the expected consequences.

Q. Why is the JANA Project necessary?

A. In 2020 the US Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued a report titled "Pipeline Risk Modeling – Overview of Methods and Tools for Improved Implementation" and in this report PHMSA identified Probabilistic Risk models as a best practice to supporting risk management decisions as part of Integrity Management Programs. As stated in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (NW Natural/500, Kizer-

[2] "JANA" is JANA Corporation, a provider of risk modeling and software. Who We Are - Helping you predict risk in your pipeline systems | JANA.

Johnson), once this report was released NW Natural performed an internal review of the existing relative risk model for the NW Natural distribution system and determined that a probabilistic risk model would allow NW Natural to remediate risk on a risk-cost optimized basis and demonstrate that proper actions are being taken on the system to both regulators and NW Natural leadership.

Q. What is the difference between a relative risk model and a probabilistic risk model?

A. In a relative risk model, a score is developed for a particular area of the system by multiplying the likelihood of failure by the consequence of failure to determine a risk score. The numerical components of this scoring system are in the NW Natural DIMP Plan. A probabilistic risk model incorporates the probability of failure in the risk calculation along with quantifying the consequence of failure. By incorporating the probability of failure along with quantifying the consequence of failure, a more quantitative assessment of risk is developed per a specific asset in the NW Natural distribution system.

Q. Did NW Natural consider retaining its relative risk model?

A. Yes, however, based on the 2020 PHMSA report and internal discussions, NW Natural determined that its current model should no longer be used, and that the industry best practice would be to transition from a relative risk model to a probabilistic risk model.

Q. Once it was determined that NW Natural would need to transition to a probabilistic risk model, how did NW Natural select its preferred solution?

A. NW Natural conducted demonstration sessions with the two vendors that implement risk models to support the natural gas industry. For the first demonstration session, the input data that NW Natural needed to use for the risk model were in a legacy format that could not be used by the vendor. The vendor presented options to resolve this issue, but such options would have resulted in an incomplete model that would not have incorporated all of the threat information that NW Natural would have needed to include in the model. The JANA demonstration provided an interface that was much more adaptable to all formats of legacy information that NW Natural had for inputs into the risk model. Additionally, the JANA risk model is also more user-friendly for employees.

Q. What is the status of the JANA Project?

A. The JANA Project is expected to be placed in service in the summer of 2025.

Q. What cost recovery is NW Natural requesting for the JANA Project?

A. The Company is requesting $1.2 million on a system basis, or $1.1 million on an Oregon-allocated basis.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Brian E. Fellon

TSA PROJECTS
EXHIBIT 800

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December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Joe S. Karney

METER MODERNIZATION
EXHIBIT 900

December 30, 2024

EXHIBIT 900 – DIRECT TESTIMONY – METER MODERNIZATION

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Joe S. Karney. I am the Vice President of Engineering and Utility Operations and Chief Engineer. I am responsible for the design, construction, emergency response, operations, maintenance, and operational regulatory compliance of the distribution system.

Q. Please describe your education and employment background.

A. I graduated from the University of Illinois at Urbana-Champaign with a Bachelor of Science in Mechanical Engineering, and I am a registered Professional Engineer in the State of Oregon. Before being promoted to my current position at NW Natural in April 2023, I was the Senior Director of Operations and Field Services. In that role I was responsible for the internal construction, contract construction, customer field services, emergency response, pressure regulation, operation, and maintenance of the distribution system. Prior to holding that role, I served as the Engineering Senior Director and Chief Engineer for NW Natural. In that role, I was responsible for design, construction, operation, and maintenance of the gas distribution system and utility storage plants, and operations support services including work management functions, mapping and compliance. Prior to holding that role, I served as the Engineering Director. I have also previously served as the Senior Manager of Code Compliance for the Company, managed the regulatory compliance department, and represented the Company during safety audits performed by the Public Utility Commission of Oregon ("Commission"). I also reviewed and ensured Company compliance with pending regulatory changes from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). Previously, I managed the Company's Construction and System Operations groups. I started my career at the Company with the Integrity Management group and worked on the development and implementation of the Transmission Integrity Management Program (TIMP) and the Distribution Integrity Management Program (DIMP). Before joining NW Natural, I worked as an Integrity Management Engineer for Colonial Pipeline Company for four years.

Q. What is the purpose of your Direct Testimony?

A. In my Direct Testimony, I provide updates to the Company's Meter Modernization Program ("MMP") that have occurred since the time that the Company filed reply testimony regarding the MMP in its last general rate case, docket UG 490. I will also provide an update to the Company's cost recovery proposal for the MMP.

II. <u>MMP UPDATES</u>

Q. Please provide a summary of the MMP.

A. The MMP is a multi-year project that focuses on the replacement of a large portion of NW Natural's metering assets, both field and technology related. The reasoning behind such a large-scale replacement is due to the aging batteries inside the communication devices attached to our meters, called "ERTs" (encoder receiver transmitters). The approximate population of eligible ERTs is 490,000. In reviewing this selection of ERT replacements, it was determined that approximately 90,000 will need meter replacement as well. This determination was made through our meter sample program, by which we remove and test to determine for which of them there is a Periodic Cause for Change ("PCC"). This program randomly samples families of meters to determine their metering accuracy. In conclusion, approximately 400,000 meters will need ERT replacements and approximately 90,000 meters will need meter replacements. The MMP is also addressing upgrading our existing metering software to the next offering by our current vendor, Itron. Our existing system's "end-of-life" date has been determined and NW Natural has created a plan to migrate over before that end-of-life date in 2028.

Q. Please describe the progression of the ERT and PCC meter replacements in the last year.

A. The Company's deployment of ERT change outs by our contract vendor began in March 2024 and is expected to continue as planned through 2027. The first PCC meter replacements were completed in May 2024 and will continue through the end of 2026. The Company is currently on track with the ERT and PCC deployment schedule.

Q. Can you please describe FCS and why it needs to be replaced?

A. FCS, or "Field Collection System," is Itron's head end system that translates the automated meter readings ("AMR") picked up via a mobile system and passes that data to our billing system so that we can bill accurately based on a customer's usage. During the planning stages of the MMP, Itron released an announcement about the end-of-life, end-of-support of FCS. As the Company detailed in its testimony in UG 490, the combination of the end-of-life for FCS and the new enhancements (e.g., cellular communication of ERTs) offered in its replacement, Temetra, led to Temetra's inclusion within the MMP.

Q. Please detail any updates to the Temetra implementation since the Company's last general rate case, UG 490.

A. The Temetra implementation was delayed due to Itron not delivering full functionality of the software in 2024. Specifically, Temetra cannot currently support off-cycle billing reads. Currently, NW Natural picks up meter reading data via mobile vehicle using FCS. The reads collected are for both on-schedule and off-cycle billing and gas measurement purposes. This allows us to accurately bill our customers on their predicted bill due date. The off-cycle data are used to perform high bill investigations and account closings/openings due to move-in and move-out situations. Temetra currently can provide the collection of on-cycle read data but cannot provide the off-cycle collection data.

NW Natural is continuing to use FCS until Itron delivers a complete software package that includes off-cycle collection data. Itron anticipates this will occur in the first quarter of 2025. However, as a result of a delay of Itron's release of ultrasonic cellular meters, NW Natural's revised project plan forecasts a full Temetra roll out by the end of 2027.

Q. Please provide an update regarding the release of the ultrasonic cellular meters.

A. Itron recently announced a delay in the product delivery time of ultrasonic cellular meters. As a result of the delayed release, NW Natural is no longer planning to deploy ultrasonic cellular meters with the MMP because the delivery time does not align with our deployment timeline for PCC meters. Instead, NW Natural will purchase AMR ultrasonic meters without cellular capabilities.

Q. How does the delay of ultrasonic cellular meters affect the Company's timeline for migration to Temetra?

A. Unlike ultrasonic cellular meters, AMR ultrasonic meters do not require the functionality of Temetra. AMR ultrasonic meters are compatible with FCS and Temetra. Consequently, we no longer have a dependency to migrate to Temetra with the installation of PCC replacement meters. This change will give us time to ensure that Temetra has the requisite functionality before its implementation.

Q. Have these changes to the MMP resulted in changes to the program's overall budget?

A. No, the MMP is still within its original budget spend.

Q. What cost recovery is NW Natural requesting for the MMP in this rate case?

A. The Company is requesting recovery of $31.7 million of MMP investment between October 2024 and the rate effective date of this case. An additional $22.3 million of investments will be placed in-service within the Test Year, for a total of $54.0 million.

III. <u>UM 2311 DEFERRAL AMORTIZATION</u>

Q. Has the Company filed a deferral application for the MMP?

A. Yes. The Company filed a deferral application on January 2, 2024, docketed as UM 2311, for the one-time operations and maintenance ("O&M") expense incurred for the limited duration of the MMP, which NW Natural estimated will be approximately $14.2 million. The Commission has not yet acted on the deferral application. NW Natural will seek reauthorization of the deferral over the four-year term of the MMP. In the Company's last rate case, UG 490, the Company did not seek amortization of this deferral but Staff stated that it "agrees with the Company that the [MMP] O&M costs are likely better recovered through a deferral."[1] Please see the Direct Testimony of Kyle T. Walker (NW Natural/1500, Walker) for the proposed amortization and tariff.

Q. What is included as O&M expense in the deferral?

A. The costs that cannot be capitalized and are included within the O&M deferral include the following categories:

- Meter and ERT Replacement: Southern Cross' installation labor costs for approximately 50 field-techs and supporting positions working across NW Natural's service territory to replace PCC meters and end-of-life ERTs.
- ERT and PCC Hardware Recycling: Shipping and recycling approximately 400,000 lithium-ion batteries in ERTs and shipping, testing, and recycling of approximately 90,000 PCC meters and ERTs. Due to the materials in meters and ERTs, we cannot "dispose" of these items without environmental impact and must do so in accordance with stated regulations.
- Incremental Non-Field Labor: Includes incremental resource costs (non-field) to support the MMP. These positions will provide customer call support with increased customer touch points, scheduling support, billing support, internal

[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Curtis Dlouhy, Staff/900 at 60 (Apr. 18, 2024).

change communication, external communications, quality assurance inspection of installations, meter shop support, and support in deploying field techs for change outs. Each of these roles carries an incremental burden for the project due to the elevated number of ERT and meter change outs required during the coming three-year period. The resources identified will be backfilled during the duration of the project to allow for continued operations of business-as-usual work with additional contractor support from Ernst and Young.

- Other External Expenses: Includes bill inserts and door hangers related to the notification and education of the MMP to our customer base. Due to the increased presence of field workers during the four-year deployment, we will need to inform customers why trucks and field technicians are in their neighborhoods.

Q. What is the estimated deferral balance as of June 30, 2025?

A. The estimated deferral balance as of June 30, 2025, is $2,605,524.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1000

December 30, 2024

EXHIBIT 1000 – DIRECT TESTIMONY– COMPENSATION & BENEFITS

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Melinda B. Rogers. My title is Vice President, Chief Human Resources and Diversity Officer. I am responsible for overseeing various administrative functions at NW Natural, including Human Resources, Diversity, Equity and Inclusion, Safety, Labor Relations, and Payroll.

Q. Please describe your education and employment background.

A. I received a Bachelor of Business Administration from Bryant University in 1987. Prior to NW Natural, I was employed by the Atkinson Graduate School at Willamette University for three years as Director of Executive Education. Before joining Willamette University, I served as Vice President of Enterprise Learning and as Vice President of Human Resources for four years at Knowledge Universe in Portland. I was employed in other senior human resource roles and management positions at Qualcomm and Hewlett Packard for 14 years prior to joining Knowledge Universe. I joined NW Natural in September 2015 and have been an officer for the Company since August 2018.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe the Company's compensation practices, which result in total compensation that is at the market median for comparable companies;

- Describe the employee benefits program offered by NW Natural, demonstrate that it is aligned with the market, and that the Company has carefully managed these benefits to ensure reasonable costs;
- Describe the overall level of compensation and benefits costs included in the Company's requested revenue requirement for the November 2025 through October 2026 test year ("Test Year"); and
- Describe the Company's requested employee headcount for Full-Time Equivalent positions ("FTE") in the Test Year.

II. NW NATURAL'S COMPENSATION PHILOSOPHY

Q. What is NW Natural's approach to determining the compensation it provides to its employees?

A. NW Natural's approach is to provide a level of total compensation that is necessary to attract, motivate, and retain qualified employees needed to run a safe and reliable natural gas delivery business, with high-quality customer service and at a cost that is reasonable. To do this, we provide a competitive total compensation package for employees that allows us to hire and retain a qualified workforce.

Q. Please explain what you mean by "competitive total compensation."

A. Total compensation is the combination of base pay, merit-based incentive pay (or "pay-at-risk"), medical benefits, and retirement benefits. Total compensation is competitive when its total value is at the median level for total compensation offered in the marketplace for comparable jobs. It is through offering a competitive total compensation package that NW Natural is able to compete in the job market to attract, hire and retain the employees it requires to run a safe, reliable, customer service-focused gas utility.

Q. How does NW Natural determine that its total compensation is at the median level?

A. As I will explain in my testimony, the Company performs research to ensure that each aspect of its compensation is at the median level and is therefore competitive with the compensation offered by its competitors for comparable jobs.

Q. Are there established practices that allow you to be confident that you are offering competitive total compensation, and not more?

A. Yes. There are well-established methodologies that we employ in order to ensure that we offer competitive compensation, based on comparable jobs. I will describe those practices in more detail in my testimony.

III. BASE PAY

Q. You mentioned that "base pay" is a major component of offering competitive total compensation. How are you defining base pay?

A. Base pay is the guaranteed financial compensation provided to employees for the work performed. It is delivered on either an hourly or salaried basis. Base pay excludes the other important components of compensation (*e.g.*, pay-at-risk) that are not guaranteed and are not paid on a regular interval but are nevertheless a critical component of offering competitive total compensation to attract qualified employees.

Q. How does the Company determine Non-Bargaining Unit ("NBU") employees' base pay?

A. NW Natural purchases and regularly analyzes comprehensive survey data to ensure that its base pay is aligned with the median of the market for comparable jobs with other companies that would typically compete with NW Natural for employee talent. NW Natural's most recent analysis, as completed by the Company in 2024, is attached as NW Natural/1001, Rogers. The analysis demonstrates that NW Natural's current base pay midpoints for NBU jobs are at the median of comparable companies. This well-established process confirms that NW Natural is offering an appropriate level of base pay to its employees as a component of competitive total compensation.

Q. How does the Company determine Bargaining Unit ("BU") employees' base pay?

A. BU employees' total compensation—including base pay—is determined through a negotiated process. The Company and the union jointly agree to utilize selected market survey data sources and union contracts, primarily of Northwest gas utility companies, as the points of comparison for setting BU wage steps. Using the agreed-upon sources of competitive pay data, the average is used to determine pay grades. Pay increase trend data and union contracts are consulted when negotiating annual wage increases throughout the term of the Collective Bargaining Agreement ("CBA"). As with any labor negotiations, trade-offs are negotiated for other terms and conditions in the CBA.

Q. Please explain the terms of the current CBA.

A. The current CBA for BU employees was executed on May 20, 2024. The CBA covers the period June 1, 2024 through May 31, 2028. BU employees received a 6 percent wage increase on June 1, 2024. There was an additional 4 percent increase on December 1, 2024, and every December 1 thereafter through December 1, 2027. BU employee health care costs reflect an 85 percent/15 percent sharing between the employer and employee, whereas previously the sharing was 80 percent/20 percent. Lastly, six jobs were re-graded, increasing the wages for those positions.

Q. How does NW Natural determine competitive compensation for Company officers?

A. As with other employees, NW Natural uses competitive compensation data to determine compensation for Company officers. In the case of officers, competitive compensation data include base pay and pay-at-risk comprised of both short- and long-term incentives. The data are collected and analyzed by an independent compensation consultant, Pay Governance, using peer company and survey data. Pay Governance's analysis, which is attached as NW Natural/1002, Rogers, demonstrates that the Company's compensation for officers is within the market competitive range of peer and survey data.

Q. What is the cost of utility employees' base pay for the Test Year, as included in the Company's requested revenue requirement?

A. Table 1 below provides the cost of base pay for the Test Year. These amounts include only the cost for gas utility employees of NW Natural and represent the Oregon-allocated base pay for FTEs.

Table 1
Utility Employee Base Pay (Wages & Salaries)
(Oregon Allocated FTEs)

Type of Utility Employee	Cost of Base Pay
Bargaining Unit (BU) Employees	$55,257,362
NBU Employees	$73,128,940
Officers	$4,516,107
Total	$132,902,409

Q. How did NW Natural determine the cost of base pay in Table 1 for NBU employees and officers in the Test Year?

A. For NBU employees and officers, the amounts shown were determined by taking base pay costs for the Base Year (calendar year 2024) and escalating them by 5.10 percent in 2025 and 4.80 percent in 2026. This reflects a 4.50 percent and 4.20 percent merit increase, respectively, and an additional 0.60 percent in 2025 and 0.60 percent in 2026 to reflect promotions and equity adjustments. The merit percentages were derived using the anticipated pay movement of competitor companies as provided in compensation trend surveys. The additional percentage for promotions and equity adjustments was determined based upon past experience and compensation trend surveys.

Q. How did NW Natural determine the cost of base pay in Table 1 for BU employees in the Test Year?

A. For BU employees, NW Natural determined the cost of base pay by first including the annual wage increases specified in the CBA. Next, an additional 1.05 percent was added each year to account for movement through training progression step increases, movement from entry rate to the experienced rate, as well as promotions, transfers and other adjustments. This additional amount was determined based upon past experience. Taken together, BU employees' base pay will increase 5.05 percent annually, which NW Natural incorporated into Table 1 above.

IV. PAY-AT-RISK

Q. In describing competitive total compensation, you stated that "pay-at-risk" is an important component. Please define what you mean by this term.

A. Pay-at-risk is compensation made to employees only if certain performance goals are met within a defined timeframe. Pay-at-risk is not guaranteed for employees and is intended to foster high performance. It represents an essential part of competitive total compensation, as it is necessary for NW Natural to compete in the job market to attract and retain the employees that it requires to run its utility business.

Q. Is "pay-at-risk" compensation a standard practice in your industry?

A. Yes, pay-at-risk is widely employed by our competitors for labor, and is expected by the professional workforce. Therefore, we believe we need to provide pay-at-risk (at different levels depending on the employee's position) in order to compete and meet pay expectations of the workforce. Pay-at-risk is preferred by organizations, rather than adding this pay directly to base pay. For general industry on average, 78 percent of companies have at least one pay-at-risk or incentive plan (see confidential NW Natural/1003, Rogers*).*

Q. Does NW Natural's "pay-at-risk" compensation result in above-market median total compensation?

A. No, it does not. Our pay-at-risk compensation is a component of total compensation, which is targeted to align with market median total compensation. In other words, if NW Natural did not provide pay-at-risk, its total cash compensation would be below the market median. Without the opportunity to receive this pay, total cash compensation would be below the comparative market.

Q. Is the Company proposing to recover the costs of pay-at-risk pay for officers of the Company?

A. No, it is not. To mitigate the size of the rate request, NW Natural determined that it would not seek recovery of the costs of pay-at-risk pay for officers of the Company in this case.

Q. Has the Company's position changed regarding the ability to recover the costs of pay-at-risk pay for officers of the Company?

A. No, it has not. While the Company believes pay-at-risk is an important part of competitive total compensation for officers, drives operational and financial goals, and is a consistent practice among its peers, NW Natural is not seeking recovery of the costs of pay-at-risk pay for officers of the Company in this rate case. In other words, even though we believe these costs are prudently incurred, NW Natural has decided not to seek recovery of officer pay-at-risk compensation in this case. Furthermore, the Company has not capitalized any portion of pay-at-risk compensation for officers since its last rate case.

Q. Is pay-at-risk provided at the same level for all employees?

A. No. To be consistent with competitive market pay practices, targets are differentiated by employee level. Generally, the market practice is to provide higher levels of at-risk compensation to officers, directors, and managers who may have a broader influence on Company activities. Table 2 below represents the pay-at-risk for our short-term incentive program for NBU employees, the only pay-at-risk the Company is requesting in this rate case.

Table 2
Short-Term Incentive Pay-At-Risk

Incentive Program Type	Participants	Target Percent of Pay	Amount Requested in Test Year as Percent of Pay
NBU Short-Term Incentive	All NBU employees (excluding officers)	7.5 percent-20 percent depending on level	7.5 percent-20.0 percent

Q. Please describe the pay-at-risk that NW Natural provides to NBU employees.

A. NW Natural provides pay-at-risk as a proportion of competitive total compensation that is in line with industry practice. Pay-at-risk is offered through a few different programs depending on job classification. The Company offers a "Goals Incentive Program" to NBU non-officer employees. This program recognizes and rewards employees who have demonstrated strong individual performance and rewards the performers for the plan year who achieve or exceed their annual performance objectives. The Company offers long-term restricted stock units ("RSUs") as well. More details on this program are discussed below.

Q. Does NW Natural offer pay-at-risk compensation to BU employees?

A. No. Short term incentive pay-at-risk is not typically found in unionized employee roles and it is not included in the CBA.

Q. Please describe the operational goals that underlie the Company's short-term incentive programs for NBU employees and explain how customers benefit when the Company meets these goals.

A. The Company's short-term incentive program for NBU employees includes an operational component with the following goals: (1) customer satisfaction, (2) Company growth, and (3) public safety and employee safety, with each described in more detail as follows:

- Customer satisfaction has two components—satisfaction with the Company as a whole, and satisfaction with employee interaction. Both are measured by customer surveys. NW Natural employees further customer satisfaction by providing efficient, courteous, and knowledgeable service in customer interactions. Customers benefit from employee behavior that increases customer satisfaction.
- Company growth measures the number of new meter sets for customers. NW Natural employees contribute to this goal by providing timely hook-ups for new customers. New customers benefit when their meters are installed in an efficient manner, while existing customers benefit from growth through sharing fixed costs with an expanding customer base.

- The public safety goal has two components—damage call response time and odor call response time. Both are measured in percentage of calls responded to in less than 45 minutes. Customers benefit when the Company works quickly to resolve leaks and other potentially dangerous situations.
- The employee safety goal has two components—Days Away Restricted Time ("DART" rate) and number of Preventable Motor Vehicles Collisions ("PMVC"). The DART rate is measured by percent of time away due to on-the-job injuries and the PMVC is measured by number of preventable collisions. Customers benefit from the Company emphasizing a safe working environment that reduces injuries to its employees because it helps ensure safe and timely service.

All of these operational goals promote the Company's provision of safe, reliable, efficient, and timely natural gas service to its customers.

Q. Please explain why NBU employees' long-term RSUs are eligible for full cost recovery.

A. The purpose of RSUs is to encourage key employees to remain with the Company, which is why they vest over time. The RSUs are not awarded to incentivize financial performance, and the number of RSUs will not increase in a good financial year. While RSUs will not vest if the Company has a very poor year, this does not determine the purpose of the incentive, which is to ensure that NW Natural retains qualified employees rather than incurring incremental costs of employee turnover.

Q. What is the total cost of at-risk pay for NBU employees that NW Natural has sought to recover as part of its revenue requirement for the Test Year in this rate case?

A. The Company is proposing to recover $9,653,498 in total at-risk pay for NBU employees in this rate case.

Q. How do you propose that the Commission view pay-at-risk in a utility's total compensation package?

A. The Commission should treat the question of cost recovery for pay-at-risk on a case-by-case basis, with an evaluation to ensure that utilities are paying at market and that the at-risk pay programs are reasonable. This approach is in line with the general regulatory construct in Oregon that allows utilities to recover prudently incurred costs necessary for the provision of utility service.

V. MEDICAL BENEFITS

Q. Please explain why NW Natural provides its employees with medical benefits.

A. NW Natural needs to provide competitive medical benefits to its employees in order to attract and retain a skilled, reliable workforce and because medical benefits are part of the package required to get to median total compensation levels. Additionally, quality medical benefits are necessary to ensure employees are receiving good care in a timely fashion. Good and timely care prevents the development of more serious health problems that would lead to more costly claims and higher employee absentee rates. Customers depend on receiving the safe, efficient, and reliable service that can only be delivered through a healthy and present workforce.

Q. Please describe the medical benefits NW Natural provides to its utility employees.

A. The Company provides medical and pharmacy insurance to its NBU employees and officers through Regence and Kaiser Permanente. Under the CBA, BU employees receive medical and pharmacy insurance from Regence and Kaiser Permanente through the Western States Health and Welfare Trust Fund of the OPEIU, a multi-employer union trust.

Q. What is the medical benefits expense proposed for recovery in this case?

A. The Company has included $20.3 million of medical benefits costs for the Test Year.

Q. Has the Company taken action to manage medical costs?

A. Yes. The Company has a practice of regularly conducting requests for proposals (“RFPs”) from medical insurance providers to ensure that our providers’ prices are competitive. NW Natural’s most recent RFP was issued in 2021. It revealed that changing one of the Company’s medical and pharmacy insurance providers for NBU employees and officers from Cigna to Regence resulted in an annual savings of $1.0 million. Given these savings, NW Natural decided to offer medical and pharmacy insurance through Regence beginning in 2022. We also regularly review the plan designs for our medical and pharmacy plans to ensure they meet the needs of employees and their families while also remaining competitive. For the 2025 plan year, we will be increasing the deductible and out-of-pocket maximum for our Regence PPO plan, resulting in lower costs of approximately $85,000.

Q. How do NW Natural's medical expenses compare with trend factors?

A NW Natural compares renewal rate increases to trend factors for the Pacific Northwest. Based on periodic survey data collected by Milliman, the regional trend was a 7.40 percent increase in costs for 2024 and is expected to be 9.5 percent for 2025. Aside from the factor discussed above, NW Natural's active NBU employees' medical expenses have been increasing at a rate that has been at or below trend factors four out of the last five years (see NW Natural/1004, Rogers). In the case of BU employees, medical increases have been below the trends for three out of the last four years.

Q. What are the key factors that influence increases in medical costs?

A. The Company's medical benefits rates are greatly influenced by the medical experience of the population being insured. Regence increases rates entirely (100 percent) on our actual insured population. On the other hand, Kaiser Permanente utilizes a combination of both manual rating and actual NW Natural experience. It places 60 percent of the formula on its book of business (manual rating) and 40 percent on the actual claims of the plan participants.

In addition to claims experience, we also know that other factors impact medical costs including age, gender and family size. Based on Kaiser Permanente's and Regence's 2024 Clinical Utilization Reports, we know that NW Natural's average age under the pre-65 covered NBU participants in 2024 was 49 years old, compared to their overall databases that indicated an average age of

40.6 for the same time period (see NW Natural/1005, Rogers*).* Having a higher average age means our employee base is more expensive to insure than a younger workforce and is more likely to have more serious medical issues than would be seen on average with a younger workforce. In addition, we also learned from the Clinical Utilization Reports that NW Natural's plan has dependent enrollment of 2.5 dependents compared to the overall database, which indicated an average of 1.6 dependents. Having a higher dependent enrollment also means that our employee base is more expensive to insure.

Finally, there are external factors that impact our renewal costs each year, and in the recent years those impacts have been especially significant. Inflation has made for even higher costs on the pharmacy side and the shortage of healthcare providers has also added costs as providers renegotiate their contracts.

Q. How does the design of NW Natural's medical plans compare with that of other companies?

A. In 2024, Parker, Smith & Feek completed an analysis of the Company's medical benefits in 2024 relative to 35 utilities in the Pacific Northwest through the Milliman survey. See NW Natural/1006, Rogers. In this comparison, Parker, Smith & Feek compared our medical benefits to those of the 35 regional utilities in everything from deductibles to coinsurance (premium sharing), to co-pays for office visits and prescriptions. There was a range of ratings depending upon the specific item being rated, although the overall rating was "Equal."

Q. Why does this testimony address medical benefits and not all components of health benefits?

A. The Company focused on medical benefits (medical and pharmacy) in my testimony because those components make up 95.5 percent of the total health care costs (medical, pharmacy, dental, vision, life, and disability) and has been the area in which significant increases have been experienced in the past 10 plus years.

Q. Are the other health benefits being offered also market competitive?

A. Yes. The same survey source noted above for medical benefits also evaluated the competitiveness of other health care and welfare benefits including dental, vision, life, and disability. All the benefits plans were found to be "Equal" to the 35 utility companies provided in the Milliman survey. While there were some variations in certain categories overall, Parker, Smith & Feek's analysis of the Milliman survey indicated that NW Natural's benefits plans were substantially at market when compared to other utilities. See NW Natural/1006, Rogers.

Q. What is the total cost of medical benefits that NW Natural has sought to recover as part of its revenue requirement for the Test Year in this rate case?

A. That amount, by employee type, is shown in Table 3 below:

Table 3
Utility Employee Medical Benefits
(Oregon Allocated FTEs)

Type of Utility Employee	Test Year
Bargaining Unit (BU) Employees	$8,783,800
NBU Employees[1]	$11,530,900

VI. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 4 below shows the retirement income benefits programs, which provide market median retirement offerings to employees:

Table 4
Retirement Benefits

Retirement Program	Eligible Employees	Summary Description of Benefit
Retirement K Savings Plan (401k) ("RKSP") - Employee Savings with Employer Match	All employees	Defined Contribution Savings plan with match: Match is 50 percent of first 8 percent saved by BU employee and 60 percent of first 8 percent saved by NBU employee.
RKSP -Enhanced	NBU employees hired after December 31, 2006 and BU employees hired after December 31, 2009 (covers employees not eligible for pension benefits)	Contribution made by the Company into "Enhanced" account-no employee contribution required. Contribution is 5 percent for NBU; 4 percent for BU.
NW Natural Pension Plan for BU and NBU Employees (NW Natural Retirement Plan) (closed)	Non-bargaining (NBU) and Bargaining (BU) employees	Defined benefits plan that was closed to new NBU employees hired after 12/31/06 and BU hired after 12/31/09.

[1] Including officers.

Q. Are there any significant changes that NW Natural has made since the Company's last rate case?

A. No. The Company is proposing no changes to retirement benefits for this case.

Q. How do NW Natural's retirement benefits compare to the retirement benefits provided by other companies?

A. In 2024, the Company asked Parker, Smith & Feek to analyze the Company's 401(k) defined contribution retirement benefits relative to other utilities. Based on data from the Milliman survey, NW Natural's 401(k) defined contribution match benefits were found to be "Equal" for BU and NBU employees when compared to the Utility database. The Enhanced 401(k), for those hired after the Pension Plan was closed, was found to be "Worse" when compared to the Utility database. See NW Natural/1006, Rogers.

Q. Please explain the total retirement benefits included for recovery in the Test Year.

A. Table 5 below shows the amount requested for recovery in the Test Year.

Table 5
Utility Retirement Benefits
(Oregon Allocated FTE)

Component	Test Year
RKSP-Matching Contribution	$6,373,590
RKSP-Enhanced Contribution	$5,796,267
Western States Pension-withdrawal liability	$502,941
Total	**$12,672,799**

VII. EMPLOYEE HEADCOUNT

Q. What is NW Natural's FTE count at the end of the Base Year (calendar year 2024)?

A. On a system level, our FTE count at the end of the Base Year is projected to be 1,287.3. The FTE projection is based on actual FTEs as of September 30, 2024, and is then adjusted based on projected FTE attrition and projected FTE hires for the final three months of 2024. Projected FTE attrition is based on known retirements. Projected FTE hires are based on positions the Company was in the process of hiring, taking into account the stage in hiring process for each position. The system FTE count of 1,287.3 FTEs does not include the 79.5 positions that are projected to be unfilled at the end of the Base Year.

Q. Is the Company proposing to adjust its Base Year system FTE count for the Test Year?

A. Yes. As explained above, the Company is projected to have 1,287.3 FTEs at the end of the Base Year. However, during the course of the year, NW Natural loses approximately one to two Customer Service Representatives and Customer Field Service Representatives per month through attrition. While vacancies for other positions within NW Natural are often filled more routinely as the need arises, due to the required training and resource demands needed to onboard FTEs for these roles, it is more efficient to hire larger classes of new Customer Service Representatives and Customer Field Service Representatives one to two times a year. The Company is planning to hire in total 14 of these FTEs in early 2025. Due to a planned retirement during the Test Year, the net increase in FTEs for the

Test Year is 13 union positions, resulting in a total of 1,300.3 FTEs on a system basis, as explained in the Direct Testimony of Tobin F. Davilla (NW Natural/1300, Davilla).

Q. You referenced the required training for onboarding new Customer Service Representatives and Customer Field Service Representatives FTEs. Please briefly explain the importance of this training and why it necessitates hiring larger classes of Customer Service Representatives and Customer Field Service Representatives.

A. Before new Customer Service Representatives and Customer Field Service Representatives can begin serving customers, they must complete extensive training to ensure that they will succeed in their vital customer-facing positions. Therefore, each new hiring class is required to go through a series of training courses over a period of one to two years. Given that all these roles have prerequisite training and testing before work can be performed, NW Natural fills these positions by hiring larger classes of FTEs in order to minimize on-boarding costs that would otherwise be associated with training these employees on an individual basis.

Q. You stated that NW Natural will have a system-level count of 1,300.3 FTEs during the Test Year. In seeking rate recovery, did NW Natural reduce its system level count of 1,300.3 FTEs?

A. Yes. NW Natural has removed 51.2 FTEs that are allocated to non-utility activities. After these FTEs are removed, NW Natural has 1,249.1 gas utility FTEs during the

Test Year. All amounts described in this testimony reflect gas utility-only costs, and not the costs of subsidiaries or affiliates.

Q. Is NW Natural seeking recovery of employees' compensation and benefits based on 1,249.1 FTEs?

A. Yes. NW Natural is seeking cost recovery of employees' compensation and benefits based on the 1,249.1 gas utility FTEs that NW Natural projects to have in the Test Year.

Since the Company serves customers in Oregon and Washington, it allocates a certain percentage (approximately 88 percent) of its employees' compensation and benefits costs to Oregon. Cost allocation between Oregon and Washington is further explained in the Direct Testimony of Kyle T. Walker (NW Natural/1500, Walker). All employees' compensation and benefits costs referenced in this testimony reflect Oregon-allocated values.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBITS 1001 - 1006

December 30, 2024

EXHIBITS 1001-1006 – COMPENSATION & BENEFITS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1001

December 30, 2024

Exhibit 1001 Base Pay Analysis

2024 Salary Structure - Base Pay Analysis

2024 Salary Structure		
NWN Grade	**NWN 2024 Midpoint**	**NWN Midpoint vs. Market Median**
14	$62,500	108.9%
15	$67,500	104.5%
16	$72,900	103.1%
17	$79,450	101.3%
18	$86,600	101.9%
19	$94,400	101.7%
20	$104,800	101.6%
21	$116,350	101.7%
22	$130,300	100.5%
23	$145,950	98.5%
24	$163,450	99.5%
25	$183,050	104.3%
26	$205,000	103.1%
	Overall	**102.3%**

Data Source: NW Natural Market Analysis 2023 for 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1002

December 30, 2024

Pay Governance®
Advisory Services to Compensation Committees

NW Natural Gas Company & NW Natural Holding Company

Total Remuneration Review

Organization and Executive Compensation Committee Meeting – February 2024

Key Findings

1. NW Natural's compensation program (target total remuneration) is competitive with the Proxy Peer Group, broader energy industry and general industry
   — Long-term incentive awards are generally higher than the survey data.
2. Officers positioned below competitive TDC and total remuneration levels (-10% or more) should be reviewed for continued movement toward competitive compensation.
   — Currently, total remuneration levels for the Officers are generally meeting the Company's compensation philosophy target (50th percentile) except for the VP, Chief HR & Diversity Officer, and the VP, Engineering & Utility Operations which are below the philosophy target.
3. All elements of compensation are generally aligned with the NW Natural philosophy of targeting median.
4. NW Natural internal equity generally aligns with the pay ranking of CEO and highest paid executives at energy industry companies (see p. 15).

	NW Natural Variance to Market								
	Peer Group			Energy Industry - Survey			General Industry - Survey		
Pay Component	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile
Base Salary	2%	-2%	-4%	12%	-2%	-15%	8%	-8%	-23%
Target Total Cash	-4%	-7%	-9%	21%	-1%	-19%	19%	-9%	-25%
Long-term Incentives	10%	-5%	-8%	139%	16%	-33%	454%	23%	-17%
Target Total Direct	2%	-6%	-9%	40%	4%	-23%	52%	-2%	-23%
Target Remuneration	1%	-5%	-7%	41%	4%	-24%	55%	0%	-23%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1003

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

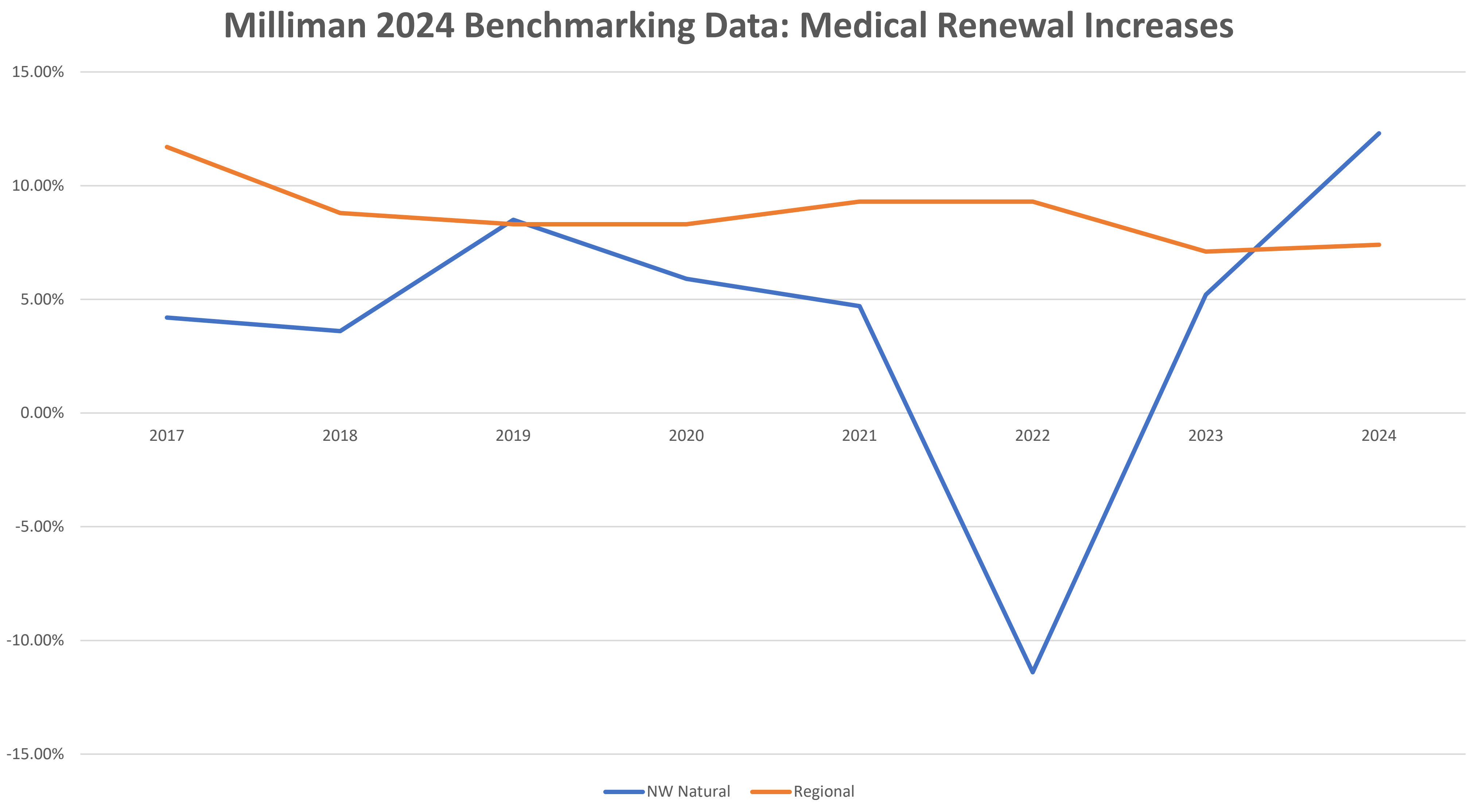
UG 520

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1004

December 30, 2024


Milliman 2024 Benchmarking Data: Medical Renewal Increases
15.00%
10.00%
5.00%
0.00%
-5.00%
-10.00%
-15.00%
2017
2018
2019
2020
2021
2022
2023
2024
NW Natural
Regional

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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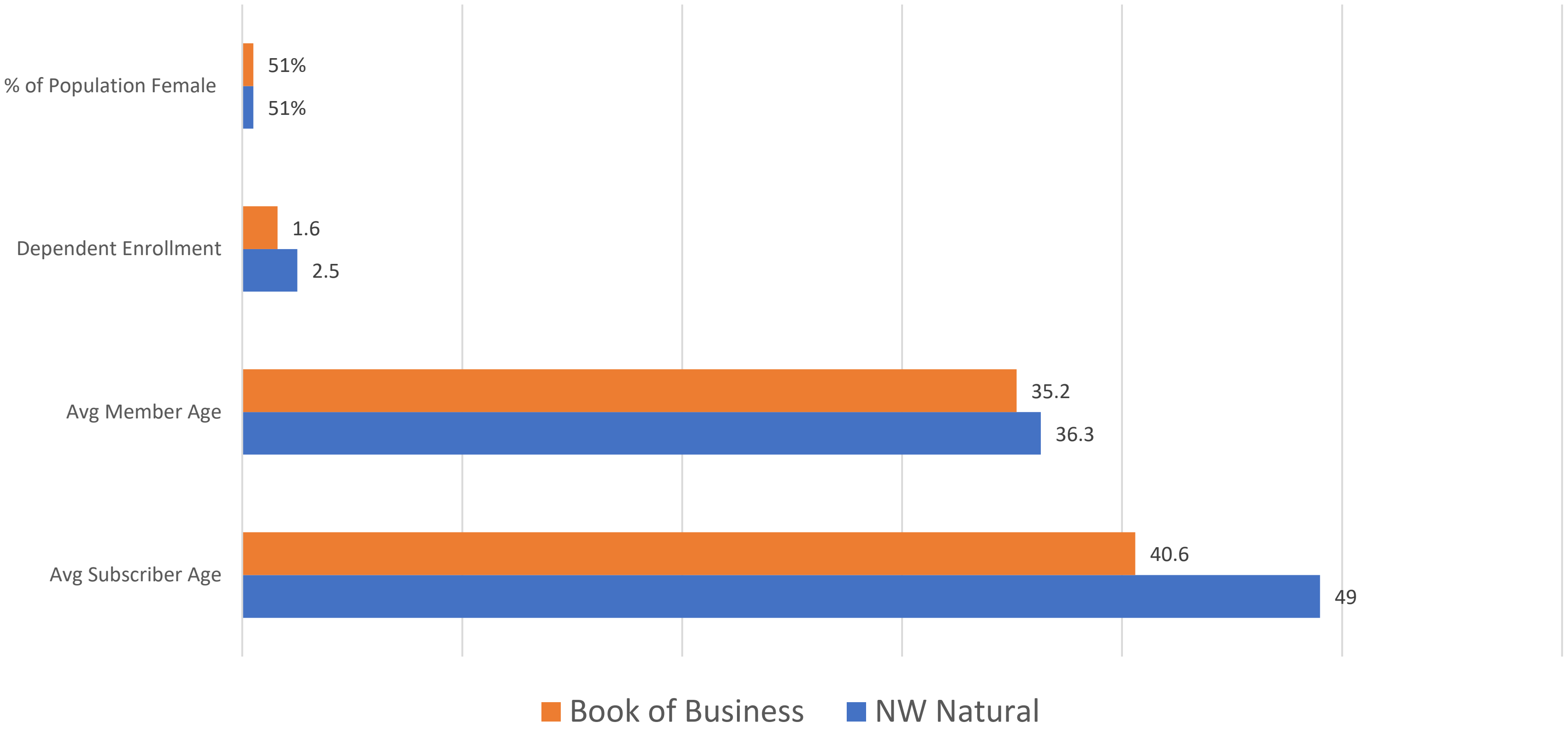
NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1005

December 30, 2024

Kaiser and Regence 2024 Demographic Benchmarking Data



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS
EXHIBIT 1006

December 30, 2024

Milliman 2024 Benchmarking Data

Medical	Ranking as compared to 35 Utilities in the PNW
Deductible	Equal
Out of Pocket Maximum	Equal
Coinsurance	Equal
Office Visit – Primary	Better
Office Visit – Specialist	Better
Telehealth Visit	Better
Pharmacy	Worse
HSA Contributions	Equal
Employer Contributions	Worse

Vision and Dental	Ranking as compared to 35 Utilities in the PNW
Vision Exam	Equal
Vision Hardware	Better
Dental Deductible	Better
Dental Annual Maximum	Equal
Class 1: Preventative	Equal
Class 2: Basic/Restorative	Equal
Class 3: Major Services	Better
Orthodontia	Equal

Continued: Milliman 2024 Benchmarking Data

Long-term Disability	Ranking as compared to 35 Utilities in the PNW
Benefit Percentage	Equal
Monthly Maximum	Equal
Elimination Period	Equal

Short-term Disability	Ranking as compared to 35 Utilities in the PNW
Benefit Percentage	Better
Elimination Period	Equal
Maximum Benefit Period	Better

Life Insurance	Ranking as compared to 35 Utilities in the PNW
Employee Coverage	Worse
Dependent Coverage	Equal
Voluntary Buy-up	Equal

Other	Ranking as compared to 35 Utilities in the PNW
Flexible Spending Accounts	Equal
Employee Assistance Program	Better

Defined Contribution	Ranking as compared to 35 Utilities in the PNW
Company Match	Equal
Enhanced (Non-Match)	Worse

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1100

December 30, 2024

EXHIBIT 1100 - DIRECT TESTIMONY - CUSTOMER COMMUNICATIONS

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Cory Beck. I am the Director of Customer Experience Services for NW Natural. My responsibilities include customer and public communications, advertising, website, digital portal and Interactive Voice Response (IVR) services, natural gas safety communications, and our Federal Public Safety Awareness program. I have worked for NW Natural since 2005.

Q. Please describe your education and employment background.

A. I received my undergraduate degree in Graphic Design from Oregon State University and a Master of Business Administration from Marylhurst University. From 1994 to 1998, I worked as an account executive at a design agency, Electro Art, in Portland, Oregon. From 1998 to 2000, I worked as an account executive at an advertising agency, Gerber Advertising, in Portland, Oregon. From 2000 to 2005, I worked as an account supervisor at a marketing and advertising agency, CMD (Creative Media Development), also in Portland, Oregon.

Q. Please summarize your testimony.

A. In my testimony, I:

- Present the Company's Category A (customer communications) proposed expense for the period November 2025 through October 2026 ("Test Year"), and explain why the proposed level is just $0.22 more per customer than the level presumed just and reasonable under Oregon Administrative Rule

("OAR") 860-026-0022(3)(a), but still far below the amount deemed reasonable for electric utilities that share a similar service territory; and

- Present the Company's Test Year Category B proposed expense.

The Company is not seeking rate recovery of any expenses in Category C (corporate imaging), Category D (political/non-utility advertising) or Category E (energy efficiency/conservation advertising related to a program approved by the Public Utility Commission of Oregon [the "Commission"]) and, therefore, I do not address those categories in my testimony.

II. CATEGORY A – CUSTOMER COMMUNICATIONS

Q. Please describe Category A customer communications.

A. The Commission's administrative rules categorize utility customer communications and set forth ratemaking standards applicable to each category. Category A communications are defined as "Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses."

Q. Under the Commission's rules, is there a level of Category A communications expense that is presumed just and reasonable?

A. Yes. Under OAR 860-026-0022(3)(a), expenditures for Category A customer communications up to 0.125 percent of gross retail operating revenues are presumed just and reasonable. In NW Natural's case, that percentage results in $1,361,733 for Category A communications based on forecasted revenues and customer count, which is equivalent to about $1.93 per customer.

Q. How does NW Natural's proposed Category A communications expense for the Test Year compare with that presumed level?

A. The Company is requesting $2.15 per customer or $1,521,430 for the Test Year, or only $0.22 more per customer than the rate derived using the level presumed just and reasonable under OAR 860-026-0022(3)(a).

Q. How does NW Natural's Category A request compare to the amounts presumed reasonable for other utilities?

A. The revenue-based formula applicable to all energy utilities results in natural gas utilities having far less Category A expense presumed reasonable as compared to electric utilities. NW Natural should be allowed rate recovery for communications that are generally in line with electric utilities in Oregon on a per customer basis. NW Natural's request for $2.15 per customer for the Test Year is far less than electric utilities that serve most of the same customers as well. For example, based on 2023 data, Table 1 below shows that the revenue-based formula translates into an allowance of $3.04 per customer for PacifiCorp and $3.20 per customer for Portland General Electric Company compared to $1.73 per customer for NW Natural. This funding gap is inequitable, given NW Natural's communication topics and service territory are not unique from electric utilities serving the same customers. Additionally, NW Natural has an expansive Oregon service territory that requires purchasing media from multiple outlets: the Oregon coast from Astoria to Coos Bay, the Willamette Valley from Portland to Eugene, and the Columbia River Gorge.

TABLE 1

2023 Category A per Customer Based on Operating Revenues

	Year	Operating Revenues	CAT A - 0.125%	# of Customers	CAT A per Customer
NW Natural	2023	978,597,720	1,223,247	707,269	1.73
PGE	2023	2,379,994,297	2,974,993	928,859	3.20
Pacificorp	2023	1,513,650,640	1,892,063	622,868	3.04

Source of Revenues and Customers - OPUC Oregon Utility Statistics 2023

Q. How much would NW Natural be allowed to recover in Category A according to the rule if the Company's per customer amount was equal to PGE?

A. Based on 2023 data, according to the rule, if NW Natural was allowed to recover $3.20 per customer, NW Natural would be allowed to recover $2,263,261 for Category A ($3.20 x 707,269 = $2,263,261).

Q. What is the difference between the amount NW Natural could recover for Category A if the per customer amount were equitable with the amount PGE is allowed to recover compared to the amount NW Natural is asking for in this case?

A NW Natural believes closing the gap between Category A allowable amounts is highly reasonable for reasons mentioned above. With that in mind, in this case NW Natural is asking for $1,521,430 which remains $741,831 *less* for Category A than the amount that is equitable compared to PGE in our service territory ($2,263,261 - $1,521,430 = $741,831).

Q. What topics does the Company's Test Year Category A communications address?

A. The Company's Test Year Category A communications addresses topics that include the following:

- Payment options and programs for customers;
- Low-income programs such as the bill discount program;
- Energy and money-saving tips and resources;
- The efficient use of natural gas;
- Options to reduce natural gas consumption and save energy by installing high-efficiency appliances;
- Required regulatory notices, such as customer Rights and Responsibilities;
- Online customer service options and information;
- Natural gas price changes and rate change information;
- Seasonal billing programs such as the Weather Adjusted Rate Mechanism (WARM);
- Contemporary items of customer interest, such as business practices and involvement in the communities we serve; and
- Phone numbers and contact information.

Q. How does the Company plan to communicate with customers on these topics?

A. The Company plans to continue communicating with customers through bill inserts, our website, on-hold messaging, customer e-newsletters, email, new customer information packets, telephone directory advertising, digital advertising, community events, television, radio and streaming media.

Q. What is the communication plan for Category A communications?

A. NW Natural plans to distribute Category A Test Year budget to address the following activities shown in Table 2 below:

TABLE 2

TOTAL CATEGORY A

Category A Channels		Total Budget		OR Test Year
Salaries/Overhead	$	650,000	$	573,625
Bill inserts	$	250,000	$	220,625
Brochures/ Customer Support Items	$	75,000	$	66,188
eNewsletter	$	35,000	$	30,888
Professional Services - Design & Writing	$	100,000	$	88,250
Website Support/Development	$	35,000	$	30,888
Welcome Letter Postage	$	85,000	$	75,013
Media - Production	$	150,000	$	132,375
Media - IVR	$	14,000	$	12,355
Media - Telephone directory	$	30,000	$	26,475
Media - Customer Service, Bill Discount Program	$	300,000	$	264,750
Category A Totals	**$**	**1,724,000**	**$**	**1,521,430**

Q. Why is the Company requesting an increase to the presumed justified and reasonable amount for Category A?

A. The Company adjusted its request for Category A by $0.22 per customer over the amount presumed reasonable by OAR 860-026-0022(3)(a) to account for additional targeted communications and outreach for the bill discount program to educate customers in communities that are located in high-energy burden affected areas.

Q. What are the plans for additional communications outreach for the bill discount program?

A. In addition to outreach and broad customer communications included in the Test Year Communications Plan such as talking points, bill inserts, newsletter articles, website postings, bill messages, and on-hold messages, the Company plans to distribute targeted marketing campaigns using direct mail, digital, social media, community newspaper, radio advertising, and community events to customers in communities that are located in high-energy burden affected areas. More information on communications to customers on energy assistance, as well as the bill discount program in general, can be found in Cecelia J. Tanaka's testimony (NW Natural/200, Tanaka).

Q. Where are the high-energy burden affected areas?

A. According to the 2024 Energy Burden Assessment ("EBA")[1], 18 percent of the households in the Pleasant Valley neighborhood in eastern Multnomah County and 21 percent of the households in Clatsop and Lincoln counties experience high energy burden. In addition to identifying the most needed areas, the EBA recommends, "locally targeted marketing campaigns" to increase effectiveness.

Q. What is the additional targeted communications plan for EBA areas?

A. NW Natural plans to distribute budget for targeted communications to EBA areas to address the following activities shown in Table 3 below:

[1] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475*, Docket No. UM 2211, NW Natural's Energy Burden Assessment (Sept. 16, 2024).

TABLE 3

EBA CATEGORY A

Category A Channels		Total Budget		OR Test Year
Direct mail	$	35,000	$	30,888
Professional Services - Design & Writing	$	15,000	$	13,238
Media - Production	$	25,000	$	22,063
Media - Digital, Social Media, Community News, Radio	$	75,000	$	66,188
Community Events - Fees, Staffing, Materials	$	25,000	$	22,063
Category A Totals	**$**	**175,000**	**$**	**154,438**

Q. Are bill discount program communications appropriate for inclusion into Category A?

A. Yes. Bill discount program communications fit squarely under the Commission's administrative rules for utility customer communications, specifically utility service advertising expenses, and utility information advertising expenses.

Q. Do some of the communications sent to customers include messages that could be interpreted to not qualify as Category A?

A. Yes. The Company sends its "Comfort Zone" newsletter to customers in their bill five-times per year and every month via email to Paperless billing customers. The majority of newsletter contains Category A messages along with several messages across categories in each issue. The Company allocated about 25 percent of the total cost for the Comfort Zone newsletters to the Category C customer communications cost center to account for messages that could be interpreted to be outside of Category A. Category C customer communications are not being requested for recovery in this case.

Q. What action does the Company request the Commission take with respect to Category A communications expense?

A. The Company requests that the Commission find that the proposed level of Test Year Category A communications expense is just and reasonable under OAR 860-026-0022, as mostly presumed by OAR 860-026-0022(3)(a). The Company's proposed expense level is necessary for the Company to effectively deliver Category A communications to our customers.

III. CATEGORY B – SAFETY-RELATED COMMUNICATIONS

Q. What are safety-related communications?

A. Category B safety-related communications are messages intended to ensure that NW Natural's customers, contractors, public officials, emergency officials and the general public within the NW Natural service territory know how to use natural gas safely, have emergency preparedness awareness, know how to recognize, react, and respond to a potential leak or safety issue related to natural gas, and know how to prevent damages to underground utility pipelines. The Company develops its safety-related communications through its Public Safety Awareness Program. Safety-related communications are also referred to as Category B communications, as defined in OAR 860-026-0022. Under OAR 860-026-0022(3)(b), Category B communications are presumed to be just and reasonable for ratemaking purposes.

Q. Please describe the Company's Public Safety Awareness Program and Category B communications provided under that program and related activities.

A. Third-party damage to NW Natural pipelines still poses a significant threat to our system and public safety. Each year, the Company executes a robust Public Safety Awareness Program that distributes audience-specific pipeline safety information to required groups, including emergency officials, first responders, public officials, excavators, contractors, multi-family property managers, floating homes, and residents and businesses located along transmission pipelines, in high-consequence areas, or along rights-of-way. The Company's Category B communications are focused on damage prevention, emergency preparedness awareness and instructions for how to be safe around natural gas.

Q. Please identify the legal mandates requiring expenditures under the Company's Public Safety Awareness Program and related activities.

A. NW Natural's Public Safety Awareness Program is required under the Federal Pipeline Safety Act, the United States Code of Federal Regulations Title 49 Parts 192 and 195, standards administered by the United States Department of Transportation, Pipeline and Hazardous Materials and Safety Administration including Recommended Practice API 1162 ("API RP 1162"), and OAR 860-024-0020. Please see Exhibit NW Natural/1101, Beck, for a copy of API RP 1162. These legal mandates require pipeline operators such as NW Natural to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the police, or other appropriate public officials.

Furthermore, natural gas safety awareness messaging as defined in API RP 1162 is much more than only requiring a utility to publish advertising about preventing and detecting leaks from gas pipelines. Federal Pipeline Safety Regulations (49 CFR 192.616 and 49 CFR 195.440) require pipeline operators to develop and implement public awareness programs that follow the guidance provided by the API RP 1162, "Public Awareness Programs for Pipeline Operators". The scope of API RP 1162 provides guidance that states that "mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included."

API RP 1162 also provides multiple recommendations for baseline messaging that is appropriate for the Affected Public (including customers) in addition to detecting and preventing leaks directly from pipelines including awareness of potential hazards and prevention measures and emergency preparedness. Importantly, "information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience." NW Natural's Public Safety Awareness Program is charged to Category B under these legal mandates and is regularly audited by the Commission's Safety Division. In October 2023, Staff completed an inspection of the NW Natural Public Safety Awareness Program and communications, and advertising distributed to support the program, and Staff concluded there were no issues or concerns and found that the Company followed state and federal regulations without infringement.

Q. Are there additional safety-related communications included in the Company Public Safety Awareness Plan that are necessary for customers?

A. Yes. The Company's Test Year Public Safety Awareness Plan includes natural gas and natural gas appliance safety communications and partners with and enhances the Category B Public Safety Awareness Plan through distribution of media across multiple channels, including TV, streaming media, radio, print, digital, social media, public relations, and community events. Media and event exposure increases the visibility and reach of the important safety messages and is more accessible to a wider audience.

Q. Why are natural gas and natural gas appliance safety messages important for customers?

A. For local natural gas distribution companies like NW Natural, safety messaging for distribution systems not only includes the mains that are usually located under city streets, but also the smaller service lines that connect to the mains and further distribute natural gas service to the local end users, including businesses and residential customers. Providing safety-related messages the Company deems appropriate to keep customers safe around natural gas in addition to messages to prevent damages to the pipeline, such as proper equipment operation, emergency preparedness, how to recognize a potential safety issue, how to respond, and properly operate gas appliances that are connected to these service lines and prevention procedures, is of the utmost importance to customers. Additionally, when a gas appliance is not properly installed or operated, there could be a safety issue within the home. Accordingly, safety information is important for all customers to be educated about.

Q. What Category B communications expenses are included in the Test Year?

A. The Company has included $900,150 for Category B communications for the Test Year.

Q. What is the communication plan for Category B?

A. NW Natural plans to distribute Category B Test Year budget to address the following activities shown in Table 4 below:

TABLE 4

TOTAL CATEGORY B				
Category B Channels		**Total Budget**		**OR Test Year**
Salaries/Overhead	$	180,000	$	158,850
Bill inserts/Brochures	$	30,000	$	26,475
Professional Services - Design & Writing	$	75,000	$	66,188
Postage	$	85,000	$	75,013
Public Safety Awareness Program & Materials	$	250,000	$	220,625
Media - Production	$	100,000	$	88,250
Media - Safety education, damage prevention	$	300,000	$	264,750
Category B Totals	**$**	**1,020,000**	**$**	**900,150**

Q. How does the proposed Category B amount requested compare to the forecast Base Year amount?

A. Yes. The Category B amount requested is only approximately $40,000 more than the forecasted amount in the Base Year.

Q. Why is the Company requesting an increase to the Category B Base Year spending level?

A. The Company plans to increase safety advertising exposure by placing safety ads on network television to increase the reach of the advertising to the age 60 and older demographic of NW Natural customers that frequently watch network television instead of less expensive cable and streaming media.

Q. Are there data to support adding additional network television to serve the 60 and older demographic?

A. Yes. 2024 demographic data provided by JD Power and Associates from recent surveys show in Figure 1 below that 43 percent of NW Natural customers are in the Boomer and Pre-Boomer age group. The Boomer generation is defined as people born between 1946 and 1964, making them between 58 and 76 years old as of June 2024. The Pre-Boomer generation (or Silent Generation) is defined as people born between 1925 and 1945, making them between 77 and 95 years old as of June 2024. In other words, 43 percent of NW Natural customers are over 58 years old.

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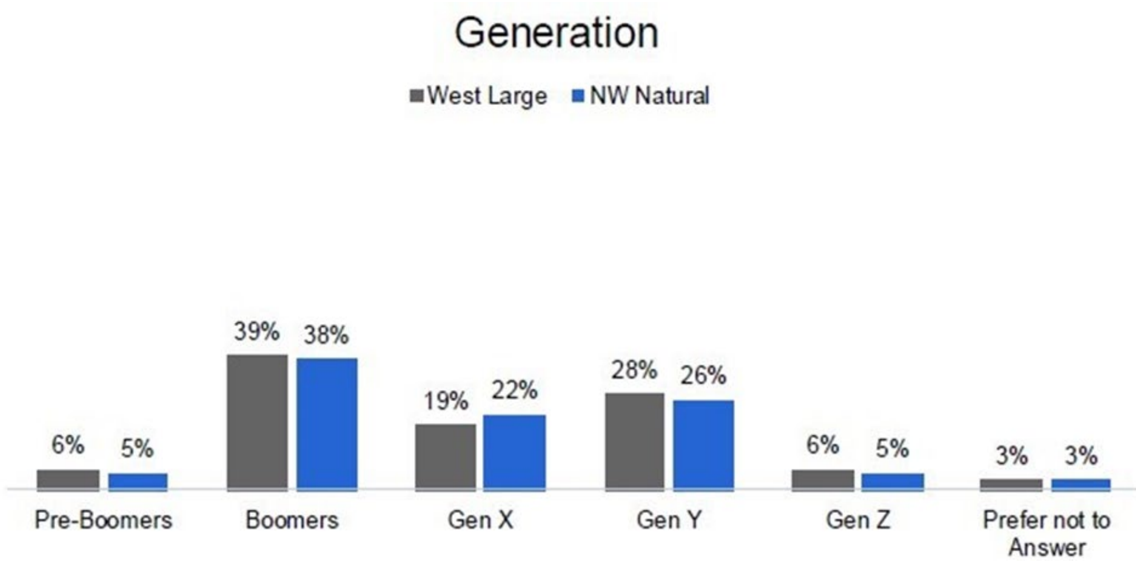
FIGURE 1[2]



Q. Do older adults watch television more than other types of media?

A. Yes. As shown in Figure 2 below, adults aged 65 and above spent double the time watching television, compared to younger adult age groups.

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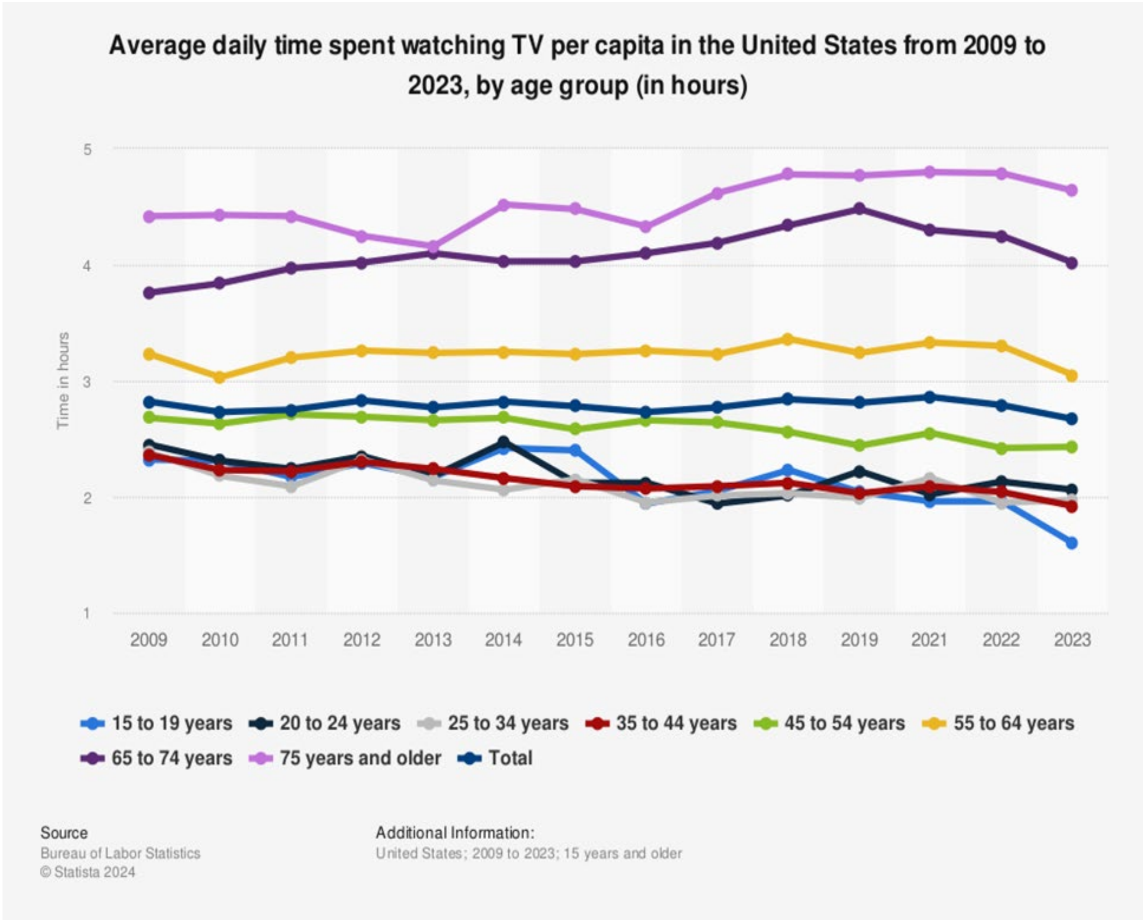
[2] Source: JD Power 2024 U.S. Gas Utility Customer Satisfaction Study.

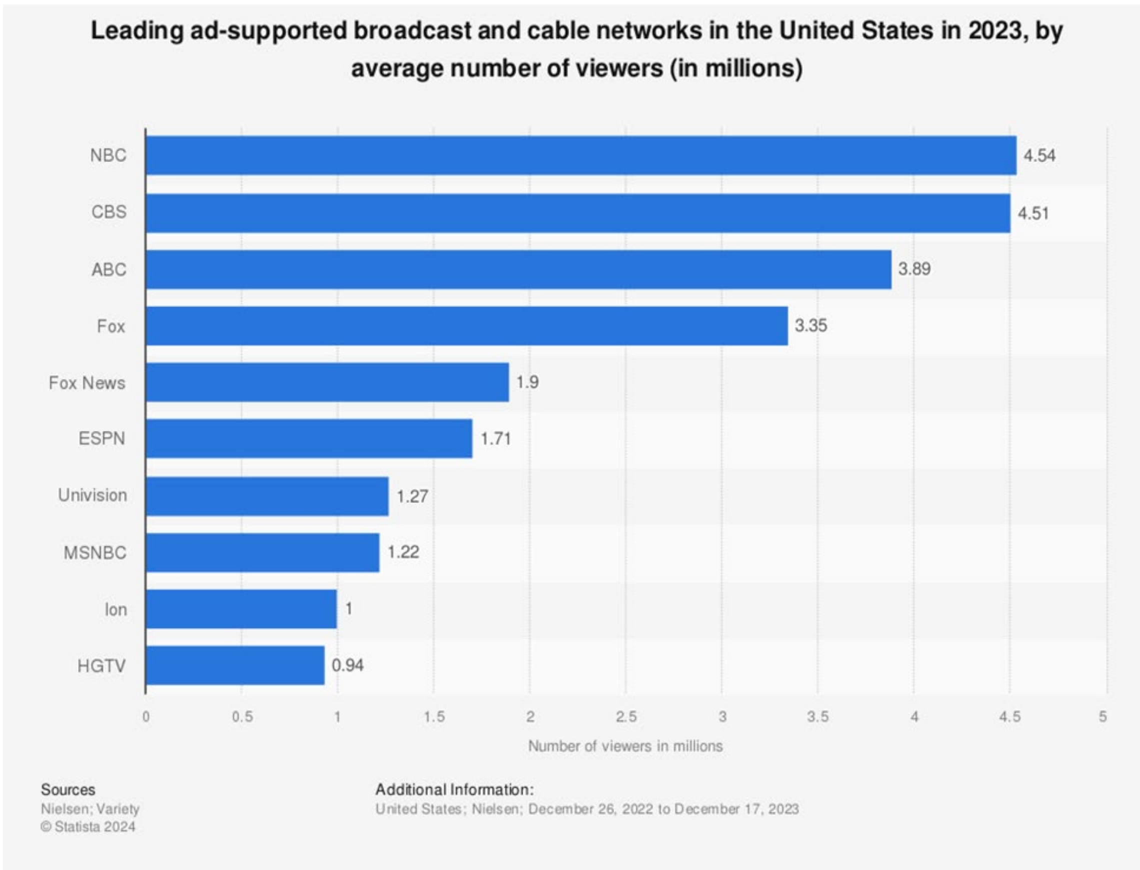
FIGURE 2



Q. Are broadcast network television channels viewed more than cable television channels?

A. Yes. Broadcast networks are also known as Network Television. Examples of broadcast networks include: ABC, NBC, CBS, FOX. Cable channels are also known as cable networks or non-broadcast channels. Examples of cable channels include: AMC, USA, TNT, FX and typically require subscription to a cable network provider. In 2023, viewership of broadcast networks was more than double in comparison with viewership of the most popular cable networks, as shown below in Figure 3.

FIGURE 3



Q. Did NW Natural's Base Year media plan include network television?

A. Yes, but the Base Year budget only allowed for network television media for two months of the year - not a full calendar year. The Test Year request in this case would provide network television coverage for the year. The extended reach would maximize overall audience reach throughout the year especially among the older demographic.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1101

December 30, 2024

EXHIBIT 1101 – CUSTOMER COMMUNICATIONS

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SLW updated version

Public Awareness Programs for Pipeline Operators

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

Approved American National Standard
ANSI

American Petroleum Institute

Helping You Get The Job Done Right.℠

Public Awareness Programs for Pipeline Operators

Pipeline Segment

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003

American Petroleum Institute

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FOREWORD

This document is a Recommended Practice (RP) for pipeline operators to use in development and management of Public Awareness Programs. Pipeline Operators have conducted Public Awareness Programs with the affected public, government officials, emergency responders and excavators along their routes for many years. The goal of this RP is to establish guidelines for operators on development, implementation, and evaluation of Public Awareness Programs in an effort to raise the effectiveness of Public Awareness Programs throughout the industry.

Representatives from natural gas and liquid petroleum transmission companies, local distribution companies, and gathering systems, together with the respective trade associations, have developed this Recommended Practice. The working group was formed in early 2002. Additionally, representatives from federal and state pipeline regulators have provided input at each step of development and feedback from all interested parties has been solicited through a wide variety of sources and surveys.

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Public Awareness Programs for Pipeline Operators

1 Introduction, Scope and Glossary of Terms

1.1 INTRODUCTION

This Recommended Practice (RP) provides guidance to be used by operators of petroleum liquids and natural gas pipelines to develop and actively manage Public Awareness Programs. This RP will also help to raise the quality of pipeline operators' Public Awareness Programs, establish consistency among such programs throughout the pipeline industry, and provide mechanisms for continuous improvement of the programs. This RP has been developed specifically for pipelines operating in the United States, but may also have use in international settings.

Public awareness and understanding of pipeline operations is vital to the continued safe operation of pipelines. Pipeline operators' Public Awareness Programs are an important factor in establishing communications and providing information necessary to help the public understand that pipelines are the major transportation system for petroleum products and natural gas in the United States, how pipelines function, and the public's responsibilities to help prevent damage to pipelines.

Public Awareness Programs should address the needs of different audiences within the community and be flexible enough to change as the pipeline system changes or as the public's needs for information change. When effectively and consistently managed, a Public Awareness Program can provide significant value to the pipeline operator in several areas: enhanced public safety, improved pipeline safety and environmental performance, building trust and better relationships with the public along the pipeline route, less resistance to pipeline maintenance and right-of-way activities, preservation of rights-of-way, enhanced emergency response coordination, and improved pipeline operator reputation.

Public awareness messages need to provide a broad overview of how pipelines operate, the hazards that may result from activity in close proximity to pipelines and those hazards possible due to pipeline operations, and the measures undertaken to prevent impact to public safety, property or the environment. These messages should be coupled with information regarding how pipeline operators prepare for emergencies in a way that minimizes the consequences of a pipeline incident.

This RP identifies for the pipeline operator four specific stakeholder audiences and associated public outreach messages and communication methods to choose from in developing and managing a successful Public Awareness Program. It also provides information to assist operators in establishing specific plans for public awareness that can be evaluated and updated.

This RP is comprised of a main body (Sections 1 – 8), and Appendices. The main body of this document contains the general, baseline program recommendations and the supplemental program components. Summary tables and diagrams are also provided in the main body. These summaries can be used as quick reference guides to assist operators when customizing their Public Awareness Programs to reflect the unique characteristics of their pipeline and facilities. The Appendices provide operators with additional, optional information and resources for further reference. The Appendices repeat many areas of the main body in order to provide the operator with comprehensive information.

1.2 SCOPE

This RP is intended as a resource that can assist pipeline operators in their public awareness efforts. Operators are urged to develop, implement and actively manage Public Awareness Programs within their companies. In implementing these programs, operators should select the most appropriate mix of audiences, message types, and delivery methods and frequencies, depending on their needs and the needs of the communities along a given pipeline segment. The guidance set forth in this RP establishes a baseline for Public Awareness Programs and describes considerations for program expansion that can further enhance specific public awareness outreach.

This RP provides guidance for the following pipeline operators:

- Intrastate and interstate hazardous liquid pipelines
- Intrastate and interstate natural gas transmission pipelines
- Local distribution systems, and
- Gathering systems.

This guidance is intended for use by pipeline operators in developing and implementing Public Awareness Programs associated with the normal operation of existing pipelines. The guidance is not intended to focus on public awareness activities appropriate for new pipeline construction or for communications that occur immediately after a pipeline-related emergency. Communication regarding construction of new pipelines is highly specific to the type of pipeline system, scope of the construction, and the community and state in which the project is located. Likewise, public communications in response to emergency situations are also highly specific to the emergency and location. This RP is also not intended to provide guidance to operators for communications about operator-specific performance measures that are addressed through other means of communication or regulatory reporting.

The primary audience for this RP is the pipeline operator for use in developing a Public Awareness Program for the following stakeholder audiences:

- The affected public—i.e., residents, and places of congregation (businesses, schools, etc.) along the pipeline and the associated right-of-way (ROW)
- Local and state emergency response and planning agencies—i.e., State and County Emergency Management Agencies (EMA) and Local Emergency Planning Committees (LEPCs)
- Local public officials and governing councils
- Excavators.

DESCRIPTION OF PIPELINE INFRASTRUCTURE

To clarify the scope of the pipeline industry covered by this RP, a brief description of the affected infrastructure components is provided below. Mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included. Unless otherwise noted, the use of the term "pipeline" in this RP will refer to all three of the following types of systems. The RP recognizes some differences between the three pipeline types and provides the operator flexibility based on the needs of the stakeholders along a particular pipeline.

1.2.1 Transmission Pipelines

The transmission pipeline systems for liquid petroleum and natural gas, move large amounts of liquids and natural gas from the producing and/or refining locations to local "outlets", such as bulk storage terminals (for liquids) and natural gas distribution systems. Transmission pipeline systems can be classified as either "intrastate pipelines", located within one state's borders, or "interstate pipelines" crossing more than one state's borders. Natural gas transmission pipelines deliver gas to direct-served customers and local distribution systems' stations, referred to as "city gates", where the pressure is lowered for final distribution to end users. Liquids transmission pipelines usually transport crude oil, refined products, or natural gas liquids. Transmission pipelines are generally the middle of the transportation link between gathering and distribution systems.

1.2.2 Local Distribution Systems

The local distribution systems for liquid petroleum and natural gas differ because of the nature and use of the products. Liquid petroleum products are distributed from bulk terminals by other modes of transportation, such as by rail cars and tank trucks. Local natural gas distribution companies (LDCs) receive natural gas at "city gates" and distribute it through distribution systems, These consist of "mains", which are usually located along or under city streets and smaller service lines that connect to the mains to further distribute natural gas service to the local end users - homes and businesses.

1.2.3 Gathering Systems

Gathering pipelines link production areas for both crude oil and natural gas to central collection points. Some gathering systems include processing facilities; others do not. Some gathering systems are regulated by the Office of Pipeline Safety, U.S Department of Transportation, while most are not. Gathering systems connect to transmission pipelines for long distance transportation of crude oil and natural gas to refinery centers and distribution centers, respectively.

1.3 GLOSSARY OF TERMS

1.3.1 Appendices: The Appendices' role is to provide a pipeline operator with additional information to develop and actively manage its Public Awareness Programs. The Appendices' mirror the main body of the RP while providing additional information such as: resources and contacts, examples of stakeholder audiences, public awareness messages, enhanced delivery methods and media, and program evaluation information.

1.3.2 Baseline Public Awareness Program: Refers to general program recommendations, set forth in Recommended Practice 1162, The baseline recommendations do not take into consideration the unique attributes and characteristics of individual pipeline operators' pipeline and facilities. Supplemental or enhanced program components are described in the RP to provide guidelines to the operator for enhancing its Public Awareness Programs. This is described more fully in Sections 2 and 6.

1.3.3 CFR: *Code of Federal Regulations*

1.3.4 Dig Safely: Dig Safely is the nationally recognized campaign to enhance safety, environmental protection, and service reliability by reducing underground facility damage. This damage prevention education and awareness program is used by pipeline companies, One-Call Centers, and others throughout the country. Dig Safely was developed through the joint efforts of the Office of Pipeline Safety and various damage prevention stakeholder organizations. Dig Safely is now within the purview of the Common Ground Alliance (CGA). For more information see www.commongroundalliance.com.

1.3.5 Enhanced Public Awareness Program: The concept developed in RP 1162 for assessing particular situations in which it is appropriate to enhance or supplement the Baseline Public Awareness Program. This is described more fully in Section 6.

1.3.6 High Consequence Areas (HCAs): A high consequence area is a location that is specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Pipeline safety regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA.

1.3.7 HVL (Highly Volatile Liquid): A highly volatile liquid, as defined in pipeline safety regulations, is a hazardous liquid that will form a vapor cloud when released to the atmosphere and has a vapor pressure exceeding 276kPa (40 psia) at 37.8 degrees C (100 degrees F).

1.3.8 Integrity Management Program (IMP): In accordance with pipeline safety regulations, an operator's integrity management program must include, at a minimum, the following elements:

- a process for determining which pipeline segments could affect a High Consequence Area (HCA)
- a Baseline Assessment Plan
- a process for continual integrity assessment and evaluation
- an analytical process that integrates all available information about pipeline integrity and the consequences of a failure
- repair criteria to address issues identified by the integrity assessment method and data analysis (the regulations provide minimum repair criteria for certain, higher risk, features identified through internal inspection)
- a process to identify and evaluate preventive and mitigative measures to protect HCAs
- methods to measure the integrity management program's effectiveness and
- a process for review of integrity assessment results and data analysis by a qualified individual.

1.3.9 IMP Overview: An overview of an operator's IMP program should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be a few pages and its availability could be mailed upon request or made available on the operator's website.

1.3.10 LDCs: Local Distribution Companies for natural gas

1.3.11 "may" versus "should": Clarification is necessary for RP 1162's use and definition of the words "may" versus "should":

- The use of the word "may" provides the operator with the option to incorporate the identified component into its Public Awareness Program.
- The use of the word "'should" provides the operator with the Public Awareness Program components that are recommended to be incorporated into the operator's Public Awareness Program.

1.3.12 NPMS: National Pipeline Mapping System (See Section 4.6.2)

1.3.13 One-Call Center: The role of the One-Call Center is to receive notifications of proposed excavations, identify possible conflicts with nearby facilities, process the information, and notify affected facility owners/operators.

1.3.14 Operator: All companies that operate pipelines that are within the scope of this RP.

1.3.15 OPS: Office of Pipeline Safety, part of the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation. OPS develops and enforces safety and integrity regulations for pipelines and pipeline operations.

1.3.16 Pipeline Right-of-Way (ROW): a defined strip of land on which an operator has the rights to construct, operate, and/or maintain a pipeline. A ROW may be owned outright by the operator or an easement may be acquired for specific use of the ROW.

1.3.17 Supplemental Public Awareness Program: Refer to the definition above, "Enhanced Public Awareness Program".

1.3.18 Third-Party Damage: outside force damage to underground pipelines and other underground facilities that can occur during excavation activities. Advanced planning, effective use of One-Call Systems, accurate locating and marking of underground facilities, and the use of safe digging practices can all be very effective in reducing third-party damage.

2 Public Awareness Program Development

The overall goal of a pipeline operator's Public Awareness Program is to enhance public environmental and safety property protection through increased public awareness and knowledge.

PUBLIC AWARENESS PROGRAM OBJECTIVES

2.1 OBJECTIVES

- **Public Awareness of Pipelines**

Public Awareness Programs should raise the awareness of the affected public and key stakeholders of the presence of pipelines in their communities and increase their understanding of the role of pipelines in transporting energy. A more informed public along pipeline routes should supplement an operator's pipeline safety measures and should contribute to reducing the likelihood and potential impact of pipeline emergencies and releases. Public Awareness Programs will also help the public understand that while pipeline accidents are possible, pipelines are a relatively safe mode of transportation, that pipeline operators undertake a variety of measures to prevent pipeline accidents, and that pipeline operators anticipate and plan for management of accidents if they occur. Finally, a more informed public will also understand that they have a significant role in helping to prevent accidents that are caused by third-party damage and ROW encroachment.

- **Prevention and Response**

Public Awareness Programs should help the public understand the steps that the public can take to prevent and respond to pipeline emergencies. "Prevention" refers to the objective of reducing the occurrences of pipeline emergencies caused by third-party damage (versus other causes under the control of the operator) through awareness of safe excavation practices and the use of the One-Call System. "Response" refers to the objective of communicating to the public the appropriate steps to take into account in the event of a pipeline release or emergency.

These objectives, together with others that may be identified by individual pipeline operators, provide the foundation on which a pipeline Public Awareness Program is built. Two important objectives of this RP include:

- Assist each pipeline operator to develop a framework for managing its Public Awareness Program so that the quality of Public Awareness Programs can be continually improved throughout the pipeline industry and
- Provide the operator with considerations to determine how to enhance its program to provide the appropriate level of public awareness outreach for a given area and certain circumstances.

2.2 OVERVIEW FOR MEETING PUBLIC AWARENESS OBJECTIVES

In general, Public Awareness Programs should communicate relevant information to the following stakeholder audiences (as defined in Section 3):

2.2.1 The Affected Public

- Awareness that they live or work near a pipeline
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to recognize and respond to a pipeline emergency
- What protective actions to take in the unlikely event of a pipeline release
- How to notify the pipeline operator regarding questions, concerns, or emergencies
- How to assist in preventing pipeline emergencies by following safe excavation/digging practices and reporting unauthorized digging or suspicious activity
- How community decisions about land use may affect community safety along the pipeline ROW
- How individuals can create undesirable encroachments upon a pipeline ROW
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas located in their area, land use practices, emergency preparedness or other matters.

2.2.2 Local Public Officials

- Information regarding transmission pipelines that cross their area of jurisdiction
- Land use practices associated with the pipeline ROW that may affect community safety
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operators with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction, land use practices, emergency preparedness or other matters.

2.2.3 Emergency Officials

- Location of transmission pipelines that cross their area of jurisdiction, and how to get detailed information regarding those pipelines
- Name of the pipeline operator and the emergency contact information for each pipeline
- Information about the potential hazards of the subject pipeline
- Location of emergency response plans with respect to the subject pipelines
- How to notify the pipeline operator regarding questions, concerns, or emergency
- How to safely respond to a pipeline emergency
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction,

land use practices, emergency preparedness or other matters.

2.2.4 Excavators

- Awareness that digging and excavating along the ROW may affect public safety, pipeline safety and/or pipeline operations
- Information about one-call requirements and damage prevention requirements in that jurisdiction
- Information about safe excavation practices in association with underground utilities
- How to notify the operator regarding a pipeline emergency or damage to a pipeline
- Hazards associated with unintended releases
- Name of the pipeline operator and who to contact for emergency or non-emergency information.

This RP focuses on those four segments of the public, as listed above, that are most directly affected by or could have the most affect on pipeline safety. The general public is a larger audience for general pipeline awareness information. General knowledge about energy pipelines is useful to the general public and may be obtained through a variety of sources, including the Office of Pipeline Safety, US Department of Transportation, pipeline industry trade associations and pipeline operators.

2.3 REGULATORY COMPLIANCE

This RP is intended to provide a framework for Public Awareness Programs designed to help pipeline operators in their compliance with federal regulatory requirements found in 49 *CFR* Parts 192 and 195.

The three principal compliance elements include:

2.3.1 Public Education (49 *CFR* Parts 192.616 and 195.440):

These regulations require pipeline operators to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the fire, police, or other appropriate public officials. The programs are to be provided in both English and in other languages commonly used by a significant concentration of non-English speaking population along the pipeline.

2.3.2 Emergency Responder Liaison Activities (49 *CFR* Parts 192.615 and 195.402):

These regulations require that operators establish and maintain liaison with fire, police, and other appropriate public officials and coordinate with them on emergency exercises or drills and actual responses during an emergency.

2.3.3 Damage Prevention (49 *CFR* Parts 192.614 and 195.442):

These regulations require pipeline operators to carry out written programs to prevent damage to pipelines by excavation activities.

2.4 OTHER RESOURCES

In addition to operator personnel, various other resources are available to assist pipeline operators in developing their Public Awareness Programs and related informational materials. These resources can often shorten development time and reduce the implementation cost of an operator's Public Awareness Program. Some of these other resources are described below.

2.4.1 Trade Associations

The major pipeline industry trade associations take an active role in sponsoring various efforts that can help operators meet public awareness objectives. These trade associations include the:

- American Petroleum Institute (API)
- Association of Oil Pipe Lines (AOPL)
- American Gas Association (AGA)
- Interstate Natural Gas Association of America (INGAA) and
- American Public Gas Association (APGA).

The websites of these associations provide a wide range of information to assist operators in developing and managing Public Awareness Programs, and developing information to use in implementing those programs. The trade associations also undertake specific efforts in public outreach, such as:

- Printing of pipeline safety brochures that can be customized by the operator
- Development and distribution of pipeline safety decals and materials
- Development of videos and brochures to aid in the education of public officials regarding pipeline emergency response
- Development of website information specifically for pipeline public awareness
- Distribution of periodic newsletters that provide additional guidance and information to operators on issues related to Public Awareness Programs
- Development and sponsorship of television and radio public service announcements (PSA)
- Participation in appropriate trade shows to inform excavators, regulators, legislators, and others.

For additional information on these efforts, contact the trade associations directly. Contact information and website addresses are provided in Appendix A.

2.4.2 One-Call Centers

The primary purpose of a One-Call System is to prevent damage to underground facilities, including pipelines, which could result from excavation activities. All states and the District of Columbia have established One-Call Systems (some states may have two or more One-Call Systems). State One-Call Centers may develop public awareness information materials and may be able to gather extensive information about excavation contractors. If available to the pipeline operator, this information will be useful to fulfill the requirements of 49 *CFR* Part 192.614 and 195.442 (Damage Prevention Programs). Many One-Call Systems perform their own public awareness outreach through public service announcements and other advertising. Some One-Call Systems may also sponsor statewide excavation hazard awareness programs. One-Call System contacts can be found at the "Dig Safely" website (see Appendix A).

2.4.3 Federal and State Agencies

Although pipeline operators are the primary sponsors of Public Awareness Programs on pipeline safety, some state agencies with regulatory authority for pipeline safety can provide training and materials. In addition, some state pipeline safety regulatory agencies sponsor or conduct pipeline public awareness efforts. The federal agency responsible for pipeline safety, the Office of Pipeline Safety of the U.S. Department of Transportation, is also a source of relevant information.

2.4.4 Common Ground Alliance

The Common Ground Alliance (CGA) is a nationally recognized nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices identified in the landmark *Common Ground Study of One-Call Systems and Damage Prevention Best Practices*. This report is available online from CGA's website (see Appendix A). Building on the spirit of shared responsibility resulting from the Common Ground Study, the purpose of the CGA is to ensure public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices. The "Dig Safely" campaign is now a component of the Common Ground Alliance.

The Common Ground Alliance is supported by its sponsors, member organizations, the Office of Pipeline Safety, and individual members. CGA sponsorship and membership is open to all stakeholder organizations that want to support the CGA's damage prevention efforts.

2.4.5 Outside Consultants

Many outside consultants are available to support an operators' Public Awareness Program. Direct-mail vendors are capable of producing pipeline safety materials and providing distribution services. These vendors can assist operators in identifying residents and special interest groups, such as excavators along the pipeline route, and can support the operator in production and distribution of the material. Public relations firms are also available to assist operators in developing material specifically geared to the intended audience. Their expertise can help heighten the readability of the public awareness materials and improve the operator's overall success in communicating the intended message.

2.4.6 Other Pipeline Companies

Pipeline companies have developed a variety of creative ways to meet their public awareness objectives. Cooperative information exchanges or shared public awareness activities between operators can be beneficial and economical.

2.4.7 Operator Employee Participation

As members of communities and community service organizations, informed employees of a pipeline operator can play an important role in promoting pipeline awareness. An operator should include in its Public Awareness Program provisions for familiarizing its employees with its public awareness objectives. Information and material used by the operator should be made available to employees who wish to promote pipeline awareness in their communities. Many Public Awareness Programs include components for key employee training in public awareness and specific communication training for specific key employees.

Operator employees can be a key part of public awareness efforts. Grass-roots employee contacts and communications can be particularly important in effectively reaching out to a community. Employees who are interested in and capable of performing a greater public communication role should be given the necessary training, communications materials and, as appropriate, be provided with opportunities for direct involvement with the community.

2.5 MANAGEMENT SUPPORT

For a Public Awareness Program to achieve its objectives, ongoing support within the operator's organization is crucial. Management should demonstrate its support through company policy, management participation, and allocation of resources and funding. Funding and resource requirements for an operator's Public Awareness Program development and implementation will vary according to the program's objectives, design, and scope. Full organizational support can make a marked difference in the way the Public Awareness Program is received and can affect the overall effectiveness and success of the program.

2.6 BASELINE AND SUPPLEMENTAL PUBLIC AWARENESS PROGRAMS

For the development of a Public Awareness Program, this RP recognizes that there are differences in pipeline conditions, release consequences, affected populations, increased development and excavation activities and other factors associated with pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. For example, some geographic areas have a low population, low turn over in residents, and little development or excavation activity; whereas other areas have very high population, high turn over, and extensive development and excavation activity.

This RP provides the operator with the elements of a recommended baseline Public Awareness Program. It also provides the operator with considerations to determine when and how to enhance the program to provide the appropriate level of public awareness outreach. Details for assessing the need for program enhancement are presented in Section 6. The appropriateness of enhanced or supplemental messages, delivery frequency and methods, and/or geographic coverage area is also one aspect of program evaluation. Recommendations on the evaluation of Public Awareness Programs are presented in Section 8.

2.7 PROGRAM DEVELOPMENT GUIDE

It is recommended that pipeline operators develop a written Public Awareness Program. The following guide may be helpful to pipeline operators in the development and implementation of their Public Awareness Programs.

Overall Program Administration

Step 1. Define Program Objectives

- Define program objectives in accordance with Section 2 of this RP.

Step 2. Obtain Management Commitment and Support

- Develop a company Policy and "statement of support" for the Public Awareness Program. This should include a commitment of participation, resources, and funding for the development, implementation, and management of the program.
- Reference Section 2.5.

Step 3. Identify Program Administration

- Name program administrator(s)
- Identify roles and responsibilities
- Document program administration
- Reference Section 7.

Step 4. Identify Pipeline Assets to be Included within the Program

- The overall program may be a single Public Awareness Program for all pipeline assets, or may be divided into individual, asset-specific programs for one or more specific pipeline systems, one or more pipeline segments, one or more facilities, or one or more geographic areas. Smaller companies and LDCs may have just one overall program.
- Name an administrator for each asset specific program.
- Reference Section 7 for documentation.

Program Development (applied to each identified asset- specific program)

Step 5. Identify the Four Stakeholder Audiences

- Establish methods to be used in audience identification.
- Establish a means of contact or address list for each audience type:
  - Affected public
  - Emergency officials
  - Local public officials
  - Excavators.
- Document methods used and output.
- Reference Section 3 for detail on stakeholder audiences.

Step 6. Determine Message Type and Content for Each Audience
- Establish which message types are to be used with which audience(s).
- Determine content for each message type.
- Document message type and content selected.
- Reference Section 4 for details on message development.

Step 7. Establish Baseline Delivery Frequency for Each Message
- Suggested delivery frequencies are described in Section 2.8.
- Document delivery frequencies selected.

Step 8. Establish Delivery Methods to Use for Each Message
- Select appropriate methods.
- Utilize alternate methods as appropriate.
- Document delivery methods selected.
- Establish process for management of input/feedback/comments received.
- Reference Sections 2.8 and 5 for additional detail.

Step 9. Assess Considerations for Supplemental Program Enhancements
- Review the criteria in this RP for enhanced programs (e.g. supplemental activities).
- Assess pipeline assets contained in the program and apply supplemental program elements.
- Solicit input from appropriate pipeline personnel (e.g. pipeline operations and maintenance personnel, other support personnel, etc.).
- Apply identified supplemental program elements to the program.
- Document supplemental program elements (describes when, what, and where program enhancements are used).
- Reference Sections 2.8 and 6.

Step 10. Implement Program and Track Progress
- Develop resource and monetary budgets for program implementation.
- Identify, assign and task participating company employees needed to implement the program.
- Identify external resources or consultants needed.
- Conduct program activities (e.g. mass mailings, emergency official meetings).
- Periodically update the program with newly identified activities.
- Collect feedback from internal and external sources.
- Document the above. Reference Section 7 for documentation and record keeping recommendations.

Step 11. Perform Program Evaluation
- Establish an evaluation process.
- Determine input data sources (e.g. company surveys, industry surveys, reply cards, feedback from participating employees, and feedback from recipient audiences, etc.).
- Assess results and applicability of operator and/or industry-sponsored evaluations.
- Document evaluation results. Reference Section 8 for program evaluation recommendations.

Step 12. Implement Continuous Improvement
- Determine program changes or modifications based on results of the evaluation to improve effectiveness. Program changes may be areas such as: audience, message type or content, delivery frequency, delivery method, supplemental activities or other program enhancements.
- Document program changes.
- Determine future funding and internal and external resource requirements resulting from program changes made.
- Implement changes.

Return to Step 5; Initiate new cycle for updating the Public Awareness Program.

The figurative description of the program development process is shown below, highlighting the continuous nature of the development, implementation and evaluation process.

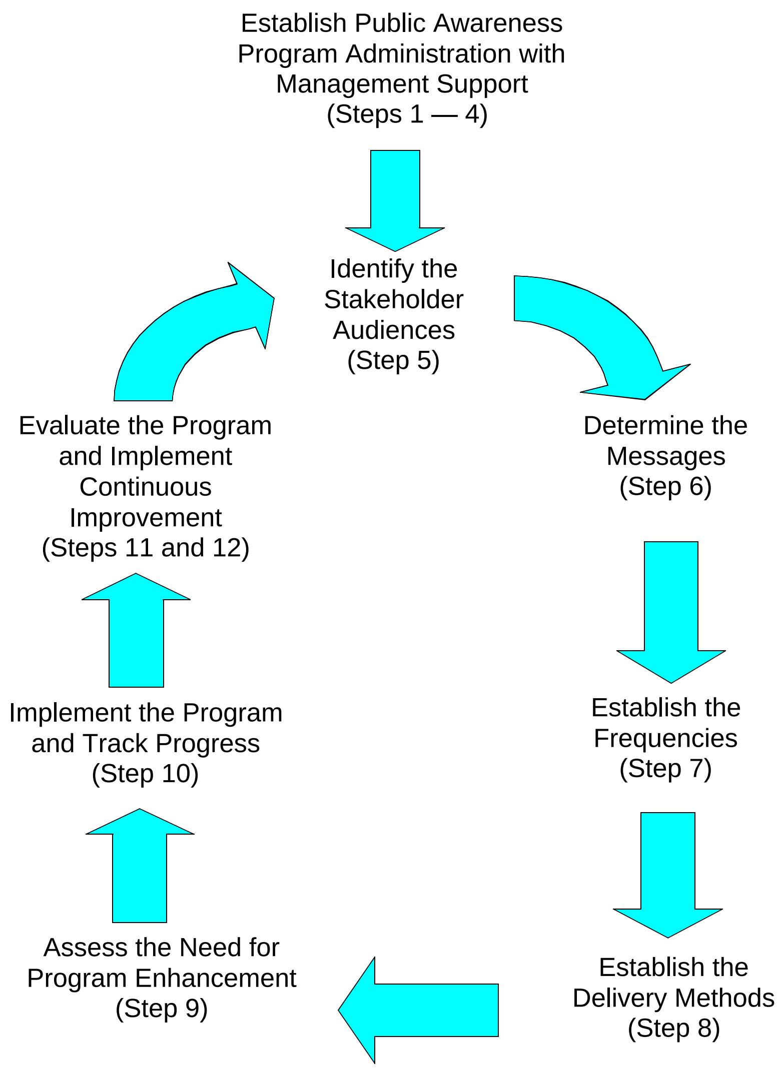

Figure 2-1—Public Awareness Program Process Guide

2.8 SUMMARY OF PROGRAM RECOMMENDATIONS

This RP has defined three categories of pipeline operators to which the RP applies. The three categories are:

1. Hazardous Liquid and Natural Gas Transmission Pipeline Operators (Table 2-1)
2. Local Natural Gas Distribution (LDC) Companies (Table 2-2)
3. Gathering Pipeline Operators (Table 2-3).

This RP recognizes that the communications and public awareness needs and activities may vary by the category of pipeline. Operators may customize their programs to best suit the needs of the stakeholder audiences and make them relevant to the type of potential hazards posed by their pipeline systems.

The tables 2-1 through 2-3 summarize the baseline recommendations for conducting public awareness for operators of Hazardous Liquid, Natural Gas Transmission, Local Natural Gas Distribution (LDC), and Gathering Pipelines. Guidance is also provided to assist the operators in determining if supplemental efforts affecting the frequency or method of message delivery and/or message content are called for, by evaluating the effectiveness of the program and the specifics of the pipeline segment or environment. Considerations for when and how an operator should implement program enhancements are described in Section 6. Further information of stakeholder audiences (Section 3); message types (Section 4); and message delivery methods (Section 5) may be found in their respective sections and related appendices.

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.1 Affected Public			
Residents located along transmission pipeline ROW **and** **Places of Congregation**	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	**Baseline Frequency =** 2 years	**Baseline Activity:** • Targeted distribution of print materials • Pipeline markers
	Supplemental Message: • Information and/or overview of operator's Integrity Management Program • ROW encroachment prevention • Any planned major maintenance/construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses
Residents near storage or other major operational facilities	**Supplemental Message:** • Information and/or overview of operator's Integrity Management Program • Special incident response notification and/or evacuation measures *if* appropriate to product or facility • Facility purpose	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency Preparedness Communications • Potential hazards • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Message: • Provide information and /or overview of Integrity measures undertaken • Maintenance construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Emergency tabletop, deployment exercises • Facility tour • Open house
2-1.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • One-call requirements • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • If applicable, provide information about designation of HCA (or other factors unique to segment) and summary of integrity measures undertaken • ROW encroachment prevention • Maintenance construction activity	**Supplemental Frequency:** • If in HCA, then annual contact to appropriate public safety officials • Otherwise, as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers
	Supplemental Messages: Pipeline purpose, prevention measures and reliability	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Group meetings
Land Developers	**Supplemental Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • One-call Requirements • Leak Recognition and Response • ROW Encroachment Prevention • Availability of list of pipeline operators through NPMS	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Pipeline markers • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.1 Affected Public			
Residents along the Local Distribution System (LDC)	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Public service announcements, OR • Paid advertising, OR • Bill stuffers (for combination electric & gas companies)
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Newspaper and magazines • Community events or • Community neighborhood newsletters
LDC Customers	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = Twice annually	**Baseline Activity:** • Bill stuffers
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials
2-2.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Print materials, OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Telephone calls • Personal contact • Videos and CDs
2-2.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Group meetings • Telephone calls • Personal contact

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies (Continued)

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Leak recognition and response • One-call requirements • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • One-Call Center outreach OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Videos and CDs • Open houses
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** • As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.1 Affected Public			
Residents, **and** **Places of Congregation within area of potential impact**	**Baseline Messages:** • Gathering pipeline purpose • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = 2 years	**Baseline Activity:** • Targeted distribution of print materials OR • Personal contact
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason.	**Supplemental Frequency:** • Annually for sour gas gathering lines • Additional frequency as determined by specifics of the pipeline segment or environment.	**Supplemental Activity:** • Pipeline markers • Print materials • Personal contact • Telephone calls • Group meetings • Mass media • Other activities described in Section 5

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Gathering pipeline location and purpose • Awareness of hazards • Prevention measures undertaken • Emergency preparedness communications, company contact and response information • Specific description of products transported and any potential special hazards • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason		**Supplemental Activity:** • Emergency tabletop deployment exercises • Facility tour • Open house
2-3.3 Local Public Officials			
Public Officials	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Copies of materials provided to affected public and emergency officials • Company contacts • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • ROW encroachment prevention • Maintenance construction activity • Special emergency procedures if sour gas or other segment specific reasons.	**Supplemental Frequency:** • If in HCA, then more frequent or annual contact with appropriate public safety officials • Otherwise as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers **Supplemental Activity:** • Personal contact • Group meetings • One-Call Center outreach • mass media
Land Developers	**Supplemental Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

3 Stakeholder Audiences

One of the initial tasks in developing a Public Awareness Program is to identify the audience(s) that should receive the program's messages. This section defines the intended audiences for the operator's Public Awareness Program and provides examples (not all inclusive) of each audience. Further explanation and examples are included in Appendix B. This information should help the operator clarify whom it is trying to reach with its program. The following audiences are considered "stakeholders" of the pipeline operator's Public Awareness Program. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

The operator should consider tailoring its communication coverage area to fit its particular pipeline location and release consequences. The operator would be expected to consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand its communication coverage area as appropriate.

The "Stakeholder Audience" definitions listed in the table below are used in the remaining sections of this RP, as applicable.

3.1 THE AFFECTED PUBLIC

Stakeholder Audience	Audience Definition	Examples
Residents located adjacent to the transmission pipeline ROW	People who live adjacent to a natural gas and/or hazardous liquid transmission pipeline ROW.	• Occupants or residents • Tenants • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along distribution systems	People who live on or immediately adjacent to the land wherein gas distribution pipelines are buried.	• LDC customers • Non-customers living immediately adjacent to the land wherein distribution pipelines are buried
Gas transmission pipeline customers	Businesses or facilities that the pipeline operator provides gas directly to for end use purposes. This does not include LDC customers.	• Power plants • Businesses • Industrial facilities
LDC customers	People that are served by gas distribution facilities.	• LDC customers
Residents near liquid or natural gas storage and other operational facilities along transmission lines	People who live adjacent to or near a tank farm, storage field, pump/compressor station and other facilities.	• Occupants or residents tenants • Farmers • Homeowner associations or groups • Neighborhood organizations
Places of congregation	Identified places where people assemble or work on a regular basis—on or along a transmission pipeline ROW, unrelated to habitation.	• Businesses • Schools • Places of worship • Hospitals and other medical facilities • Prisons • Parks & recreational areas • Day-care facilities • Playgrounds
Residents located along rights-of-way for gathering pipelines	• People who live or work on land along which the gathering pipeline is located, and within the right-of-way. • For higher consequence gathering lines (e.g. H_2S), people who live or work a distance on either side of right-of-way that is based on the potential impact in the event of an emergency.	• Occupants or residents • Tenants • Farmers • Businesses • Schools

3.2 EMERGENCY OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Emergency officials	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction along the pipeline route.	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • County and State Emergency Management Agencies (EMA) • Other emergency response organizations • Other public safety organizations

3.3 LOCAL PUBLIC OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Public officials	Local, city, county or state officials and/or their staffs having land use and street/road jurisdiction along the pipeline route.	• Planning boards • Zoning board • Licensing departments • Permitting departments • Building code enforcement departments • City and county managers • Public and government officials • Public utility boards • Includes local "Governing Councils" as defined by many communities • Public officials who manage franchise or license agreements

3.4 EXCAVATORS

Stakeholder Audience	Audience Definition	Examples
Excavators	Companies and local/state government agencies who are involved in any form of excavation activities.	• Construction companies • Excavation equipment rental companies • Public works officials • Public street, road and highway departments (maintenance and construction) • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Well drillers
Land developers	Companies and private entities involved in land development and planning.	• Home builders • Land developers • Real estate sales
One-Call Centers	Excavation One-Call Centers relevant to the area.	• Each state, region, or other organization established to notify underground facility owner/operators of proposed excavations. Excavation One-Call Centers relevant to the area.

4 Message Content

An operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. Information materials may also include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message conveyed to the intended audience should provide information that will allow the operator to meet the program objectives. The communications should include enough information so that in the event of a pipeline emergency, the intended audience will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator. Several components of these messages are discussed in this section.

4.1 PIPELINE PURPOSE AND RELIABILITY

Operators should consider providing a general explanation of the purpose of the pipeline and/ or facilities and the reliability of pipelines to meet the energy needs of the region, even though this is not a primary objective of pipeline public awareness. Operators should provide assurances that security is considered.

4.2 HAZARD AWARENESS AND PREVENTION MEASURES

Operators should provide a very broad overview of potential hazards, their potential consequences and the measures undertaken by the operator to prevent or mitigate the risks from pipelines (including, at the operator's discretion, an overview of the industry's safety record). Additionally, operators should provide an overview of their preventative measures to help assure safety and prevent incidents. The scope of the hazard awareness and prevention message should be more detailed for the emergency responder audience than for other audiences, and should include how to obtain more specific information upon request from the operator.

4.3 LEAK RECOGNITION AND RESPONSE

The pipeline operator should provide information in the following key subject areas to the affected public and excavator stakeholder groups.

4.3.1 Potential Hazards of Products Transported

Information about specific release characteristics and potential hazards posed by hazardous liquids or gases should be included.

4.3.2 How to Recognize a Pipeline Leak

Information should address how to recognize a pipeline leak through the senses of sight, unusual sound, and smell and describe any associated dangers as appropriate to the product type.

4.3.3 Response to a Pipeline Leak

Information should address an outline of the appropriate actions to take if a pipeline leak or release is suspected.

4.3.4 Liaison with Emergency Officials

Information should describe the ongoing relationship between the operator and local emergency response officials to help prevent incidents and assure preparedness for emergencies.

4.4 EMERGENCY PREPAREDNESS COMMUNICATIONS

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. Operators should provide a summary of emergency preparedness information to local public officials and should indicate that detailed information has been provided to emergency response agencies in their jurisdictions. The following information should be provided to the emergency officials stakeholder audience.

4.4.1 Priority to Protect Life

The operator's key messages to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

4.4.2 Emergency Contacts

Contact information for the operator's local offices and 24-hour emergency telephone line should be shared with local and state emergency officials. Operators should also use the contacts with emergency officials to confirm that both emergency officials and the operators have the current, correct contact information and calling priorities.

4.4.3 Emergency Preparedness Response Plans

Operators are required by federal regulations to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state emergency regulations. 49 *CFR* 192 and 195 and some state regulations outline the specific requirements for emergency response plans and who to contact for additional information. The operator should include information about how emergency officials can access the operator's emergency response plans covering their jurisdiction.

4.4.4 Emergency Preparedness—Drills and Exercises

A supplemental means of two-way communication about emergency preparedness is to establish a liaison with emergency response officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

4.5 DAMAGE PREVENTION

Because even relatively minor excavation activities can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the key "Dig Safely" messages developed by the Common Ground Alliance (CGA). CGA contact information is located in Appendix A.

The use of an excavation One-Call Notification system should be explained to the audience. Information on the prevalence of digging-related damage, also known as "third-party" damage, should be provided as appropriate. The audience should be requested to call the state or local One-Call System in their area before they begin any excavation activity. If the state or locality has established penalties for failure to use established damage prevention procedures, that fact may also be communicated, depending on the audience and situation. Additional information is located in Appendix C.

Additionally, third-party contractors are subject to the Occupational Safety and Health Administration's (OSHA) requirements. OSHA cites in its "General Duty Clause" possible regulatory enforcement action that could be taken against excavation contractors who place their employees at risk by not utilizing proper damage prevention practices. The lack of adequate damage prevention could subject the excavator to OSHA regulatory enforcement. OSHA contact information is located in Appendix A.

4.6 PIPELINE LOCATION INFORMATION

4.6.1 Transmission Pipeline Markers

The audience should know how to identify a transmission pipeline ROW by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. The operator's awareness communications should include information about what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in certain areas. As such, use of the One-Call Notification system should be encouraged. Additional detail is located in Appendix C.

4.6.2 Transmission Pipeline Mapping

Pipeline maps developed by transmission pipeline operators can be an important component of an operator's Public Awareness Program. The level of detail provided on the map should, at a minimum, include the line size, product transported and the approximate location of the pipeline, as well as any other information deemed reasonable and necessary by the operator. National energy infrastructure security issues should be considered in determining information and distribution related to pipeline maps. The public can also receive information about which pipelines operate in their community by accessing the National Pipeline Mapping System (NPMS). The NPMS will provide the inquirer a list of pipeline operators and operator contact information. Operators should include information on the availability of the NPMS within their public awareness materials. NPMS information is provided in Appendix A. Additional mapping information is provided in Appendix C.

4.7 HIGH CONSEQUENCE AREAS (HCAs) AND INTEGRITY MANAGEMENT PROGRAM OVERVIEW FOR TRANSMISSION OPERATORS

4.7.1 Message Content for Affected Public within HCAs

Public awareness materials should include a general explanation that, in accordance with federal regulations, some segments along transmission pipelines have been designated as High Consequence Areas (HCAs) and that supplemental hazard assessment and prevention programs (called Integrity Management Programs) have been developed. Information provided to the affected public should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.7.2 Message Content for Emergency Officials within HCAs

For emergency official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should include an overview of the operator's Integrity Management Programs. Inclusion of this information during emergency official liaison interface will provide an opportunity for feedback from the emergency official on the operator's Integrity Management Programs.

4.7.3 Message Content for Public Officials within HCA's

For public official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.8 CONTENT ON OPERATOR WEBSITES

Pipeline operators who maintain websites can include the following information (further examples of this information are provided in Appendix C):

- Company information
- General information on pipeline operations
- General or system pipeline map(s)
- Affected public information
- Emergency and security information
- Damage prevention awareness and One-Call Notification.

4.9 RIGHT-OF-WAY ENCROACHMENT PREVENTION

Pipeline operators should communicate that encroachments upon the pipeline ROW inhibit the operator's ability to respond to pipeline emergencies, eliminate third-party damage, provide ROW surveillance, perform routine maintenance, and perform required federal/state inspections. Stakeholder specific information is listed in Appendix D.

4.10 PIPELINE MAINTENANCE CONSTRUCTION ACTIVITIES

Pipeline maintenance-related construction activities should be communicated to the audience affected by the specific activity in a timely manner appropriate to the nature and extent of the activity.

4.11 SECURITY

Where applicable and in accordance with the national Homeland Security efforts, pipeline operators should communicate an overview pertaining to security of their pipelines and related facilities.

4.12 FACILITY PURPOSE

Where appropriate, communication with the affected public and emergency and public officials in proximity to major facilities (such as storage facilities, compressor or pump stations) should include information to promote understanding of the nature of the facility. Operators should communicate general information regarding the facility and product(s) stored or transported through the facility. Communication with emergency officials should also include emergency contact information for the specific facility.

5 Message Delivery Methods and/or Media

This section describes several delivery methods and tools available to pipeline operators to foster effective communications with the intended stakeholder audiences previously described. The operator is reminded that not all methods are effective in all situations. The content of the communication efforts should be tailored to:

- Needs of the audience
- Type of pipeline and/or facilities
- Intent of the communication, and
- Appropriate method/media for the content.

A more detailed discussion of the summary information below is provided in Appendix D.

5.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audience and message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed below.

5.1.1 Brochures, Flyers, Pamphlets, and Leaflets

Brochures, flyers, pamphlets and leaflets are probably the most common message delivery methods currently used by the pipeline industry. These print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. These print materials also afford an effective opportunity to communicate content in a graphical or pictorial way.

5.1.2 Letters

Research has indicated that letters mailed to residents along the pipeline ROW are an effective tool to communicate specific information, such as how to recognize and what to do in the event of a leak, how to identify and report suspicious activity, and notification of planned operator activities.

5.1.3 Pipeline Maps

Pipeline maps can be an important component of an operator's Public Awareness Program and should be considered where they can enhance the appropriate stakeholder(s) awareness of the operator's pipeline and facilities. Additional information regarding pipeline mapping is available in Appendix C.

5.1.4 Response Cards

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other items. The inclusion of a response card can be used in a variety of ways (refer to Appendix D).

5.1.5 Bill Stuffers

Bill stuffers are printed brochures frequently used by local distribution companies (LDCs) in conjunction with customer invoices. Due to the nature of customers for transmission and gathering pipelines, bill stuffers are not considered an appropriate option. LDCs using bill stuffers can easily reach their customers with appropriate messages and can increase their effectiveness by using bill stuffers repeatedly. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even those that may not be natural gas customers.

5.2 PERSONAL CONTACT

Personal contact describes face-to-face contacts between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication and allows for two-way discussion. Personal contacts may be made on an individual basis or in a group setting. Some examples of personal contact communications are described further in Appendix D and include:

- Door-to-door contact along pipeline ROW
- Telephone calls
- Group meetings
- Open houses
- Community events
- Charitable contribution presentations by pipeline companies.

5.3 ELECTRONIC COMMUNICATION METHODS

5.3.1 Videos and CDs

There are a variety of approaches operators may use to supplement their public awareness efforts with videos and CDs. While considered a supplement to the baseline components of an effective Public Awareness Program, videos and CDs may be quite useful with some stakeholders or audiences in some situations. These media can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual responses in ways that printed materials cannot.

5.3.2 E-mail

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholder audiences. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by postal mail or personal contact.

5.4 MASS MEDIA COMMUNICATIONS

5.4.1 Public Service Announcements

Public Service Announcements (PSAs) can be an effective means for reaching a large sector of the public. Radio and television stations occasionally make some airtime available for PSAs. They are no longer required by law to donate free airtime and as a result, there is great competition from various public interest causes for the small amount of time made available. If the operator is an advertiser with the radio or television station, this might be leveraged to gain advantage in acquiring PSA time.

5.4.2 Newspapers and Magazines

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline companies can submit or encourage reporters to write constructive and informative articles about pipeline issues, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure.

5.4.3 Paid Advertising

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community.

5.4.4 Community and Neighborhood Newsletters

Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with other outreach to those communities and/or neighborhoods. This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

5.5 SPECIALTY ADVERTISING MATERIALS

Specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These materials also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods. Examples are included in Appendix D.

5.6 INFORMATIONAL OR EDUCATIONAL ITEMS

Companies can develop informational and educational materials to heighten pipeline awareness. The cost-effectiveness of producing such materials can be increased through partnering with an industry association or group of other operators.

5.7 PIPELINE MARKER SIGNS

The primary purposes of aboveground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency and
- Facilitate aerial or ground surveillance of the pipeline ROW by providing aboveground reference points.

Refer to Section 4 and Appendix C for additional information on marker sign types and information content.

Below-ground markers, such as warning tape or mesh, can also be effective warnings to excavators of the presence of buried pipe. When burying pipe following repairs, relocations, inspections, etc., operators should consider whether it is appropriate to add below-ground markers in the location.

5.8 ONE-CALL CENTER OUTREACH

Most state One-Call Centers provide community outreach or conduct public awareness activities about one-call requirements and damage prevention awareness, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such communication as a part of their own Public Awareness Programs. Many One-Call Centers host awareness meetings with excavators to further promote the damage prevention and one-call messages. It is the operator's responsibility to request documentation for these outreach activities.

To enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become one-call members in localities where they operate pipelines. Since all One-Call Center members share the center's public awareness outreach costs, the costs to an individual operator are usually comparatively low.

5.9 OPERATOR WEBSITES

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Additional information located in Appendix C.8 describes features for a company's pipeline operations that should fit into any corporate structure and overall website design. A company's website will supplement the other various direct outreach delivery tools discussed in this RP.

6 Recommendations for Supplemental Enhancements of Baseline Public Awareness Program

The pipeline operator has a number of stakeholder audiences for delivering messages regarding the safe operation of pipelines. The message content, the delivery medium, delivery frequency, and audience's retention of the delivered message should be carefully considered during the development and implementation of the operator's Public Awareness Program to achieve maximum effectiveness. Many of the communications should be available on demand or evergreen (e.g., websites, pipeline markers) and others are periodic in nature (e.g., mass mailings, public meetings, and advertisements). The combination of the specific messages, delivery methods, and delivery frequencies should be designed into the operator's program for each audience. These elements should allow each audience to develop and maintain an awareness of the pipeline's safe operation appropriate to the audience's responsibilities for pipeline awareness, response to pipeline emergencies, and its possible exposure to pipeline emergencies.

Section 2 includes summary tables of the overall Public Awareness Program recommendations. The summary tables include a baseline Public Awareness Program for the three pipeline categories. The tables also provide a recommended delivery frequency for each of the message types intended for the respective audiences. These frequencies are the suggested baselines and the pipeline operator should consider to what extent an enhanced, supplemental program is warranted.

The term "program enhancement" refers to the operator's decision to supplement its Public Awareness Program beyond the recommended baseline. Throughout this RP the terms "enhancement" and "supplemental" are used interchangeably and mean those communications measures added to the Public Awareness Program beyond the baseline program elements. To support this decision, the operator should consider external factors along the pipeline system and determine if some additional level of public awareness communications is warranted, beyond the recommended baseline program. Those supplemental aspects would then be incorporated into the Public Awareness Program for that pipeline segment or system. Supplemental enhancement considerations are discussed in detail on the following pages.

In addition, the operator should include in its Public Awareness Program Evaluation a periodic review and evaluation of its program (see Section 8), determine if supplemental public awareness efforts/activities are warranted and include those enhancements and related documentation into its program.

6.1 CONSIDERATIONS FOR SUPPLEMENTAL ENHANCEMENTS FOR THE BASELINE PROGRAM

This RP recognizes that there are differences in pipeline conditions, consequences, population, property development, excavation activities and other issues along pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. This RP recommends that an operator enhance its baseline program with supplemental program components when conditions along the pipeline suggest a more intensive effort is needed.

Baseline program recommendations are established for each of the three pipeline categories. The following sections are provided for guidance when the operator's consideration of relevant factors along the pipeline route indicates that supplemental program enhancement is warranted. Three primary forms of enhancement are provided for consideration in the development and administration of each Public Awareness Program:

6.1.1 Increased Frequency (Shorter Interval)

Increased frequency refers primarily to providing communications to specific stakeholder audiences on a more frequent basis (shorter interval) than the baseline recommended components to reach the intended audience.

6.1.2 Enhanced Message Content and Delivery/ Media Efforts

Enhanced message content and delivery/media efforts refer to providing additional or supplemental communications activities beyond those identified in the baseline, using an enhanced or custom-tailored message content and/or different, or additional, delivery methods/media to reach the intended audience.

6.1.3 Coverage Areas

Coverage areas refer to broadening or widening the stakeholder audience coverage area beyond those contained in the baseline for delivery of certain communications messages. This can also be considered relative to widening the buffer distance for reaching the stakeholder audience along the pipeline route.

6.2 CONSIDERATIONS OF RELEVANT FACTORS

When the operator develops its Public Awareness Program and performs subsequent periodic program evaluations, it is recommended that a step for assessing relevant factors along the pipeline route be included to consider what components of the Public Awareness Program should be enhanced.

The operator should consider each of the following factors applied along the entire route of the pipeline system:

- Potential hazards
- High Consequence Areas
- Population density
- Land development activity
- Land farming activity
- Third-party damage incidents
- Environmental considerations
- Pipeline history in an area
- Specific local situations
- Regulatory requirements
- Results from previous Public Awareness Program evaluations
- Other relevant needs.

The presence of federally designated High Consequence Areas (HCAs) should prompt an operator to consider public awareness activity above the baseline level described in the RP. For natural gas transmission pipelines, 49 *CFR* Part 192.761 defines HCAs related to the population or places of congregation. For hazardous liquid transmission pipelines, 49 *CFR* Part 195.450 describes HCAs related to high population, Unusually Sensitive Areas (USAs) and navigable waterways.

Another factor to consider is the hazard associated with the pipeline as perceived by either the operator or the audience. For example, if a pipeline segment has experienced third-party damage, the operator could increase the frequency of messages to those third-parties and other relevant audiences. If the public's confidence in pipeline safety is undermined by a high profile emergency, even though an individual operator is experiencing no upward trend in incidents, that operator could consider expanding its public awareness communications to its public audiences to further increase awareness of its nearby pipeline system.

Further detail of considerations for program enhancement is discussed in the following sections.

6.3 HAZARDOUS LIQUID AND NATURAL GAS TRANSMISSION PIPELINE OPERATORS

Since Hazardous Liquids and Natural Gas Transmission pipelines are similar in many aspects with respect to public awareness, the two categories of pipelines have been combined.

Considerations for program enhancement for transmission pipelines could include, for example:

6.3.1 The Affected Public

Consideration should be given to *supplemental program enhancement* where:

- The occurrences indicate an elevated potential for third-party damage. Examples include:
  - A mailing to farmers along the right-of-way just prior to the deep plowing season where deep till plow methods are used
  - An additional or interim mass mailing to or face-to-face communications with residents of new housing developments in areas along the pipeline route that may not have previously been reached
  - Increasing the frequency of baseline communication efforts
- The pipeline runs through heavily developed urban areas that are more likely to have a frequently changing population than a more stable, less dense suburban or rural areas. Frequently changing population in an identified audience area should be considered when determining supplemental efforts to:
  - Residents in areas such as multi-family developments or densely populated urban areas
  - Increase the frequency of communications to residents
- Right-of-way encroachments have occurred frequently. Examples of supplemental efforts include:
  - Enhanced mailings to, face-to-face communications with, or increasing the frequency of communications to residents/developers/contractors in areas of right-of-way encroachment
- The potential for concern about consequences of a pipeline emergency is heightened. Consideration should be given to widening the coverage area for:
  - HVL pipelines in high population areas, extend the coverage area beyond the $^{1}/8^{th}$ mile minimum distance each side of the pipeline
  - Large diameter, high pressure, high volume pipelines where a pipeline emergency would likely affect the public outside of the specified minimum coverage area—extend the coverage area to a wider distance as deemed prudent.

6.3.2 Public Officials

Consideration should be given to *supplemental program enhancement* where:

- Heightened public sensitivity to pipeline emergencies exists in the area, independent of cause or which operator was involved
- Significant right-of-way encroachments (such as new construction developments) are occurring.

6.3.3 Emergency Officials

Consideration should be given to *supplemental program enhancement* where:

- Emergency officials have heightened sensitivity to pipeline emergencies
- After post-emergency review, or where there's potential for enhanced "liaison activities" between the operator and emergency officials that could have improved the emergency response to a pipeline emergency
- Requested by emergency officials to provide additional communications.

6.3.4 Excavators/Contractors and One-Call Centers

Consideration should be given to *supplemental program enhancement* where:

- There are instances that indicate an elevated potential for third-party damage
- Developers and contractors are performing a high number of excavations along a pipeline route in developing areas
- There are instances of problems identified with excavators' use or lack of use of the One-Call System. In those cases the operator should also request that the one-call Center perform additional public awareness outreach activities

6.4 LOCAL NATURAL GAS DISTRIBUTION COMPANIES (LDCs)

Many of the aspects of Public Awareness Programs for LDCs are similar to liquid and transmission pipeline operators. However, there are some differences because LDCs serve a different audience. Unlike transmission pipeline operators, LDCs have many more individual customers and have existing communication paths with those customers through monthly billing statements and other customer relationships. Table 2-2, for LDCs, in Section 2, provides baseline and supplemental communication recommendations for each of the different audiences.

Among LDCs there may be some variability in the frequency of communications with specific audiences. Public officials and emergency response personnel in a small rural city will likely be more accessible to the LDC pipeline operators than those in a major metropolitan area. Therefore, LDC operators should tailor their programs based on specific local considerations.

6.5 GATHERING PIPELINE OPERATORS

Gathering pipelines are usually small in diameter and operate at low pressures. In general, the audiences involved in public awareness communications for gathering pipelines tend to be in rural areas. The operator should tailor the specific communication program to fit the needs of the audiences and the circumstances in the particular area. Table 2-3 for gathering pipeline operators provides baseline and supplemental recommended communication frequencies for different audiences.

7 Program Documentation and Recordkeeping

Each operator should establish policies and procedures necessary to properly document its Public Awareness Program and retain those key records for purposes of program evaluation.

7.1 PROGRAM DOCUMENTATION

Each operator of a hazardous liquid pipeline system, natural gas transmission pipeline system, gathering pipeline system or a natural gas distribution pipeline system should establish (and periodically update) a written Public Awareness Program designed to cover all required components of the program described in this RP.

The written program should include:

a. A statement of management commitment to achieving effective public/community awareness.
b. A description of the roles and responsibilities of personnel administering the program.
c. Identification of key personnel and their titles (including senior management responsible for the implementation, delivery and ongoing development of the program).
d. Identification of the media and methods of communication to be used in the program, as well as the basis for selecting the chosen method and media.
e. Documentation of the frequency and the basis for selecting that frequency for communicating with each of the targeted audiences.
f. Identification of program enhancements, beyond the baseline program, and the basis for implementing such enhancements.
g. The program evaluation process, including the evaluation objectives, methodology to be used to perform the evaluation and analysis of the results, and criteria for program improvement based on the results of the evaluation.

In addition, some operators are required to have an Operations and Maintenance Procedure (O&MP) manual under 49 *CFR* Part 192 or 195. While the overall written program will likely be too extensive and schedule-specific to be suitable for an O&MP manual, the operator should include in the manual an overall statement of management commitment, roles and responsibilities (by group or title), a requirement for a written program and evaluation process, and a summary of the operator's Public Awareness Program.

7.2 PROGRAM RECORDKEEPING

The operator should maintain records of key program elements to demonstrate the level of implementation of its Public Awareness Program. Record keeping should include:

a. Lists, records or other documentation of stakeholder audiences with whom the operator has communicated.
b. Copies of all materials provided to each stakeholder audiences.
c. All program evaluations, including current results, follow-up actions and expected results.

7.3 RECORD RETENTION

The record retention period for each category in Section 7.2 should be a minimum of five (5) years, or as defined in the operator's Public Awareness Program, whichever is longer.

8 Program Evaluation

This section provides guidance to operators on how to periodically evaluate their Public Awareness Programs. The overall written plan for the Public Awareness Program should include a section describing the operator's evaluation program that includes the baseline elements described in the following paragraphs. Also included are suggestions for operators to consider in periodically supplementing their evaluation efforts in a particular segment, with a selected stakeholder audience or to provide greater depth of evaluation. This section includes only a brief description of each element. Appendix E provides additional explanations and examples for operator personnel who are new to developing Public Awareness Program evaluations.

8.1 PURPOSE AND SCOPE OF EVALUATION

The primary purposes of the evaluation of the Public Awareness Program are to:

- Assess whether the current program is effective in achieving the objectives for operator Public Awareness Programs as defined in Section 2.1 of this RP, and
- Provide the operator information on implementing improvements in its Public Awareness Program effectiveness based on findings from the evaluation(s).

A secondary purpose for Public Awareness Program evaluation is to demonstrate to company management and regulators, for pipelines subject to federal or state pipeline safety jurisdiction, the status and validity of the operator's Public Awareness Programs.

8.2 ELEMENTS OF EVALUATION PLAN

A program evaluation plan should include the measures, means and frequency for tracking performance. The selected set of measures should reflect:

- Whether the program is being implemented as planned—**the process**
- Whether the program is effective—**program effectiveness**.

Based on the results of the evaluation addressing these two questions, the operator may need to make changes in the program implementation process, stakeholder identification effort, messages, means and/or frequency of delivery. The sections below suggest specific measures and methods recommended to complete a baseline evaluation of the Public Awareness Program.

8.3 MEASURING PROGRAM IMPLEMENTATION

The operator should complete an annual audit or review of whether the program has been developed and implemented according to the guidelines in this RP. The purpose of the audit is to answer the following two questions:

- Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described Section 2 and the remainder of this RP?
- Has the Public Awareness Program been implemented and documented according to the written program?

Appendix E includes a sample set of questions that will aid an operator in auditing the program implementation process.

The operator should use one of the following three alternative methodologies when completing an annual audit of program implementation.

- Internal self-assessments using, for example, an internal working group, or
- Third-party audits where the evaluation is undertaken by a third-party engaged to conduct an assessment and provide recommendations for improving the program design or implementation, or
- Regulatory inspections, undertaken by inspectors working for federal or state regulators who inspect operator pipeline programs subject to pipeline safety regulations.

8.4 MEASURING PROGRAM EFFECTIVENESS

Operators should assess progress on the following measures to assess whether the actions undertaken in implementation of this RP are achieving the intended goals and objectives:

- Whether the information is reaching the intended stakeholder audiences
- If the recipient audiences are understanding the messages delivered
- Whether the recipients are motivated to respond appropriately in alignment with the information provided
- If the implementation of the Public Awareness Program is impacting bottom-line results (such as reduction in the number of incidents caused by third-party damage).

The following four measures describe how the operator should evaluate for effectiveness:

8.4.1 Measure 1—Outreach: Percentage of Each Intended Audience Reached with Desired Messages

This is a basic measurement indicating whether the operator's public awareness messages are getting to the intended stakeholders. A baseline evaluation program should establish a methodology to track the number of individuals or entities reached within an intended audience (e.g., households, excavating companies, local government, and local first responder agencies). Additionally, this measure should estimate the percentage of the stakeholders actually reached within the target geographic region along the pipeline. This measurement will help to evaluate the effectiveness of the delivery methods used.

- **Supplemental measures:** Other indicators that an operator may want to consider tracking as a supplement to measuring program outreach effectiveness include:
  - Track the number of inquiries by phone to operator-personnel or to the public awareness portions of an operator's website (however operators are cautioned that unless such information is specifically sought by the operator, this measure would not define if the caller or website viewer is a member of the target stakeholder audience nor whether this measure includes counts of repetitive website reviewers)
  - Track input received via feedback postcards (often called reply or bounce-back cards) from representatives of the stakeholder audience at events or meetings, sent by mail, or as a result of the operator's canvassing of the rights-of-way
  - Track the number of officials or emergency responders who attend emergency response exercises (this is an indicator of interest and the opportunity to gain knowledge).

8.4.2 Measure 2—Understandability of the Content of the Message

This measure would assess the percentage of the intended stakeholder audience that understood and retained the key information in the message received. This measurement will help to evaluate the effectiveness of the delivery media and the message style and content. This measurement will also help to assess the effectiveness of the delivery methods used.

- **Pre-test materials:** Operators should pre-test public awareness materials for their appeal and the messages for their clarity, understandability and retain-ability before they are widely used. A pre-test can be performed using a small representative audience, for example, a small sample group of operator employees not involved in developing the Public Awareness Program, a small section of the intended stakeholder audience or others (often referred to as focus groups described more fully in Appendix E).
- **Survey target stakeholder audiences:** An effective method for assessing understandability is to survey the target stakeholder audience in the course of face-to-face contacts, telephone or written surveys. Sample surveys are included in Appendix E. Factors to consider when designing surveys include:
  - Sample size appropriate to draw general conclusions
  - Questions to gauge understandability of messages and knowledge or survey respondent
  - Retention of messages
  - Comparison of the most effective means of delivery.

Program effectiveness surveys are meant to validate the operator's methodologies and the content of the materials used. Upon initial survey, improvements should be incorporated into the program based on the results. Once validated in this initial manner, a program effectiveness survey is only required about every four years. However, when the operator introduces major design changes in its Public Awareness Program a survey to validate the new approaches may be warranted.

An operator may choose to develop and implement its own program effectiveness survey in-house; have a survey designed with the help of third-party survey professionals; or participate in and use the results of an industry group or trade-association survey. If the latter approach is used, the industry or trade-association survey should allow the operator to assess the results relevant to the operator's own pipeline corridors and Public Awareness Programs.

8.4.3 Measure 3—Desired Behaviors by the Intended Stakeholder Audience

This measure is aimed at determining whether appropriate prevention behaviors have been learned and is taking place when needed and whether appropriate response or mitigation behaviors would occur and have taken place. This is a measure of learned and, if applicable, actual reported behavior.

- **Baseline evaluation:** The survey conducted as the means of assessing Measure 2 (above) should be designed to include questions that ask respondents to report on actual behaviors following incidents.
- **Supplemental evaluation:** As a supplement to these measures, operators may also want to assess whether the Public Awareness Program successfully drove other behaviors. Operators may consider the following examples as a supplemental means of assessing this measure:
  - Whether excavators are following through on all safe excavation practices, in addition to calling the One-Call Center
  - The number of notifications received by the operator from the excavation One-Call Center (e.g. is there a noticeable increase following distribution of public awareness materials?)
  - An assessment of first responder behaviors, including the response to pipeline-related calls, and a post-incident assessment to determine whether their actions would be and were consistent with the key messages included in the public awareness communications. Assessments of actual incidents should recognize that each response would require unique on-scene planning and response to specifics of each emergency.
  - Measuring the appropriateness of public stakeholders' responses is also anecdotal but could include tracking whether an actual incident that affected residents was correctly identified and whether reported and personal safety actions undertaken were consistent with public awareness communication.

8.4.4 Measure 4—Achieving Bottom-Line Results

One measure of the "bottom-line results" is the damage prevention effectiveness of an operator's Public Awareness Program and the change in the number and consequences of third-party incidents. As a baseline, the operator should track the number of incidents and consequences caused by third-party excavators. This should include reported near misses; reported pipeline damage occurrences that did not result in a release; and third-party excavation damage events that resulted in pipeline failures. The tracking of leaks caused by third-party excavation damage should be compared to statistics of pipelines in the same sector (e.g. gathering, transmission, local distribution). While third-party excavation damage is a major cause of pipeline incidents, data regarding such incidents should be evaluated over a relatively long period of time to determine any meaningful trends relative to the operator's Public Awareness Program. This is due to the low frequency of such incidents on a specific pipeline system. The operator should also look for other types of bottom-line measures. One other measure that operators may consider is the affected public's perception of the safety of pipelines.

8.5 SUMMARY OF BASELINE EVALUATION PROGRAM

Table 8-1—Summary of Baseline Evaluation Program

The results of the evaluation need to be considered and revisions/updates made in the public awareness program plan, implementation, materials, frequency and/or messages accordingly

Evaluation Approaches	Evaluation Techniques	Recommended Frequency
Self Assessment of Implementation	Internal review, ***or*** third-party assessment ***or*** regulatory inspection	Annually
Pre-Test Effectiveness of Materials	Focus groups (in-house or external participants)	Upon design or major redesign of public awareness materials or messages
Evaluation of effectiveness of program implementation: • Outreach • Level of knowledge • Changes in behavior • Bottom-line results	1. Survey: Can assess outreach efforts, audience knowledge and changes in behavior • Operator-designed and conducted survey, or • Use of pre-designed survey by third-party or industry association, or • Trade association conducted survey segmented by operator, state or other relevant separation to allow application of results to each operator. 2. Assess notifications and incidents to determine anecdotal changes in behavior. 3. Documented records and industry comparisons of incidents to evaluate bottom-line results.	No more than four years apart. Operator should consider more frequent as a supplement or upon major redesign of program.
Implement changes to the Public Awareness Program as assessment methods above suggest.	Responsible person as designated in written Public Awareness Program	As required by findings of evaluations.

APPENDIX A—RESOURCE CONTACT INFORMATION

A.1 Trade Associations

American Petroleum Institute
www.api.org
1220 L Street, NW
Washington, DC 20005

Association of Oil Pipe Lines
www.aopl.org
1101 Vermont Avenue, NW, Suite 604
Washington, DC 20005

American Gas Association
www.aga.org
400 N. Capitol Street, NW
Washington, DC 20001

American Public Gas Association
www.apga.org
11094-D Lee Highway, Suite 102
Fairfax, VA 22030-5014

Interstate Natural Gas Association of America
www.ingaa.org
10 G Street NE, Suite 700
Washington, DC 20002

A.2 Government Agencies

Office of Pipeline Safety
www.ops.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Rm. 7128
Washington, DC 20590-0001

The National Pipeline Mapping System (OPS/DOT)
www.npms.rspa.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Room 7128
Washington, DC 20590-0001

Transportation Safety Institute
www.tsi.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
6500 South MacArthur Blvd.
Oklahoma City, OK 73169

Occupational Safety and Health Administration
www.osha.gov
"Hazards Associated with Striking Underground Gas Lines"
www.osha.gov/dts/shib/shib_05_21_03_sugl.pdf

A.3 Private Organizations

Common Ground Alliance
www.commongroundalliance.com

Dig Safely
www.digsafely.com

A.4 Publications

The AGA's Gas Pipeline Technology Committee's GPTC Guide—ASC GPTC Z-380.1

APPENDIX B—EXAMPLES OF STAKEHOLDER AUDIENCES

When a Public Awareness Program is being developed, one of the initial tasks is to identify the audience(s) that should receive the program's messages. Section 3 identified the intended audiences for the operator's Public Awareness Program and included a "Stakeholder Audience Definition Table". This appendix will provide further examples. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

B.1 Stakeholder Audience Identification

Identification of the individual stakeholder audiences (i.e., members of the four target audiences) may be done by any means available to the operator. Several methods are available. Operators may identify their stakeholder audiences on their own or may elect to hire outside consultants who specialize in audience identification. Where lists are developed, they should be kept current or redeveloped prior to effecting a particular communication.

B.1.1 AFFECTED PUBLIC

Some examples of how an operator may determine specific affected public stakeholder addresses along the pipeline, such as within a specified distance either side of the pipeline centerline, include the use of nine-digit zip code address databases and geo-spatial address databases. These databases generally provide only the addresses and not the names of the persons occupying the addresses. Broad communications to this audience are typically addressed to "Resident." It is important to note that when contacting apartment dwellers, individual apartment addresses should be used, not just the address of the apartment building or complex.

Some operators maintain "line lists" which provide current information on names and addresses of people who own property on which the pipeline is located. It should be noted, however, that not all property owners live on the subject property and that the program should address those people living on the property. Additionally, where the operator has a customer base, the operator can use its customer databases for identifying audience members.

For the sub-groups "Residents located along transmission pipeline ROW" and "Places of Congregation," it is recommended that transmission pipeline operators provide communications within a minimum coverage area distance of 660 feet on each side of the pipeline, or as much as 1000 feet in some cases. The transmission pipeline operator should tailor its communications coverage area (buffer) to fit its particular pipeline, location, and potential impact consequences. At a minimum, operators should consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand the coverage area accordingly.

A sub-set of the affected public that the operator may desire to send specific public awareness materials to is farmers. Farmers engage in deep plowing and clearing activities that could impact pipelines. One method of determining names and addresses of farmers along a pipeline route is the use of third-party vendors who purchase periodicals databases related to the farming and agricultural community. Due to the size of farming operations in some areas and the proximity of farming residents, it is recommended that the operator increase its affected public awareness mailing coverage as appropriate.

B.1.2 EMERGENCY OFFICIALS

There are several methods used by operators to identify the names and addresses of emergency officials. Depending upon the size of the county or parish, this may include all emergency officials in the affected jurisdiction.

The means used by many operators is through the use of SIC (Standard Industrial Classification) code. Where SIC codes are utilized to identify emergency officials, the operator should include the list of code categories applicable to the emergency officials stakeholder group.

The pipeline operator should consider all appropriate emergency officials who have jurisdiction along the pipeline route and should communicate with any emergency officials that the operator deems appropriate for a given coverage area. This will generally include all emergency officials whose jurisdictions are traversed by the pipeline.

B.1.3 LOCAL PUBLIC OFFICIALS

Operators use several methods to identify names and addresses for specific public officials. These primarily include the use of local company resources, local phone books, and the Internet. Where SIC codes are used to identify public officials, the operator should include the categories applicable the public officials stakeholder group.

B.1.4 EXCAVATORS

While "excavators" is a broad category, its use here is intended to identify companies that perform or direct excavation work. Operators should identify, on a current basis, persons who normally engage in excavation activities in the areas in which the pipeline is located. There are several methods used by pipeline operators to identify specific excavator stakeholder names and addresses.

Where SIC codes are used to identify excavators, the operator should include the categories applicable to the Excavator stakeholder group. The SIC/NAICS list should be considered the minimum for excavator audience identification where those codes are used. The operator may add to or expand the list as other excavator information becomes available. Another source for identifying excavators is the One-Call Center that covers the area designated by the Public Awareness Program. Several One-Call Centers provide "excavator lists" to their members. This may also be accomplished by the use of a third-party vendor who specializes in this service.

APPENDIX C—DETAILED GUIDELINES FOR PUBLIC AWARENESS MESSAGES

Section 4 of this RP recommends that an operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. This appendix expands that recommendation by providing further explanation or examples of the content of messages to be communicated.

Information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message is conveyed to the intended audience should provide information that will allow the operator to meet the program objectives set forth in Section 2. The communications should include enough information so that in the event of a pipeline emergency, the intended audience members will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator.

C.1 Pipeline Purpose and Reliability

While not a primary objective, pipeline operators should consider providing general information about pipeline transportation, such as:

- The role of pipelines in U.S. energy supply
- Pipelines as part of the energy infrastructure
- Efficiency and reliability of pipelines
- Positive messages about the energy transportation pipeline safety record
- The individual operator's pipeline safety actions and environmental record.

For local distribution companies:

- Typical distribution network (stations, mains, services, meters)
- How to detect a natural gas leak (e.g., how natural gas smells)
- Who uses natural gas and why.

Many of these messages are available in print and videos from the pipeline industry trade associations listed in Section 2 and Appendix A.

The operator should describe the purpose and function of the pipeline and/or associated facilities and the nature, uses, and purposes of the products transported. Where practical, it might be helpful to communicate the benefit(s) of the pipeline to the community. Examples of "benefits" include:

- "This pipeline provides gasoline to motorists at X gas stations in the area of Y."
- "This natural gas pipeline network provides gas to X thousands of homes and businesses in Y city or Z state."

Pipelines are a safe and reliable means of transporting energy. Where appropriate, operators should describe how pipelines are a reliable means of transporting energy products and point out that they are extensively regulated by Federal and State regulations with regard to design, construction, operation and maintenance. Operators may also describe applicable operational activities that promote pipeline integrity, safety and reliability, which could include initial and periodic testing practices, internal inspections and their frequency, patrolling types and frequencies, and other such information. Operators may also reference the National Transportation Safety Board finding that pipelines provide the highest level of public safety as compared to other transportation modes.

C.2 Hazard Awareness and Prevention Measures

C.2.1 OVERVIEW OF POTENTIAL HAZARDS

General information about the nature of hazards posed by pipelines should be included in the message, while also assuring the stakeholder audience that accidents are relatively rare. The causes of pipeline failures, such as third-party excavation damage, corrosion, material defects, worker error, and events of nature can also be communicated.

C.2.2 OVERVIEW OF POTENTIAL CONSEQUENCES

Information should identify the product release characteristics and potential hazards that could result from an accidental release of hazardous liquids or gases from the pipeline.

C.2.3 SUMMARY OF PREVENTION MEASURES UNDERTAKEN

The potential hazard message should be coupled with a general overview of the preventative measures undertake by the operator in the planning, design, operation, maintenance, inspection and testing of the pipeline. This message should also reinforce how the stakeholder audience can play an important role in preventing third-party damage and right-of-way encroachments.

C.2.4 OPTIONAL SUMMARY OF PIPELINE INDUSTRY SAFETY RECORD

Depending on the stakeholder audience and the delivery methods used, the operator may want to consider including a general overview of the industry's safety record.

Communication materials should also convey the qualification that the information provided on hazards, consequences and preventative measures is very general and that more specific information could be obtained from the operator or other sources (noting phone or website(s) for contacts). Information communicated to emergency responders needs to be more specific, provide an opportunity for two-way feedback and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison. Operators may want to consider referring to publications or websites produced by the trade associations listed in Appendix A for specific example language developed to provide overviews of hazards, consequences and preventative measures tailored to each stakeholder audience.

C.3 Leak Recognition and Response

The pipeline operator should provide the following information to the affected public and excavator stakeholder groups. To accomplish this, operators may want to consider using generic or standard printed materials developed by trade associations as aides for their member companies. However, operators will need to ensure the materials used are specific to the type of pipeline and product(s) transported in their systems.

C.3.1 POTENTIAL HAZARDS

Specific information about the release characteristics and potential hazards posed by the accidental release of hazardous liquids or gases from the pipeline should be included in the operator's communications.

C.3.2 RECOGNIZING A PIPELINE LEAK

Operators should include in their communications information on how to recognize a pipeline leak through the senses of sight, unusual sound, and smell (as appropriate to the product type) and describe any associated dangers.

- By Sight—What to Look for...
- By Sound—What to Listen for...
- By Smell—What to Smell for...

C.3.3 RESPONDING TO A PIPELINE LEAK

Operators should include in their communications an outline of the appropriate actions to take once a pipeline leak or release is suspected. This information should include:

- What to do if a leak is suspected
- What not to do if a leak is suspected.

It is especially important to include specific information on detection response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of hydrogen sulfide).

C.3.4 LIAISON WITH EMERGENCY OFFICIALS

This information should indicate that both the operator and the local emergency response officials have an ongoing relationship designed to prepare and respond to an emergency.

C.4 Emergency Preparedness Communications

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. The following information should be provided to the emergency officials stakeholder audience. Local public officials should be provided a summary of the information that is available in more detail from the emergency response agencies in their jurisdictions.

C.4.1 PRIORITY TO PROTECT LIFE

Operator emergency response plans and key messages relayed to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

C.4.2 EMERGENCY CONTACTS

Contact information on the operator's local offices and 24-hour emergency telephone numbers should be communicated to local and state emergency officials. Operators should also use the public awareness contact opportunity to confirm the contact information for the local and state emergency officials and calling priorities.

C.4.3 EMERGENCY PREPAREDNESS—RESPONSE PLANS

Operators are required by federal regulation to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state regulations. 49 *CFR* 192 and 194 and some state regulations outline the specific requirements for emergency response plans. In developing Emergency Response Plans, the operator should work with the local emergency responders to enhance communications and response to emergencies.

C.4.4 EMERGENCY PREPAREDNESS—DRILLS AND EXERCISES

A very effective means of two-way communication about emergency preparedness is the liaison with emergency officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

C.5 Damage Prevention

Because even relatively minor excavation activities (for example: installing mail boxes, privacy fences and flag poles, performing landscaping, constructing storage buildings, etc.) can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the damage prevention best practices developed by the Common Ground Alliance (CGA).

The use of an excavation One-Call Notification system should be explained to the audience. The audience should be reminded to call the state or local One-Call System before beginning any excavation activity and that in most states it is required by law. Information on the prevalence of "third-party" damage should be provided as appropriate. If the state or locality has established penalties for failure to use established damage prevention procedures, that information may also be communicated, depending on the audience and situation.

As a baseline practice, excavation and one-call Information should include:

- Request that everyone contact the local One-Call System before digging
- Explain what happens when the One-Call Center is notified
- Provide the local or toll-free One-Call Center telephone numbers
- Explain that the one-call locate service is typically free (Note: Some exceptions by state)
- Remind, if applicable, that to call is required by law.

One-Call Center telephone numbers for all 50 states can be found at the Dig Safely website or by calling the Dig Safely national referral number at 1-888-258-0808.

The "Dig Safely" message should be included in public awareness materials distributed to the affected public and excavators by the operator in its communications:

- Call the One-Call Center before digging
- Wait for the site to be marked
- Respect the marks
- Dig with care.

For information see the "Dig Safely" website listed in Appendix A. Operators may also consider use of the widely recognized "No Dig" symbol in their materials.

C.6 Pipeline Location Information

C.6.1 TRANSMISSION PIPELINE MARKERS

The audience should know how to identify transmission pipeline rights-of-way by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. Communications should include what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in some areas.

Public awareness materials should include illustrations and descriptions of pipeline markers used by the operator and the information that the markers contain. Displaying the penalties for removing, defacing, or otherwise damaging a pipeline marker may also be beneficial.

In addition to meeting applicable federal and state regulations, transmission pipeline markers may:

- Indicate a pipeline right-of-way (not necessarily the exact pipeline location)
- Identify the product(s) transported
- Provide the name of the pipeline operator
- Provide the operator's telephone number, available 24-hours a day and 7-days a week
- Be brightly colored and highly visible
- Have weather resistant paint and lettering
- Include "Warning Petroleum Pipeline" or "Warning Gas Pipeline" and show the universal "No Dig" symbol
- Provide a one-call number.

Additional guidance for liquid pipeline marker design, installation, and maintenance is provided in API Recommended Practice 1109.

C.6.2 TRANSMISSION PIPELINE MAPPING

Transmission pipeline maps can be an important component of an operator's Public Awareness Program. The level of detail in the map provided will be relevant to the stakeholder's need, taking security of the energy infrastructure into consideration.

Members of the general public can also receive information about operators who have pipelines that might be located in their community by accessing the National Pipeline Mapping System (NPMS) on the Internet. The NPMS will provide the inquirer a list of pipeline operators and contact information for operators having pipelines in a specific area. Inquiries are made by zip code or by county and state. Operators should include information on the availability of the NPMS within their public awareness materials.

Following is a summary of the types of maps that are referred to in this RP in describing how operators can incorporate pipeline maps in their efforts to improve public awareness.

- *System Maps*—Typically system maps provide general depiction of a pipeline transmission system shown on a state, regional or national scale. This type of map generally is not at a scale that poses security concerns and is often used by operators in a number of publications available to the industry and general public. A system map generally depicts a portion of the pipeline system shown in relationship to a region of the country. Generally these types of maps do not include any detail on the location of facilities.

- *General Maps*—General maps are another form of system map, which may be presented, in a more graphical format or smaller scale.
- *Local Maps*—Local maps are generally shown on a neighborhood, town, city or county level and usually do not show the entire pipeline system. Local maps are especially appropriate in communication with local emergency officials, One-Call Centers and elected public officials. Local maps should be distributed in accordance with regulatory or operator's company security guidelines. Local maps could include pipeline alignment maps, GIS-system produced maps, or other types of mapping that show more detail about the physical location of the pipeline system.
- *Community Pipeline Infrastructure*—Maps of communities that depict all of the natural gas and liquid transmission pipeline systems in the area. Available from the state or OPS to public and emergency officials.
- *National Pipeline Mapping System (NPMS)*—The U.S. Department of Transportation's Office of Pipeline Safety has developed the National Pipeline Mapping System, through which pipeline location maps are made available electronically to state and local emergency officials, in accordance with federal security measures.

Operators of transmission pipelines should make available appropriate system or general maps to the affected public and provide them guidance in how they can determine the location of the pipelines near where they live and work. Such maps should include company and emergency contact information and a summary of the type of products transported.

As part of the damage prevention program, all operators should also communicate the process for contacting the excavation One-Call System so that the specific location of the pipeline (and other nearby utilities) can be marked prior to excavation activity.

Operators of transmission pipelines should make available local maps to public and emergency officials in their effort to assure effective emergency preparedness and land use planning. In addition, operators must follow regulatory guidelines on providing such maps as required under 49 *CFR* Part 192 and 195. Maps should include company and emergency contacts, information on the type of products transported, and sufficient detail on landmarks, roads or location information relevant to the official's needs.

Operators should provide paper or digitized maps, or alternative information to the state or regional excavation One-Call Center, consistent with the One-Call System's requirements.

C.7 High Consequence Areas and Integrity Management Program (IMP) Overview for Transmission Pipelines

C.7.1 MESSAGE CONTENT FOR AFFECTED PUBLIC WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of Integrity Management Program (IMP) Plans for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry. The information should make system maps of HCAs available to the general or affected public. An overview of an operators IMP should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The summary may only be a few pages long and its availability could be mailed upon request or made available on the operator's website.

C.7.2 MESSAGE CONTENT FOR EMERGENCY OFFICIALS WITHIN HCAs

When conducting liaison activities with emergency officials required by the public awareness plan, operators should include information on how the emergency official may gain access to the National Pipeline Mapping System for their jurisdiction through the Office of Pipeline Safety. In addition, the operator may supplement their messages and materials by including overviews of IMPs and specifically solicit feedback from the emergency official about local conditions or activities that may be useful and/or prompt changes to the operator's IMP for that area. For example, mitigation measures that may be included in a HCA segment's risk analysis and action plan is supplemental emergency response planning, staging area identification or equipment deployment. A two-way discussion with emergency officials of the components of the HCA risk mitigation plan would be helpful.

C.7.3 MESSAGE CONTENT FOR PUBLIC OFFICIALS WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of IMPs for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry.

An overview of an operator's IMP plan should include a description of the basic requirements and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be several pages long and its availability could be mailed upon request or made available on the operator's website.

C.8 Content on Company Websites

The information listed below will guide pipeline operators who maintain websites on the recommended informational components to be included on the website.

C.8.1 COMPANY INFORMATION

In addition to describing the purpose of the pipeline and markets served, the website should include a general description of the pipeline operator and system. This could include:

- Operator and owner name(s)
- Region and energy market served
- General office and emergency contacts telephone numbers and e-mail addresses
- Products being transported by pipeline
- System or general map and location of key offices (headquarters, region or districts).

C.8.2 INFORMATION ON PIPELINE OPERATIONS

A broad overview of the operator's pipeline safety and integrity management approach should be included describing the various steps the company takes to ensure the safe operation of its pipelines. While not specifically recommended, additional information to consider for the website includes:

- General pipeline system facts
- An overview of routine operating, maintenance and inspection practices of the system
- An overview of major specific inspection programs and pipeline control and monitoring programs.

C.8.3 TRANSMISSION PIPELINE MAPS

A general or system map (see previous section describing types of maps) should be on the website. Details on how to obtain additional information should be provided, including reference to the National Pipeline Mapping System ((NPMS).

C.8.4 PUBLIC AWARENESS PROGRAM INFORMATION

The operator should include a summary of its Public Awareness Program developed under the guidance of this RP and should consider including printed material used in these efforts on the website. The public should also be provided information on company contacts to request additional information.

C.8.5 EMERGENCY INFORMATION

The website should contain emergency awareness information from two aspects. First, it should contain a summary of the operator's emergency preparedness. Second, it should contain information about how the public, and residents along the pipeline rights-of-way, and/or public officials should help protect, recognize, report and respond to a suspected pipeline emergency. Emergency contact information should be prominent and accessible from anywhere on the pipeline portion of the website.

C.8.6 DAMAGE PREVENTION AWARENESS

Pipeline operators are encouraged to either provide or link the viewer to additional guidance on preventing excavation damage, such as "Dig Safely" program information, contact information for the One-Call System in each of the states in which the operator has pipelines, and the "Common Ground Alliance" website noted in Appendix A.

C.9 Right-of-way Encroachment Prevention

Pipeline operators should communicate that encroachments upon the pipeline right-of-way inhibit the operator's ability to reduce the chance of third-party damage, provide right-of-way surveillance and perform routine maintenance and required federal/state inspections. The communication can describe that in order to perform these critical activities, pipeline maintenance personnel must be able to access the pipeline right-of-way, as provided in the easement agreement. It should also describe that to ensure access; the area on either side of the pipeline contained within the right-of-way must be maintained clear of trees, shrubs, buildings, fences, structures, or any other encroachments that might interfere with the operator's access to the pipeline. It should also point out that the landowner has the obligation to respect the pipeline easement or right-of-way by not placing obstructions or encroachments within the right-of-way, and that maintaining a pipeline right-of-way free of encroachments is an essential element of maintaining pipeline integrity and safety.

Residents, excavators, and land developers should be requested to contact the pipeline operator if there are questions concerning the pipeline or the right-of-way, especially if property improvements or excavations are planned that might impact the right-of-way. These audiences should also be informed that they are required by state law to provide at least 48 hours advance notice, more in some states, to the appropriate One-Call Center prior to performing excavation activities. Longer lead times for planning major projects are advised and sometimes required by state law.

Operators should consider communicating with local authorities regarding information concerning effective zoning and land use requirements/restrictions that will protect existing pipeline rights-of-way from encroachment. Communications with local land use officials could include consideration of:

- How community land use decisions (e.g. planning, zoning,) can impact community safety
- Establishing setback requirements for new construction and development near pipelines

- Requiring prior authorization from easement holders in the permit process so that construction/development does not impact the safe operation of pipelines
- Requiring pipeline operator involvement in road widening or grading, mining, blasting, dredging, and other activities that may impact the safe operation of the pipeline.

C.10 Communication of Pipeline Maintenance Activities

When planning pipeline maintenance-related construction activities, operators should communicate to the audience affected by the activity in a manner that is appropriate to the nature and extent of the activity. For major maintenance construction projects (such as main-line rehabilitation or replacement projects) operators should also notify appropriate emergency and local public officials and include information on further communications appropriate to the nature or local impact of the maintenance or construction activity. Operators should communicate appropriately in accordance with requirements associated with the acquisition of permits.

C.11 Security

Operators should include in their communications, where applicable, appropriate information pertaining to security of their pipelines and related facilities. Communications messages could include:

- General information about the pipeline or aboveground facility security measures
- Increased public awareness about security
- Communications to pipeline and facility neighbors to:
  - Become familiar with the pipelines in their area (identification via pipeline marker signs)
  - Become familiar with the pipeline facilities in their area (identification via fence signs at gated entrances)
  - Record the operator name, contact information and any pipeline information from nearby pipeline marker signs or facility signs and keep in a permanent location near the telephone
  - Be observant for any unusual or suspicious activities and unauthorized excavations taking place within or near the pipeline right-of-way or pipeline facility. Report such activities to their local law enforcement and the pipeline operator.

Pipeline neighbors are the operator's first line of defense against unauthorized excavation and other such activity in the right-of-way, and they can help by contacting the operator or the proper local authorities of suspicious activities if they have contact information available.

C.12 Facility Purpose

Communication with the affected public, emergency and public officials in proximity of major facilities (such as storage facilities, compressor or pump stations) should include an understanding of the nature of the facility. Operators should include in their communications general information about the facility and the product(s) stored or transported through the facility. Liaison with emergency officials should also include an understanding of emergency contact information for the specific facility.

APPENDIX D—DETAILED GUIDELINES FOR MESSAGE DELIVERY METHODS AND/OR MEDIA

Section 5 describes the delivery methods and tools available to pipeline operators to foster effective communication programs with the stakeholder audiences previously described. This Appendix expands on those guidelines by providing further explanation or examples of delivery methods and/or media. This section does not imply that all methods are effective in all situations. The content of the communication efforts should be tailored to the needs of the audience and the intent of the communication. Refer to Section 4 for a detailed description of the message content that the following materials or delivery methods should contain for each intended audience.

D.1 Print Materials

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audiences and the message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed here.

D.1.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

This is the most common message delivery mechanism currently used by the pipeline industry. Print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. Print materials also afford an effective opportunity to communicate content in a graphical or pictorial way. However, note that targeted distribution of print materials alone should not be considered effective communication with local emergency response personnel.

Consideration should be given to joining with other pipeline companies in a local, regional or national setting (including both the local distribution company and transmission pipelines) to produce common message materials that can be either jointly sponsored, (e.g., include all sponsors company names/logos) or used as a "shell" and then customized to each company's individual needs, to help ensure that a consistent message is being delivered. This approach can also effectively reduce the cost to individual operators.

Print materials can be mailed to residents or communities along the pipeline system or handed out at local community fairs, open houses, or other public forums. Operators can hire facilitators to organize mass mailings, using nine-digit zip codes or geo-spatial address databases; to designated residents in the community located along the pipeline, such as within an appropriate distance either side of the pipeline centerline. In this case it is often advisable to get information from the postal service or service provider on size, folding and closure requirements to minimize the postage costs for mass mailings. There are services that can handle the printing of materials, mailing address identification, mailing and documentation for the operator as a package.

D.1.2 LETTERS

Research has indicated that letters mailed to residents along a pipeline system are an effective tool for the operator to use to communicate specific information, such as what to do in the event of a leak, identification of suspicious activity or notification of planned maintenance activities within the right-of-way.

Notification letters are usually effective where there is a high likelihood for third-party damage such as in agricultural areas, new developments and where other types of ground-disturbing activities may take place. Similar letters may also be send to contractors, excavators and equipment rental companies informing them of the requirement to use One-Call Systems and providing other important safety information for their workers and the public.

Letters, along with other print materials, should provide information about where the recipient can obtain further information (such as website address, e-mail address, local phone numbers and one-call numbers).

D.1.3 PIPELINE MAPS

Pipeline maps can be presented as printed material and are an important component of an operator's Public Awareness Program. The operator should consider whether maps should be part of the communications to appropriate local stakeholder(s), and what type of maps should be used to accomplish the objective. See Appendix C.6.2 for further explanation of types and availability of maps.

D.1.4 RESPONSE CARDS

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other print materials. When delivering public awareness information to nearby residents, public or emergency officials, the inclusion of response cards can be used in a variety of ways:

- To maintain/update current mailing lists. Response cards permit the recipients to notify the operator of any changes in address
- To provide a convenient venue for recipients to provide comments, request additional information, raise concerns or ask questions
- To help evaluate the effectiveness of the operator's Public Awareness Program.

D.1.5 BILL STUFFERS

Bill stuffers are printed materials frequently used by local distribution companies (LDCs) in conjunction with invoice mailings to their customers. Due to the nature of their customers, these are not an appropriate option for transmission and gathering pipelines. LDCs using bill stuffers can increase the effectiveness of their programs by communicating to their active customers frequently through the repeated use of bill stuffers. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even when some may not be natural gas customers.

D.2 Personal Contact

Personal contact describes face-to-face contact between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication, and it allows for two-way discussion. This may be done on an individual basis or in a group setting. Some examples of communications through personal contact are described below:

D.2.1 DOOR-TO-DOOR CONTACT ALONG PIPELINE RIGHT-OF-WAY

This method is often used to make contact with residents along the pipeline right-of-way to relay pipeline awareness information or information on upcoming pipeline maintenance. This method can help to build stakeholder trust, which is an integral part of communication and an enhancement to the long-term Public Awareness Program. Operator representatives conducting door-to-door contact should be knowledgeable and courteous, be prepared for these types of communications and be able to discuss and respond to questions relating to the communication materials provided so that contact is meaningful and positive. They should provide the landowner/resident with basic pipeline safety information and a means for future contact.

If pipeline safety is to be discussed in this forum, the operator representative should be generally knowledgeable about the company's pipeline integrity program and emergency response procedures. In addition to the general information described in Section 4, the following additional information should also be considered:

a. Description of facilities on or near the property (i.e., pipelines, meter/regulator stations, compressor/pump stations, wellheads, treating facilities, tankage, line markers, cathodic protection, communication, etc.)
b. Description of easement and property owner's rights and limitations within the easement
c. Name and phone number of local contact within company for further information and the operator's emergency notification number to report emergencies or suspicious activity
d. Information on damage prevention and local "Call Before You Dig" programs
e. What to do in case of emergency (fire, leak, noise, suspicious person)
f. Informational items (i.e., calendar, magnetic card, pens, hats, etc.) to retain important telephone numbers
g. As appropriate, additional local information such as upcoming maintenance, projects, events and/or company community involvement such as United Way, other charities, environmental projects, etc.

D.2.2 TELEPHONE CALLS

When the intended audience is small in number, the operator may find it effective to communicate by telephone. This personal form of contact allows for two-way discussion. The operator should decide which elements of their Public Awareness Program are suitable for conducting via telephone calls.

D.2.3 GROUP MEETINGS

Group meetings can be an effective way to convey the messages to selected audiences. Meetings may be between the operator (or group of operators) and an individual stakeholder audience or between the operator (or group of operators) and a number of the stakeholder audience groups at one time.

For example, the operator could conduct individual meetings with emergency response officials, combined industry meetings with emergency response officials, and participation by emergency response officials and personnel in the operator's emergency response tabletop drills and deployment exercises. Meetings are particularly effective in conducting liaison activities with the emergency official stakeholder group.

Another example is group meetings conducted by the operator in classrooms and with educators at local schools. Informational materials can be presented to school administrators and students and can contain important public awareness messages for students to take home to their parents. This method of personal contact can readily reach a large number of people with the operator's public awareness messages and reinforce positive messages about the operator and/or the pipeline industry.

Additional group meetings could include those with state One-Call System events, local excavators, contractors, land developers, and municipalities.

D.2.4 OPEN HOUSES

Operators often hold open houses to provide an informal setting to introduce an upcoming project, provide a "get to know your neighbor" atmosphere or to discuss an upcoming maintenance activity such as pipeline segment replacement. Tours of company facilities, question and answer sessions, videos, or presentations about pipeline safety and reliability do well in an open house environment. Even without formal presentations, allowing the public to see the facility can also be very effective. Often this type of forum would include refreshments and handouts (e.g. print material, trinkets, etc.) that attendees can take with them. Targeted or mass mailings can be used to announce planned open houses and can, in themselves, communicate important information.

D.2.5 COMMUNITY EVENTS

Community sponsored events, fairs, charity events, or civic events may provide appropriate opportunities where public awareness messages can be communicated to the event participants. Companies can participate with a booth or as a sponsor of the event.

These forums are generally used to remind the community of the operator's presence, show support for community concerns, and heighten public awareness about the benefits of pipeline transportation and about pipeline safety. Examples of community events include:

- County and state fairs
- Festivals and shows
- Job fairs
- Local association events
- Trade shows (Energy Fair)
- Chamber of Commerce events.

Operators should plan in advance and secure a large number of handout materials; as such events often include a large number of attendees and can take place over several days.

D.2.6 CHARITABLE CONTRIBUTIONS BY PIPELINE OPERATORS

While contributions to charities and civic causes are not in themselves a public awareness effort, companies should consider appropriate opportunities where public awareness messages can be conveyed as part of or in publicity of the contribution. Examples include:

- Contribution of gas detection equipment to the local volunteer fire department
- Donation of funds to acquire or improve nature preserves or green space
- Sponsorship to the community arts and theatre
- Support of scholarships (especially when to degree programs relevant to the company or industry)
- Sponsorship of emergency responders to fire training school.

D.3 Electronic Communications Methods

D.3.1 VIDEOS AND CDs

There are a variety of approaches companies may use to supplement their delivery tools with videos. While a supplement to the baseline components of an effective Public Awareness Programs, videos may be quite useful with some stakeholders or audiences in some situations. Videos can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual response that printed materials often cannot. Companies may seek industry specific videos from trade organizations or develop their own customized version. Such videos can be used for landowner contacts, emergency official meetings, or the variety of community or group meetings described elsewhere in this section. Companies could also consider adding such videos to their company websites.

D.3.2 E-MAIL

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholders. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by mail, by person or in meetings.

E-mail contact information can be provided on company handouts, magazine advertisements, websites and other written communications. This provides an effective mechanism for the public to request specific information or to be placed on distributions lists for specific updates.

An advantage of e-mail is the ease of requesting and receiving return information from the recipient, similar to contact information, survey or feedback described in bounce-back cards explained above. Note that it is important for the operator to designate a response contact within the organization to handle follow-up responses to e-mail queries in a timely manner.

D.4 Mass Media Communications

D.4.1 PUBLIC SERVICE ANNOUNCEMENTS (PSAs)

Radio and television stations occasionally make airtime available for public service announcements. There is great competition from various public interest causes for the small amount of time available because the broadcast media is no longer required by law to donate free airtime for PSAs. Given the popularity of radio and television and the large areas covered by both, public service announcements can be an effective means for reaching a large sector of the public. Pipeline operators (or groups of pipeline operators) could consider contacting local stations along the pipeline route to encourage their use of the PSAs. The use of cable TV public access channels may also be an option.

D.4.2 NEWSPAPERS AND MAGAZINES

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline operators can encourage reporters to write constructive stories about pipeline issues in various topics of relevance, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure. Even if the reporter is covering an emergency or controversial issue, pipeline operators can leverage the opportunity to reinforce key safety information messages such as damage prevention and the need to be aware of pipelines in the community. Trade magazines such as those for excavators or farmers often welcome guest articles or submission or assistance in writing a positive, safety-minded story for their readers. Local weekly newspapers and "metro" section inserts will sometimes include a news release verbatim at no cost to the sender.

D.4.3 PAID ADVERTISING

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community. This type of advertising can be very expensive, but can be made more cost effective by joining with other pipelines, including the local utilities, to deliver a consistent message. One example is placement of a public awareness advertisement on a phone book cover, thus achieving repetitive viewing by the audience for a whole year. Another example is advertising in local shopping guides.

D.4.4 COMMUNITY AND NEIGHBORHOOD NEWSLETTERS

Information provided should be similar to that made available for newspapers and magazines. Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with outreach to those communities and/or neighborhoods and is usually done for free. Operators can also develop their own newsletters tailored to specific communities. These newsletters can be used to highlight the operator's involvement in that community, provide the operator's public awareness messages, and to address any pipeline concerns that community may have.

This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

D.5 Specialty Advertising Materials

Company specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These tools also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. Many such materials or items exist, including refrigerator magnets, calendars, day planners, thermometers, key chains, flashlights, hats, jackets, shirts, clocks, wallet cards, and other such items containing a short message (i.e. "Call Before You Dig"), the company logo and/or contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods.

D.6 Informational Items

Operators can develop (or participate in industry associations or along with other companies) informational materials for groups or schools that heighten pipeline awareness. Operators (and their industry associations) may also sponsor or develop training materials for emergency response agencies that are designed to increase knowledge and skills in responding to pipeline emergencies. Alternatively, local emergency officials will hold training as part of their own continuing education, and attendance by pipeline personnel at these sessions is often welcome and an ideal setting for relaying public awareness information about pipelines.

D.7 Pipeline Marker Signs

The primary purposes of above ground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency
- Facilitate aerial or ground surveillance of the pipeline right-of-way by providing aboveground reference points.

Refer to Section 4 for additional information on marker sign types and information content.

Below ground markers are also effective warnings. While some may not consider this part of a proactive public awareness communication program, buried warning tape or mesh can be an effective reminder to excavators of the presence of underground utilities and have proven effective in preventing damage to pipelines and other buried utilities.

D.8 One-Call Center Outreach

Most state One-Call Centers provide community outreach or implement public awareness activities about the one-call requirements and the Dig Safely awareness messages, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such Public Awareness Programs within their own Public Awareness Program. Some One-Call Centers focus on hosting awareness meetings with excavators to further promote the Dig Safely and One-Call Messages. It is the operator's responsibility to request documentation for these outreach activities.

In order to enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become members of one-call organizations in areas where they operate pipelines. Since all underground facility members share One-Call Center public awareness outreach costs, the costs to an individual operator are usually comparatively low, and can demonstrate effectiveness by increased use of the One-Call Notification system.

D.9 Operator Websites

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Since corporate websites may vary in serving the business needs of the company (e.g. investor relations, marketing, affiliate needs), the guidance in Appendix C.8 describes features of the components of a website for a company's pipeline subsidiary or operations that should fit into any corporate structure and overall website design. Many pipeline operators may choose to place additional or more detailed information on their websites to supplement their public awareness and informational efforts.

An operator's website will supplement the other various direct outreach delivery tools discussed in this RP.

APPENDIX E—ADDITIONAL GUIDELINES FOR UNDERTAKING EVALUATIONS

This appendix provides additional explanation for several methods described in Section 8 for conducting program evaluations and provides a sample survey.

E.1 Focus Groups (Interview Panels)

A focus group is a group of people representative of one or more target audiences who are gathered to provide feedback about the materials or other aspects of a planned Public Awareness Program or to comment on an existing one.

Typically, a focus group has about 6 to 12 participants. While focus groups can be professionally facilitated, feedback about public awareness materials can be gained by an informal discussion run by individuals connected with the public education program. Often participants will be asked to review draft materials and to comment on what they understood from the materials and whether the materials would draw appeal when received by mail. Focus groups can also be used to provide input on the relative effectiveness of various means of delivery.

Focus group participants might be operator employees who are not familiar with the Public Awareness Program, citizens living along a stretch of pipeline or representatives of homeowner associations or business people along the right-of-way. Target stakeholder audiences should not be mixed. The participants usually are not chosen at random but rather are selected to be reasonably representative of their focus group and capable of articulating their reactions to the materials.

E.2 Sample Assessment of Program Implementation

Table E-1—Sample Audit of Program Implementation

I Program Development and Documentation: Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described in Section 2 and the remainder of this RP?
1. Does the operator have a written Public Awareness Program?
2. Have all of the elements described in Section 2 of this RP been incorporated into the written program?
3. Does the written program address all of the objectives of this RP as defined in Section 2.1?
4. Does the documented program address regulatory requirements identified in Section 2.2 of this RP and other regulatory requirements that the operator must comply with?
5. Does the operator have a plan that includes a schedule for implementing the program?
6. Does the program include requirements for updating responsibilities as organizational changes are made?
II Program Implementation: Has the public awareness plan been implemented and documented according to the written plan?
1. Is the program updated and current with any significant organizational or major new pipeline system changes that may have been made?
2. Are personnel assigned responsibilities in the written program aware of their responsibilities and have management support (budget and resources) for carrying out their responsibilities on the program?
3. Has the program implementation been properly and adequately documented?
4. Have all required elements of the program plan been implemented in accordance with the written plan and schedule?
5. Does the operator have documentation of the results of evaluating the program for effectiveness?
6. Are the results of the evaluation of program effectiveness being used in a structured manner to improve the program or determine if supplemental actions (e.g. revised messages, additional delivery methods, increased frequency) in some locations?

E.3 Supplemental Information to Operators Conducting Surveys to Evaluate Effectiveness

E.3.1 Type of Survey—Surveys may be conducted in person, over the phone, or via mail questionnaires. Conducting them in person is more labor intensive and costly but yields the best result and the largest return. Mail surveys are least expensive but typically have only 10-20 percent of the forms returned, which raises questions about whether the results are representative. Incentives for completing mail surveys may improve participation. Telephone surveys are a good compromise for the modest size samples needed to draw broad conclusions, but any of the methodologies can be made to work.

E.3.2 Sample Size—Typically a survey is designed to reach a random number of the targeted stakeholder audience. A variation on the random sample when conducting surveys in person is a "cluster sample" in which a block may be chosen at random and then a cluster of several households on the block visited at the same time. That is a relatively efficient way to increase sample sizes and not sacrifice much in statistical validity. The telephone number for affected residents is typically not readily accessible to the operator, although a random survey in a designated zip code or geographic area may include questions on whether the respondent lives or works along the right-of-way (to ensure a sufficient number of the affected public is included in the survey). For conducting a survey in person, the operator can work with a random selection of homes or businesses drawn from aerial maps or simply by selecting segments at random to be visited near the right-of-way. Mail surveys might be sent to all in a census tract, all in a zip code, or sub-zip code area. Third-party experts in conducting surveys can readily assist, at least for the first time a survey is attempted.

E.3.3 Statistical Confidence—There is typically concern about being statistically reliable. Often this leads to needlessly expensive surveys when one really only needs to know the approximate percentage of the target group that has been reached and is knowledgeable.

In deciding sample size, one can keep in mind a simplification of a lot of statistical rules and tables:

> The statistical error associated with a random survey is approximated by $1/\sqrt{n}$,where n is the size of the sample. A sample of 100 gives an accuracy of approximately $\pm 1/\sqrt{100}$, or about 10 percent.

There are a number of detailed assumptions behind that approximation, which is more valid the larger the total population to be surveyed. For smaller populations, the sampling error is actually even smaller than that approximation. Very modest-size surveys can be used for evaluating pipeline safety for public awareness and still have statistical validity to support broad conclusions that, in turn, drive changes (as necessary) or support continuation (when supported) to the Public Awareness Program.

E.3.4 Content—Different sets of questions are needed for different audiences. There obviously would be a different set of questions asked of households along a pipeline versus those asked of excavators. The survey questionnaire should be clear, brief and pre-tested to increase the participation and minimize the cost. Operators should try to keep their questions the same over time so that trends can be evaluated. The questions can be yes/no, multiple choice, or open-ended. It is easier to analyze data from multiple choice or yes/no questions than open-ended questions; the latter require someone to read and interpret them, and then complete computer-readable tallies or do a tally by hand. A combination of both open-end and multiple-choice questions can be used. A survey can focus on only one program element or several elements and can measure the following with one or more of the selected stakeholder audiences:

- **Outreach:** Surveys can determine whether the audience received the public awareness communication.
- **Knowledge:** Surveys can also inquire about what the person would do hypothetically in certain situations, such as "If you observed a suspected leak in a pipeline, what would you do?"
- **Behavior:** In addition to knowledge and attitudes, surveys can be designed to inquire of actual behaviors; e.g., "Have you ever called to inquire about the location of a pipeline," "Have you ever been involved in any way with a pipeline break or spill," etc.

As a supplement to the baseline survey, the operator or operators working in collaboration or with trade associations may also include information about general attitudes about pipelines and knowledge of their role in delivering energy.

Some thought is needed as to whether it is better to get open-ended responses that do not prompt the respondent, to avoid bias. A short example: One might be tempted to ask, "What number would you call if you saw a break in a pipeline," but that question already assumes somebody would look up a number, which may be what you are trying to determine. A less biased question would be "what would you do if you saw a break in a pipeline?"

E.3.5 Implementation—An operator can:

- Develop and conduct a survey on its own system using internal or external expertise
- Select a survey format designed by external parties or an industry association
- Adapt surveys designed by others and conduct on its own systems, or
- Join with others in a regional survey.

E.4 Sample Survey

E.4.1 Survey Questions—The content of the questions on the survey should reflect the goals of the public education program. The wording of questions is critical.

Developing appropriate wording is more difficult than it may appear to be on the surface. It is easy to inadvertently build in biases or confuse the person being interviewed. The questionnaires should be tested before use. A focus group or small sample can be used for that purpose. If the wording is changed, the questions should be retested.

Preferably, the same wording would be used for a group of operators if not all of the industry, to achieve comparability and be able to compare statistics for the industry or a region. Individual operators should try to keep their questions the same over time so that trends can be evaluated.

Where possible, it is preferable to use multiple-choice questions rather than open-ended questions, because the former are easier to analyze objectively. A combination of both open-end and multiple-choice questions can be used. Negative answers or problems raised by respondents preferably should be followed up by a diagnostic question to understand the respondent's point of view better, and to get insight for making improvements.

In the tables below are two sample sets of survey questions—one for the general public near pipelines, the other for excavators. These lists of questions can be used as menus from which to choose if there is time only for a few questions. The asterisked questions are the most important.

The questions may refer to the respondent's experience in the past six months, year, or two years; generally one does not ask about information older than one year because of memory problems, except for dramatic events likely to be remembered.

E.4.2 Introduction—In administering a survey, there should be a brief introduction to set the stage. For example:

> "Our company [or insert company name association] believes it is important to get feedback from people (excavators) such as you about pipeline safety. We would like to ask you a few questions and would greatly appreciate your candid answers. The information on your particular response will be kept confidential. Let me start by asking ...."

E.4.3 Venues—Basically the same questions can be asked during a formal survey, whether undertaken by mail, telephone, or in person. They also can be used during customer contacts or as part of contacts with appropriate personnel from excavators.

Tables

Table E-2—Sample Survey Questions for Affected Public

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Outreach	*1.	In the last year [or 2 years], have you seen or heard any information from [our company] relating to pipeline safety? *[Yes or No]* If yes: 1a. What was the source of the information (check all that apply): a. Written material (brochure, flyer, handout) b. Radio? c. TV? d. Newspaper ad or article? e. Face-to-face meeting? f. Posted information (e.g., on or near pipeline) g. Other: ____________ 1b. About how many times did you see information on pipeline safety in the last year?____________
Outreach	2.	Have you or has or anyone in your household ever tried to obtain information about pipeline safety in the last 12 months? *[Yes or No]* ____________ 2a. If yes, where did you try? Check all that apply: a. Internet b. Call c. Letter d. Visit e. Other: ____________
Knowledge	*3.	Do you live close to a petroleum or gas pipeline? *[Yes, No, do not know]* 3a. If yes, where is it (or how close are you to it)?____________ ____________
Knowledge	*4.	What would you do in the event you were first to see damage to a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ____________
Knowledge	5.	What would you do if you saw someone intentionally trying to damage a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: ____________
Behavior	*6.	Have you ever called a pipeline operator, 911, or anyone else to report suspicious or worrisome activity near a pipeline? *[Yes or No]* 6a. If yes, what did you report: a. Break b. Product release c. Digging d. Other: ____________

Table E-2—Sample Survey Questions for Affected Public (Continued)

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Behavior	*7.	Have you or has anyone in your household [or company if a business] ever encountered a damaged pipeline or product released from a pipeline? *[Yes or No]* If yes, what did you do? ____________________ ____________________ ____________________
Behavior	8.	Have you ever passed information about pipeline safety to someone else? *[Yes or No]* If yes, what information and to whom: ____________________ ____________________ ____________________
Outcomes	9.	Has anyone in your household or have nearby neighbors ever had any injuries or damage associated with a pipeline break or spill? *[Yes or No]* 9a. If yes, describe event. ____________________ ____________________ ____________________
Attitude	10.	Do you agree or disagree that your local pipeline operator has been doing a good job of informing people like you about pipeline safety? a. Strongly agree b. Agree c. Disagree d. Strongly disagree If you disagree, why: ____________________ ____________________ ____________________

Table E-3—Sample Survey Questions for Excavators

The questions below could be worded for a specific operator or for any operator; some excavators may deal with more than one pipeline.

Outreach

*1. In the last 12 months, have you been contacted or received written information from [local pipeline operator] regarding pipeline safety? *[Yes or No]*

If yes, what was the source:
- a. Telephone call
- b. Mail
- c. Visit or in-person meeting
- d. E-mail
- e. Sign or billboard
- f. Other:____________________

Outreach

2. Have you received information from any other sources about pipeline safety? *[Yes or no]*

2a. If yes, which? ____________________

Behavior

3. Have you contacted [pipeline operator name] in the past year to inquire about the location of pipelines? *[Yes or no]*

3a. If yes, about how many times? ____________________

3b. If yes, how did you make the contact:
- a. Telephone
- b. E-mail
- c. Letter
- d. In-person
- e. Other: ____________________

Behavior

*4. How often would you say your operator checks whether a pipeline exists before digging in a new spot?
- a. Always
- b. Usually
- c. Sometimes
- d. Rarely or Never
- e. Don't know.

4a. If not always: why not?
- a. Didn't know where to get information
- b. Not necessary
- c. Didn't think about it
- d. Takes too much time
- e. Think we can tell where pipeline is on our own
- f. Other: ____________________

Outreach

5. How do you make sure that all the right people in the company get the information on whom to call before digging? That is, how do you disseminate the information?
- a. Post it
- b. Discuss in meetings
- c. E-mail
- d. Calls
- e. Put in company's written procedures
- f. Put in company newsletter
- g. Other: ____________________

Outreach (Audience Size)

6. About how many people in your company actually determine where to dig?
____

Table E-3—Sample Survey Questions for Excavators (Continued)

	6a. What jobs do they have (e.g., excavator equipment operator; executive; operations boss; etc.): ____________
Outreach	6b. How many of them probably have information on where to call before digging? a. All b. Most c. Some d. Few or None
Outcome	*7. Has your company ever unexpectedly encountered a pipeline while digging? *[Yes or No]*
	7a. If yes, how often has this occurred? ____________ Explain whether pipeline location was unknown and why. ____________ ____________ ____________
	7b. If yes, how many were “close calls”? ____________
	7c. How many resulted in damage: ____________

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ____________________________representing ____________________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have an oil or gas pipeline running through your community? _____(Y/N)
If not yes, tell them. [Reviewers: Should we also ask if they know where it is?]

2. Do you know the name of your local pipeline operator? ________ (Y/N)

2a. If yes, who? ____
[This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding pipeline safety in the last 12 months?
___________ (Y/N)

3a. If yes, about how many? ____________

4. Before today, about when was your last contact with someone from the pipeline industry related to pipeline safety? ______________________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call in the pipeline company if there is an incident or you need more information? ___________(Y/N)

6. Have you heard of the Office of Pipeline Safety in the U. S. Department of Transportation?
_________ (Y/N)

7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a pipeline? _______ (Y/N)

7a. If yes, what are they? ____

8. Are you familiar with the one-call line? _________ (Y/N)
(If no, they should be informed about it.)

9. How would you rate the adequacy of information you have about pipeline safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? ________
   b. Too much? ______
   c. Not enough? ______

[This question is essentially a self-assessment of knowledge for a measure such as “percent of local officials who felt they needed more information about pipeline safety.”]

Behavior

10. Does your community have an emergency response plan to deal with a pipeline break (regard less of whether intentional or accidental)? _______(Y/N)

Outcome

11. Are you aware of any pipeline breaks that occurred in your community in the last 10 years?
____________ (Y/N)

11a. If yes, how many? ________

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines (Continued)

11b. What were they? ____
[The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding pipeline safety? __________ (Y/N)

12a. If yes, what was it? ____

13. Overall, do you feel the pipeline industry has an adequate public safety awareness program?
a. Definitely yes ________
b. Pretty much so _______
c. Not sure ____________
d. Don't know _________
e. Probably not ________
f. Definitely not _______

[This is an overall perception of their awareness program. The operatory could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-4.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you know where the nearest oil or gas pipeline is in or near your community? ______(Y/N) [If not, tell them after the interview.]

2. Do you know the name of your local pipeline operator? ________ (Y/N)

   15a. If yes, who? ____

3. Do you know who to call in the pipeline company if there is an incident, or if you need more information? _________(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding pipeline safety in any media in the last year? ________ (Y/N)

   17a. If yes, do you recall what? ____________________________________

5. Have you or anyone else in your department to your knowledge met with any representatives of the pipeline company to discuss pipeline safety within the last 12 months, prior to today? ______________(Y/N)

   18a. If yes, when?_________________________

   18b. With whom? ____

Behavior

6. Do you have a response plan or SOPs for responding to a pipeline incident, such as a break? ___________ (Y/N)

7. Have you done any practical training to deal with a break? ____________(Y/N)

Outcome

8. Do you know if there were any pipeline incidents within the last ten years in your community? _________ (Y/N)

   8a. If yes, about when? ____________

   8b. What was the incident? ____

   8c. Did the department respond? ________(Y/N)

   8d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.]

   ____

   ____

   ____

   ____

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am ____________________________representing ____________________________

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have natural gas pipelines running through your community? _____(Y/N)
2. Do you know the name of your local natural gas company? ________ (Y/N)

   2a. If yes, who? ____
   [This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding natural gas safety in the last 12 months? ___________ (Y/N)

   3a. If yes, about how many? ____________

4. Before today, about when was your last contact with someone from the natural gas industry related to pipeline safety? _______________ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call the natural gas company if there is an incident or you need more information? ___________(Y/N)
6. Do you know who regulates the natural gas company in this community? _________ (Y/N) (If no, they should be informed about it.)
7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a natural gas pipeline? _________ (Y/N)

   7a. If yes, what are they? ____

8. Are you familiar with the one-call line? _________ (Y/N) (If no, they should be informed about it.)
9. How would you rate the adequacy of information you have about natural gas safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? ________
   b. Too much? ______
   c. Not enough? ______

   [This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a natural gas leak (regardless of whether intentional or accidental)? _______(Y/N)

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies (Continued)

Outcome

11. Are you aware of any pipeline leaks that occurred in your community in the last 2 years? ____________ (Y/N)

    11a. If yes, how many? ________

    11b. What were they? ____
    [The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding natural gas safety? __________ (Y/N)

    12a. If yes, what was it? ____

13. Overall, do you feel the natural gas industry has an adequate public safety awareness program?
    a. Definitely yes _______
    b. Pretty much so ______
    c. Not sure ___________
    d. Don't know ________
    e. Probably not _______
    f. Definitely not ______

    [This is an overall perception of their awareness program. Could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-5.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

First Responders/Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you have natural gas pipelines running through your community?? ______(Y/N)
[If not, tell them after the interview.]

2. Do you know the name of your local natural gas company? ________ (Y/N)

15a. If yes, who? ____

3. Do you know how to contact the local natural gas company if there is an incident, or if you need more information? __________(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding natural gas safety in any media in the last year? ____________ (Y/N)

17a. If yes, do you recall what? ________________________________

5. Have you or anyone else in your department to your knowledge met with any representatives of the natural gas company to discuss pipeline safety within the last 12 months, prior to today? ______________(Y/N)

18a. If yes, when?_____________

18b. With whom? _____________________________________

Behavior

6. Do you have a response plan or SOPs for responding to a natural gas incident, such as a leak? ______ (Y/N)

7. Have you done any practical training to deal with a leak? ____________(Y/N)

8. Do you feel reasonably well prepared to deal with a natural gas leak, should one occur in your community? ___________(Y/N) If not, in what areas are there deficiencies? (Check all that apply.)
   a. Training ______
   b. Special Equipment _____
   c. Knowledge about leaks _____
   d. Inherent dangers _____
   e. Other: (Write in.)____

9. If you heard a report of a natural gas leak right now, what actions would you or your department take? [Write in the steps; someone should grade the responses to get a sense of whether there has been adequate training or preparation, or if the respondent just mentioned general procedures applicable to any kind of incident.]

____

____

Outcome

10. Do you know if there were any natural gas leaks within the last two years in your community? _________ (Y/N)

10a. If yes, about when? ____________

10b. What was the incident? ___________________________________

10c. Did the department respond? ________(Y/N)

10d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.] ______________________________

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Kathryn M. Williams

GOVERNMENT AFFAIRS
EXHIBIT 1200

December 30, 2024

EXHIBIT 1200 - DIRECT TESTIMONY – GOVERNMENT AFFAIRS

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Kathryn M. Williams. I am the Vice President, Chief Public Affairs and Sustainability Officer. My responsibilities include government affairs, community relations, corporate giving, and environmental policy and compliance.

Q. Please describe your education and employment background.

A. I have degrees in History and Latin American Studies from Colorado College, and I have completed an executive education program at Harvard University's Kennedy School of Government on Economics and the Environment. From 2007 to 2015, I worked at the Port of Portland as the Business and Rail Relations Manager and then the State Affairs Manager, overseeing state governmental affairs for the Port of Portland's three airports, including Portland International Airport, four marine terminals and business parks. Previously, I was an associate at the regional public affairs consulting firm Imeson & Carter, representing infrastructure, transportation, utility and nonprofit clients for more than a decade. I joined NW Natural in 2018 as its Government and Community Affairs Manager, became its Vice President, Public Affairs in 2019 and its Vice President, Public Affairs and Sustainability in 2020, and began my current role in May 2023.

Q. Please summarize your testimony.

A. My testimony addresses the Public Utility Commission of Oregon's (the "Commission") resolution of "Lobbying Costs and Tracking" in Section V.H of its

Order No. 24-359 issued in the Company's most recent general rate case (UG 490) on October 25, 2024, as it applies to this general rate case.

II. COMMISSION ORDER NO. 24-359 – RESOLUTION OF "LOBBYING COSTS AND TRACKING"

Q. Please summarize the development of the disputed issue "Lobbying Costs and Tracking" in the Company's most recent general rate case, UG 490.

A. In compliance with Order No. 22-388 issued in the Company's penultimate rate case (UG 435) on October 24, 2022,[1] NW Natural's application in UG 490 updated the Company's time-tracking policy for political activities, or activities intended to influence a legislative body, through exception time reporting. Effective January 1, 2023, employees began recording exception time for political activities in the Company's time tracking system, called "WorkForce." The Company created a "Time Charging Procedures – Political Activities" ("General Procedure") to guide its employees with the exception time tracking function. The intent of each employee is critical in determining whether a political or lobbying activity is being performed at a particular time. As a result of that exception time reporting, the Company removed $625,160 of expense from its request for cost recovery in UG 490,[2] resulting in the total Government Affairs test year expense of $1,714,350.[3]

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[1] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision (UG 435), Advice 20-19, Schedule 198 Renewable Natural Gas Recovery Mechanism (ADV 1215) (UG 411)*, Docket No. 435, Order No. 22-388 at 23 ("Going forward, we expect NW Natural to provide detailed expense information that clearly categorizes its [political] activity.") (Oct. 24, 2022).

[2] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Reply Testimony of Kathryn M. Williams, NW Natural/3300 at 6-7 (June 4, 2024).

[3] *See In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 35 (Oct. 25, 2024).

The Coalition[4] proposed to disallow the $1.7 million budget for the Government Affairs Department "because the company has failed to adequately track its political activities in accordance with Order No. 22-388 and that its definition of lobbying or political activity is too narrow."[5] The Coalition also recommended that the Commission "require NW Natural track and report on all activities by its governmental affairs employees."[6] NW Natural disputed the Coalition's assertions, arguing that the General Procedure reflected political and lobbying activities as defined in 18 CFR § 367.4264, and the Company's implementation of exception time tracking was appropriate.[7]

Q. How did the Commission resolve "Lobbying Costs and Tracking" in UG 490?

A. The Commission's resolution of "Lobbying Costs and Tracking" in UG 490 addressed cost recovery for the 2024 rate case, required forward-looking changes to the Company's time tracking procedures, and articulated a rebuttable presumption for cost recovery for certain categories of Government Affairs employee time. First, regarding cost recovery, the Commission authorized the Company to recover 75 percent of the government affairs budget NW Natural proposed for recovery, or approximately $1.3 million, recognizing that "many utility

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[4] The "Coalition" in UG 490 was comprised of the Coalition of Communities of Color, Climate Solutions, Verde, Columbia Riverkeeper, Oregon Environmental Council, Community Energy Project and Sierra Club.

[5] *See In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 35 (Oct. 25, 2024).

[6] *Id.*

[7] *Id.* at 38.

government affairs activities do serve the core interests of customers."[8] Second, the Commission stated that NW Natural misinterpreted the Order by time-tracking only exception time, rather than both exception and non-exception time, even though it "recognize[d] that this is a departure from standard practice in this area"[9] and did not specifically direct NW Natural to time track both exception time and non-exception time. Consequently, the Commission directed NW Natural to clarify its General Procedure and implement one of the following two options, (1) apply the General Procedure to "exception and non-exception time tracking," ***or*** (2) "adopt a procedure that tracks only *non*-exception time."[10] Third, the Commission adopted "a prospective policy that certain categories of activities will be subject to a rebuttable presumption of 50-50 sharing."[11]

Q. Did the Commission explain how it determined that the Company should recover 75 percent of its requested government affairs budget?

A. Yes. The Commission stated that it set rates in UG 490 "according to the presumptions consistent with the sharing approach" discussed below.[12] The Commission provided the following explanation:

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8 *Id*. at 39.

9 *Id.* at 42.

10 *Id.* at 38 (emphasis in original).

11 *Id.*

12 *Id.* at 42.

> Even in the absence of non-exception time tracking data, we find it reasonable to assume that as a regulated utility, at least half of NW Natural's remaining community and government affairs functions serve core customer interests, including educating the public and local, state and federal government officials on issues core to the safe and reliable operation of the gas system. For the other half, lacking a sufficient record to evaluate, we apply 50-50 sharing to recognize that some costs are dual purpose or arguably not purely in the interests of core customers.[13]

Q. Did the Company set rates to recover 75 percent of its government affairs budget for which it sought recovery?

A. Yes. The Company's rates that became effective November 1, 2024, reflect recovery of the cost of 75 percent of its requested government affairs budget.

Q. Did the Commission provide context for its direction to the Company about implementing one of the two time-tracking options?

A. Yes. The Commission noted that it was "clarify[ing]" its "intention" from Order No. 22-388 in UG 490 "that recovery of government affairs costs in rates requires NW Natural to track exception and non-exception time, or at a minimum, to track the non-exception time that provides the underlying support for its test year level of expense."[14]

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[13] *Id.*

[14] *Id.*

Q. How did the Commission describe the above-referenced "certain categories of activities" in Order No. 24-359?

A. The Commission referred to those "certain categories of activities" as "indirect efforts to influence the decisions of public officials in regulatory matters."[15] It provided as a "good example" of such indirect activities the Company's "outreach to homebuilders" about "the opportunity to attend a public hearing."[16] Such efforts, the Commission explained, "fall outside the express exclusion in 18 CFR § 367.4264(b) for activities 'directly related to appearances' before regulators" and, therefore, warrant "different treatment" by being "partially non-recoverable."[17]

Q. How did the Company classify the time-tracked for outreach to homebuilders to inform them of an opportunity to comment on an issue that would directly impact their business?

A. As the Commission noted in its Order, NW Natural "voluntarily excluded this activity from the supporting materials for the budget it proposed for rate recovery."[18] However, the Commission's stated understanding that the Company "continued to argue that it should be recoverable under the FERC standard" did not accurately capture the Company's position. To be clear, the Company stated

[15] *Id.* at 39. The Commission also referred to "activities" in which the utility "engage[s] in local, state, or federal government advocacy related to issues of public interest on which customer and shareholder interests arguably diverge, *including* indirect activity related to regulatory policy decisions." Id. at 42 (emphasis added). For the purpose of this rate case, the Company treats such "activities …related to issues of public interest on which customer and shareholder interests arguably diverge" as "indirect activities."

[16] *Id*. at 40. UG 490, NW Natural/3300, Williams/15 (emphasis added).

[17] *Id.*

[18] *Id.*

its position as follows: "The Company has booked such time and activities to a non-utility (i.e., below-the-line) Civic cost center (FERC account) for which it does not seek cost recovery. *The Company does not agree with the Coalition that such communications are political lobbying,* and, out of an abundance of caution, has decided to book its time associated with such activities to a non-recoverable account."[19] In other words, that time was not political lobbying by definition under the FERC standard, but the Company clearly excluded the costs from recoverability for other reasons.

Q. How did the Commission ultimately resolve this issue?

A. The Commission stated: "In an attempt to avoid time-consuming and divisive line drawing," the Commission decided to "apply a rebuttable presumption of 50-50 sharing between customers and shareholders" for such "indirect activities to inform and influence regulatory outcomes."[20] The Commission stated that such presumption can be rebutted "with clear and convincing evidence that the activity was either core to customer interests or aligned only with the company's interests."[21] The Commission directed the Company to update its General Procedure "for its government affairs employees to ensure that future filings for rate recovery capture activities that attempt to influence public officials with regard

[19] UG 490, NW Natural/3300, Williams/15 (emphasis added).

[20] *Id.*

[21] *Id.* at 41.

to regulatory decisions, but that are not directly related to appearance before regulatory or other governing bodies."[22]

III. IMPLEMENTATION OF ORDER NO. 24-359 IN THIS GENERAL RATE CASE

Q. Is the Company updating its General Procedure as directed by the Commission in Order No. 24-359?

A. Yes. The Company is in the process of updating its General Procedure to incorporate the Commission's resolution in Order No. 24-359, issued in October 2024, with the Company's accountants' confirmation of their continued guidance from 18 Code of Federal Regulations ("CFR") Section 367.4264[23] for the Federal Energy Regulatory Commission ("FERC") as "the prevailing standard for differentiating recoverable from non-recoverable activities."[24] The Company will provide its updated General Procedure as an exhibit to its Reply Testimony in this case.

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[22] *Id*. at 40.

[23] That CFR section describes the below-the-line (i.e., non-recoverable) FERC account 426.4, as follows: "426.4 Expenditures for certain civic, political and related activities. This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."

[24] *See In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 39 (Oct. 25, 2024).

Q. Has the Company selected one of the two reporting options identified in Order No. 24-359?

A. Yes. The Company has decided at this time to apply the General Procedure to "exception and non-exception time tracking," to be effective January 1, 2025.

Q. What time tracking is the Company using for the Base Year (calendar year 2024)?

A. The Company has been exception time reporting in the Base Year as set forth in the General Procedure that became effective January 1, 2024, based upon its reasonable, good faith interpretation of and compliance with Order No. 22-388. The Company learned, through Commission Order No. 24-359, issued October 25, 2024, that the Commission did not intend its Order No. 22-388 to require only exception time reporting. As NW Natural is filing this general rate case a few months after the Commission issued Order No. 24-359, the Base Year in this rate case reflects exception time reporting only and, based on that reporting, the Company has removed from its request for cost recovery in this rate case $479,757 of Oregon-allocated lobbying and indirect activities payroll expense incurred by the Government Affairs Department in the Test Year. As a result of that exception time reporting, the Company's Oregon-allocated Test Year expense for its Government Affairs Department is $1,054,947. Effective January 1, 2025, both exception and non-exception time will be tracked.

Q. Why is the Company not beginning to track non-exception time earlier than January 1, 2025?

A. The Company needs to use the time between the issuance of Order No. 24-359, on October 25, 2024, and December 31, 2024 to ensure that processes are in place for non-exception time to be tracked effectively and efficiently. Moreover, it would not be appropriate or practical to require the Company to go back to the beginning of the Base Year (i.e., January 1, 2024) and recreate its daily reporting entries for non-exception time in addition to the exception time that the Company has been tracking since that date based upon its reasonable, good faith interpretation of and compliance with Order No. 22-388. Instead, the Company can make its exception time and non-exception time reporting, effective January 1, 2025, available to the parties in this case through the data request process.

Q. Has the Company addressed the Commission's adoption of a prospective policy that indirect activities will be subject to a rebuttable presumption of 50-50 sharing?

A. Yes. For the purpose of this general rate case, the Company has decided to track all such indirect activities as exception time rather than to apply the rebuttable presumption of 50-50 sharing for those activities. In other words, NW Natural is not seeking recovery of any costs categorized as "indirect activities." The Company is doing so in this rate case and erring on the side of caution by exception time reporting indirect activities so customers do not pay for that time, because NW Natural recognizes that it is filing this case several months after the Commission issued Order No. 24-359 and that the Company has not been tracking non-exception time during the Base Year. In future general rate cases, the Company may decide to apply the rebuttable presumption of 50-50 sharing for indirect activities through its exception time and non-exception time reporting.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1300

December 30, 2024

EXHIBIT 1300 – DIRECT TESTIMONY – OPERATIONS & MAINTENANCE /

CAPITAL EXPENDITURES

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Tobin Davilla. I am the Senior Manager of Financial Planning and Budget at NW Natural. I am responsible for producing the annual operations and maintenance ("O&M") budget, the capital expenditures budget, the income statement budget, developing the short-term and long-term financial forecasts for senior management, and generally supporting the organization with financial modeling and analysis.

Q. Please summarize your educational background and business experience.

A. I hold both a Bachelor of Science degree and a Master of Business Administration degree from Oregon State University. Prior to joining NW Natural, I held a position in Finance at PacifiCorp. I joined NW Natural in 2007 as a financial analyst and have held numerous positions within the Finance department and have been in my current position since 2018.

Q. Please provide a summary of your testimony.

A. In my testimony, I:

- Explain how the Company developed the O&M amount included in the revenue requirement, including how the Company calculated O&M costs for the calendar year 2024 base year ("Base Year") and used those costs to develop the Oregon-allocated O&M costs for the test period consisting of the 12-months ending October 31, 2026 ("Test Year"); and
- Present the Company's ongoing capital expenditures levels.

II. TEST YEAR OPERATIONS AND MAINTENANCE COSTS

Q. What is the Oregon-allocated O&M expense included in NW Natural's revenue requirement in this case?

A. The Oregon-allocated Test Year O&M expense included in the revenue requirement in this case is $234.5 million. This compares to a Company total of $262.2 million of O&M for the Test Year, which is adjusted for state allocations, and amounts that represent O&M for which the Company is not seeking cost recovery in this case. Exhibit NW Natural/1301, Davilla shows the Base Year O&M expense and Exhibit NW Natural/1302, Davilla shows the Test Year O&M expense by Federal Energy Regulatory Commission ("FERC") account.

Q. You state that the Base Year is calendar year 2024. How did NW Natural establish Base Year O&M costs given that this filing is being made in December 2024?

A. The Company used the actual expenses for January through September 2024 and forecast the expenses for the remaining three months of 2024 to develop the total Base Year O&M expenses. The total Company Base Year O&M is forecast to be $226.6 million, or $202.5 million on an Oregon-allocated basis. The Company adopted the calendar year 2024 as the Base Year because that period reflects the most recent historical information available and allows for a comparison of the Base Year with historical years consisting of the same months. NW Natural took this same approach in its last general rate case, UG 490.

Q. How did NW Natural determine the forecasted costs for October through December 2024?

A. The costs for these months are based on a forecast provided by the different business units. Business units prepare an annual budget for the coming year and provide periodic forecast updates throughout the year, the most recent update being in October 2024. The projected O&M and capital by month for the year is based on historical activity levels, in addition to planned projects and activities. NW Natural used actual expenses for the first nine months of 2024 and the forecast for the three remaining months of the calendar year to develop total Base Year O&M expense.

Q. How were the Test Year O&M costs developed?

A. O&M is composed of three components: A) O&M payroll costs; B) O&M non-payroll costs; and C) O&M other cost adjustments. The Company Base Year O&M amounts were separated into these three components. Except for several specific items, non-payroll costs were adjusted using the most current U.S. Urban Consumer Price Index ("CPI") as reported in the December 2024 Oregon Economic and Revenue Forecast, published by the Oregon Office of Economic Analysis ("OEA").[1] Other O&M cost adjustments were calculated specifically for the Test Year. Base Year payroll costs were also adjusted for increases through the Test Year.

[1] NW Natural/1303, Davilla/47.

A. O&M Payroll Costs

Q. What was the first step in calculating Test Year O&M payroll costs based on the Base Year costs?

A. The forecasted number of the Company's full-time equivalent positions ("FTEs") in the Test Year is the largest factor in the Test Year payroll O&M cost estimate. The year-end 2024 Base Year forecast includes 1,287 FTEs. These 1,287 FTEs represent positions that are expected to be filled and working at NW Natural.

Q. How did you project the number of FTEs at the end of the Base Year?

A. NW Natural's Human Resources Department provided FTE projections for the final three months of 2024 by considering actual FTE counts, projected FTE retirements, and projected FTE hires. Projected FTE attrition is based on known retirements. Projected FTE hires are based on positions the Company was in the process of hiring, considering the stage in the hiring process for each position.

Q. Do you request rate recovery for any incremental FTEs added after the Base Year?

A. Yes. The Company is seeking recovery of the costs associated with 13 FTEs after the Base Year, consisting of 14 additions expected to be hired prior to the rate effective date (i.e., November 1, 2025) and the removal of an FTE due to a planned retirement during the Test Year, for a net increase of 13 FTEs. These FTE additions are union positions in both the Customer Contact Center (Customer Service Representatives) and in Customer Field Service (Customer Field Service Representatives). Our hiring for these groups takes place with larger class hires once or twice a year. The planned classes included in this case are for the

Customer Field Service Representatives planned for March 2025 and the Customer Contact Center Representatives planned for April 2025. Additional testimony of these planned class hires can be found in the direct testimony of Melinda B. Rogers (NW Natural/1000, Rogers).

Q. Did the projected Test Year FTE count consider vacancies and FTEs allocated to non-utility activities?

A. Yes. NW Natural does not seek to recover in rates costs for 66.5 vacant FTE positions and 51.2 FTEs allocated to non-gas utility activities (termed "non-regulated FTEs" in this testimony). Table 1 below illustrates the adjustments made to the total internally approved FTEs.

Table 1

	Test Year
Approved FTEs	1,366.8
Unfilled FTE Adjustment	(66.5)
Hired FTEs	1,300.3
Non-Regulated FTE Removal	(51.2)
Regulated FTEs	**1,249.1**

Q. You state that NW Natural does not seek recovery for non-regulated FTEs in the Test Year. Please explain how non-regulated FTEs are determined.

A. Based on their historical work allocation, utility FTEs were assigned, either in part or in full, to gas-regulated or non-gas-regulated operations. A total of 51.2 FTEs were assigned to non-gas-regulated activities, which includes NW Natural employees' directly or indirectly charged time to NW Natural's affiliates. Table 2 below shows the calculated FTEs for which the Company does not seek cost recovery:

Table 2

	Test Year
Appliance Center	(8.2)
North Mist Storage	(8.0)
Interstate Storage	(6.8)
Affiliate and Other Non-Regulated Activity	(28.2)
Non-Regulated FTE Removal	**(51.2)**

Q. Please explain how FTEs are allocated to affiliates.

A. The Company has several departments that may provide services to affiliates that specifically benefit another entity. These departments direct-charge time incurred to the respective affiliate, known as "Shared Services." The Test Year allocation of FTEs to Shared Services reflects the historical number of FTEs allocated out of NW Natural to the affiliates during the Base Year.

In addition, the Company has several departments that perform administrative and general functions for the benefit of NW Natural, Northwest Natural Holding Company ("NW Holdings") and its affiliates. These departments' labor costs are indirectly charged via a corporate allocation to the affiliates that benefit from their service.

The two labor allocation mechanisms are described in more detail in the Company's Cost Allocation Manual ("CAM")[2].

Q. Please explain your escalation methodology for payroll costs.

A. Bargaining unit ("BU") employee wage increases are set according to the Collective Bargaining Agreement ("CBA") with the Union. The current agreement

[2] See *NW Natural's 2023 Affiliated Interest Report and Cost Allocation Manual*, Docket No. RG 8, Exhibit B at 4 (Apr. 30, 2024).

commenced on June 1, 2024, and will run through May 31, 2028.[3] Under the agreement all bargaining unit employees are scheduled to receive a wage increase of 4.0 percent on December 1, 2024, and on December 1, 2025. The Company also assumes an additional 1.05 percent per year for promotions, job reclassifications and movements from entry rate to experienced rate as described in the CBA.

Similarly, payroll costs were escalated for expected salary increases for non-bargaining unit ("NBU") employees. These increases are expected to be 4.50 percent on March 1, 2025, and 4.20 percent on March 1, 2026. Based on historical trends, the Company also assumes an additional 0.60 percent per year for NBU employee promotions/equity adjustments. For more detail on the salary increases, see NW Natural/1000, Rogers.

Payroll costs were also adjusted for expected changes in benefits costs. The Direct Testimony of Melinda B. Rogers (NW Natural/1000, Rogers) discusses salary and benefits cost increases.

Q. How did you determine the utility regulated payroll that is allocated to O&M activities?

A. Once the Company determines the regulated utility payroll costs, it allocates utility regulated payroll expenses to O&M and capital. NW Natural uses two approaches to allocate expenses and to charge time for various activities. In the first approach, most employees who directly work on capital activities will track and directly charge

[3] See NW Natural/1304, Davilla.

their time to capital. In the second approach, employees who are generally supportive of both capital and O&M projects, such as human resources, accounting, or finance, have a portion of their time applied to capital via an administrative transfer. The O&M payroll allocation used in the Test Year is 59.7 percent. The Company calculated this allocation using the historical O&M allocation for the trailing 12-month period ended September 2024 and incorporating the O&M allocation of FTEs hired after that date.

Q. How were payroll overhead expenses calculated for the Test Year?

A. Payroll overhead is used to allocate benefits expense. The payroll overhead expenses included in O&M are a calculated ratio of the total Test Year payroll overhead expense for executives and non-executives multiplied by the percentage of executive and non-executive labor allocated to O&M.

B. O&M Non-Payroll Costs

Q. Please explain your escalation methodology for non-payroll costs.

A. The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the U.S. Urban CPI as reported in the December 2024 Oregon Economic and Revenue Forecast, published by the OEA.[4] These escalation factors were applied on January 1, 2025, and January 1, 2026. 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.

[4] See NW Natural/1303, Davilla/47.

Q. Why did NW Natural use the U.S. Urban CPI as the escalator for these accounts instead of the West Region All-Urban CPI as has been proposed by the Company in past proceedings?

A. NW Natural continues to believe that a regional CPI provides a better measure of aggregate price changes experienced than the national CPI because the Company's expenses are regional in nature, generated in Oregon or southwest Washington, and Oregon's higher cost of living has aligned much more with the states that make up the West Region CPI than the national average. However, the Company is amenable to using the U.S. Urban CPI in this rate case because: (1) the West Region CPI rate for December 2024 Oregon Economic and Revenue Forecast closely aligns to the U.S rate in 2026 (10 basis points lower in 2026); and (2) the Company does not wish to burden witnesses and parties in this case with arguments as to which applicable rate is most accurate when the rates, although different, are closely aligned.

Q. You state above that the Company adjusted for certain items in the Test Year instead of using a CPI growth rate applied to the Base Year. Please explain what these items are and why it is more appropriate to use these cost adjustments instead of the CPI escalation factor.

A. The Company made these adjustments to ensure that the Test Year expense is as accurate as possible. These items change because of either fluctuation of contractual agreements which are both known and measurable, or the Company knows that the expenses will increase or decrease at a rate that would not be best reflected using CPI as an escalation factor. An escalation factor should only be relied on where actual costs are unknown or otherwise fail to be indicative of future costs. The following Oregon-allocated expenses in the Test Year have been adjusted accordingly:

Company Headquarters Lease Expense and Tenant Improvement Amortization (FERC 931): The contracted headquarters lease expense and tenant improvement amortization is increasing, but at a lower rate than the forecasted CPI escalation factor in this case. As a result, an adjustment is made to reduce expenses in the Test Year. The total expense adjustment decrease in the Test Year is $67 thousand, and the Oregon-allocated amount after administrative transfer is $38 thousand.

Well Casing Integrity Inspection Program (FERC 832): In December 2016, the Pipeline and Hazardous Materials Safety Administration (PHMSA) under the Department of Transportation published in the Federal Register an interim final rule (IFR) that revised the federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities.

In accordance with 49 CFR 192.12(d)(2), NW Natural initiated a rig-based casing inspection program in 2017 to satisfy the integrity management baseline risk assessment requirement. The current well work schedule supports completing the baseline casing inspection program in 2025. The baseline casing inspection program work is capitalized. Beginning in 2024, NW Natural began its first re-inspection program to perform re-assessments consistent with intervals established from the baseline casing inspection logs and updated risk analyses to satisfy the conditions of 49 CFR 192.12(d)(3). This reassessment work is an O&M expense. The total expense increase for re-inspections in the Test Year is $716 thousand, and the Oregon-allocated amount is $637 thousand.

Advertising Adjustment (FERC 913 & 909): The Company included advertising costs for Category A equivalent to $2.15 per customer, and $900,000 for Category B expense and removed expense for all other categories of advertising. The Direct Testimony of Cory A. Beck *(*NW Natural/1100, Beck) discusses in more detail the advertising expense decrease. The total expense decrease in the Test Year is $586 thousand, and the Oregon-allocated amount is $556 thousand.

Contracted Customer Payment Processing Fees and Postage (FERC 903): The Company entered into an agreement with Paymentus[5] to provide electronic bill payment services in March 2019 that went into effect in October 2020. The Company recently signed a contract amendment and extension through May 2027.[6] The agreed-upon amendment includes a new service fee schedule. In addition to the impact of the new fee schedule, the Company has experienced a strong customer preference to pay by bankcard, as evidenced by the historical number of transactions increasing annually. Test Year transactions are expected to grow at a 10 percent compound annual growth rate from the Base Year to the Test Year. In addition to these impacts, the postage rate has grown by 4.7 percent

[5] See Confidential NW Natural/1305, Davilla.

[6] See Confidential NW Natural/1306, Davilla.

on average each year over the past five years. This annual increase is expected to continue to occur from the Base Year to the Test Year. The total expense increase in the Test Year is $1.92 million, and the Oregon-allocated amount is $1.69 million.

Contracted Locating & Survey Services (FERC 874): The Company employs the services of a third-party contactor, Heath Consultants Incorporated ("Heath Consultants"), to provide locating and marking services to the Company, and survey and inspection services. The Company entered into an amended agreement with Heath Consultants effective September 1, 2023.[7] This agreement runs through December 31, 2026. The agreement between the Company and Heath Consultants sets the rate per locate for both low and high pressure locates, as well as hourly standby rates. This rate is set to increase at a 3 percent annual increase throughout the contract. In addition to these increases in rates per locate in the Test Year, NW Natural has also experienced annual increases in the number of low-pressure locating service units it receives. This increase is due to customer education and customer growth. The Company expects that locating units will continue to increase 1.5 percent annually through the Test Year. In addition to the locating and marking services, they provide survey and inspection services to the Company. The Company and Heath Consultants have a contractual agreement that sets the rate per foot of inspection. This rate is set to increase at 3 percent annually throughout the contract. The total expense increase for both locating and

[7] See Confidential NW Natural/1307, Davilla.

survey services in the Test Year is $523 thousand, and the Oregon-allocated amount is $463 thousand.

Information Technology and Services ("IT&S") (FERC 921): The Direct Testimony of Brian E. Fellon (NW Natural/700, Fellon*)* discusses in more detail the largest components of the IT&S O&M expense increase. The total expense increase in the Test Year is $2.8 million, and the Oregon-allocated amount after administrative transfer is $2.1 million.

Insurance (FERC 924): The Company has incurred insurance premiums for the fiscal period 2024-2025 and 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. The Company's excess liability insurance costs are increasing beginning November 2025 for two reasons: (1) pricing for excess liability insurance has increased dramatically across insurance markets, particularly for gas and electric utilities; and (2) the Company is falling behind its peers with respect to the levels of excess liability insurance limits purchased. Both of these factors are driven by unprecedented losses experienced in the United States in a number of industries. The size and frequency of catastrophic jury awards, often referred to as “nuclear verdicts”, have been increasing at a pace that far exceeds inflation for the past several years. The effect of these verdicts is exacerbated for gas and electric utilities due to the rapid increase in size and frequency of catastrophic wildfire claims. Combined, these circumstances have resulted in significantly higher premiums and reduced market capacity for excess liability. For the 2024-2025 insurance year, the Company saw a 22 percent increase in premium for policies that provide the same level of excess liability limits purchased in the prior year and a wildfire coverage limit that was 29 percent lower than the prior year.

The Company has conducted benchmarking and determined that peers are purchasing excess liability limits that are between 25 percent and 67 percent higher than the limits the Company is purchasing. Considering these trends, it is reasonable and prudent for the Company to increase the liability insurance limit purchased in order to maintain adequate coverage. The need for higher limits and rising costs for those higher limits will result in an increase in excess liability premiums. The total expense increase in the Test Year is $3.6 million, and the Oregon-allocated amount after administrative transfer is $2.7 million.

Grant Mining Service (FERC 921): The Company has initiated work with a grant mining service in the Base Year to investigate grants that may be available to the Company. Grant mining services have become a critical tool given the influx of federal and state funding available for emissions reduction projects and clean energy integration. Successfully securing funding would allow the Company to implement projects while minimizing rate impacts, and in recent years utilities have secured funding through grants well exceeding the application and mining costs.

The service provides specialized expertise that would otherwise require extensive training and resources to develop in-house. By utilizing a dedicated service, the utility gains immediate access to experts who understand the complex landscape of available funding sources, eligibility requirements, and the nuances of competitive applications. This approach ensures a streamlined process and maximizes the utility's chances of securing high-impact grants without the added costs and responsibilities of hiring and retaining new staff members. The total expense increase in the Test Year is $239 thousand, and the Oregon-allocated amount is $178 thousand.

Pipeline Inspection Integrity Program (FERC 856): The Company is required by code to perform assessments on transmission system pipelines every seven years. The Company will utilize inline inspection technologies to assess the Company’s 8-inch diameter through 24-inch diameter transmission pipelines that have been made piggable. Each year's inspections can vary by the transmission pipeline’s diameter being inspected, the pipeline length being inspected, and the location of the pipeline such as in urban areas or rural areas. Each of these variables impacts our transmission pipeline assessment vendor and internal labor costs. In summary, the Company’s transmission assessment costs vary by year due to the variability in pipeline, size, length and location of pipeline to be assessed. The Test Year is expected to inspect larger and longer pipelines than in the Base Year. The total expense increase in the Test Year is $3.42 million, and the Oregon-allocated amount is $3.37 million.

Employee Protection Equipment (FERC 921): BU employees who are required to wear fire retardant ("FR") clothing, required to wear safety footwear, or require prescription safety glasses receive an annual allowance for reimbursement set according to the CBA with the Union. The current agreement commenced on June 1, 2024, and will run through May 31, 2028. Under the new agreement[8] the reimbursement amounts have increased. The total expense increase in the Test Year is $261 thousand, and the Oregon-allocated amount after administrative transfer is $194 thousand.

Legal Fees (FERC 921): NW Natural is subject to claims and litigation arising in the ordinary course of business. However, the Company has recently experienced a heightened level of litigation, particularly as a defendant. As such, the Company will defend itself in more legal proceedings than in the Base Year, resulting in incremental recoverable legal expense in the Test Year. The total expense increase in the Test Year is $1 million, and the Oregon-allocated amount after administrative transfer is $744 thousand.

Q. Are Non-Payroll O&M costs adjusted to reflect services provided from NW Natural to its affiliates?

A. Yes. NW Natural's O&M costs are reduced to reflect a credit for expenses associated with services to affiliates. The non-payroll portion of Shared Services is calculated by imputing an administrative overhead of 24.1 percent to the payroll

[8] See NW Natural/1304, Davilla/77.

charges.[9] The Oregon-allocated credit amount after administrative transfer during the Test Year is $519 thousand.

In addition, the Company has several departments that perform administrative and general functions for the benefit of NW Natural, NW Holdings and its affiliates. These departments' labor and non-labor costs are indirectly charged via a corporate allocation to the affiliates that benefit from their service. The payroll, and a forecasted 24.1 percent non-payroll overhead is applied to payroll is credited through a mechanism described in more detail in the CAM.[10] The Oregon-allocated indirect non-payroll allocated amount and 24.1 percent administrative overhead rate credited to the utility during the Test Year is $457 thousand.

Q. Does the Test Year include any other adjustments?

A. Yes. All Executive Incentive Compensation was removed from the Test Year (NW Natural/1000, Rogers), as NW Natural is not seeking recovery for these costs.

C. O&M Other Cost Adjustments

Q. Once you have calculated O&M payroll and non-payroll expenses, do you perform any further adjustments?

A. Yes. Once payroll and non-payroll expenses are calculated, O&M is adjusted to reflect: a) the Commission-authorized amount of $5.0 million expense related to environmental remediation (see UM 1635, Order No. 15-049, where a tariff rider

[9] See *NW Natural's 2023 Affiliated Interest Report and Cost Allocation Manual*, Docket No. RG 8, Exhibit B at 6 (Apr. 27, 2023).

[10] *Id*. at 7.

of $5.0 million was established to be applied toward recovery of environmental remediation expense); b) the Commission-authorized amount of $7.1 million expense related to pension balancing amortization (see UG 344 Phase II, Order No. 19-105); c) Oregon Horizon Amortization expense of $976 thousand (see UG 435 Order No. 22-388), and d) corporate O&M adjustments.

Q. What items are included in the corporate O&M adjustments?

A. Listed below are the items included in the Oregon-allocated corporate adjustments:

- Administrative Transfer: $26.3 million credit – The administrative transfer allocates a portion of payroll and non-payroll administrative expenses, such as the salaries and expenses of Accounting, Human Resources, Facilities, and general administration, from O&M to construction activities. These costs are categorized as indirect construction overhead because they are not charged directly to specific or individual construction projects.
- Payroll Tax: $7.9 million credit – This credit removes payroll tax expense from O&M and transfers it to the “Other Taxes” line of the revenue requirement. This adjustment is required by FERC accounting methodology. The payroll tax expense is included in the revenue requirement in this case under the “Other Taxes” area and is not included in O&M costs.
- Post-Retirement Medical Non-Service: $921 thousand expense – The total post-retirement medical plan expense (ASC-715-60) is forecasted by our actuary, Fidelity. The Company used the latest forecast provided to us prior

to filing this rate case. The actuary forecasted total post-retirement medical plan costs in the Test Year to be $1.0 million. This is made up of a service component (Operating Cost) and a non-service component (Non-Operating Cost). The service expense forecasted in the Test Year is $62 thousand and is included in the payroll overhead rates that are allocated to O&M, capital, and non-utility work based on the payroll work mix. The total non-service expense projected by the actuary for the Test Year is $965 thousand, or $921 thousand Oregon-allocated. This cost is an O&M expense.

- Pension Non-Service: $6.0 million expense – The total pension expense (ASC 715) is forecasted by our actuary, Fidelity. The Company used the latest forecast provided to us prior to filing this rate case. The actuary forecasted total system pension cost in the Test Year to be $9.4 million. This is made up of a service component and a non-service component. The system service expense forecasted in the Test Year is $3.2 million and is included in the payroll overhead rates that are allocated to O&M and capital based on the payroll work mix. The total non-service expense projected by the actuary for the Test Year is $6.3 million, or $6.0 million Oregon-allocated. This non-service portion of pension is an O&M expense.
- Claims and Damages: $140 thousand expense – This expense is based on a three-year historical average.
- Severance: $74 thousand expense – This expense is based on a three-year historical average.

- Stock Expense: $790 thousand expense – This expense includes the employee stock purchase plan for non-officer employees, as well as employee stock expense compensation for non-officer employees. The Direct Testimony of Melinda B. Rogers (NW Natural/1000, Rogers*)* discusses this plan in detail.
- Long Term Incentive Plan: $138 thousand expense – This long-term incentive applies to key non-officer employees. The Direct Testimony of Melinda B. Rogers (NW Natural/1000, Rogers*)* discusses this plan in detail.

The overall effect of these corporate adjustments is a reduction to Company O&M of $26.1 million.

Q. How did NW Natural allocate O&M expenses to Oregon?

A. The Company converted its O&M forecast into FERC accounts based on actual historical FERC allocations to allow for a state allocation based on FERC accounts. For Test Year expenses that may not have been incurred in the historical period, the costs were allocated to the appropriate FERC account. NW Natural then applied the relevant Oregon allocation factor to each FERC account to calculate Oregon-allocated O&M. The Oregon FERC allocation factors are determined by considering the specific drivers, such as volumes or customers, that have a causative effect on costs in that account. The allocation methodology is described in the Direct Testimony of Kyle T. Walker (NW Natural/1500, Walker).

Q. Does NW Natural have cost control protocols and practices in place?

A. Yes. Under the direction of the Chief Financial Officer and Chief Executive Officer, my department engages in an annual budgeting and financial planning process, through which we determine and manage to a Company-wide budget. This budget is informed by individual departmental needs, overall Company goals, and an ongoing focus on controlling costs. Throughout the year, we provide reporting on budgets to actuals for each department and engage with departments on their spending levels. We also require justifications for department budgets and significant departures from budgeted amounts.

Q. Please provide your view of NW Natural's O&M levels, and the amounts of O&M reflected in the Test Year.

A. NW Natural's O&M levels have grown at a reasonable rate, reflecting good cost management practices within the Company. As is true with most companies, much of the pressure on our O&M expense levels comes from inflation and its impact on goods and services, and salary and wage growth. In addition, as described above, the Company's O&M in the Test Year is increasing based on contracted increases that represent "lumpier" increases to O&M, such as the recent customer payment processing contract and locating and survey service contract.

Furthermore, as described more in the Direct Testimony of Brian E. Fellon (NW Natural/700, Fellon), NW Natural seeks to ensure the same foundational level of service and reliability to customers, while allowing for the flexible adoption of evolving technological solutions such as cloud-based solutions. The Company works to balance the growing need for technological innovation, while preserving and extending the useful life of existing IT&S platforms and programs.

III. CAPITAL EXPENDITURES AND FORECAST

Q. What are the forecasted capital expenditures for the next three calendar years and the Test Year?

A. The utility capital expenditures planned for calendar year 2024 is $377 million, for 2025 is $353 million, and for 2026 is $361 million. The capital expenditures forecasted during the Test Year is $343.1 million.

Q. Please describe NW Natural's recent history related to capital investments.

A. The Company has been making important capital investments in natural gas distribution, system reinforcement, gas supply and storage, and new technology to better serve the needs of our customers. These investments center on enhancement of safety, service reliability, and the replacement of aging infrastructure.

Q. Please explain the capital projects for which the Company seeks recovery in this case.

A. The Company seeks to add to rate base its investment in the following categories of capital projects:

1. All capital expenditures completed since the Company's last rate case, UG 490, that will be used and useful as of the rate effective date of this case—November 1, 2025. These include both the Company's discrete and non-discrete investments. For these capital expenditures, the Company seeks to recover the total investment, less depreciation incurred since the date the investment was completed.

2. All capital expenditures, both discrete and non-discrete, that will be completed during the Test Year. These projects may be completed at various times during that year. The Company used an average through the Test Year so that customers' rates will reflect those investments only to the extent that they are used and useful in providing utility service within the Test Year.

Q. Please describe NW Natural's capital expenditures budgeting process, and how the Company calculates projected capital expenditures.

A. The forecasted capital expenditures are developed using the following steps:

1. Operating units submit a detailed capital forecast based on their business need.
2. The Financial Planning Department reviews the forecasted capital and verifies that each operating unit has adequately supported its assumptions.
3. The operating units' forecasts are summarized to create the capital requirements by year.
4. The capital requirements are reviewed by their respective executive for completeness and reasonableness, and adjustments are made as appropriate.
5. Once the calendar year forecasts are completed, program and project expenditures are spread by month based on projected project spending schedules. Most capital construction projects are planned for construction during the summer months and are placed in-service in the fall. This is to

avoid any delays and complications due to inclement weather as well as providing the benefits by the start of the heating season.

Q. Please describe the difference between "discrete" and "non-discrete" expenditures.

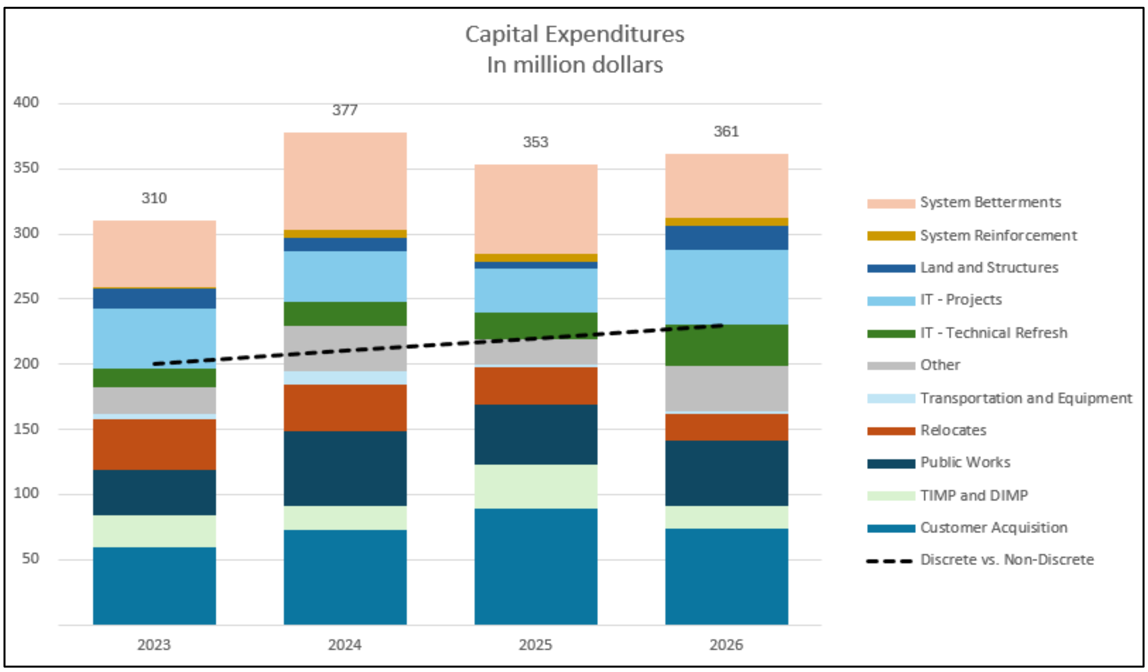
A. The Company's capital expenditures can be thought of as falling into one of two categories. The first category consists of "discrete investments" that the Company has proposed and planned to implement to fulfill a specific operational aim, or to address a specific system issue. These discrete projects tend to fall into subcategories of System Betterments (*e.g*. investments in Newport LNG, Portland LNG, and Mist storage or gate stations), System Reinforcement Projects, Information Technology and Land and Structures. These discrete projects tend to represent lumpy investments, and costs associated with these projects can vary year over year.

The second category can be thought of as "non-discrete capital expenditures," in which investments are made consistently year-over-year, and over which the Company generally does not exercise much discretion. The consistency of expenditures in this category forms the basis of a predictable recurring level of investment. 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"). A portion of the Company's IT&S investment falls under this category as well, and is very consistent year-over-year, following a clear trend line and is therefore very predictable.

Q. Have you prepared an illustration of the Company's discrete and non-discrete capital investment in recent years?

A. Yes. Figure 1 below shows year-over-year capital expenditures, in both discrete and non-discrete capital, and I have added a trend line that shows the increased spend on non-discrete capital projects over time. As you can see, some of the categories of non-discrete investment remain quite stable over time or have increased over time due to factors such as inflation, customer growth or jurisdictional requirements. However, overall, the spending related to NW Natural's non-discrete investment has increased slowly and steadily over time.

<u>Figure 1</u>



Q. Does the Company describe the primary drivers behind NW Natural's discrete planned capital expenditures?

A. Yes, these drivers are discussed in the Direct Testimonies of Daniel B. Kizer and Scott S. Johnson *(*NW Natural/500, Kizer-Johnson), Wayne K. Pipes (NW Natural/600, Pipes)*,* and Brian E. Fellon (NW Natural/700 and 800, Fellon).

Q. In forecasting expenditures in non-discrete categories for the Test Year, did the Company rely solely on historical trends?

A. No. To forecast certain non-discrete investment for the Test Year, the Company also relied on plans prepared in the regular course of business by managers in charge of each category.

Q. Can you describe the types of investments included in each non-discrete category and summarize how forecasts were prepared for the Test Year for each category?

A. Each of these categories contains investments that occur consistently and are related to the day-to-day operation of the Company as follows:

- ***Customer Acquisition.*** Customer growth projects are the capital expenditures necessary to connect new customers to the Company's system. These projects require extending mains and installing service lines, regulators, and meters, as well as related permitting. The Company can accurately forecast these costs based on its gross customer addition projections. Meter and regulator equipment cost trends are also influenced by periodic changes for cause requirements (*e.g.*, replacements of faulty or outdated equipment).

- ***TIMP and DIMP***. These programs are federally mandated and require the Company to undertake projects to increase the safety and reliability of the transmission and distribution systems. While these costs are generally projected based on historical trends, they have been increasing—and are expected to continue to increase—based on the need for in-line inspections[11] on the Company's system.
- ***Public Works***. These are projects that are required by the governmental jurisdictions in which the Company operates. These may include moving, replacing, or adding infrastructure. Typically, at the time budgets are prepared for these projects, the Company has no project-specific information about what will be required in the upcoming year, and therefore it budgets based on historical trends.
- ***Relocates.*** These projects involve the relocation of pipe for safety and compliance purposes. Projections for relocates are based on historical trends.
- ***Transportation and Equipment.*** The Company incurs costs each year to replace or improve the aged portion of its fleet of vehicles and construction equipment that is necessary to operate the Company. The Company can forecast these costs based on its annual trends, as well as an ongoing

[11] In-line inspections require that the Company ascertain the status of pipe through inspections from within the pipe, accomplished through using electronic devices that are transported through the pipe. These devices are commonly referred to as "pigs".

assessment of the condition and use of vehicles currently in the Company's fleet, and industry standards for lifecycle of the vehicles and equipment.

- ***Other (Damages, Tools, Leakage and District Regulators).*** *Damages* - The Company's system incurs damage each year. At the time of planning, the Company does not know where and when the damage will occur, but based on historical trends, it can forecast the costs with accuracy. *Tools* - Like transportation and equipment, the Company incurs costs each year to purchase and repair its small tools (items that can be small or larger in nature such as electronics that detect gas) that are necessary for employees to perform their job functions. These costs are projected based on annual trends, the Company's inventories, safety needs, and best practices for replacement of equipment at the end of its useful life. *Leakage* – Leakage costs represent replacements of services and mains that result from leaks on the Company's system. Like damage and public works projects, these projects are not necessarily identified in advance. However, the Company can rely on historical trends to project the costs during the Test Year. *District Regulators* – These costs represent the installation or replacement of district regulators due to system expansion, public works, system reinforcement, quality assurance remediation, and corrosion protection or compliance requirements.
- ***Information Technology***. This category includes radio/electronic equipment (*e.g.*, radio, microwave, telemetry equipment) and computer software/hardware equipment. These costs tend to increase year-over-

year based on new projects and needs. The Company builds these projections from the bottom up based on identifiable needs. These costs have experienced an increase due to cybersecurity threats and other increasing demands and complexity in the IT arena.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NW Natural

Exhibits of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBITS 1301 – 1307

December 30, 2024

EXHIBITS 1301-1307 – OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES

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NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1301

December 30, 2024

NW Natural
Base Year Twelve Months Ended December 31, 2024
Operations and Maintenance Expense

FERC Acct.	Description	BASE YEAR System (a)	BASE YEAR Oregon (b)
	Natural Gas Storage		
	Underground Storage Expense		
	Operation		
816	**Wells Expense**	$598,825	$537,324
818	**Compressor Station Expense**	96,262	85,635
819	**Compressor Station Fuel**	0	0
820	**Measuring and Regulator Station Expense**	3,381,823	3,009,151
821	**Purification Expense**	-	-
	Maintenance		
832	**Wells Expense**	279,233	248,406
834	**Compressor Station Expense**	1,599,543	1,422,954
	Total Underground Storage Expense	5,955,687	5,303,469
	Other Storage Expense		
	Operation		
840	**Supervision and Engineering**	9,875	8,785
	Total Other Storage Expense	9,875	8,785
	Liquified Natural Gas Expense		
	Operation		
844	**Supervision and Engineering**	1,774,735	1,578,805
845	**LNG Fuel**	(37,631)	(33,477)
	Maintenance		
847	**Supervision and Engineering**	1,342,850	1,194,600
	Total Liquified Natural Gas Expense	3,079,954	2,739,927
	Total Natural Gas Storage	9,045,517	8,052,182
	Transmission Expense		
	Operation		
856	**Mains Expense**	1,133,265	1,119,124
	Maintenance		
863	**Maintenance of Mains**	-	-
	Total Transmission Expense	1,133,265	1,119,124
	Distribution Expense		
	Operation		
870	**Supervision and Engineering**	3,847,465	3,542,243
874	**Mains and Services Expense**	22,373,434	19,807,512
875	**Measuring and Regulator Station Expense - General**	427,570	389,417
877	**Measuring and Regulator Station Expense - City Gate**	708,358	640,667
878	**Meter and House Regulator Expense**	5,719,922	5,024,379
879	**Customer Installation Expense**	14,649,764	12,868,765
880	**Other Expense**	2,241,098	1,973,927
881	**Rents**	369,494	320,366
	Maintenance		
885	**Supervision and Engineering**	6,102,365	5,526,939
887	**Mains**	5,287,297	4,865,401
889	**Measuring and Regulator Station Expense - General**	2,484,121	2,250,597
891	**Measuring and Regulator Station Expense - City Gate**	218,419	199,420
892	**Services**	422,043	370,722
893	**Meters and House Regulators**	3,561,244	3,132,494
894	**Other Equipment**	16,247	14,271
	Total Distribution Expense	68,428,840	60,927,121
	Customer Accounts Expense		
	Operation		
901	**Supervision**	2,218,235	1,948,498
902	**Meter Reading Expenses**	1,030,007	904,758
903	**Customer Records and Collection Expense**	21,886,182	19,251,186
904	**Uncollectible Accounts**	-	-
	Total Customer Accounts Expense	25,134,424	22,104,441
	Customer Service and Informational		
	Operation		
906	**Customer Service and Informational Expenses**	930,195	817,083
907	**Supervision**	-	-
908	**Customer Assistance Expense**	2,074,215	1,822,198
909	**Customer Information Expense**	2,821,374	2,478,295
910	**Miscellaneous Customer Service Expense**	191,862	168,187
	Total Customer Service and Informational	6,017,647	5,285,763
	Sales Expense		
	Operation		
911	**Supervision**	211,930	186,159
912	**Demonstration and Selling Expense**	1,340,804	1,177,638
913	**Advertising**	869,495	763,764
916	**Miscellaneous Sales Expense**	-	-
	Total Sales Expense	2,422,229	2,127,561
	Administrative and General Expense		
	Operation		
921	**Office Supplies and Expense**	97,543,783	85,401,996
922	**Administrative Expenses Transferred - Credit**	(34,188,416)	(30,064,400)
924	**Property Insurance Premium**	5,903,957	5,210,242
925	**Injuries and Damages**	185,909	164,065
926	**Employee Pensions and Benefits**	17,266,573	16,808,724
928	**Regulatory Commission Expense**	-	-
930	**Miscellaneous General Expense**	5,097,964	4,680,902
931	**Rents**	10,921,021	9,638,244
	Maintenance		
932	**Maintenance of General Plant**	6,692,635	6,006,208
	Total Administrative and General Expense	109,423,426	97,845,980
	Total Operations and Maintenance Expense	221,605,346	197,462,173
407	**Environmental Rider**	5,000,000	5,000,000
	Total O&M Expense including Environmental Rider	226,605,346	202,462,173

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1302

December 30, 2024

NW Natural
Test Year Twelve Months Ended October 31, 2026
Operations and Maintenance Expense

FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
	Natural Gas Storage		
	Underground Storage Expense		
	Operation		
816	**Wells Expense**	$622,163	$558,264
818	**Compressor Station Expense**	100,504	89,409
819	**Compressor Station Fuel**	0	0
820	**Measuring and Regulator Station Expense**	3,870,409	3,443,895
821	**Purification Expense**	-	-
	Maintenance		
832	**Wells Expense**	1,029,874	916,176
834	**Compressor Station Expense**	1,673,494	1,488,740
	Total Underground Storage Expense	7,296,444	6,496,485
	Other Storage Expense		
	Operation		
840	**Supervision and Engineering**	10,835	9,639
	Total Other Storage Expense	10,835	9,639
	Liquified Natural Gas Expense		
	Operation		
844	**Supervision and Engineering**	2,025,261	1,801,672
845	**LNG Fuel**	(39,264)	(34,929)
	Maintenance		
847	**Supervision and Engineering**	1,549,360	1,378,311
	Total Liquified Natural Gas Expense	3,535,358	3,145,055
	Total Natural Gas Storage	10,842,638	9,651,179
	Transmission Expense		
	Operation		
856	**Mains Expense**	4,651,581	4,593,538
	Maintenance		
863	**Maintenance of Mains**	-	-
	Total Transmission Expense	4,651,581	4,593,538
	Distribution Expense		
	Operation		
870	**Supervision and Engineering**	4,544,102	4,183,616
874	**Mains and Services Expense**	24,871,704	22,019,266
875	**Measuring and Regulator Station Expense - General**	487,314	443,831
877	**Measuring and Regulator Station Expense - City Gate**	805,569	728,588
878	**Meter and House Regulator Expense**	6,742,973	5,923,027
879	**Customer Installation Expense**	17,193,875	15,103,584
880	**Other Expense**	2,652,843	2,336,587
881	**Rents**	386,801	335,372
	Maintenance		
885	**Supervision and Engineering**	7,262,866	6,578,010
887	**Mains**	6,100,054	5,613,305
889	**Measuring and Regulator Station Expense - General**	2,885,611	2,614,345
891	**Measuring and Regulator Station Expense - City Gate**	253,040	231,029
892	**Services**	490,668	431,003
893	**Meters and House Regulators**	4,207,503	3,700,948
894	**Other Equipment**	19,436	17,073
	Total Distribution Expense	78,904,361	70,259,583
	Customer Accounts Expense		
	Operation		
901	**Supervision**	2,649,734	2,327,526
902	**Meter Reading Expenses**	1,219,248	1,070,987
903	**Customer Records and Collection Expense**	26,636,920	23,429,956
904	**Uncollectible Accounts**	-	-
	Total Customer Accounts Expense	30,505,902	26,828,470
	Customer Service and Informational		
	Operation		
906	**Customer Service and Informational Expenses**	1,106,867	972,272
907	**Supervision**	-	-
908	**Customer Assistance Expense**	2,482,182	2,180,597
909	**Customer Information Expense**	3,540,335	3,109,830
910	**Miscellaneous Customer Service Expense**	229,254	200,964
	Total Customer Service and Informational	7,358,637	6,463,662
	Sales Expense		
	Operation		
911	**Supervision**	253,571	222,737
912	**Demonstration and Selling Expense**	1,572,786	1,381,389
913	**Advertising**	0	0
916	**Miscellaneous Sales Expense**	-	-
	Total Sales Expense	1,826,358	1,604,126
	Administrative and General Expense		
	Operation		
921	**Office Supplies and Expense**	108,433,000	94,935,775
922	**Administrative Expenses Transferred - Credit**	(39,272,217)	(34,534,962)
924	**Property Insurance Premium**	9,490,282	8,375,174
925	**Injuries and Damages**	187,173	165,180
926	**Employee Pensions and Benefits**	20,034,915	19,452,013
928	**Regulatory Commission Expense**	-	-
930	**Miscellaneous General Expense**	5,520,588	5,074,330
931	**Rents**	11,358,034	10,023,925
	Maintenance		
932	**Maintenance of General Plant**	7,398,475	6,639,655
	Total Administrative and General Expense	123,150,251	110,131,090
	Total Operations and Maintenance Expense	257,239,728	229,531,649
407	**Environmental Rider**	5,000,000	5,000,000
	Total O&M Expense including Environmental Rider	262,239,728	234,531,649

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1303

December 30, 2024

DAS
DEPARTMENT OF ADMINISTRATIVE SERVICES

Oregon Economic and Revenue Forecast

December 2024

Volume XLIV, No. 4
Release Date: November 20th, 2024

Department of Administrative Services
Berri Leslie
DAS Director
Chief Operating Officer

Office of Economic Analysis
Carl Riccadonna, Chief Economist
Mitchell D’Sa, Economist
Michael Kennedy, Economist
Jordan Macias, Economist
Kanhaiya Vaidya, Senior Demographer

http://oregon.gov/DAS/OEA
http://oregoneconomicanalysis.com
http://twitter.com/OR_EconAnalysis

Foreword

This document contains the Oregon economic and revenue forecasts. The Oregon economic forecast is published to provide information to planners and policy makers in state agencies and private organizations for use in their decision-making processes. The Oregon revenue forecast is published to open the revenue forecasting process to public review and is the basis for much of the Oregon state government budgeting process.

The report is issued four times a year: March, June, September and December.

The economic model assumptions and results are reviewed by the Department of Administrative Services Economic Advisory Committee and by the Governor's Council of Economic Advisors. The Department of Administrative Services Economic Advisory Committee consists of 15 economists employed by state agencies. The Governor's Council of Economic Advisors is a group of 12 economists from academia, finance, utilities and industry.

Members of the Economic Advisory Committee and the Governor's Council of Economic Advisors provide a two- way flow of information. The Department of Administrative Services makes preliminary forecasts and receives feedback on the reasonableness of such forecasts and assumptions employed. After the discussion of the preliminary forecast, the Department of Administrative Services makes a final forecast using the suggestions and comments made by the two reviewing committees.

The results from the economic model are used to provide a preliminary forecast for state tax revenues. The preliminary results are reviewed by the Council of Revenue Forecast Advisors. The Council of Revenue Forecast Advisors consists of 15 specialists with backgrounds in accounting, financial planning and economics. Members bring specific specialties in tax issues and represent private practices, accounting firms, corporations, government (Oregon Department of Revenue and Legislative Revenue Office) and the Governor's Council of Economic Advisors. After discussion of the preliminary revenue forecast, the Department of Administrative Services makes the final revenue forecast using the suggestions and comments made by the reviewing committee.

Readers who have questions or wish to submit suggestions may contact the Office of Economic Analysis by email at das_dl_oea@das.oregon.gov.

Berri Leslie

Berri Leslie
DAS Director
Chief Operating
Officer

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Executive Summary

December 2024 — Economic Resilience Complicating Inflation Normalization

The national economy appears on track to continue normalizing relative to post-pandemic distortions, but the campaign to restore stable, low inflation remains incomplete. The pace of output growth, as measured by GDP, continues to moderate but remains above the economy's longer-term potential. As a result, inflation pressures are proving persistent as the economy continues to face labor and capacity constraints.

The consensus among forecasters anticipates real GDP growth of 2.7% in 2024 (annual average) compared to 2.9% in 2023. For reference, trend growth—that which would reflect the economy growing near its potential, and thereby be consistent with inflation returning to policymakers' 2% objective—is generally assumed to be closer to 1.8%. With the labor market near full capacity, as reflected in a national unemployment rate of 4.1%, continued progress toward lower inflation is likely to prove difficult with growth exceeding potential. At the time of writing, tracking nowcasts for current quarter growth (~2.6%) were again exceeding forecasters' estimates.

The November presidential and congressional elections will have significant consequences for the national economic outlook. While it is premature to economically "score" many of these measures until more granular details are available, it is still possible to see clear economic repercussions for the outlook as a result. In particular, expansion of tariffs, more restrictive immigration policies, tax reforms/cuts and deregulation stand as significant departures from the status quo, which broadly informed consensus estimates prior to the election.

The OEA assesses the impact of these potential measures apolitically—judging them as neither good nor bad, but rather as factors influencing the outlook. Until the timing and details of the next administration's priorities are more clearly defined, it is prudent to say that medium-term economic tail risks have increased; or put another way, the potential distribution of outcomes relative to pre-election projections has widened.

At the state level, Oregon's economy is currently demonstrating moderate health. Output growth is lagging the national statistics but is showing some signs of reacceleration. Net job creation remains positive, but it is concerning to see job creation concentrated in just a few industry categories.

Oregon economic activity will be highly vulnerable to the national priorities noted above. Oregon's labor market has proven resilient in the post-pandemic era and is operating at high levels of labor utilization, based on measures such as labor force participation or the employment-population ratio. As such, the state will need to depend on in-migration (from other states or internationally) to supply sufficient additional workforce. Tariffs will be extremely consequential to key industrial pillars of the Oregon economy, including timber, agriculture, tech/semiconductors and apparel. And tax reforms will have meaningful consequences for both overall growth prospects (particularly if tax cuts are unfunded, thereby amounting to potentially significant fiscal stimulus), but they may also impact Oregon's linkages to the national economy, for example if the SALT deduction cap is modified.

A more moderate economic deceleration relative to previous forecasts has resulted in state revenues continuing to outpace expectations in recent months. In particular, both personal and corporate income taxes have come in somewhat higher than the previous forecast. Consumption-based revenues like lottery, the corporate activity tax, and recreational marijuana are in line with expectations.

Many consecutive positive revisions to the General Fund forecast necessitated a thorough review of the methodologies and assumptions underlying prior forecasts. The findings are that certain modeling choices and errant relationships were causing low predictions relative to actual collections. This December forecast attempts to rectify these issues, resulting in significant increases in expected Personal and Corporate Income Tax revenues. In addition, the Personal Income Tax forecast exhibits an additional bump due to expectations about capital gains in light of currently robust market conditions. The exact results of these conditions will not be known until the bulk of 2024 tax returns are processed through fall of 2025.

The revenue picture for the current 2023-25 biennium is improved by $947.0 million compared to the prior forecast. The total increase since the Close of Session forecast is $2,838.6 million. Increased revenues in the current biennium also increase the projected kickers. The personal kicker now stands at an expected $1,792.4 million that will be returned to taxpayers as a credit on their 2025 tax return. The corporate kicker now stands at an expected $1,024.5 million and will be retained in the General Fund and spent on education next biennium.

For 2025-27, available General Fund resources, which includes an increase in the beginning balance carried forward from the current biennium, are increased by $2.267 billion to a total of $37.8 billion. The full effects of the personal income tax revisions discussed previously are muted by the increase in the projected kicker credit factored into the 2025-27 revenue stream.

Consumption-based tax collections for the corporate activity tax, the lottery, and recreational marijuana are increased a combined $31.5 million for the 2023-25 biennium, while total revenues across the three sources are revised upward $14.3 million for the upcoming 2025-27 biennium.

Economic Outlook

Macroeconomic Setting

The national economy appears on course to experience a post-pandemic “soft landing” (i.e. economic normalization that avoids lapsing into recession). As a result, the State of Oregon similarly faces improving economic prospects heading into the 2025-27 biennium. Recession risks have diminished appreciably as moderating price pressures have given policy makers the opportunity to begin lowering interest rates.

In the modern era, it has been extremely unusual for policy makers to successfully reduce elevated inflation through restrictive monetary policy while not overtightening financial conditions and ultimately driving the economy into recession. However, the consensus among professional forecasters is increasingly convinced that just such an outcome is at hand. They anticipate both growth and inflation near 2% in 2025.

In recent years, Oregon economic activity has demonstrated a tighter correlation with the national economy, as measured by variables such as production or unemployment. This coordination is attributable to a multitude of factors of varying permanence. Powerful developments at the national level during the pandemic, such as lockdowns, aggressive use of fiscal and monetary stimulus and the resulting inflationary surge, have dominated weaker regional or local trends, thereby aligning economic activity among states. While extraordinarily powerful, these factors are temporary in nature and already diminishing.

In contrast, an increasingly diversified Oregon economy has become less vulnerable to fluctuations in historically dominant industries such as timber and agriculture. This has resulted in a tighter coupling with the national economic outlook and less idiosyncratic behavior tied to factors such as timber prices. Evidence of this tighter linkage to national trends was evident prior to the pandemic. Even so, there can still arise meaningful deviations from national patterns, and these will tend to reemerge as pandemic era policies fade.

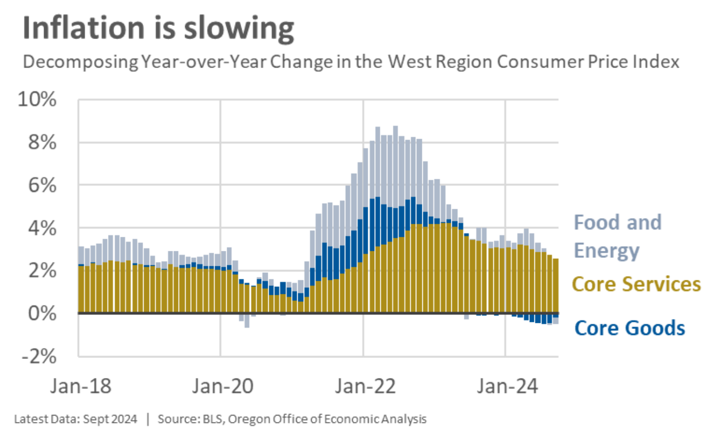
The regional inflation dynamics in the West do not look materially different from the national trend. The pace of inflation has slowed considerably over the past two years, but lingering price pressures remain concentrated in housing and other labor-sensitive services, such as childcare, healthcare, education and other professional services. All of the aforementioned categories are acutely sensitive to labor costs—which have moderated but remain elevated. A full normalization of inflation to policymakers’ target (of 2%) will largely rely on further cooling of wage pressures.

The state-level employment statistics have shown comparatively greater deviation from national patterns. Since early 2020, the Oregon unemployment rate generally ran above the national rate; but more recently, as national unemployment drifted higher, Oregon’s rate declined. Other signals of labor market health are evident in jobless benefits claimants, labor force engagement and manufacturing hours worked. The number of Oregonians claiming unemployment insurance benefits is stable and the share of claimants exhausting those benefits appears to have stabilized near typical mid-to-late cycle norms and may even be incrementally declining.

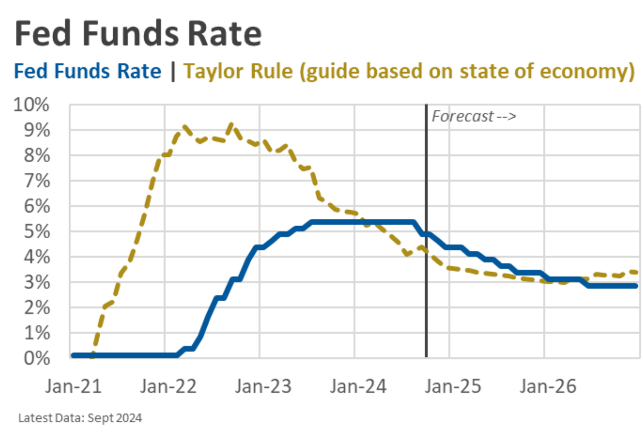
Meanwhile, labor force engagement—as measured by labor force participation or the employment-to-population ratio—are not only at or near cyclical highs, but they are also showing impressive performance over multiple economic cycles. (Labor force participation is the highest since 2012.) The breadth of job gains has been uneven over the past year, concentrated mainly in health services, private education and government. However, a recovery in hours worked in the manufacturing sector year-to-date bears watching as a potential harbinger of increasing demand for factory-sector labor. More broadly, Oregon wage growth appears to be stabilizing at healthy levels relative to inflation, consisting with a rebalancing, not a retrenchment in the labor market.

Higher Interest Rate Regime Ahead

The Federal Reserve has begun the process of reducing interest rates as the risks around its dual mandate of price stability and maximum employment come into better balance. Inflation is still running above the Fed's 2% objective, but it has retreated considerably over the past several quarters. The less volatile core consumer price index (or CPI excluding food and energy) grew at a year-over-year pace of 3.3% in October compared to a peak above 6% in 2022.



To be sure, policy makers do not view the progress to date as sufficient, and prioritize low, stable inflation as a necessary precursor to achieving other priorities in a strong, healthy economy. Even so, with inflation closer to target, and public inflation expectations relatively steady at levels which have been historically consistent with price stability, policy makers are afforded the opportunity to give greater import to the maximum employment side of their dual mandate. By responding to more balanced labor market dynamics—such as the ratio of job openings to unemployment—Federal Reserve officials are striving to avoid keeping policy too restrictive for too long, which could risk pushing the economy toward excessive weakness or even recession. What officials are pursuing at present should be viewed as a moderate recalibration of their policy stance, not a more typical cutting cycle designed to pull the economy out of a downturn. If this recalibration is successful, then fed funds rate cuts will be slower and smaller compared to a typical cutting cycle.

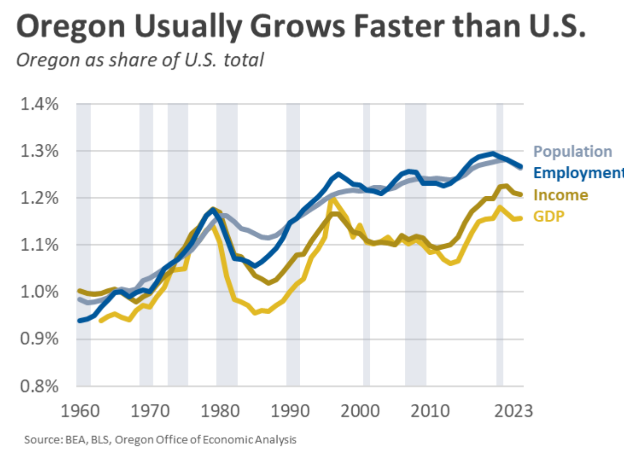


The degree to which the Fed can continue to lower interest rates remains an open question, as recent economic data have presented a mixed outlook regarding continued progress toward the 2% inflation objective. To the extent that economic activity in general and the labor market in particular respond favorably to the recent easing of financial conditions, the need for additional interest rate cuts may diminish. Further, persistent inflation pressures would not only reduce the Fed's willingness to cut rates, but it could also boost inflation premiums in longer-duration interest rates, for example 10-year treasury yields or mortgage rates.

In summary, firmer economic performance and/or persistent inflation pressures could result in higher interest rates more broadly relative to the norm of recent economic cycles.

Oregon's Economic Outlook

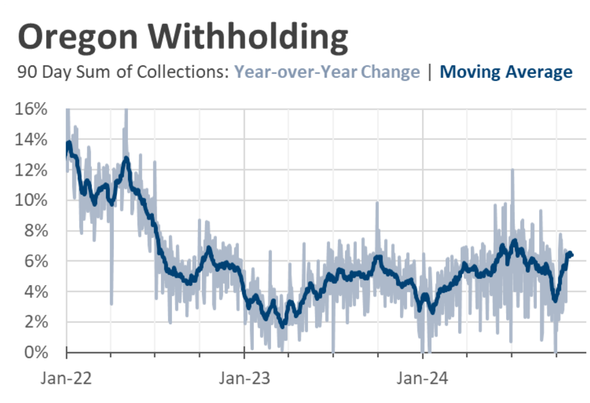
Historically Oregon's economy has grown at an above-average rate compared to the nation overall. Oregon is generally more volatile, with local recessions deeper, and expansions stronger than those experienced nationally. The pandemic cycle has been different. The initial economic shock was about the same size in Oregon as it was nationally. Over the entire cycle to date, Oregon's economy in terms of jobs and income is in the middle of the pack across all states, although a bit below the median.



By some measures, Oregon has behaved asynchronously more recently. This is both in relation to the typical cyclical patterns, and also relative to performance across states or compared to national trends. Much of this is likely tied to the slowdown, or outright declines in the state's population. Historically, migration is strongest among 20- and 30-somethings who move in search of a job, and then set down roots.

There are a few green shoots that Oregon's relative growth may be picking up. Job gains, employment revisions, income revisions, withholding tax collections and the number of income tax returns filed so far this year all point toward the potential of stronger gains. At present, these factors are encouraging prospects, but OEA judges it premature to ascertain a new trend. Nonetheless, these trends warrant careful scrutiny.

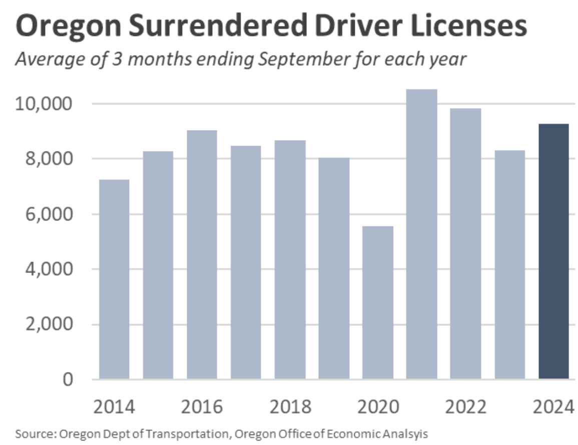
Job growth and withholding tax collections have accelerated in recent months. Note that in previous forecasts OEA was trying to get a better understanding of the source of the withholding acceleration. Further analysis led to the conclusion that the initial pickup in withholding appears to be related to $1.3 billion Powerball jackpot winnings in the state.



Excluding the lottery winnings impact reveals that withholdings have perked up and are running at around 6% today on a year-over-year basis. Such growth is more in line with the typical rate seen in past economic expansions in the state. It also matches the fastest growth seen since the pandemic reopenings. This pick up should be carefuly monitored in order to discern whether it will ultimately prove fleeting or if it is an indication that Oregon is moving out of the pandemic lull and back toward the typical, more vigorous expansion pattern.

Additionally, part of the cycle dynamic to date has been Oregon's job gains being both slower and more volatile than the nation, making it harder to get a read on the current state of the labor market. In terms of our office's forecast, revisions to the Oregon data from BLS will have no impact on the outlook. The reason is that for the past 15 years our office has been doing our own preliminary benchmark revisions each quarter to keep abreast of labor market dynamics. Our colleagues at the Oregon Employment Department also do their own quarterly benchmark revisions for the state and local data. This means Oregon has more up-to-date and accurate data, comparatively.

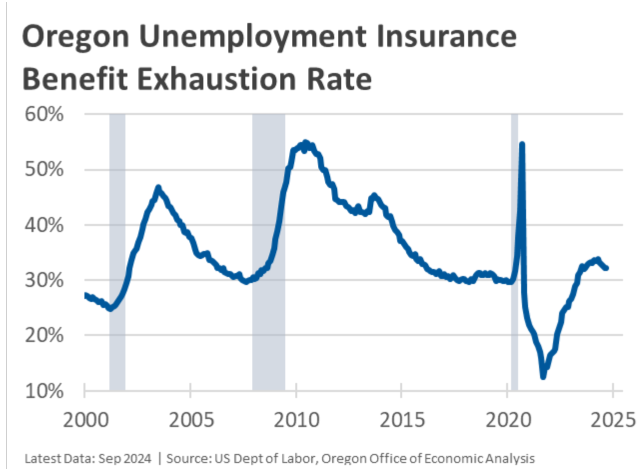
In terms of real-time data, Oregon continues to see mixed population signals. The number of surrendered driver licenses at Oregon DMVs remains steady at around the same pace as last decade. However, migration data from the Federal Reserve Bank of Cleveland based on credit bureau reports, shows continued net out-migration from the Portland metro area as of 2024q2.



The 2024 mid-year population preliminary estimate along with revisions for the past years have just been released by Portland State University on November 15th and have been incorporated into our office's forecast. Looking forwad, the Census Bureau will release their 2024 estimate in December and PSU will finalize the estimate in April of 2025.

Update on Oregon Unemployment

The Oregon unemployment insurance benefit exhaustion rate is now slightly higher than it was pre-pandemic. This measures the share of Oregonians who have received their maximum allotment of UI benefits (following 26 weeks). An elevated exhaustion rate is one symptom indicative of labor market fragility and difficulties for displaced workers to find new sources of employment. The current benefit exhaustion rate is relatively low historically, an indication that the labor market is not deteriorating further.

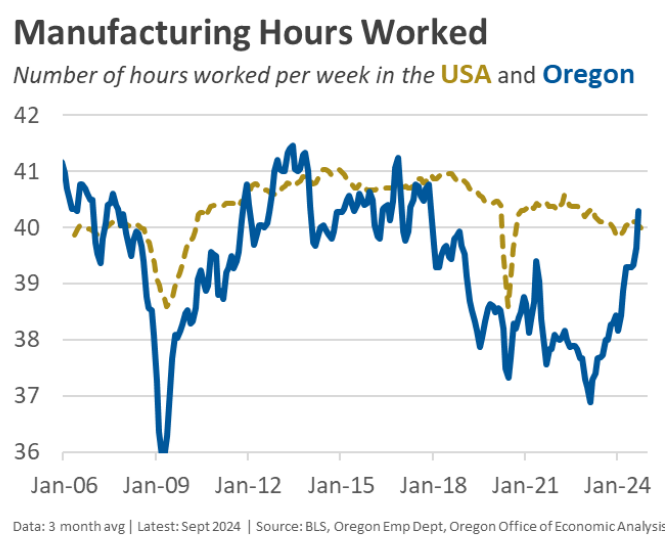


A moderating labor market is also showing up in a leveling out of wage growth, both per worker and in aggregate wages and salaries. A legitimate concern in recent years was if labor income continued to boom, it meant consumer spending would as well, keeping a floor under inflation. However the shift in labor market dynamics now points toward growth more on par with pre-pandemic patterns.

Update on Oregon Manufacturing

As discussed in greater detail in the June 2024 forecast, Oregon's experienced sizable manufacturing layoffs in the past several quarters. Historically manufacturing has been a key strength for the regional economy. The layoffs, relative to a stronger U.S. economy that did not see noticeable manufacturing layoffs, were unique compared to usual historical performance.

In recent months a few different patterns have emerged. First, U.S. manufacturing employment has stalled out and declined slightly in the real-time estimates. Second, Oregon manufacturing jobs appear to have stabilized. The rebound in manufacturing hours worked is an encouraging signal. It is an indication that demand for labor is rising among the remaining manufacturing employees. In terms of the outlook this should mean that further layoffs are unlikely.

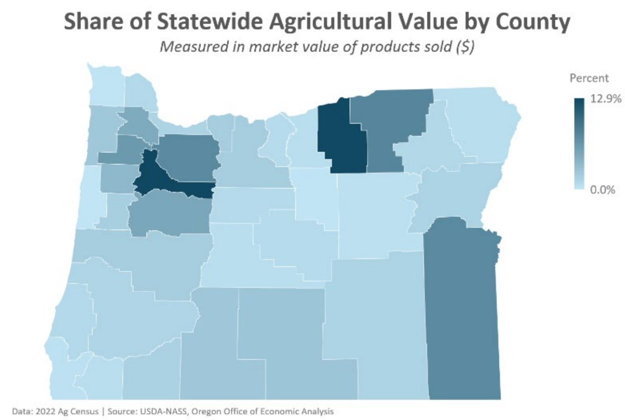


Topline Forecast Changes

The overall economic forecast is stable. Jobs are slightly lower relative to the previous outlook, but these changes are by tenths of a percentage point here or there. Income is now higher relative to the previous outlook. This is in large part because of the huge upward revision to non-wage income reported in the Bureau of Economic Analysis's (BEA's) annual update of the National Economic Accounts.

The nature of the economic outlook is for a modest rebound in migration leading to slow, but positive population gains in the state. The labor market is expected to remain at or near full employment. The unemployment rate will remain in the low 4% range, while the share of working-age Oregonians with a job will be at or near an all-time high. The strong labor market translates into average wage growth per workers of approximately four percent at an annualized basis.

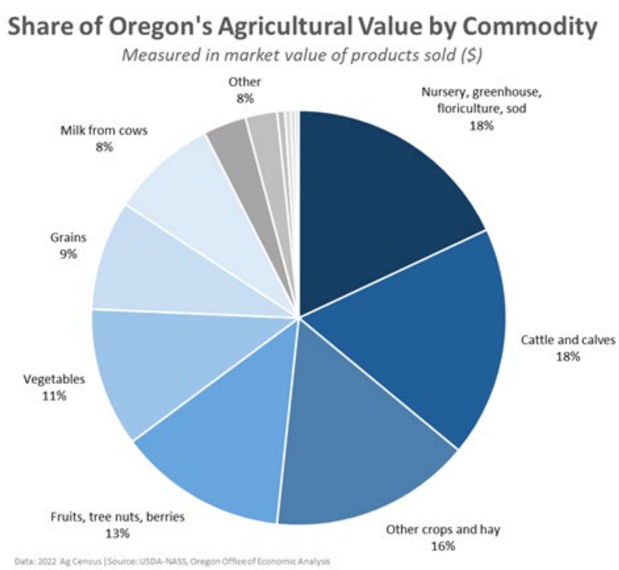
Oregon's Agricultural Economy



Recently, the 2022 Census of Agriculture was released, providing the most detailed data available at the state and county levels. This comprehensive survey, conducted every five years, offers valuable insights into the agricultural sector.

According to these data, Oregon's agricultural sales were nearly $6.8 billion, or approximately 1% of all U.S. sales. While the agricultural industry is not large in terms of employment numbers in the state, at about 1.8% of all private jobs, it is still an important part of the economy.

Oregon excels in the production of a diverse range of crops, including berries, wine grapes, nursery plants, and hay, as well as livestock and dairy. These agricultural subsectors are vital in supporting local economies and sustaining rural communities.

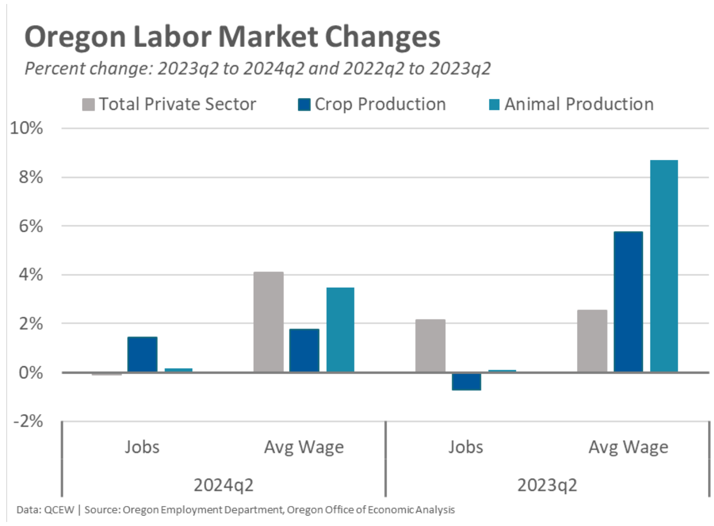


The top five commodities in Oregon's agricultural sector, based on the market value of products sold are as follows: greenhouse and nursery stock, cattle and calves, other crops and hay, fruits and nuts, and vegetables.

These commodities contribute significantly to Oregon's agricultural market value and vary in their importance to specific counties across the state. The western part of the state emphasizes fruits, berries, and nursery products, while the eastern part focuses on hay, cattle, and specialty crops like grains and oilseeds. Each region's agricultural strengths underscore how farming practices are adapted to local conditions and land use.

Agricultural Employment and Wages

In recent quarters we have highlighted QCEW data, the nearly real-time data coming from businesses submitting records for unemployment insurance purposes. Agricultural data displays signifcant seasonality, so getting a clear handle on trends can be more challenging. As of this forecast, data is available for the first quarter of 2024 for the U.S. (all states) and Oregon, with Oregon having additional data from the second quarter of 2024.

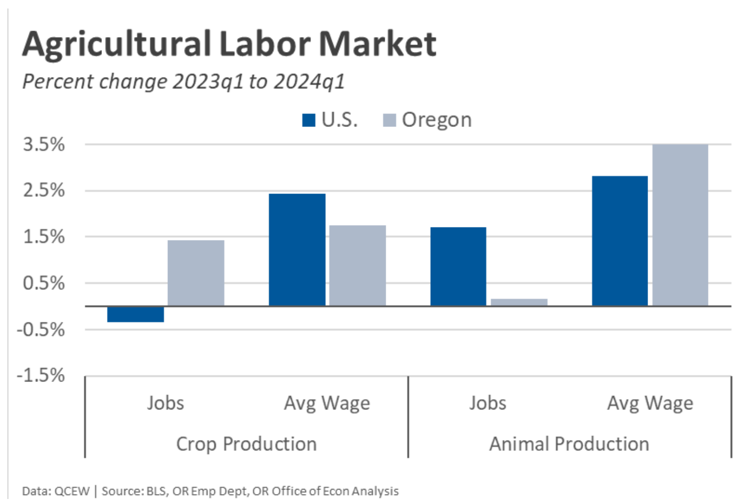


State employment trends within agriculture are a bit stronger than the broader economy in 2024 so far, specifically in crop production. In terms of wage gains, Oregon wages are rising in a tight labor market, but average wages in both crop and animal production are lagging behind the statewide increases.

The Oregon Legislature passed HB 4002 (2022) which establishes maximum hour and overtime compensation requirements for agricultural workers. This law went into effect starting at the beginning of 2023, so it is still early to discern any impact from the law.

Across all states, agricultural employment is lagging the broader economy. In Oregon, the percentage change in the average wage for crop production is slightly behind the national average, whereas the average wage gains in animal production are significantly higher than those seen nationally.

It is hard to determine whether Oregon's experiences are influenced by the new law or if they are more reflective of broader industry trends, where animal production is driving wage growth while crop production lags behind. OEA will continue to track relevant develepments in relationship to this legislation.



Near- to Medium-Term Forecast Risks

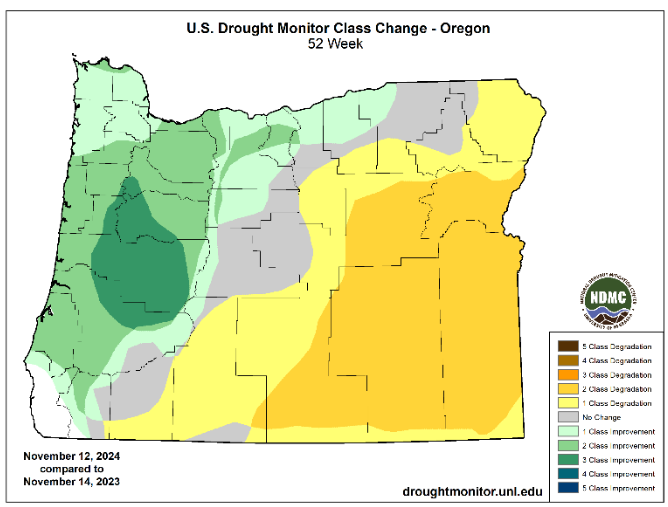
Oregon faces several near- to medium-term risks that could impact its economy. Geopolitical tensions and potential disruptions in global trade are among the most immediate concerns. An oil price spike, whether due to conflict in the Middle East or restrictions on global supply chains, could increase transportation and energy costs, disproportionately affecting rural communities reliant on long commutes and agriculture dependent on fuel for machinery. Similarly, the escalation of a tariff or trade war—particularly with major trading partners like China—could negatively impact Oregon's key exports, such as timber, wheat, wine, and hazelnuts. These products rely heavily on international demand, and tariffs or restrictions could reduce export volumes, drive down prices, and harm associated industries like transportation and warehousing.

Another potential threat is a resurgence of a global pandemic, particularly one driven by zoonotic diseases such as avian influenza. A severe outbreak could disrupt supply chains, depress consumer spending, and strain public health resources. Oregon's poultry industry, while smaller compared to other states, could face significant losses, with downstream effects on agricultural workers and associated industries. Lessons learned from the COVID-19 pandemic should guide preparedness strategies to minimize economic and social disruption.

While the severity, duration, and timing of catastrophic events like drought, wildfires, and earthquakes are difficult to predict, they hold the potential to severely impact regional economies. Fires not only damage forests and disrupt timber production, they have shown to materially impact tourism and recreation. Droughts impact our agricultural sector and rural economies to a greater degree. Ice storms temporarily shut-in economic activity, medical care and education; and recent experience has shown that these temporary disruptions are not fully regained during the subsequent recovery period.

Drought

Drought conditions across Oregon remain a significant concern. Western parts of the state, including portions of the Willamette Valley and the coast, have experienced notable improvements in drought severity. This progress is largely attributed to favorable winter precipitation and improved snowpack levels. In contrast, central and eastern Oregon continue to grapple with persistent drought, with some areas seeing further degradation in conditions over the past year.

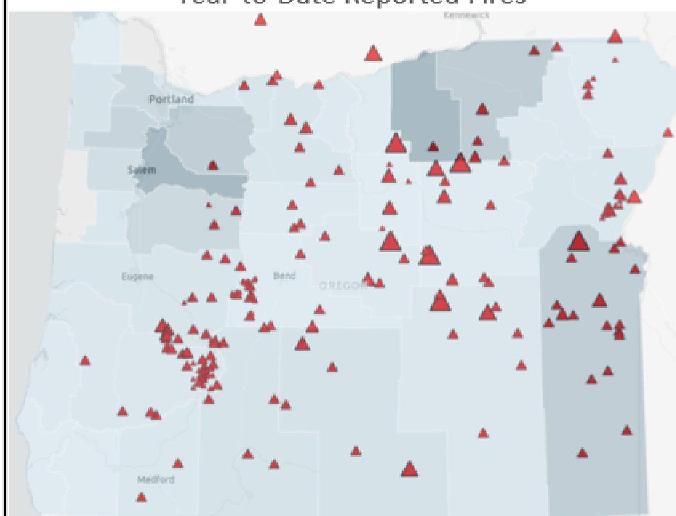


The impacts of these drought patterns are felt differently across the state. Western Oregon has seen benefits from improved water availability, particularly for municipal water supplies and hydropower generation. However, the ongoing drought in central and southeastern regions presents continued challenges for agriculture, where reliance on groundwater and depleted reservoirs limits production potential. In these areas, prolonged dry conditions also exacerbate wildfire risks and place additional pressure on local ecosystems.

Wildfires

Recent wildfires in Oregon have underscored the growing economic challenges posed by both direct and indirect impacts. This year's wildfire season, though less catastrophic in terms of structural damage compared to 2020, has seen concentrated acreage loss, and the broader economic effects continue to unfold. Wildfires in the western U.S. have increased in frequency and scale over the past decade, and Oregon has seen its fire season lengthen, with wildfires now starting earlier and lasting longer. This shift poses substantial risks for the state's economy, public health and livability.

Wildfires on High-Value Agricultural Counties
Year-to-Date Reported Fires



Data: 2022 Ag Census | Source: USDA- NASS, ICS-209 NWCC 2024, OEA

Beyond the tangible destruction of property, wildfires worsen air quality. Prolonged exposure to wildfire smoke contributes to health issues and respiratory problems, thus further straining healthcare systems. The economic toll includes increased absenteeism, reduced worker productivity and higher medical costs. Moreover, sectors like tourism and agriculture are particularly vulnerable to wildfire smoke, with declines in travel and disruptions in crop production.

Flooding

Conversely, atmospheric rivers—a phenomenon where concentrated bands of moisture bring heavy precipitation—pose the opposite risk in certain parts of the state. While these events can help replenish water supplies and reservoirs, they also increase the likelihood of flooding, particularly in low-lying agricultural regions like the Willamette Valley. Flooding can damage crops, disrupt planting and harvest schedules and lead to costly infrastructure repairs.

Cascadia Earthquake

Oregon also faces the ever-present risk of a Cascadia Subduction Zone earthquake, an event with the potential to devastate the region's infrastructure, including transportation networks, utilities, and housing. Such a disaster could displace hundreds of thousands of residents and lead to prolonged economic recovery efforts. Ongoing investments in seismic retrofitting, disaster response planning, and public awareness campaigns remain critical to mitigate the impacts of this potential catastrophe.

Longer-Term Forecast Risks

The latest CPI statistics reveal that victory over inflation remains incomplete, which means the upcoming biennium will continue to be haunted by persistent price pressures. This is not only problematic to the economic outlook, but also a challenge for OEA's modeling of state revenue trends, as higher inflation boosts nominal activity.

Many of the sources of the post-covid inflation flare-up appear poised to be present, or reemerge in slightly different forms, during the next presidential term. The major factors from the prior episode included fiscal stimulus, supply chain stress, labor market pressures and insufficiently restrictive interest rates. Major policy priorities of the next presidential administration will critically impact these same themes, including immigration restrictions, fiscal policy and tax reforms, more aggressive use of tariffs and continued lowering of interest rates. The progress toward 2% inflation, as measured by the core consumer prices index, appears to have stalled closer to 3.3% since mid-year.

Beyond inflation risks, the State of Oregon may be particularly vulnerable to economic crosswinds in the next presidential term. Trade policy is likely to be specifically oriented toward Pacific trading partners (impacting western states to larger degree); and it is poised to be particularly focused on the semi-conductor/tech sectors, which are vital pillars of Oregon economic activity. Meanwhile, based on recent history, retaliatory measures from major US trading partners have been particularly punitive toward domestic agriculture, timber and manufacturing—all of which are core industries of the state, as well. As trade tensions increased in 2017-18, Oregon statistics on production and unemployment both deteriorated relative to national trends.

Fiscal policy will also be a significant source of risk to the baseline economic forecast, albeit one which is difficult to quantify until the broad parameters of a federal fiscal plan emerge. The incoming administration has expressed a prioritization of quick passage of cuts to both corporate and personal income taxes, and it has also signaled that the SALT deduction cap could be impacted. More broadly, looser fiscal policy relative to current law raises the risk of elevated interest rates (perhaps persistently) due to both supply/demand dynamics in the debt markets as well as through firmer growth and inflation channels. Among many interest-sensitive sectors, higher rates would be particularly harmful toward housing and residential construction—sectors which have been weaker in recent years.

While inflation risks are a prominent feature of the medium-term outlook, not all news is unfavorable, such as rising worker productivity. A recurring post-pandemic theme has been economic constraints, such as labor shortages or commodity scarcity. One factor which could mark a critical break with the recent past could come from a substantial rise in labor productivity (defined as output per hour worked). Rising productivity enables the existing workforce to accomplish higher levels of output, all else equal. While artificial intelligence may be among factors lifting productivity, there is a much broader increase in capital investment underway. Historically, high pressure economic periods that also coincided with increased capital investment have resulted in sustained productivity rebounds. This trend bears watching and could have profound impacts on the medium-term outlook.

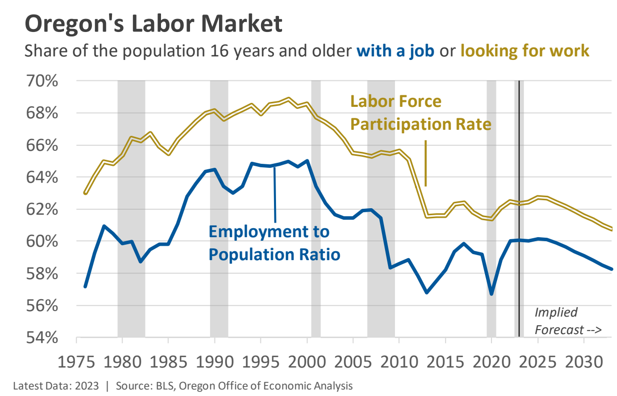
Extended Outlook

Labor Supply

Oregon has typically benefited from an influx of households from other states, including an ample supply of skilled workers. Households continued to move to Oregon even when local jobs were scarce. Relative housing prices contribute to net migration flows for the state. Over Oregon's recent history – data available from 1976 – the labor force in the state has both grown faster than the nation overall and the labor force participation rate has typically been higher.

Currently, Oregon's labor force is at an all-time high, and the labor force participation rate is currently higher than it was pre-pandemic. These are impressive dynamics pointing to resilience in the state labor market.

Over the medium term, overall labor force participation rates will decline due to the aging of the population. As more Baby Boomers enter their retirement years, the share of all adults working or looking for work will fall as a result. As such, comparing Oregon's participation rate against a demographically adjusted measure is important. Here, too, the current strength of the Oregon's labor market is evident and encouraging.



The demographic and workforce challenges over the medium-term horizon are twofold: First, there is a question whether overall population growth and whether that rebounds as expected in the years ahead. Second, whenever future recessions impact a high participation rate. The severity of a recession and subsequent contours of an economic recovery critically impact the share of discouraged workers, or those who drop out of the labor force, as witnessed during the dotcom and housing busts. It was only once the economy became strong again in the late 2010s and early 2020s that those losses reversed.

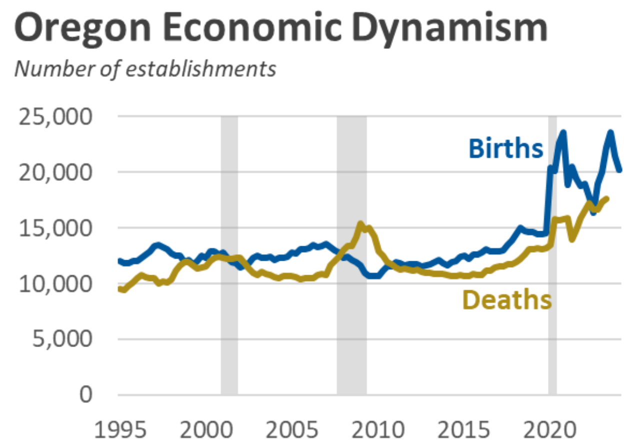
Industrial structure

Oregon's industrial structure is similar to the U.S. overall. Productivity and output from the state's technology producers warrants careful scrutiny, particularly as the fortunes of the sector will be impacted by tariffs, a prioritization of re-shoring of semiconductor production and also in response to disbursement of CHIPS Act funding. Similarly, the timber industry remains under pressure from both market-based conditions and federal regulations. Barring major changes to either, the slow growth to downward trajectory of the industry in Oregon is likely to continue. Some notable differences with he national economy are that the state's manufacturing sector is tilted more toward semiconductors and wood products versus automobiles nationally.

In and of itself, industrial diversity is not necessarily good or bad. If a region has one big industry, then the entire region can do extremely well when that industry is booming. The problem arises when that one key sector is hurting. Then the overall region suffers more as there are fewer other types of businesses to drive growth. This dynamic tends to make less diverse economies more boom-bust. Depending upon the nature and duration of each business cycle, this is either a net win or net loss for a region compared to the rest of the country.

New Business Formation

New businesses are frequently a primary source of innovation as new ideas, products, and services help propel future economic growth. Unfortunately in the decades leading up to the pandemic, start-up activity, while steady in level terms, was declining as a share of the state economy. New businesses as a share of all businesses were at or near record lows in 2019. Employment at start-ups followed a similar pattern.



Data: 4 qtr sum | Latest: Births 2024q1, Deaths 2023q2
Source: BLS, Oregon Office of Economic Analysis

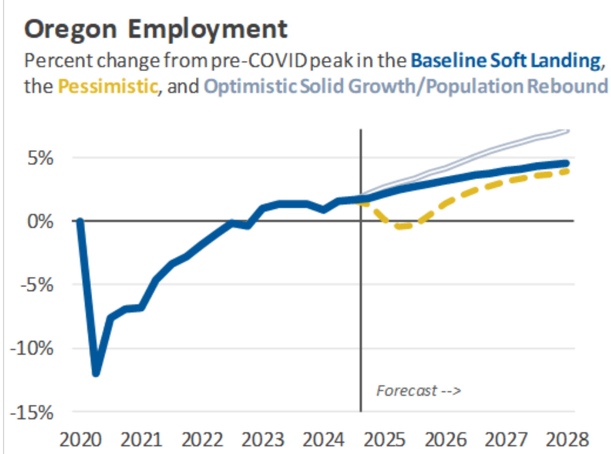
To the extent the lower levels of entrepreneurship were to continue in a post-pandemic world, slower productivity gains and weaker overall economic growth wold result. However, to the extent that larger firms that have won out in today's marketplace are investing in R&D and making those investments themselves, then worries about the number of start-ups and economic dynamism may be overstated. While realized productivity in the economy has been sluggish in recent decades, an encouraging rebound appears at hand, although the magntidude and duration are unclear.

Encouragingly, new business formation during the pandemic actually accelerated, stopping the aforementioned longer-run decline. Looking forward, these gains provide some hope for future economic growth. Even if the per firm probability of success remains the same, having more candidates overall increases the probability that a few will ultimately succeed.

Alternative Economic Scenarios

The baseline outlook is our forecast for the most likely path for the Oregon economy. As with any forecast, however, many other scenarios are possible. The alternative scenarios below are not the upper or lower bounds to all outcomes, but rather are two plausible scenarios modeled on what OEA determines to be realistic assumptions for tail risks. For the revenue implications, see page 26.

Alternative Scenarios **December 2024**



	2023	2024	2025	2026	2027	2028
Employment						
Opt: Solid Growth	2.1%	0.3%	1.6%	1.6%	1.4%	1.1%
Base: Soft Landing	2.1%	0.2%	1.0%	0.9%	0.7%	0.6%
Pes: Recession	2.1%	0.1%	-1.4%	2.2%	1.3%	0.7%
Unemployment Rate						
Opt: Solid Growth	3.7%	4.2%	3.9%	3.8%	3.9%	3.9%
Base: Soft Landing	3.7%	4.2%	4.2%	4.3%	4.4%	4.4%
Pes: Recession	3.7%	4.7%	6.7%	6.5%	6.1%	4.8%
Personal Income						
Opt: Solid Growth	5.7%	5.3%	5.4%	6.1%	6.0%	5.8%
Base: Soft Landing	5.7%	5.3%	5.3%	5.6%	5.4%	5.0%
Pes: Recession	5.7%	5.2%	2.4%	6.0%	5.9%	5.2%

Pessimistic Scenario: Moderate Recession

For now, the most likely pessimistic scenario is a moderate recession. There are no clear imbalances in the economy, household finances remain in good shape and firms will be reluctant to let go of workers given the structurally tight labor market.

The moderate recession scenario is for a three-quarter decline in employment totaling 2.1%, followed by a six-quarter recovery period, more in line with the so-called jobless recoveries following the 1990 and 2001 cycles, compared to the faster recoveries in the 1950s, 1960s, and 1970s.

The 2% decline in employment is a loss of over 40,000 jobs. The unemployment rate increases to a high of 6.8% by early 2025. Nominal income does not fall outright but growth slows considerably. Next biennium, in 2025-27, total personal income in Oregon is nearly 3% below the baseline.

Optimistic Scenario: "No landing"--Solid Growth/Population Rebound

Some factors which could mark a critical break with the baseline forecast could come from a substantial rise in labor productivity (defined as output per hour worked) and an increasing labor force participation rate. Rising productivity enables the existing workforce to accomplish higher levels of output, all else equal. While the labor force participation rate is not particularly contingent on higher population growth and net in-migration, this is one aspect that could result in higher employment levels. Oregon has experienced periods where employment growth has exceeded population growth, necessarily driven by changes in the labor force participation rate.

Pandemic migration patterns differ from recent history substantially. There is good reason to think some of those changes will remain in the decade ahead, particularly when it comes to the combination of housing affordability and working from home resulting in lower migration to Oregon than in decades past. However, such a slow growth baseline does leave upside risks. What would happen if Oregon were to see a typical cyclical rebound in migration in the years ahead? By 2033, Oregon's employment is nearly 73,000 higher than in the baseline, and total personal income is 3.25% higher than in the baseline.

Zero Migration, a Demographic Alternative

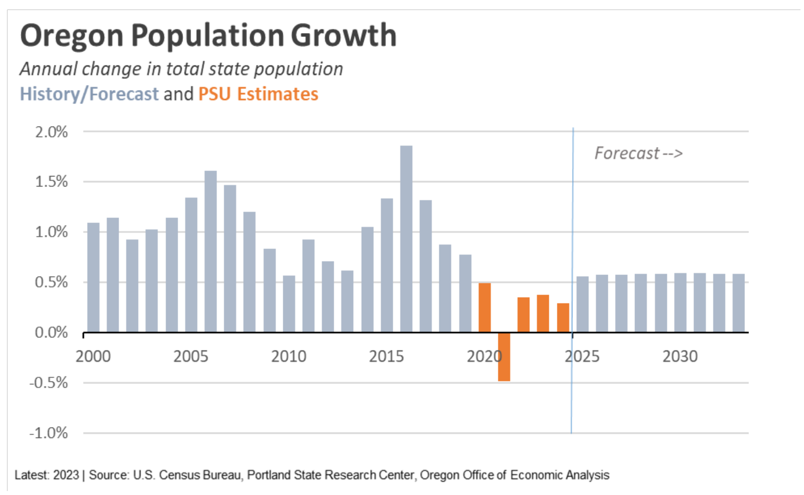
Our office has developed a demographic alternative scenario of what the state's economy, and public tax revenues may look like should migration not rebound as expected. What follows is a short summary of that scenario. You may find the full report in the December 2023 forecast, and a standalone copy on our website[1].

Historically migration has been the primary reason Oregon's economy has outpaced the typical state over time. However, the bottom-line impacts of the Zero Migration scenario are smaller than our office first anticipated. There are at least three main reasons why this appears to be the case.

The first reason is simply that the baseline population forecast is already weak from an historical perspective. Removing the modest population gains of less than 1% per year has less of an impact than if the baseline had population growth of 2-3%, like Oregon experienced in decades past.

The second reason is due to inflation and rising incomes and asset values for existing residents. While the state's overall population may decline slowly given there is no migration to offset the fact deaths outnumber births, total incomes and taxes paid will increase. However, those aggregate increases will be slightly slower given the lack of any underlying population gains, even as incomes per worker or per household will increase in the years ahead.

The third reason is one of timing and focusing on the first decade of no net migration. Given the age demographics of migration to Oregon, and the fact that middle-aged Oregonians, and in particular late middle-aged Oregonians have the largest incomes, of which many are taxed at the highest rate, the economic and revenue impacts are likely to be greater in the second or third decade than in the first.



As such, seemingly small differences in any given year have little long-run implications for the trajectory of Oregon's economy or state revenues. However, like a snowball just starting to roll down a mountain, as these small annual changes accumulate, so too do the long-run differences between the baseline outlook and the world in which migration does not return to the state.

[1] https://oregoneconomicanalysis.com/2024/01/10/report-zero-migration-a-demographic-alternative-scenario/

Revenue Outlook

Revenue Summary

This December forecast exhibits a significant upward correction to the General Fund forecast. The long string of consecutive positive revisions to the forecast necessitated a deep forensic analysis of the methodological underpinnings and assumptions driving prior forecasts. The fundamental finding was that major relationships in the Personal and Corporate Income Tax models, such as Capital Gains realizations and the U.S. equities forecast and corporate tax liability and U.S. Corporate Profits, had become disconnected. In addition, the manner in which the Personal Income Tax kicker was modeled resulted in potential confusion when looking at recent tax collection patterns. Correcting these flaws produces significant increases in available resources for the current and next biennium.

The revenue picture for the current 2023-25 biennium is improved by $947.0 million compared to the prior forecast. The total increase since the Close of Session forecast is $2,838.6. Increased revenues in the current biennium also increase the projected kickers. The personal kicker now stands at an expected $1,792.4 million that will be returned to taxpayers as a credit on their 2025 tax return. The corporate kicker now stands at an expected $1,024.5 million and will be retained in the General Fund and spent on education next biennium.

Table R.1

2023-25 General Fund Forecast Summary

(Millions)	2023 COS Forecast	Sep 2024 Forecast	Dec 2024 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$21,019.7	$21,889.4	$22,690.8	$801.4	$1,671.1
Corporate Income Tax	$2,228.9	$3,111.7	$3,253.4	$141.7	$1,024.5
All Other Revenues	$2,011.3	$2,150.4	$2,154.2	$3.9	$142.9
Gross GF Revenues	$25,259.9	$27,151.5	$28,098.5	$947.0	$2,838.6
Offsets, Transfers, and Actions[1]	-$437.0	-$496.1	-$497.8	-$1.7	-$60.8
Beginning Balance	$7,493.5	$8,082.5	$8,082.5	$0.0	$589.0
Net Available Resources	**$32,316.4**	**$34,737.8**	**$35,683.2**	**$945.4**	**$3,366.8**
Appropriations	$31,873.6	$32,897.2	$32,897.2	$0.0	$1,023.6
Ending Balance	**$442.8**	**$1,840.6**	**$2,786.0**	**$945.4**	**$2,343.2**
Confidence Intervals					
67% Confidence	+/- 3.2%		$887.9	$27.21B to $28.99B	
95% Confidence	+/- 6.3%		$1,775.8	$26.32B to $29.87B	

1 Reflects personal and corporate tax transfers, Rainy Day Fund tranfer, and Dept of Ag transfer

For 2025-27, available General Fund resources, which includes an increase in the beginning balance carried forward from the current biennium, are increased by $2.267 billion to a total of $37.8 billion. The full effects of the personal income tax revisions discussed previously are muted by the increase in the projected kicker credit factored into the 2025-27 revenue stream.

Outside of the General Fund, the major revenue sources are the Corporate Activity Tax and Lottery. Corporate Activity Tax revenues have been revised downward $5.9 million for 2023-25 due entirely to slightly weaker collections activity in recent months. The impact is amplified for 2025-27, where available resources are decreased $48.1 million. Conversely, Lottery earnings to the Economic Development Fund have been increased from the prior forecast by $37.1 million in the current biennium owing primarily to a transfer of administrative savings in the latest quarter. Next biennium's resources has been revised upward $72.3 million, including the increased beginning balance.

2023-25 General Fund Revenues

The December forecast marks a major revision from the prior forecast. General Fund revenues are increased $947.0 million, primarily due to personal income tax increases. Corporate income tax is also increased substantially from prior projections. All other revenue sources are little changed. The estimated ending balance in the General Fund is now $2.79 billion.

Personal Income Tax

For personal income taxes, tax year 2023 is coming into focus. Absent the $5.6 billion kicker credit, it is currently estimated that collections will grow 2.6% from the prior year when all is said and done. The previous forecast assumed a 4.0% decline. In addition, tax year 2024 is now expected to be exhibit much stronger growth than was previously expected. The net result is an approximately $1.0 billion per year increase in anticipated personal income tax receipts for tax years currently in progress. The impact of these changes is not uniform across the forecast horizon as the latest forecast is now tied more closely to the economic baseline and exhibits milder growth than previous projections.

The forecast for 2023-25 is now $21.89 billion, increased $801.4 million since the September forecast. Table B.8 presents tracking information for the first fiscal quarter of 2025. Personal income taxes finished $81.8 million above the prior forecast. Withholding and estimated payments both exceeded expectations and are consistent with the raised expectation for the tax year as a whole. In terms of reconciliation on tax year 2023, refunds came in higher than expected. This could be the result of the incentive to file earlier due to the significant kicker credit.

Corporate Excise Tax

The corporate income tax forecast models collections by tax year on U.S. corporate profits adjusted for the size of the Oregon economy relative to the nation. Previous forecasts assumed that corporate profits would experience a significant correction in the immediate future even as this assumption failed to materialize quarter after quarter. This forecast reconnects the forecast to the U.S. corporate forecast provided by our national forecast provider, Standard and Poors, additionally informed by input from the office's advisory bodies. This update causes a level shift upward throughout the forecast horizon.

For the 2023-25 biennium, corporate income tax collections are projected to total $3.25 billion, up $141.7 million from the September forecast. As indicated in Table B.8 in the appendix, collections during the quarter ended September 30th were $15.3 million higher than expected. This was entirely due to reconciliation related to tax year 2023.

Other Sources of Revenue

While there are a variety of other sources of revenue in the General Fund, in aggregate they account for only 8% of the total. In addition, non-income tax sources have historically been rather stable compared to their income tax counterparts. All other General Fund revenues are expected to total $2.15 billion in 2023-25, a change of just $3.9 million from the prior forecast and $142.9 million from the Close of Session forecast.

The two largest contributors to the “other sources” category are Estate Taxes and Interest Earnings. Estate Taxes have grown significantly in recent years due to an aging population and nominal growth in asset values. For the current biennium, the forecast for Estate Taxes is currently $662.5 million and is 23% above the Close of Session forecast. Interest Earnings have also magnified dramatically as cash balances statewide have ballooned and interest rates have risen. The current projection for 2023-25 is $658.6 million, which is 39% above the original forecast upon which the legislatively adopted budget was based.

Extended General Fund Outlook

Table R.2 exhibits the long-run forecast for General Fund revenues through the 2031-33 biennium. Of particular interest now is the 2025-27 revenue picture. Budget development is in full swing as the Governor’s Recommended Budget will be released around December 1st. General Fund revenues for 2025-27 have been increased $1.3 billion due to methodological changes described earlier.

Table R.2 December 2024

General Fund Revenue Forecast Summary

Millions of Dollars, Current Law

Revenue Source	2023-25 Biennium	% Chg	2025-27 Biennium	% Chg	2027-29 Biennium	% Chg	2029-31 Biennium	% Chg	2031-33 Biennium	% Chg
Personal Income Taxes	22,690.8	*-11.7%*	30,287.9	*33.5%*	35,825.7	*18.3%*	40,021.7	*11.7%*	44,600.7	*11.4%*
Corporate Income Taxes	3,209.2	*1.7%*	3,439.8	*7.2%*	3,577.4	*4.0%*	3,786.5	*5.8%*	4,117.3	*8.7%*
All Others	2,154.2	*11.1%*	1,840.5	*-14.6%*	1,895.8	*3.0%*	1,978.9	*4.4%*	2,086.0	*5.4%*
Gross General Fund	28,054.2	*-8.9%*	35,568.1	*26.8%*	41,298.9	*16.1%*	45,787.1	*10.9%*	50,804.0	*11.0%*
Offsets and Transfers	*(233.1)*		*(211.1)*		*(220.3)*		*(199.6)*		*(187.4)*	
Net Revenue	27,821.2	*-9.1%*	35,357.0	*27.1%*	41,078.6	*16.2%*	45,587.5	*11.0%*	50,616.6	*11.0%*

Note that the large percentage changes between biennia are due to kicker credits affecting personal income tax collections. Beyond 2025-27, when these considerations are no longer in effect, growth reflects underlying economic assumptions characterized elsewhere in this document. Users should note that the potential for error in the forecast increases substantially the further ahead we look.

Corporate Activity Tax

Oregon's new corporate activity tax (CAT) went into effect January 2020. Revenues from this tax on business receipts are dedicated to education through the Fund for Student Success. The tax was designed to generate approximately $1 billion per year in new state resources, or $2 billion per biennium. These figures include both CAT revenues and the impact of the reduction in personal income tax rates which reduce state revenues, leaving a net revenue change of approximately $1 billion per year.

Due to the significant lag in the availability of tax return data (tax year 2021 is the latest available), CAT collections are modeled by tax year on Gross State Product, the best aggregate economic indicator for which data are universally available. Tax year 2023 is nearing completion from a collections standpoint while tax year 2024 is just starting to take shape. From either perspective, collections are a tad weaker than they appeared previously. In addition, a methodological change is tying long-run collections growth more closely to the overall economic outlook. The overall result is a lower forecast throughout the forecast horizon.

Anticipated revenues for the current biennium are down $5.9 million, while revenues have decreased $40.1 million for 2025-27. Including a change in the beginning balance, available resources for 2025-27 are down $48 million to total $3,280.1 million.

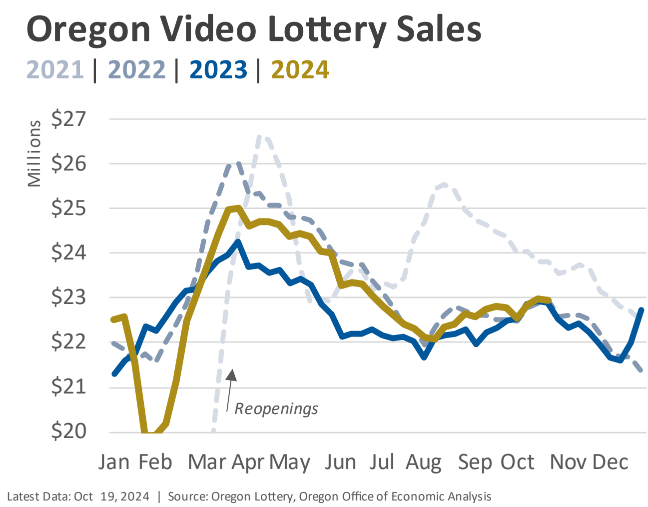
Table B.12 in Appendix B summarizes the 10-year forecast and the allocation of resources, while Table B.13 presents a more detailed quarterly breakdown of the forecast. The personal income tax reductions are built into the General Fund forecasts shown in Tables B.1 and B.2.

Lottery Forecast

The December lottery forecast has been raised slightly from the September outlook, reflecting an upward adjustment in overall resources. For the current 2023-25 biennium, total resources are increased by $37 million, while resources in future biennia are raised by approximately $20-40 million. These adjustments vary across lottery categories: video lottery forecasts are lowered slightly, traditional lottery sales have risen, and sports betting remains largely unchanged.

Specifically, video lottery resources are lowered by $15.7 million (-1.0%) in 2023-25 and $5.9 million (-0.3%) in 2025-27. Forecasts for 2027-29, 2029-31, and 2031-33 are also revised downward by 1-1.5%. The introduction of a $30 Scratch-It ticket has boosted traditional lottery sales, although there may be a potential reduction in transfer rates due to a narrower profit margin on higher-priced tickets.

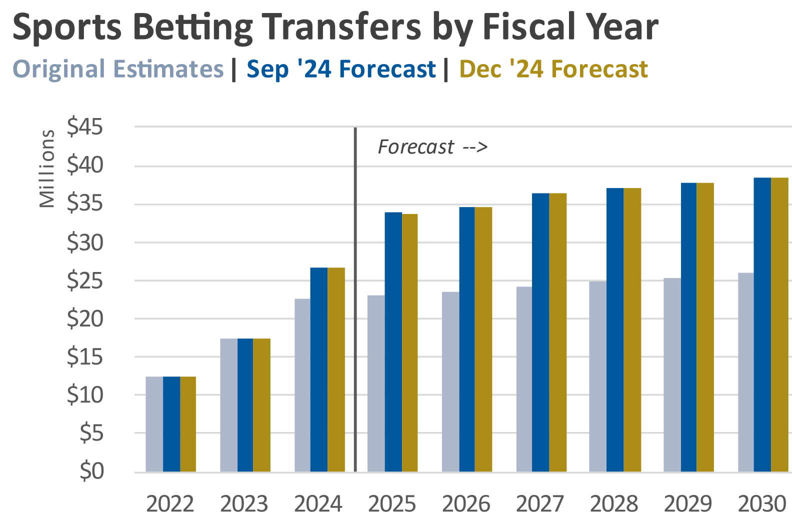
Video Lottery



Following the rapid growth during the pandemic reopening phase, video lottery sales have stabilized, with current growth rates somewhat below earlier projections. Despite the recent $5.6 billion personal income tax kicker paid out to Oregonians, no significant boost in video lottery sales was observed. Although sales in this segment continue to grow, the overall forecast is more conservative, reflecting current spending patterns.

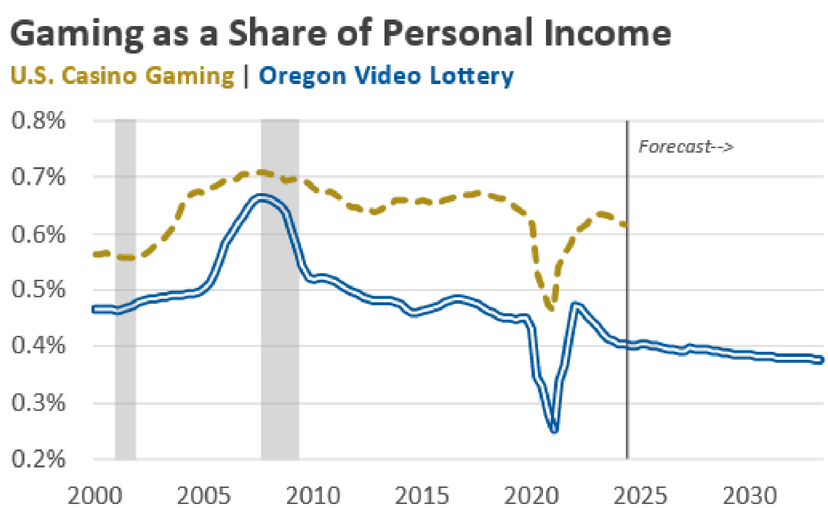
Sports Betting

The sports betting forecast remains largely in line with September's outlook, with revenues continuing to exceed early projections. While the forecast itself has not changed significantly, sports betting appears to exhibit less seasonality than previously anticipated. The steady revenue flow may be due to players engaging in a broader variety of events across staggered sports seasons, leading to more consistent betting activity throughout the year. This pattern suggests that sports betting is maturing in Oregon as player preferences diversify, contributing to stable, year-round revenue.



Longer-Term Outlook

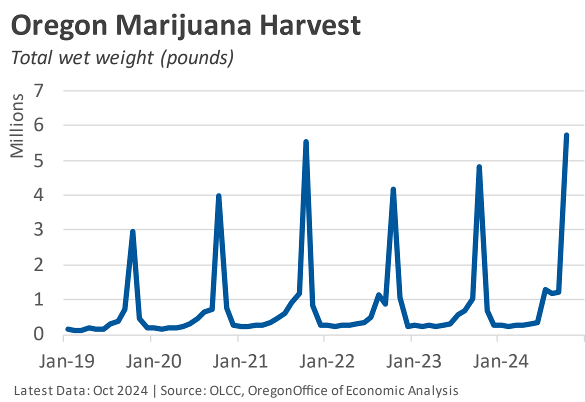
Lottery revenues continue to be closely linked to consumer behavior, household budgets and evolving entertainment preferences. Current trends point toward increased competition for entertainment dollars, shifting gaming preferences, and generational changes in gaming habits. The December forecast projects continued growth in lottery resources but at a pace slightly slower than Oregon's overall personal income growth, resulting in a marginally smaller share of the consumer spending pie over time.

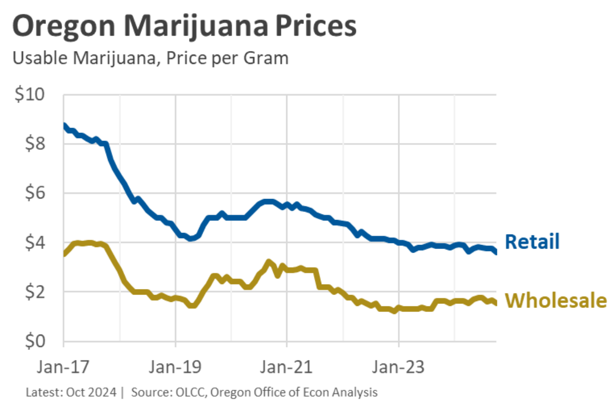


The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

Recreational Marijuana Forecast

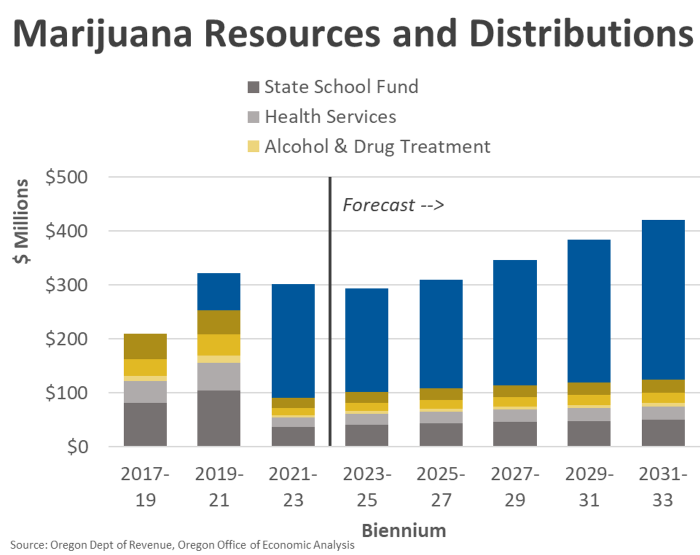
The December marijuana forecast is largely unchanged from September. Recent sales and tax collections remain stable, closely tracking prior projections, with slight adjustments based on current data. In the current 2023-25 biennium, resources are raised by $0.3 million (+0.1%), and 2025-27 sees a modest increase of $0.7 million (+0.2%). Similarly, the outer biennia forecasts are raised by approximately $0.9 to $1.1 million each, representing an increase of about 0.3%.





This year's harvest has been notably strong, with a record-breaking yield in October of over 5.7 million pounds. The large harvest continues to contribute to low prices, which are expected to remain stable at these lower levels. With ongoing oversupply and low prices, underlying revenue growth will depend more on increases in the number of consumers and the quantity consumed per user, rather than any broader economic or income growth factors. Consequently, marijuana sales are projected to occupy a smaller share of consumer income in the future, even as overall sales and tax revenues gradually increase.

As previously noted, Oregon does not currently tax medical marijuana; however, this tax exemption is set to expire at the end of 2027, with medical marijuana taxation scheduled to begin in 2028. Although this exemption could be extended by the Legislature, the current forecast assumes medical marijuana will be taxed per current law. The forecasted revenue from medical marijuana taxation is adjusted to align with the revised recreational forecast, correcting the previous overestimation of medical tax revenue.



In total, the forecast changes for recreational marijuana are minor. The December forecast assumes steady growth in the number of users and quantities purchased, and while marijuana tax collections are still expected to rise, the pace of growth has been scaled back given persistent low prices and an increasingly mature market.

Psilocybin Forecast

Ballot Measure 109 (2020) legalized psilocybin, including a 15% retail sales tax on the psilocybin products used. This sales tax does not apply to the overall cost of a session which can be hundreds or thousands of dollars. The vast majority of the overall cost goes to cover operational expenses for the service center and the facilitator's time and expertise.

The industry has been growing and has now been operating legally for more than a year. The current forecast remains a work in progress; however, it is now based on that first full year of data as opposed to pure assumptions. Even so, expectations are the industry is still in its ramp up period. The number of businesses, facilitators, and customers are all expected to grow in the years ahead. As more data becomes available, our office will adjust the outlook accordingly.

The average product price reported is approximately $40, however there is a wide range of values around that average. The average price is in line with previous conversations our office has had with multiple service centers in Oregon in recent years. And while not a low price, the cost of the product is relatively small compared to the overall cost of a session. For fiscal year 2024, which ran from July 2023 to June 2024, the sales tax revenue amounted to less than $100,000.

Looking forward, the number of sessions, and products sold is expected to increase. The exact rate of growth is unknown. Our office is monitoring the quarterly tax returns and looking forward to the updated OHA dashboard that will include more information on the number of sessions and customers that is expected to launch in Spring 2025. Our office will adjust the forecast accordingly as we learn more.

For now, the revenue forecast is tied to a multiyear ramp up period of stronger growth based on the patterns seen in Oregon for recreational marijuana and sports betting. After the ramp up, growth is expected to slow something closer to growth in the population which is a proxy for the user base until better information is available.

Oregon Psilocybin Retail Sales Tax Revenue

Dec-24

	Biennium				
	2023-25	2025-27	2027-29	2029-31	2031-33
No. of Session	34,000	56,000	65,000	69,000	73,000
Avg Product Price	$40	$42	$44	$45	$47
Total Sales	$1,376,000	$2,355,000	$2,843,000	$3,140,000	$3,456,000
Taxes	$206,000	$353,000	$426,000	$471,000	$518,000

Lastly, it is important to note that the sales tax applies only to the purchase price of the psilocybin product itself. As such, service centers may charge customers the traditional retail price that includes a markup over wholesale costs which largely relates to production, testing, and distribution costs. Service centers may choose to sell the products at cost. And while they are not supposed to do this, they may charge customers a minimal product cost that is below their own cost. The potential benefit of doing so would be to increase revenues and profits for service centers and facilitators as less of the overall session price would be sent to pay taxes. To date, the data indicate this last possibility is not happening, or at least not enough to notice in industrywide information. However, as with all other sales taxes, revenue is driven by both the number of transactions and the price per transaction.

Revenue Alternative Scenarios

The latest revenue forecast for the current biennium represents the most probable outcome given available information. Our office feels that it is important that anyone using this forecast for decision-making purposes recognize the potential for actual revenues to depart significantly from this projection. For the economic assumptions these scenarios are based on, see page 15.

The Office of Economic Analysis is characterizing two alternative scenarios to the baseline forecast: an optimistic scenario and a recessionary scenario. The display below presents the revenue differentials between these two alternatives and the baseline. With only seven months remaining in the current biennium, the potential for revenues to deviate from the baseline owes to normal historic variation.

The optimistic scenario assumes that the U.S. and Oregon economies perform somewhat better than assumed in the baseline. While not particularly contingent on higher population growth and net in-migration, this is one aspect that could result in significantly higher revenues in the long run. Oregon has experienced periods where employment growth has exceeded population growth, necessarily

Alternative Scenarios **December 2024**

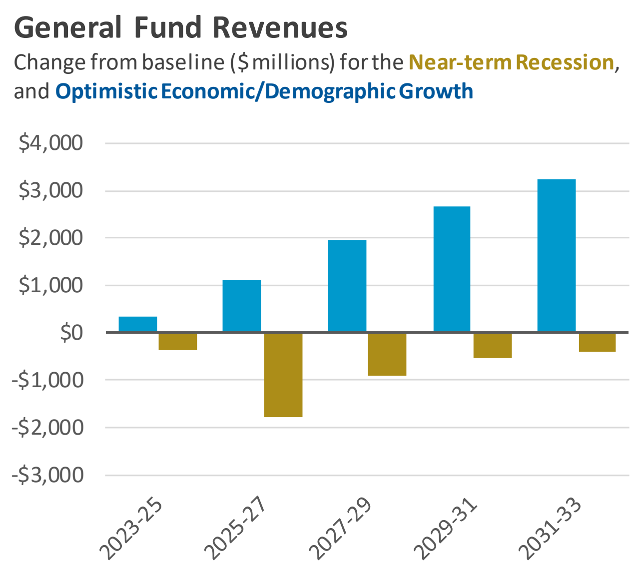
Changes relative to the baseline ($ millions)

General Fund	2023-25	2025-27	2027-29	2029-31	2031-33
Optimistic	$357	$1,129	$1,947	$2,675	$3,231
Pessimistic	-$371	-$1,771	-$917	-$529	-$411

Corporate Activity Tax	2023-25	2025-27	2027-29	2029-31	2031-33
Optimistic	$36	$95	$145	$182	$204
Pessimistic	-$27	-$201	-$118	-$89	-$58

Lottery	2023-25	2025-27	2027-29	2029-31	2031-33
Optimistic	$26	$66	$97	$118	$129
Pessimistic	-$20	-$101	-$79	-$65	-$49

Source: Oregon Office of Economic Analysis

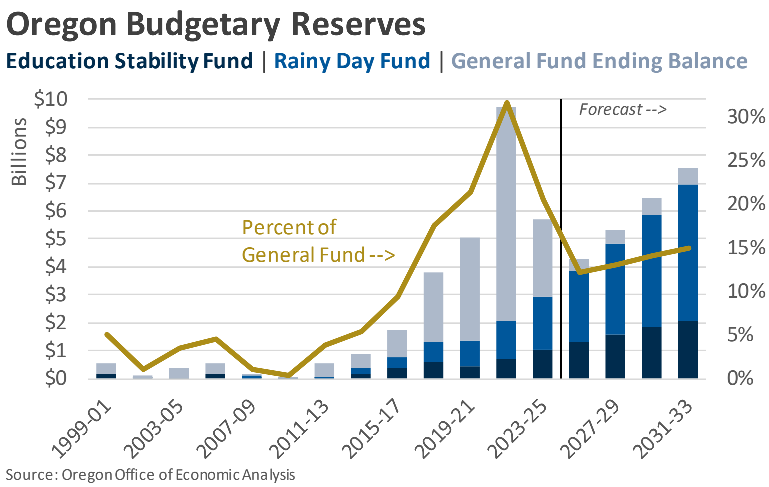


driven by changes in the labor force participation rate. In addition, a major component of the variation in past General Fund growth has owed to equity and profits gains and can be attributed in part to increase productivity. Thus, the optimistic scenario can be viewed as the potential for any or all of these factors to manifest throughout the forecast horizon.

The recession scenario is based on the historic tendency for the U.S. economy to recede periodically due to accumulated imbalances or other exogenous factors. A survey of private economists currently estimates the probability of recession in the next twelve months at 25%. The revenue change profile exhibited in the table above is based on previous recessions and the Office of Economic Analysis' current expectations for the likely severity and timing of a recession. Specifically, General Fund revenues would be expected to deviate 6.9% from the baseline in 2025-27 as a relatively modest recession occurs sometime during the first fiscal year. Corporate Activity Tax and Lottery would experience lighter losses due to being associated with consumer spending, a phenomenon less sensitive to economic variation than income.

Budgetary Reserves

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund[2] (ORDF) and the Education Stability Fund[3] (ESF). As of this forecast the two reserve funds currently total a combined $2.6 billion at the end of October 2024. At the end of the current 2023-25 biennium, they will total $2.9 billion, which is equal to 10.0% of current revenues. Including the projected General Fund ending balance of $2.8 billion, the total effective reserves at the end of the current 2023-25 biennium are projected to be $5.7 billion, or 20.5% of current revenues.



Effective Reserves ($ millions)

	Current Dec-24	*End of 2023-25*	*2025-27 Est.*
ESF	$900	1,007.4	1,282.1
RDF	$1,708	$1,908	$2,554
Reserves	$2,607	$2,915	$3,837
Ending Balance	$2,786	$2,786	$500
Total	**$5,393**	**$5,701**	**$4,337**
% of GF	19.4%	20.5%	12.3%

As noted above, the current probability of an economic downturn is estimated at 25%. The worst decline in General Fund revenues relative to the Close-of-Session forecast in the last 50 years was 15.3% during the 2001-03 biennium associated with the tech industry boom-bust. The final column of the table above presents the projected balances in the ORDF, ESF and a hypothetical budgetary ending balance based on historic legislatively adopted balances. Total available reserves under this scenario would amount to 12.3% of General Fund revenues. It is quite likely that Oregon's reserves are adequate to weather a potential downturn given that a mild to moderate recession is the most likely scenario.

B.10 in Appendix B provides more details for Oregon's budgetary reserves.

[2] The ORDF is funded from ending balances each biennium, up to 1% of appropriations. The Legislature can deposit additional funds, as it did in first populating the ORDF with surplus corporate income tax revenues from the 2005-07 biennium. The ORDF also retains interest earnings. Withdrawals from the ORDF require one of three triggers, including a decline in employment, a projected budgetary shortfall, or declaration of a state of emergency, plus a simple majority vote of the Legislature. Withdrawals are capped at two-thirds of the balance as of the beginning of the biennium in question. Fund balances are capped at 7.5% of General Fund revenues in the prior biennium.

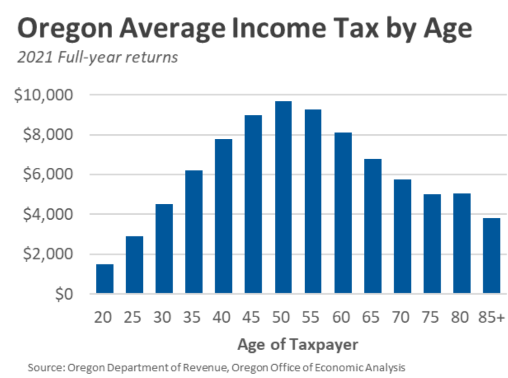
[3] [3] The ESF gained its current reserve structure and mechanics via constitutional amendment in 2002. The ESF receives 18% of lottery earnings, deposited on a quarterly basis – 10% of which are deposited in the Oregon Growth sub-account. The ESF does not retain interest earnings. The ESF has similar triggers as the ORDF but does not have the two-thirds cap on withdrawals. The ESF balance is capped at 5% of General Fund revenues collected in the prior biennium.

Aging and State Revenues

Oregon's population is gradually aging. This trend mirrors national patterns but is particularly pronounced in the state. As the Baby Boomer generation began to reach retirement age in larger numbers in the mid-2010s, the impact on the labor market has been significant. Retirements create substantial challenges for businesses. It is a daunting task to replace seasoned workers who have decades of valuable experience and institutional knowledge.

The revenue implications of these demographic changes are for slower growth in the decades ahead as traditional state tax instruments like personal income and general sales taxes become less effective.

As one transitions into retirement, it often results in a fixed, or reduced income. The composition of income also changes with a larger reliance on Social Security as opposed to wages or business income. As a result, taxable income declines more than total income for older households. Relative to taxpayers in their 40s and 50s, the average personal income tax paid by 70-somethings in Oregon is 40% lower. The average tax bill for Oregonians 85 years and older is 60% lower than those in the prime-working, and peak-earning years.



Similar to income, overall spending declines with age. Lifestyle changes and adjustments in financial priorities also shift the nature of spending. Expenditures on big-ticket durable goods, such as cars, computers, and furniture, typically see a notable decline with age. Spending on essentials such as food and housing exhibits a more stable pattern, while spending on healthcare and cash contributions, such as donations to charity or financial support for family members, generally increases with age.

Oregon’s Corporate Activity Tax has a broader tax base than a traditional retail sales tax, in large part because it includes services. As such, the CAT is likely to be less affected than most states when it comes to the compositional shift in spending. However, Oregon will still be impacted by the relative slowing in overall spending in the years ahead.

Estate taxes are one traditional type of public revenues that are likely to see stronger gains with a larger, older cohort in the years ahead. This is due to the combination of rising asset prices over time and the underlying demographic changes. Oregonians (and Americans) tend to age in place. It is only in one’s 80s or older that we really move into residential care facilities. The aging impact of this won’t be felt for another decade. This means the bigger increases in medical expenses and the impacts of downsizing/moving into a nursing homes on the housing market are still to come.

Tax Law Assumptions

The revenue forecast is based on existing law, including measures and actions signed into law during the 2023 Oregon Legislative Session. OEA makes routine adjustments to the forecast to account for legislative and other actions not factored into the personal and corporate income tax models. These adjustments can include expected kicker refunds, when applicable, as well as any tax law changes not yet present in the historical data. For a detailed treatment of the components of the 2023 Legislatively Enacted Budget, see:

Legislative Fiscal Office's 2023-25 Budget Summary[4]

Although based on current law, many of the tax policies that impact the revenue forecast are not set in stone. In particular, sunset dates for many large tax credits have been scheduled. As credits are allowed to disappear, considerable support is lent to the revenue outlook in the outer years of the forecast. To the extent that tax credits are extended and not allowed to expire when their sunset dates arrive, the outlook for revenue growth will be reduced. The current forecast relies on estimates taken from the Oregon Department of Revenue's 2023-25 Tax Expenditure Report together with more timely updates produced by the Legislative Revenue Office.

[4] https://www.oregonlegislature.gov/lfo/Documents/2023-25%20Legislatively%20Adopted%20Budget%20-%20General%20Fund%20and%20Lottery%20Funds%20Summary.pdf

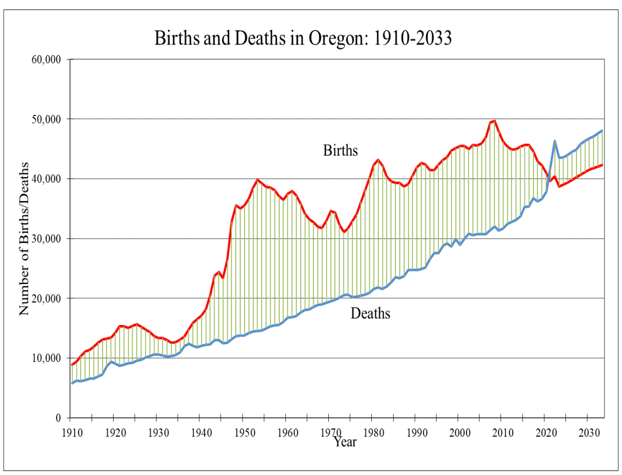
Population and Demographic Outlook

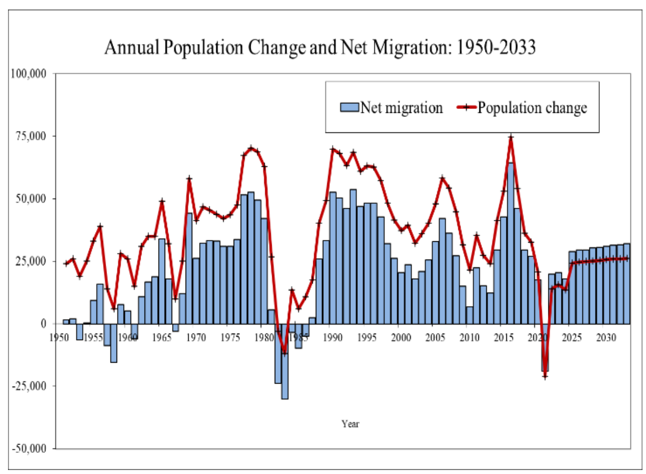
Population and Demographic Summary

Based on the most recent decennial census, Oregon's resident population on April 1, 2020, was 4,237,256. During the past decade, Oregon gained 406,182 residents or 10.6%. This decennial gain was the second lowest since the first census count in Oregon in 1860 after gaining statehood. Still, the gain was substantial enough to yield one additional congressional seat for the state. Oregon now has a total of six members in the House of Representatives. This is rare because it took 40 years for Oregon to gain one additional seat.

Oregon's population growth of 10.6% in the last decade was 11th highest in the nation, excluding Washington D.C. The growth rate for the decade lagged all our neighboring states, except California. Oregon's growth has experienced some turbulence since the 2020 census. At OEA we use the Population Research Center, PSU's recent post-censal estimate as the base for our office's population forecasts. The PRC has revised its past estimates for the years 2020 through 2023. The revised estimate shows a loss of 20,478 people between 2000 and 2001.

Additionally, a substantial population increase between 2021 and 2023 estimated previously was revised to a small gain for each year. During the early stage of the COVID-19 pandemic Oregon lost population, according to PSU estimates. PSU's new and revised estimates now show Oregon population growth has remained low, indicating timid economic recovery in the post-pandemic years. The population growth is expected to show a steady but slow increase in the future reaching 4.487 million in the year 2033 with an annual rate of growth of 0.6% between 2024 and 2033.

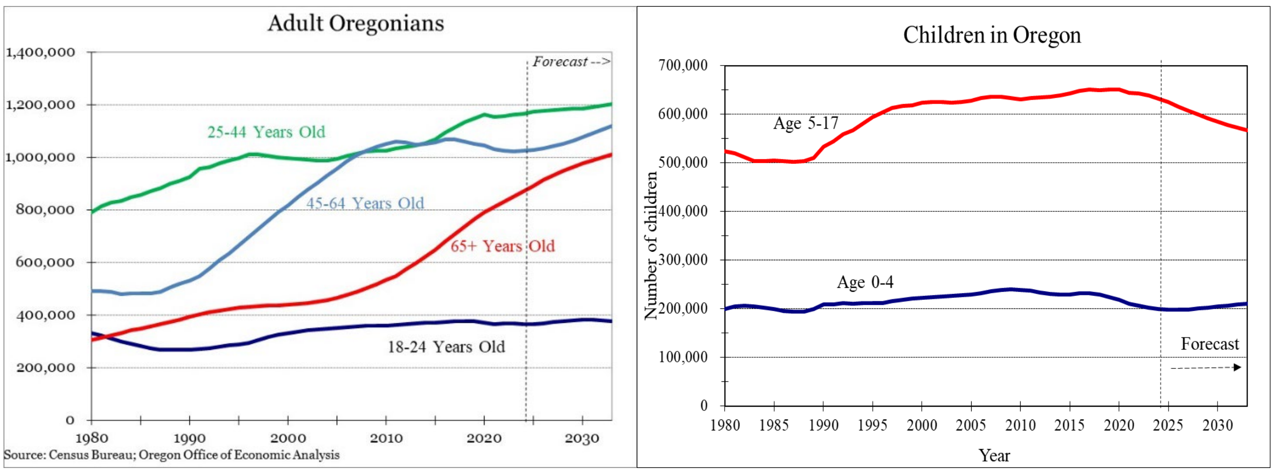




Oregon's economic environment heavily influences the state's population growth. Its economy determines the ability to retain existing work force as well as attract job seekers from national and international labor markets. As Oregon's total fertility rate remains well below the replacement level and number of deaths continue to rise due to aging population, long-term growth relies entirely from net in-migration.

Working-age adults come to Oregon as long as there are favorable economic conditions such as: affordable housing and childcare, a good educational environment, and a better quality of life that project real and perceived positivity about the state. As a result of a sudden rise in the number of deaths and drop in the number of births coinciding with the COVID-19 pandemic, the natural increase turned negative starting in the year 2020 and will continue through 2033 and beyond. Migration will be solely responsible for Oregon's future population growth. Without a positive net migration stream, Oregon's population will start a steady decline. Under a few scenarios, the negative natural increase may reverse itself. Such reversal can happen if people capable of giving birth start to have more children due to behavioral or motivational factors, improved life expectancy leading to fewer deaths, or a significant migration of individuals of childbearing age into Oregon.

Age structure and its change affect employment, state revenue collection, and tax expenditures. The demand for public services varies by age groups. Demographics are the major budget drivers, which are modified by policy choices on service coverage and delivery. Births, deaths, and migration histories of decades past remain impactful on the current age-sex structure. Growth in many age groups will show the effects of the depression era birth cohort, baby boom and their echo generations, and composition of migrants during the forecast period of 2024-2033.



Elderly (65+)

The overall elderly population (65+) was growing at a relatively slow pace during the late 1990s and early 2000s when the depression era birth cohort entered this age group. The elderly population picked up a faster pace of growth when the early baby-boom cohort started maturing into the elderly age group. This age cohort has hit the plateau of high growth rates of above 4% annually between 2011 and 2018. The group will experience continued high but diminishing rate of growth in the coming years. The average annual growth of the elderly population will be 1.6% during the 2024-2033 forecast period.

As a sign of massive demographic structural change of Oregon's population, the number of elderly people has exceeded the number of children under the age of 18 since 2023. To illustrate the contrast, in 2000 elderly population numbered a little over half of the number of children in Oregon, now the elderly outnumber the children. Different age groups among the elderly population show quite varied and fascinating growth trends:

- The youngest elderly group (aged 65-74) —which was growing at an extremely fast pace in the recent past (averaging 5.2% annually)— will taper off to negative growth by the end of the forecast period as a sign to the end of the baby boom generation transitioning to the elderly age group. This high growth transitioning into a net loss of this youngest elderly population resulting in 0.6% annual average loss in the coming nine years.

- The next older generation of population aged 75-84 has been growing rapidly for a decade after several years of slow as well as negative growth until a decade ago. An unprecedented fast pace of growth, exceeding 6% annually in this age group has already started as the baby boom generation is maturing and the depression era birth cohort exiting this 75-84 age group. Annual growth rate is expected to be unusually high at 3.7% during the forecast period.
- The oldest elderly population (aged 85+) will resume growth at a strong rate steadily gaining momentum due to the combination of cohort change, historical positive net migration, and improving longevity. The average annual rate of growth for this oldest elderly group over the forecast horizon will be 5.5%. An unprecedented annual growth exceeding 8% will commence near the end of the forecast horizon.

Working Age and Young Adults (18-64)

The oldest working age population aged 45-64 also has seen the dramatic demographic impact as the baby boom generation matures out of this age group and is replaced by smaller baby-bust cohort or Gen X. As the effect of this demographic transition is combined with slowing net migration, the once fast-paced growth has tapered off to negative growth. The growth rate will reverse to positive and will see gaining momentum over the forecast horizon with 1.0% annualized rate of change. The younger working-age population of 25-44 age group will have steady but slow growth of 0.3% annual average throughout the forecast period.

The young adult population (aged 18-24) will see only a small change, averaging 0.3% annually over the forecast period. Although the slow growth of the college-age population (age 18-24), in general, tend to ease the pressure on public spending on higher education, college enrollment typically goes up during times of a very competitive job market, high unemployment, and scarcity of well-paying jobs when the older cohort flock back to colleges to better position themselves in a tough job market.

School Age (5-17) and pre-School Age (0-4) Children

The growth in K-12 population (aged 5-17) has been very slow or negative in the past and is expected to decline consistently through the forecast years mainly due to the declining number of births over the years. This will translate into slow growth or decline in the school enrollments. On average for the forecast period, this school-age population will decline by -1.2% annually. The growth rate for children under the age of five has remained near or below zero percent in the recent past and will continue negative or slow growth averaging 0.6% annually in the near future. The demand for childcare services and pre-Kindergarten programs is determined by the size of this population as well as the labor force participation and poverty rates of the parents.

Overall, the elderly population over age 65 will increase rapidly whereas the number of children will decline over the forecast horizon. The number of working-age adults in general will show slow growth during the forecast horizon. Hence, based solely on demographics of Oregon, demand for public services geared towards children and young adults will likely decline or increase only at a slower pace, whereas demand for elderly care and services will increase rapidly.

Procedure and Assumptions

Population forecasts by age and sex are developed using the cohort-component projection procedure. The population by single year of age and sex is projected based on the specific assumptions of vital events and migrations. The cohort-component projection procedure entails the model "survives" the initial population distribution by age and sex to the next age-sex category in the following year, and then applies age-sex-specific birth and migration rates to the mid-period population.

The population by single age-sex detail from the 2020 census and the most recent estimated total population for Oregon by Population Research Center of Portland State University are the base for the forecast. The numbers of births and deaths through 2023 are from Oregon's Center for Health Statistics. All other numbers and age-sex detail are generated by OEA.

Annual numbers of births are determined from the age-specific fertility rates projected based on Oregon's past trends and past and projected national trends. Oregon's total fertility rate is assumed to be 1.4 per woman in 2024 and this rate is projected to 1.5 children per woman by 2033 which is well below the replacement level fertility of 2.1 children per woman during their reproductive life.

Life Table survival rates are developed for the year 2020. Male and female life expectancies for the 2020-2033 period are projected based on the past three decades of trends and national projected life expectancies. After a sudden decline during the COVID pandemic, gradual improvements in life expectancies are expected over the forecast period. At the same time, the difference between the male and female life expectancies will continue to shrink. The male life expectancy at birth was 77.3 and the female life expectancy was 81.8 in 2010. Because of the COVID-19 pandemic, number of deaths suddenly increased, and the actual life expectancies declined. The life expectancy at birth in 2020 was 76.9 and 81.7 years for males and females, respectively. This is expected to improve to 78.4 years for women and 83.1 years for men by 2033.

Estimates and forecasts of the number of net migrations are based on the residuals from the difference between population change and natural increase (births minus deaths) in a forecast period. The migration forecasting considers Oregon's employment, unemployment rates, income/wage data from Oregon, neighboring states and the nation, and past migration trends. Distribution of migrants by age and sex is based on detailed data from the American Community Survey. The role of net migration in Oregon's population growth has gained prominence as the natural increase has begun to turn negative. Between 2024 and 2033 net migration is expected to be in the range of 28,476 to 31,966, averaging 30,500 persons annually with net migration rate ranging between 6.67 to 7.15 per thousand population.

Appendix A: Economic Forecast Detail

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 3rd quarter 2024

(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,994.0	0.8	1,994.4	0.2	(0.4)	(0.0)	0.4
Total Private	1,679.0	0.7	1,680.5	0.2	(1.5)	(0.1)	(0.1)
Mining and Logging	5.9	(2.6)	6.1	4.9	(0.2)	(3.7)	(5.2)
Construction	116.1	(1.1)	117.2	3.7	(1.2)	(1.0)	(1.6)
Manufacturing	189.1	1.6	188.3	(2.4)	0.7	0.4	(0.5)
Durable Goods	132.2	(0.1)	131.8	(4.1)	0.4	0.3	(0.7)
Wood Product	22.5	(1.5)	22.8	(0.7)	(0.3)	(1.3)	(1.4)
Metals and Machinery	36.5	(1.9)	37.2	1.5	(0.7)	(1.8)	(1.7)
Computer and Electronic Product	40.5	1.2	39.1	(14.0)	1.5	3.8	0.1
Transportation Equipment	11.1	0.2	11.5	3.2	(0.4)	(3.4)	(1.2)
Other Durable Goods	21.6	1.6	21.3	(1.6)	0.3	1.5	0.5
Nondurable Goods	56.8	5.9	56.5	1.7	0.3	0.5	0.0
Food	28.3	(0.1)	28.6	0.3	(0.3)	(1.1)	(0.4)
Other Nondurable Goods	28.5	12.3	27.9	3.3	0.6	2.2	0.4
Trade, Transportation & Utilities	359.2	(0.0)	360.2	(0.1)	(1.1)	(0.3)	(1.5)
Retail Trade	202.1	(3.3)	204.4	(0.2)	(2.2)	(1.1)	(2.9)
Wholesale Trade	78.6	4.4	78.1	0.9	0.4	0.5	0.1
Transportation, Warehousing & Utilities	78.5	4.3	77.7	(0.6)	0.7	1.0	0.3
Information	35.0	(8.0)	36.2	5.8	(1.3)	(3.5)	(4.4)
Financial Activities	99.6	(6.1)	103.5	0.7	(3.9)	(3.7)	(4.2)
Professional & Business Services	263.0	3.1	262.3	1.6	0.7	0.3	(0.9)
Educational & Health Services	340.9	7.0	333.2	(2.1)	7.7	2.3	5.5
Educational Services	37.9	15.3	36.5	(1.3)	1.5	4.0	4.8
Health Services	303.0	6.0	296.7	(2.2)	6.2	2.1	5.6
Leisure and Hospitality	204.0	(6.2)	208.5	1.9	(4.5)	(2.1)	(1.4)
Other Services	66.3	2.8	64.9	(0.5)	1.4	2.1	1.1
Government	315.0	1.3	313.9	0.3	1.1	0.3	2.8
Federal	29.5	2.4	29.5	1.4	(0.0)	(0.1)	3.3
State	47.8	2.7	48.2	3.7	(0.4)	(0.8)	3.4
State Education	1.5	(29.8)	1.5	13.6	0.0	1.5	2.1
Local	237.7	0.9	236.2	(0.5)	1.5	0.6	2.7
Local Education	134.1	(1.2)	134.7	(0.9)	(0.6)	(0.4)	1.8

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly						Annual				
	2024:3	2024:4	2025:1	2025:2	2025:3	2025:4	2023	2024	2025	2026	2027
Personal Income ($ billions)											
Nominal Personal Income	303.9	307.4	311.8	316.1	320.5	324.7	287.2	302.4	318.3	336.1	354.1
% change	3.8	4.6	5.8	5.7	5.6	5.4	5.7	5.3	5.3	5.6	5.4
Real Personal Income (base year=2017)	245.8	247.5	249.9	252.0	254.0	255.8	238.3	245.0	253.0	260.8	269.4
% change	2.5	2.9	3.9	3.4	3.2	2.9	1.8	2.8	3.2	3.1	3.3
Nominal Wages and Salaries	149.8	151.7	153.6	155.6	157.5	159.4	142.4	148.9	156.5	164.4	172.3
% change	3.9	5.4	4.9	5.2	5.0	5.0	4.8	4.6	5.1	5.0	4.8
Other Indicators											
Per Capita Income ($1,000)	70.4	71.1	72.0	72.9	73.8	74.7	66.8	70.1	73.4	77.0	80.7
% change	3.3	4.1	5.1	5.1	5.1	4.8	5.0	4.9	4.7	5.0	4.8
Average Wage rate ($1,000)	74.7	75.4	76.1	76.8	77.6	78.4	71.2	74.3	77.2	80.4	83.7
% change	3.8	3.5	3.7	4.1	4.1	4.1	2.7	4.3	3.9	4.1	4.2
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.30	4.31	4.34	4.36	4.39
% change	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.4	0.6	0.6	0.6
Housing Starts (Thousands)	14.6	15.1	15.4	15.6	16.0	16.8	18.1	14.4	16.0	18.3	19.5
% change	18.6	15.0	7.1	7.5	10.1	20.6	(9.3)	(20.5)	10.7	14.7	6.4
Unemployment Rate	4.2	4.2	4.2	4.2	4.3	4.3	3.7	4.2	4.2	4.3	4.4
Point Change	(0.0)	0.0	0.0	0.0	0.0	0.0	(0.2)	0.5	0.0	0.1	0.1
Employment (Thousands)											
Total Nonfarm	1,994.0	1,998.0	2,004.3	2,010.1	2,014.6	2,018.6	1,985.8	1,991.0	2,011.9	2,030.0	2,043.7
% change	0.8	0.8	1.3	1.2	0.9	0.8	2.1	0.3	1.1	0.9	0.7
Private Nonfarm	1,679.0	1,682.1	1,688.7	1,694.9	1,699.4	1,703.4	1,679.3	1,676.7	1,696.6	1,714.9	1,729.5
% change	0.7	0.8	1.6	1.5	1.1	0.9	1.8	(0.2)	1.2	1.1	0.9
Construction	116.1	116.7	117.0	117.4	118.0	118.6	117.8	116.4	117.8	120.1	122.1
% change	(1.1)	2.1	1.2	1.4	2.1	1.8	2.2	(1.2)	1.2	1.9	1.7
Manufacturing	189.1	186.3	186.2	186.5	186.7	186.6	191.1	188.0	186.5	188.0	188.9
% change	1.6	(5.6)	(0.3)	0.7	0.5	(0.3)	(1.0)	(1.6)	(0.8)	0.8	0.5
Durable Manufacturing	132.2	129.1	129.0	129.3	129.6	129.5	133.8	131.4	129.4	130.9	131.8
% change	(0.1)	(9.2)	(0.4)	1.0	0.9	(0.2)	(1.0)	(1.8)	(1.6)	1.2	0.7
Wood Product Manufacturing	22.5	22.1	22.1	22.2	22.3	22.1	22.8	22.5	22.2	22.1	22.2
% change	(1.5)	(6.0)	(0.5)	2.4	1.0	(4.1)	(2.0)	(1.5)	(1.3)	(0.2)	0.1
High Tech Manufacturing	40.5	37.7	37.7	37.8	37.9	38.1	40.9	39.7	37.9	39.4	40.4
% change	1.2	(24.9)	(0.6)	0.8	1.3	2.5	(0.8)	(3.0)	(4.6)	4.0	2.5
Transportation Equipment	11.1	11.2	11.2	11.3	11.4	11.5	11.2	11.2	11.4	11.7	11.7
% change	0.2	3.7	1.9	3.4	3.4	3.4	2.8	(0.2)	1.9	2.7	0.3
Nondurable Manufacturing	56.8	57.2	57.2	57.2	57.2	57.1	57.3	56.5	57.2	57.1	57.1
% change	5.9	3.0	(0.2)	0.2	(0.6)	(0.4)	(0.9)	(1.3)	1.2	(0.1)	0.1
Private nonmanufacturing	1,489.9	1,495.8	1,502.5	1,508.4	1,512.7	1,516.7	1,488.2	1,488.7	1,510.1	1,527.0	1,540.6
% change	0.6	1.6	1.8	1.6	1.1	1.1	2.1	0.0	1.4	1.1	0.9
Retail Trade	202.1	202.9	203.6	204.3	204.9	205.6	208.5	203.3	204.6	206.6	208.2
% change	(3.3)	1.4	1.5	1.4	1.3	1.3	(0.9)	(2.5)	0.7	1.0	0.7
Wholesale Trade	78.6	78.3	78.3	78.1	78.0	78.0	78.2	78.1	78.1	77.8	77.8
% change	4.4	(1.3)	(0.3)	(0.7)	(0.5)	(0.1)	1.7	(0.2)	0.0	(0.3)	0.0
Information	35.0	35.4	35.7	35.7	35.8	35.8	36.7	35.5	35.7	35.9	36.1
% change	(8.0)	5.1	3.3	0.3	0.3	0.1	(0.3)	(3.2)	0.6	0.5	0.5
Professional and Business Services	263.0	265.3	268.0	269.8	270.8	272.1	266.2	262.3	270.2	275.3	278.2
% change	3.1	3.5	4.2	2.7	1.6	1.8	1.1	(1.5)	3.0	1.9	1.1
Health Services	303.0	305.3	306.1	307.5	308.3	309.0	284.8	300.2	307.7	310.9	314.4
% change	6.0	3.2	1.0	1.8	1.1	0.9	5.7	5.4	2.5	1.0	1.1
Leisure and Hospitality	204.0	204.6	205.6	206.4	207.0	207.7	206.9	205.6	206.6	209.1	211.3
% change	(6.2)	1.1	2.0	1.5	1.1	1.4	4.2	(0.6)	0.5	1.2	1.0
Government	315.0	315.9	315.6	315.2	315.2	315.3	306.5	314.3	315.3	315.0	314.2
% change	1.3	1.1	(0.4)	(0.6)	(0.0)	0.1	4.0	2.5	0.3	(0.1)	(0.3)

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs Previous)

	Quarterly						Annual				
	2024:3	**2024:4**	**2025:1**	**2025:2**	**2025:3**	**2025:4**	**2023**	**2024**	**2025**	**2026**	**2027**
Personal Income ($ billions)											
Nominal Personal Income	303.9	307.4	311.8	316.1	320.5	324.7	287.2	302.4	318.3	336.1	354.1
% change	4.2	4.2	3.9	3.7	3.5	3.4	3.8	4.6	3.6	3.1	2.9
Real Personal Income (base year=2017)	245.8	247.5	249.9	252.0	254.0	255.8	238.3	245.0	253.0	260.8	269.4
% change	4.3	4.4	4.1	3.9	3.7	3.5	3.7	4.6	3.8	3.1	2.9
Nominal Wages and Salaries	149.8	151.7	153.6	155.6	157.5	159.4	142.4	148.9	156.5	164.4	172.3
% change	0.6	0.6	0.4	0.3	0.3	0.2	(0.3)	0.9	0.3	0.1	(0.0)
Other Indicators											
Per Capita Income ($1,000)	70.4	71.1	72.0	72.9	73.8	74.7	66.8	70.1	73.4	77.0	80.7
% change	4.2	4.2	3.9	3.7	3.5	3.4	3.8	4.6	3.6	3.1	2.9
Average Wage rate ($1,000)	74.7	75.4	76.1	76.8	77.6	78.4	71.2	74.3	77.2	80.4	83.7
% change	0.8	0.7	0.5	0.3	0.2	0.2	(0.3)	0.9	0.3	0.0	(0.0)
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.4	4.4
% change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Housing Starts (Thousands)	14.6	15.1	15.4	15.6	16.0	16.8	18.1	14.4	16.0	18.3	19.5
% change	3.5	6.0	5.8	5.6	4.9	4.3	0.2	2.8	5.1	3.3	2.1
Unemployment Rate	4.2	4.2	4.2	4.2	4.3	4.3	3.7	4.2	4.2	4.3	4.4
Point Change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Employment (Thousands)											
Total Nonfarm	1,994.0	1,998.0	2,004.3	2,010.1	2,014.6	2,018.6	1,985.8	1,991.0	2,011.9	2,030.0	2,043.7
% change	(0.0)	(0.2)	(0.1)	(0.1)	(0.0)	0.0	(0.0)	(0.1)	(0.0)	0.1	(0.0)
Private Nonfarm	1,679.0	1,682.1	1,688.7	1,694.9	1,699.4	1,703.4	1,679.3	1,676.7	1,696.6	1,714.9	1,729.5
% change	(0.1)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	0.0	(0.0)
Construction	116.1	116.7	117.0	117.4	118.0	118.6	117.8	116.4	117.8	120.1	122.1
% change	(1.0)	(1.5)	(1.6)	(1.7)	(1.6)	(1.6)	(0.0)	(0.4)	(1.6)	(1.9)	(2.1)
Manufacturing	189.1	186.3	186.2	186.5	186.7	186.6	191.1	188.0	186.5	188.0	188.9
% change	0.4	(0.3)	(0.6)	(0.5)	(0.4)	(0.5)	0.2	(0.1)	(0.5)	(0.2)	0.4
Durable Manufacturing	132.2	129.1	129.0	129.3	129.6	129.5	133.8	131.4	129.4	130.9	131.8
% change	0.3	(0.9)	(1.2)	(1.1)	(0.9)	(1.1)	0.2	(0.3)	(1.1)	(0.7)	0.1
Wood Product Manufacturing	22.5	22.1	22.1	22.2	22.3	22.1	22.8	22.5	22.2	22.1	22.2
% change	(1.3)	(2.5)	(2.5)	(1.8)	(1.6)	(2.6)	0.1	(1.2)	(2.1)	(2.3)	(1.8)
High Tech Manufacturing	40.5	37.7	37.7	37.8	37.9	38.1	40.9	39.7	37.9	39.4	40.4
% change	3.8	0.8	0.5	0.6	0.7	0.8	(0.0)	1.1	0.7	1.4	2.1
Transportation Equipment	11.1	11.2	11.2	11.3	11.4	11.5	11.2	11.2	11.4	11.7	11.7
% change	(3.4)	(3.1)	(3.2)	(3.3)	(3.0)	(2.7)	(0.2)	(2.4)	(3.1)	(2.3)	(1.5)
Nondurable Manufacturing	56.8	57.2	57.2	57.2	57.2	57.1	57.3	56.5	57.2	57.1	57.1
% change	0.5	0.9	0.7	0.9	0.8	0.9	0.2	0.3	0.8	0.9	0.9
Private nonmanufacturing	1,489.9	1,495.8	1,502.5	1,508.4	1,512.7	1,516.7	1,488.2	1,488.7	1,510.1	1,527.0	1,540.6
% change	(0.2)	(0.3)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	(0.2)	(0.1)	0.0	(0.1)
Retail Trade	202.1	202.9	203.6	204.3	204.9	205.6	208.5	203.3	204.6	206.6	208.2
% change	(1.1)	(1.2)	(1.1)	(0.8)	(0.6)	(0.3)	(0.0)	(0.6)	(0.7)	(0.2)	0.0
Wholesale Trade	78.6	78.3	78.3	78.1	78.0	78.0	78.2	78.1	78.1	77.8	77.8
% change	0.5	(0.3)	(0.2)	(0.3)	(0.3)	(0.2)	0.0	0.1	(0.2)	(0.1)	(0.2)
Information	35.0	35.4	35.7	35.7	35.8	35.8	36.7	35.5	35.7	35.9	36.1
% change	(3.5)	(2.8)	(2.2)	(2.2)	(2.1)	(2.0)	(0.1)	(1.5)	(2.1)	(1.8)	(1.6)
Professional and Business Services	263.0	265.3	268.0	269.8	270.8	272.1	266.2	262.3	270.2	275.3	278.2
% change	0.3	0.7	1.0	1.0	0.9	0.9	0.0	0.1	0.9	0.9	(0.1)
Health Services	303.0	305.3	306.1	307.5	308.3	309.0	284.8	300.2	307.7	310.9	314.4
% change	2.1	1.8	1.9	1.8	1.8	1.8	0.0	1.0	1.9	1.7	1.6
Leisure and Hospitality	204.0	204.6	205.6	206.4	207.0	207.7	206.9	205.6	206.6	209.1	211.3
% change	(2.1)	(2.0)	(1.8)	(1.8)	(1.8)	(1.7)	(0.1)	(0.9)	(1.8)	(1.4)	(1.3)
Government	315.0	315.9	315.6	315.2	315.2	315.3	306.5	314.3	315.3	315.0	314.2
% change	0.3	0.5	0.5	0.4	0.4	0.4	(0.0)	0.2	0.4	0.3	0.2

Table A.4 – Annual Economic Forecast

Dec 2024 - Personal Income

(Billions of Current Dollars)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Personal Income*												
Oregon	271.8	287.2	302.4	318.3	336.1	354.1	371.8	389.9	409.0	428.4	448.3	469.0
% Ch	2.4	5.7	5.3	5.3	5.6	5.4	5.0	4.9	4.9	4.8	4.7	4.6
U.S.	22,088.9	23,402.5	24,747.8	25,902.1	27,210.5	28,473.4	29,757.0	31,069.7	32,419.3	33,803.6	35,240.2	36,753.2
% Ch	3.1	5.9	5.7	4.7	5.1	4.6	4.5	4.4	4.3	4.3	4.2	4.3
Wage and Salary												
Oregon	135.8	142.4	148.9	156.5	164.4	172.3	180.3	188.7	197.8	206.9	216.3	226.1
% Ch	7.5	4.8	4.6	5.1	5.0	4.8	4.6	4.6	4.8	4.6	4.5	4.5
U.S.	11,123.1	11,725.2	12,494.4	13,050.0	13,633.2	14,150.0	14,720.5	15,313.4	15,938.2	16,579.5	17,250.9	17,965.4
% Ch	7.8	5.4	6.6	4.4	4.5	3.8	4.0	4.0	4.1	4.0	4.0	4.1
Other Labor Income												
Oregon	32.1	34.2	35.8	38.0	40.0	42.0	44.0	46.1	48.3	50.6	52.9	55.3
% Ch	3.2	6.5	4.8	6.0	5.3	5.0	4.7	4.8	4.9	4.6	4.6	4.5
U.S.	1,548.3	1,643.9	1,763.6	1,851.0	1,933.8	2,007.1	2,088.0	2,172.1	2,260.8	2,351.7	2,447.0	2,548.3
% Ch	0.9	6.2	7.3	5.0	4.5	3.8	4.0	4.0	4.1	4.0	4.0	4.1
Nonfarm Proprietor's Income												
Oregon	22.6	24.0	25.1	26.5	28.0	29.3	30.7	32.4	34.3	36.3	38.3	40.5
% Ch	(2.1)	6.0	4.7	5.4	5.6	4.7	4.7	5.6	5.9	5.8	5.5	5.7
U.S.	1,777.6	1,877.7	1,966.7	2,063.9	2,164.3	2,251.4	2,341.2	2,450.9	2,575.9	2,705.3	2,839.1	2,980.2
% Ch	2.2	5.6	4.7	4.9	4.9	4.0	4.0	4.7	5.1	5.0	4.9	5.0
Dividend, Interest and Rent												
Oregon	53.7	59.3	61.6	64.7	68.9	73.2	77.2	80.8	84.2	87.8	91.2	94.8
% Ch	8.4	10.4	3.9	4.9	6.6	6.2	5.4	4.6	4.3	4.2	4.0	3.9
U.S.	4,344.3	4,812.0	4,996.6	5,219.2	5,571.2	5,926.9	6,247.2	6,534.1	6,807.9	7,083.5	7,369.8	7,667.1
% Ch	9.9	10.8	3.8	4.5	6.7	6.4	5.4	4.6	4.2	4.0	4.0	4.0
Transfer Payments												
Oregon	57.4	59.9	65.0	68.5	72.3	76.6	80.8	85.2	89.6	94.3	99.1	104.2
% Ch	(8.9)	4.3	8.4	5.4	5.6	5.9	5.5	5.4	5.2	5.2	5.2	5.1
U.S.	4,013.8	4,146.5	4,394.2	4,595.4	4,804.1	5,053.5	5,314.3	5,593.6	5,871.4	6,160.4	6,455.0	6,761.1
% Ch	(12.0)	3.3	6.0	4.6	4.5	5.2	5.2	5.3	5.0	4.9	4.8	4.7
Contributions for Social Security												
Oregon	23.7	25.2	26.2	27.8	29.3	30.8	32.3	33.9	35.6	37.4	39.1	40.9
% Ch	8.8	6.4	4.0	6.0	5.4	5.2	4.9	4.9	5.0	4.9	4.6	4.5
U.S.	939.5	995.6	1,044.2	1,076.7	1,118.5	1,147.4	1,190.3	1,238.3	1,289.1	1,341.4	1,396.1	1,454.2
% Ch	10.2	6.0	4.9	3.1	3.9	2.6	3.7	4.0	4.1	4.1	4.1	4.2
Residence Adjustment												
Oregon	(6.9)	(7.6)	(7.9)	(8.3)	(8.6)	(9.0)	(9.3)	(9.7)	(10.2)	(10.6)	(11.0)	(11.5)
% Ch	8.0	9.9	4.0	4.8	4.1	4.1	4.1	4.2	4.4	4.2	4.2	4.3
Farm Proprietor's Income												
Oregon	0.7	0.2	0.0	0.3	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6
% Ch	91.4	(68.7)	(91.7)	1,484.6	57.9	12.2	2.3	3.2	4.3	3.2	2.5	2.7
Per Capita Income (Thousands of $)												
Oregon	63.6	66.8	70.1	73.4	77.0	80.7	84.3	87.9	91.6	95.5	99.3	103.3
% Ch	1.2	5.0	4.9	4.7	5.0	4.8	4.4	4.3	4.3	4.2	4.1	4.0
U.S.	66.0	69.2	72.4	75.1	78.5	81.8	85.1	88.5	92.0	95.5	99.2	103.2
% Ch	2.4	4.8	4.7	3.8	4.4	4.2	4.1	4.0	3.9	3.9	3.9	3.9

* Personal Income includes all classes of income minus Contributions for Social Security

Dec 2024 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Nonfarm												
Oregon	1,944.9	1,985.8	1,991.0	2,011.9	2,030.0	2,043.7	2,055.2	2,068.6	2,083.8	2,095.0	2,104.3	2,113.8
% Ch	3.7	2.1	0.3	1.1	0.9	0.7	0.6	0.7	0.7	0.5	0.4	0.5
U.S.	152.5	156.1	158.6	159.9	160.3	160.5	160.9	161.6	162.3	162.8	163.3	163.7
% Ch	4.3	2.3	1.6	0.8	0.2	0.1	0.2	0.4	0.5	0.3	0.3	0.3
Private Nonfarm												
Oregon	1,650.3	1,679.3	1,676.7	1,696.6	1,714.9	1,729.5	1,741.8	1,755.8	1,770.5	1,782.7	1,792.2	1,801.8
% Ch	3.8	1.8	(0.2)	1.2	1.1	0.9	0.7	0.8	0.8	0.7	0.5	0.5
U.S.	130.3	133.3	135.3	136.4	136.7	136.7	137.1	137.7	138.3	138.8	139.2	139.5
% Ch	4.9	2.3	1.5	0.8	0.2	0.1	0.2	0.5	0.4	0.4	0.3	0.3
Mining and Logging												
Oregon	6.2	6.1	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
% Ch	(5.6)	(1.4)	(3.1)	0.5	0.1	0.1	(0.2)	0.1	0.2	0.3	0.3	0.1
U.S.	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	8.0	5.8	(0.2)	0.2	6.0	3.8	(1.9)	(1.1)	(0.9)	(0.1)	2.1	2.6
Construction												
Oregon	115.2	117.8	116.4	117.8	120.1	122.1	123.7	125.3	126.7	128.3	130.0	131.6
% Ch	3.6	2.2	(1.2)	1.2	1.9	1.7	1.3	1.3	1.1	1.2	1.3	1.2
U.S.	7.8	8.0	8.2	8.4	8.5	8.7	8.8	9.0	9.2	9.3	9.3	9.4
% Ch	4.4	3.3	2.8	1.7	1.8	1.7	1.9	2.1	1.6	1.0	0.8	0.8
Manufacturing												
Oregon	193.0	191.1	188.0	186.5	188.0	188.9	189.0	188.7	188.2	187.5	186.7	185.8
% Ch	3.4	(1.0)	(1.6)	(0.8)	0.8	0.5	0.0	(0.2)	(0.2)	(0.4)	(0.4)	(0.5)
U.S.	12.8	12.9	12.9	12.6	12.3	12.2	12.0	11.9	11.9	11.8	11.7	11.6
% Ch	3.7	1.0	(0.0)	(2.5)	(2.1)	(1.5)	(1.2)	(0.7)	(0.4)	(0.6)	(0.9)	(1.2)
Durable Manufacturing												
Oregon	135.2	133.8	131.4	129.4	130.9	131.8	131.4	130.7	129.9	129.2	128.3	127.3
% Ch	4.7	(1.0)	(1.8)	(1.6)	1.2	0.7	(0.3)	(0.6)	(0.6)	(0.5)	(0.7)	(0.8)
U.S.	8.0	8.1	8.1	7.9	7.7	7.5	7.4	7.3	7.3	7.2	7.1	7.0
% Ch	3.7	1.7	0.2	(3.1)	(2.3)	(1.8)	(1.9)	(1.2)	(0.7)	(0.8)	(1.0)	(1.5)
Wood Products												
Oregon	23.3	22.8	22.5	22.2	22.1	22.2	22.1	22.0	21.9	22.0	21.9	21.6
% Ch	2.4	(2.0)	(1.5)	(1.3)	(0.2)	0.1	(0.2)	(0.5)	(0.5)	0.4	(0.3)	(1.4)
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
% Ch	4.2	(2.2)	(0.8)	(0.4)	2.8	1.3	1.9	5.7	6.6	3.6	0.8	(1.9)
Metal and Machinery												
Oregon	38.0	37.4	36.6	36.4	36.4	36.5	36.2	36.0	35.8	35.6	35.2	35.0
% Ch	4.5	(1.5)	(2.1)	(0.5)	(0.1)	0.3	(0.6)	(0.7)	(0.5)	(0.8)	(0.9)	(0.6)
U.S.	2.9	3.0	3.0	2.8	2.7	2.7	2.6	2.6	2.5	2.5	2.5	2.5
% Ch	4.1	2.1	0.3	(4.1)	(3.7)	(1.9)	(2.3)	(2.0)	(1.3)	(0.4)	(0.6)	(1.0)
Computer and Electronic Products												
Oregon	41.2	40.9	39.7	37.9	39.4	40.4	40.6	40.5	40.3	40.1	39.9	39.7
% Ch	8.6	(0.8)	(3.0)	(4.6)	4.0	2.5	0.6	(0.3)	(0.5)	(0.5)	(0.5)	(0.5)
U.S.	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0
% Ch	2.9	1.7	(0.6)	(1.2)	(0.6)	(0.6)	(1.4)	(1.6)	(1.3)	(0.7)	(0.2)	(0.0)
Transportation Equipment												
Oregon	10.9	11.2	11.2	11.4	11.7	11.7	11.7	11.7	11.7	11.6	11.5	11.4
% Ch	1.7	2.8	(0.2)	1.9	2.7	0.3	(0.2)	0.4	(0.4)	(0.8)	(0.8)	(0.4)
U.S.	1.7	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.6	1.6	1.5
% Ch	4.4	4.2	2.8	(1.8)	(0.4)	(2.9)	(2.4)	(1.4)	(1.8)	(2.7)	(2.7)	(2.9)
Other Durables												
Oregon	21.9	21.6	21.6	21.5	21.3	21.1	20.8	20.5	20.1	19.9	19.7	19.5
% Ch	2.2	(1.3)	(0.1)	(0.1)	(1.0)	(1.1)	(1.6)	(1.5)	(1.5)	(1.1)	(1.1)	(1.3)
U.S.	2.3	2.2	2.2	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
% Ch	3.3	(0.8)	(1.6)	(3.8)	(2.9)	(1.3)	(1.2)	0.1	1.1	0.3	(0.7)	(1.8)

Dec 2024 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Nondurable Manufacturing												
Oregon	57.8	57.3	56.5	57.2	57.1	57.1	57.6	58.0	58.3	58.3	58.4	58.5
% Ch	0.3	(0.9)	(1.3)	1.2	(0.1)	0.1	0.8	0.7	0.6	(0.0)	0.1	0.3
U.S.	4.8	4.8	4.8	4.7	4.7	4.6	4.6	4.6	4.6	4.6	4.6	4.5
% Ch	3.7	(0.1)	(0.4)	(1.6)	(1.9)	(1.0)	(0.2)	0.0	0.1	(0.3)	(0.6)	(0.7)
Food Manufacturing												
Oregon	28.8	28.6	28.3	28.7	28.9	29.0	29.2	29.4	29.8	29.9	30.1	30.4
% Ch	0.8	(0.5)	(1.1)	1.5	0.6	0.4	0.7	0.9	1.1	0.6	0.7	0.8
U.S.	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8
% Ch	3.6	1.6	0.9	(0.8)	(1.3)	0.3	1.5	1.6	1.8	1.1	0.8	0.6
Other Nondurable												
Oregon	29.1	28.6	28.2	28.5	28.2	28.2	28.4	28.5	28.6	28.4	28.3	28.2
% Ch	(0.2)	(1.4)	(1.5)	0.9	(0.8)	(0.3)	0.9	0.6	0.2	(0.7)	(0.4)	(0.4)
U.S.	3.1	3.1	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8	2.7	2.7
% Ch	3.7	(1.1)	(1.2)	(2.0)	(2.2)	(1.7)	(1.1)	(0.9)	(0.9)	(1.3)	(1.5)	(1.5)
Trade, Transportation, and Utilities												
Oregon	366.3	364.9	359.2	361.5	363.6	365.5	365.9	366.7	367.7	367.9	367.5	366.9
% Ch	1.4	(0.4)	(1.6)	0.7	0.6	0.5	0.1	0.2	0.3	0.1	(0.1)	(0.2)
U.S.	28.6	28.8	29.0	28.8	28.6	28.5	28.3	28.1	28.1	28.1	28.1	28.0
% Ch	3.6	0.7	0.5	(0.7)	(0.6)	(0.5)	(0.7)	(0.6)	(0.2)	0.1	(0.1)	(0.3)
Retail Trade												
Oregon	210.4	208.5	203.3	204.6	206.6	208.2	208.4	209.2	210.1	210.5	210.4	210.5
% Ch	0.6	(0.9)	(2.5)	0.7	1.0	0.7	0.1	0.3	0.4	0.2	(0.0)	0.0
U.S.	15.5	15.6	15.7	15.4	15.2	15.0	14.9	14.8	14.9	15.0	15.0	15.1
% Ch	1.5	0.6	0.4	(1.8)	(1.5)	(1.0)	(0.8)	(0.4)	0.3	0.6	0.4	0.3
Wholesale Trade												
Oregon	76.9	78.2	78.1	78.1	77.8	77.8	77.8	77.9	78.0	78.0	77.9	77.7
% Ch	2.5	1.7	(0.2)	0.0	(0.3)	0.0	(0.1)	0.1	0.1	0.0	(0.2)	(0.3)
U.S.	6.0	6.1	6.2	6.2	6.2	6.2	6.2	6.1	6.1	6.0	6.0	6.0
% Ch	4.7	2.3	0.8	0.5	0.3	0.3	(0.8)	(0.9)	(1.0)	(0.5)	(0.5)	(0.8)
Transportation and Warehousing, and Utilities												
Oregon	79.1	78.3	77.9	78.9	79.1	79.4	79.6	79.7	79.6	79.4	79.2	78.8
% Ch	2.3	(1.0)	(0.5)	1.3	0.3	0.4	0.2	0.1	(0.1)	(0.2)	(0.3)	(0.5)
U.S.	7.2	7.1	7.2	7.2	7.3	7.3	7.2	7.2	7.1	7.1	7.0	7.0
% Ch	7.2	(0.3)	0.4	0.7	0.5	0.1	(0.5)	(0.6)	(0.7)	(0.5)	(0.8)	(1.1)
Information												
Oregon	36.8	36.7	35.5	35.7	35.9	36.1	36.3	36.5	36.7	36.9	37.1	37.3
% Ch	4.9	(0.3)	(3.2)	0.6	0.5	0.5	0.5	0.6	0.6	0.5	0.6	0.7
U.S.	3.1	3.0	3.0	3.0	3.1	3.0	2.9	3.0	3.0	3.0	3.0	3.0
% Ch	7.2	(1.1)	(0.6)	1.2	0.7	(2.7)	(1.4)	0.3	0.2	(0.0)	0.3	(0.4)
Financial Activities												
Oregon	104.9	103.6	100.6	100.8	101.8	102.3	102.1	101.9	101.7	101.8	102.1	102.5
% Ch	0.7	(1.2)	(2.9)	0.2	1.0	0.4	(0.1)	(0.2)	(0.1)	0.1	0.3	0.4
U.S.	9.1	9.2	9.2	9.4	9.5	9.5	9.5	9.4	9.4	9.4	9.4	9.4
% Ch	2.9	1.5	0.4	1.3	1.5	0.3	(0.4)	(0.4)	(0.6)	(0.1)	0.4	0.0
Professional and Business Services												
Oregon	263.4	266.2	262.3	270.2	275.3	278.2	281.7	287.5	293.7	298.9	302.5	306.3
% Ch	4.7	1.1	(1.5)	3.0	1.9	1.1	1.2	2.1	2.2	1.8	1.2	1.2
U.S.	22.5	22.8	23.0	23.4	23.6	23.3	23.4	23.9	24.3	24.6	24.9	25.1
% Ch	5.4	1.4	0.6	2.0	0.6	(1.1)	0.4	1.9	1.9	1.3	0.9	1.1

Dec 2024 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Education and Health Services												
Oregon	303.9	320.7	337.3	345.1	348.1	351.4	353.5	356.2	359.3	361.6	363.2	365.3
% Ch	1.5	5.6	5.2	2.3	0.9	0.9	0.6	0.8	0.9	0.6	0.4	0.6
U.S.	24.3	25.3	26.4	26.8	26.9	27.2	27.5	27.7	27.9	28.2	28.4	28.7
% Ch	2.9	4.1	4.0	1.7	0.5	1.0	0.9	0.8	0.8	1.0	1.0	0.9
Educational Services												
Oregon	34.5	36.0	37.1	37.5	37.3	37.1	36.8	36.6	36.3	36.0	35.7	35.5
% Ch	7.7	4.2	3.2	1.2	(0.6)	(0.6)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.6)
U.S.	3.8	3.8	3.9	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9	3.9
% Ch	4.8	1.6	1.4	(1.6)	(1.2)	1.1	2.1	1.0	(0.4)	(0.2)	0.1	0.5
Health Care and Social Assistance												
Oregon	269.3	284.8	300.2	307.7	310.9	314.4	316.8	319.6	323.0	325.5	327.4	329.7
% Ch	0.8	5.7	5.4	2.5	1.0	1.1	0.8	0.9	1.0	0.8	0.6	0.7
U.S.	20.6	21.5	22.5	23.0	23.2	23.4	23.6	23.7	24.0	24.3	24.5	24.8
% Ch	2.6	4.6	4.4	2.3	0.8	0.9	0.7	0.7	1.0	1.1	1.1	1.0
Leisure and Hospitality												
Oregon	198.6	206.9	205.6	206.6	209.1	211.3	215.2	218.0	220.9	223.8	226.4	228.8
% Ch	13.7	4.2	(0.6)	0.5	1.2	1.0	1.9	1.3	1.3	1.3	1.2	1.1
U.S.	15.8	16.6	17.0	17.3	17.4	17.6	17.7	17.7	17.6	17.4	17.3	17.2
% Ch	11.9	4.9	2.3	2.1	0.3	0.9	0.6	(0.1)	(0.5)	(0.9)	(0.9)	(0.5)
Other Services												
Oregon	62.0	65.1	65.9	66.3	67.0	67.8	68.5	69.0	69.5	70.1	70.6	71.2
% Ch	4.7	5.0	1.3	0.6	1.0	1.3	1.0	0.8	0.8	0.8	0.8	0.8
U.S.	5.7	5.8	5.9	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.4	6.5
% Ch	4.3	2.3	1.4	0.0	0.8	2.0	2.2	1.5	0.7	0.6	0.6	0.5
Government												
Oregon	294.6	306.5	314.3	315.3	315.0	314.2	313.3	312.8	313.3	312.3	312.2	312.1
% Ch	3.1	4.0	2.5	0.3	(0.1)	(0.3)	(0.3)	(0.2)	0.2	(0.3)	(0.0)	(0.0)
U.S.	22.2	22.8	23.3	23.6	23.6	23.7	23.8	23.9	24.0	24.0	24.1	24.2
% Ch	1.0	2.6	2.4	0.9	0.4	0.4	0.3	0.3	0.6	0.0	0.3	0.3
Federal Government												
Oregon	27.8	28.5	29.5	29.5	29.4	29.3	29.3	29.2	30.1	29.1	29.1	29.1
% Ch	(2.3)	2.2	3.5	0.0	(0.3)	(0.2)	(0.2)	(0.2)	3.0	(3.2)	(0.1)	(0.1)
U.S.	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.0	3.0	3.0
% Ch	(0.7)	2.0	2.5	0.5	0.0	0.0	0.0	0.0	2.3	(2.3)	0.0	0.0
State Government, Oregon												
Total	43.1	45.9	47.8	48.5	48.5	48.4	48.5	48.7	48.8	49.1	49.3	49.4
% Ch	1.4	6.5	4.1	1.5	(0.1)	(0.3)	0.3	0.3	0.4	0.5	0.4	0.4
Education	1.2	1.4	1.6	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.3
% Ch	18.6	19.2	10.9	(2.5)	(3.0)	(2.1)	(1.7)	(1.1)	(1.1)	(0.8)	(0.7)	(0.8)
Non-Education	42.0	44.5	46.2	47.0	47.0	46.9	47.1	47.3	47.4	47.7	47.9	48.1
% Ch	0.9	6.1	3.9	1.7	0.0	(0.2)	0.4	0.3	0.4	0.5	0.4	0.4
Local Government, Oregon												
Total	223.6	232.1	237.0	237.3	237.2	236.5	235.6	234.9	234.4	234.1	233.8	233.6
% Ch	4.2	3.8	2.1	0.1	(0.1)	(0.3)	(0.4)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)
Education	128.0	132.2	134.2	133.9	133.7	132.9	131.8	130.7	129.8	128.9	128.1	127.4
% Ch	4.8	3.3	1.5	(0.2)	(0.2)	(0.6)	(0.9)	(0.8)	(0.7)	(0.7)	(0.6)	(0.6)
Non-Education	95.6	99.9	102.9	103.4	103.4	103.6	103.8	104.2	104.6	105.2	105.7	106.2
% Ch	3.5	4.5	2.9	0.5	0.1	0.2	0.2	0.4	0.4	0.5	0.5	0.5

Dec 2024 - Other Economic Indicators

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Real GDP,												
Chain Weight (Bil of 2017$)	22,034.8	22,671.1	23,288.9	23,776.8	24,201.2	24,604.7	25,047.9	25,504.0	25,947.8	26,381.1	26,826.8	27,297.9
% Ch	2.5	2.9	2.7	2.1	1.8	1.7	1.8	1.8	1.7	1.7	1.7	1.8
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2017=100	118.0	122.3	125.1	127.8	131.0	133.9	136.8	139.9	143.0	146.3	149.7	153.2
% Ch	7.1	3.6	2.4	2.1	2.5	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Personal Consumption Deflator,												
Chain Weight U.S., 2017=100	116.1	120.5	123.4	125.8	128.8	131.4	134.0	136.7	139.5	142.3	145.2	148.1
% Ch	6.6	3.8	2.4	2.0	2.4	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CPI, Urban Consumers,												
1982-84=100												
West Region	310.5	323.8	332.2	337.4	347.6	355.2	363.1	371.4	379.7	388.0	396.5	405.3
% Ch	8.0	4.3	2.6	1.6	3.0	2.2	2.2	2.3	2.2	2.2	2.2	2.2
U.S.	292.6	304.7	313.3	319.6	329.4	336.4	343.8	351.4	359.2	367.1	375.2	383.5
% Ch	8.0	4.1	2.8	2.0	3.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Oregon Average Wage												
Rate (Thous $)	69.3	71.2	74.3	77.2	80.4	83.7	87.2	90.6	94.3	98.2	102.2	106.4
% Ch	3.8	2.7	4.3	3.9	4.1	4.2	4.1	4.0	4.1	4.1	4.1	4.1
U.S. Average Wage												
Wage Rate (Thous $)	72.9	75.1	78.8	81.6	85.0	88.2	91.5	94.8	98.2	101.8	105.6	109.7
% Ch	3.4	3.0	4.8	3.6	4.2	3.7	3.8	3.6	3.6	3.7	3.8	3.9
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	612.1	612.1	622.1	628.9	654.0	680.5	709.6	740.4	769.9	800.9	836.4	871.6
% Ch	10.4	0.0	1.6	1.1	4.0	4.0	4.3	4.3	4.0	4.0	4.4	4.2
FHFA National Housing Price Index												
1991 Q1=100	383.3	402.4	421.2	430.1	442.9	456.0	470.7	486.9	503.7	521.1	539.3	558.2
% Ch	13.7	5.0	4.7	2.1	3.0	2.9	3.2	3.4	3.4	3.5	3.5	3.5
Housing Starts												
Oregon (Thous)	20.0	18.1	14.4	16.0	18.3	19.5	20.2	20.7	20.8	20.9	20.9	20.9
% Ch	(1.0)	(9.3)	(20.5)	10.7	14.7	6.4	3.8	2.4	0.6	0.3	(0.1)	(0.0)
U.S. (Millions)	1.6	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.4
% Ch	(3.3)	(8.4)	(4.8)	1.3	2.0	0.9	3.3	3.0	0.3	(0.4)	(1.6)	(3.6)
Other Indicators												
Unemployment Rate (%)												
Oregon	3.9	3.7	4.2	4.2	4.3	4.4	4.4	4.3	4.2	4.2	4.3	4.3
Point Change	(1.2)	(0.2)	0.5	0.0	0.1	0.1	(0.0)	(0.1)	(0.1)	(0.0)	0.0	0.0
U.S.	3.6	3.6	4.0	4.3	4.5	4.6	4.5	4.4	4.3	4.2	4.2	4.2
Point Change	(1.7)	(0.0)	0.4	0.3	0.2	0.1	(0.0)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)
Industrial Production Index												
U.S, 2017 = 100	102.7	102.9	102.7	103.5	104.9	105.9	107.1	108.7	110.0	111.3	112.4	113.6
% Ch	3.4	0.2	(0.1)	0.8	1.3	1.0	1.1	1.4	1.3	1.1	1.0	1.0
Prime Rate (Percent)	4.9	8.2	8.3	6.9	5.8	5.7	5.7	5.7	5.7	5.7	5.7	5.8
% Ch	49.3	68.8	1.5	(16.5)	(16.9)	(0.4)	0.0	0.0	(0.0)	(0.0)	0.0	0.0
Population (Millions)												
Oregon	4.27	4.30	4.31	4.34	4.36	4.39	4.41	4.44	4.46	4.49	4.51	4.54
% Ch	1.2	0.6	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
U.S.	334.9	338.4	341.8	344.7	346.8	348.3	349.7	351.1	352.5	353.8	355.1	356.3
% Ch	0.7	1.1	1.0	0.8	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.3
Timber Harvest (Mil Bd Ft)												
Oregon	3,652.0	3,677.5	3,650.4	3,609.7	3,658.6	3,711.5	3,713.1	3,703.1	3,696.0	3,690.8	3,686.1	3,685.8
% Ch	(5.9)	0.7	(0.7)	(1.1)	1.4	1.4	0.0	(0.3)	(0.2)	(0.1)	(0.1)	(0.0)

Appendix B: Revenue Forecast Detail

Table B.1a – General Fund Revenues – 2023-25

General Fund Revenue Statement -- 2023-25

	Estimate at COS 2023	Forecasts Dated: 9/1/2024 2023-24	Forecasts Dated: 9/1/2024 2024-25	Forecasts Dated: 9/1/2024 Total 2023-25	Forecasts Dated: 12/1/2024 2023-24	Forecasts Dated: 12/1/2024 2024-25	Forecasts Dated: 12/1/2024 Total 2023-25	Difference 12/1/2024 Less 9/1/2024	Difference 12/1/2024 Less COS
Taxes									
Personal Income Taxes	21,019,693,000	9,149,827,000	12,739,563,000	21,889,390,000	9,149,827,000	13,540,987,000	22,690,814,000	801,424,000	1,671,121,000
Transfers & Offsets	(37,030,000)	(33,619,000)	(70,951,000)	(104,570,000)	(32,975,000)	(68,501,000)	(101,476,000)	3,094,000	(64,446,000)
Corporate Income Taxes	2,228,945,000	1,621,807,000	1,489,923,000	3,111,730,000	1,621,808,000	1,631,634,000	3,253,442,000	141,712,000	1,024,497,000
Transfer to RDF (Minimum Tax)	(91,604,000)	0	(126,836,000)	(126,836,000)	0	(131,594,000)	(131,594,000)	(4,758,000)	(39,990,000)
Insurance Taxes	145,011,000	55,513,000	67,071,000	122,584,000	55,513,000	67,302,000	122,815,000	231,000	(22,196,000)
Estate Taxes	539,732,000	338,976,000	301,081,000	640,057,000	338,976,000	323,514,000	662,490,000	22,433,000	122,758,000
Transfer to PERS UAL	0	0	0	0	0	0	0	0	0
Cigarette Taxes	43,144,000	21,151,000	19,996,000	41,147,000	21,151,000	18,394,000	39,545,000	(1,602,000)	(3,599,000)
Other Tobacco Products Taxes	61,303,000	26,767,000	27,191,000	53,958,000	26,767,000	20,421,000	47,188,000	(6,770,000)	(14,115,000)
Other Taxes	1,796,000	1,370,000	1,008,000	2,378,000	1,370,000	1,008,000	2,378,000	0	582,000
Fines and Fees									
State Court Fees	123,317,000	53,784,000	57,093,000	110,877,000	53,784,000	54,208,000	107,992,000	(2,885,000)	(15,325,000)
Secretary of State Fees	101,804,000	43,777,000	47,054,000	90,831,000	43,777,000	47,054,000	90,831,000	0	(10,973,000)
Criminal Fines & Assessments	15,514,000	0	230,000	230,000	0	0	0	(230,000)	(15,514,000)
Securities Fees	31,595,000	15,062,000	12,791,000	27,853,000	15,062,000	12,791,000	27,853,000	0	(3,742,000)
Central Service Charges	16,100,000	8,077,000	8,077,000	16,154,000	8,077,000	8,077,000	16,154,000	0	54,000
Liquor Apportionment	401,822,000	178,852,000	169,252,000	348,104,000	178,852,000	149,315,000	328,167,000	(19,937,000)	(73,655,000)
Interest Earnings	473,325,000	413,015,000	238,567,000	651,582,000	413,015,000	245,595,000	658,610,000	7,028,000	185,285,000
Miscellaneous Revenues	16,000,000	9,776,000	9,000,000	18,776,000	9,776,000	11,500,000	21,276,000	2,500,000	5,276,000
One-time Transfers	40,834,635	23,009,000	2,815,000	25,824,000	23,009,000	5,936,000	28,945,000	3,121,000	(11,889,635)
Gross General Fund Revenues	25,259,935,635	11,960,763,000	15,190,712,000	27,151,475,000	11,960,764,000	16,137,736,000	28,098,500,000	947,025,000	2,838,564,365
Total Transfers	(128,634,000)	(33,619,000)	(197,787,000)	(231,406,000)	(32,975,000)	(200,095,000)	(233,070,000)	(1,664,000)	(104,436,000)
Net General Fund Revenues	25,131,301,635	11,927,144,000	14,992,925,000	26,920,069,000	11,927,789,000	15,937,641,000	27,865,430,000	945,361,000	2,734,128,365
Plus Beginning Balance	7,493,482,790			8,082,487,603			8,082,487,603	0	589,004,812
Less Anticipated Administrative Actions*	0			0			0	0	0
Less Statutory Transfers**	(308,375,734)			(264,732,444)			(264,732,444)	0	43,643,290
Available Resources	32,316,408,692			34,737,824,159			35,683,185,159	945,361,000	3,366,776,467
Appropriations	31,873,575,550			32,897,195,261			32,897,195,261	*0*	1,023,619,711
Estimated Ending Balance	442,833,142			1,840,628,898			2,785,989,898	945,361,000	2,343,156,756

Notes: Corporate income tax figure includes Corporate Multistate taxes. Other taxes include General Fund portions of the Eastern Oregon Severance Tax, Western Oregon Severance Tax and Amusement Device Tax. Cigarette, Other Tobacco, and Liquor are the General Fund portions only, see Table B.6 and B.7 for more.

* The Anticipated Administrative Actions line includes items like Tax Anticipation Note borrowing costs. None of these costs are anticipated for the 2023-25 biennium.

** "Statutory Transfers" amounts to the Rainy Day Fund transfer, The return of $19.8 million in unexpended balance from the Department of Agriculture per SB 892 (2021 second special session) is now included in one-time transfers. The BM 110 Transfer that was included for the Close of Session forecast is now included in the PIT "Transfers and Offsets" line. The amount of the BM 110 transfer is $2,157,766 in FY 2024 and $37,512,017 in FY 2025.

Table B.1b – General Fund Revenues – 2025-27

General Fund Revenue Statement -- 2025-27

	Forecasts Dated: 9/1/2024			Forecasts Dated: 12/1/2024			Difference
	2025-26	2026-27	Total 2025-27	2025-26	2026-27	Total 2025-27	12/1/2024 Less 9/1/2024
Taxes							
Personal Income Taxes	13,876,897,000	15,403,874,000	29,280,771,000	14,342,681,000	15,945,174,000	30,287,855,000	1,007,084,000
Transfers & Offsets	(32,723,000)	(33,050,000)	(65,773,000)	(32,537,000)	(33,549,000)	(66,086,000)	(313,000)
Corporate Income Taxes	1,493,558,000	1,627,168,000	3,120,726,000	1,708,229,000	1,731,541,000	3,439,770,000	319,044,000
Transfer to RDF (Minimum Tax)	0	(127,203,000)	(127,203,000)	0	(144,989,000)	(144,989,000)	(17,786,000)
Insurance Taxes	96,952,000	99,433,000	196,385,000	97,443,000	99,798,000	197,241,000	856,000
Estate Taxes	316,163,000	332,807,000	648,970,000	338,295,000	356,103,000	694,398,000	45,428,000
Transfer to PERS UAL	0	0	0	0	0	0	0
Cigarette Taxes	19,730,000	19,294,000	39,024,000	17,415,000	16,759,000	34,174,000	(4,850,000)
Other Tobacco Products Taxes	26,365,000	25,462,000	51,827,000	26,346,000	25,241,000	51,587,000	(240,000)
Other Taxes	1,008,000	1,008,000	2,016,000	1,008,000	1,008,000	2,016,000	0
Fines and Fees							
State Court Fees	58,234,000	58,514,000	116,748,000	57,061,000	58,634,000	115,695,000	(1,053,000)
Secretary of State Fees	48,148,000	47,252,000	95,400,000	48,148,000	47,252,000	95,400,000	0
Criminal Fines & Assessments	258,000	258,000	516,000	510,000	510,000	1,020,000	504,000
Securities Fees	13,895,000	14,297,000	28,192,000	13,895,000	14,297,000	28,192,000	0
Central Service Charges	8,884,000	8,884,000	17,768,000	8,884,000	8,884,000	17,768,000	0
Liquor Apportionment	145,821,000	155,462,000	301,283,000	136,570,000	145,599,000	282,169,000	(19,114,000)
Interest Earnings	176,413,000	133,840,000	310,253,000	168,836,000	128,228,000	297,064,000	(13,189,000)
Miscellaneous Revenues	9,000,000	9,000,000	18,000,000	11,750,000	12,000,000	23,750,000	5,750,000
One-time Transfers	0	0	0	0	0	0	0
Gross General Fund Revenues	16,291,326,000	17,936,553,000	34,227,879,000	16,977,071,000	18,591,028,000	35,568,099,000	1,340,220,000
Total Transfers	(32,723,000)	(160,253,000)	(192,976,000)	(32,537,000)	(178,538,000)	(211,075,000)	(18,099,000)
Net General Fund Revenues	16,258,603,000	17,776,300,000	34,034,903,000	16,944,534,000	18,412,490,000	35,357,024,000	1,322,121,000
Plus Beginning Balance			1,840,628,898			2,785,989,898	945,361,000
Less Anticipated Administrative Actions*			0			0	0
Less Statutory Transfers**			(328,971,953)			(328,971,953)	0
Available Resources			35,546,559,945			37,814,041,945	2,267,482,000

Table B.2 – General Fund Revenues by Fiscal Year

General Fund Revenue Forecast

Millions of dollars

Fiscal Years	**2021-22 Fiscal Year**	**2022-23 Fiscal Year**	**2023-24 Fiscal Year**	**2024-25 Fiscal Year**	**2025-26 Fiscal Year**	**2026-27 Fiscal Year**	**2027-28 Fiscal Year**	**2028-29 Fiscal Year**	**2029-30 Fiscal Year**	**2030-31 Fiscal Year**	**2031-32 Fiscal Year**	**2032-33 Fiscal Year**
Taxes												
Personal Income	12,436.6	13,246.9	9,149.8	13,541.0	14,342.7	15,945.2	17,382.6	18,443.1	19,460.5	20,561.2	21,697.5	22,903.2
Film & Video, Gain Share, Industrial Lands	(26.2)	(27.4)	(33.0)	(68.5)	(32.5)	(33.5)	(33.6)	(33.6)	(27.5)	(10.0)	(8.5)	(2.5)
Corporate Excise & Income	1,538.5	1,618.5	1,621.8	1,631.6	1,708.2	1,731.5	1,771.3	1,806.1	1,860.0	1,926.5	2,010.3	2,107.0
Transfer to RDF & PERS UAL	0.0	(128.6)	0.0	(131.6)	0.0	(145.0)	0.0	(153.2)	0.0	(162.1)	0.0	(176.4)
Insurance	86.2	96.0	55.5	67.3	97.4	99.8	102.6	105.3	108.0	110.7	113.5	116.6
Estate	325.5	297.6	339.0	323.5	338.3	356.1	369.2	377.9	390.0	396.7	406.5	418.4
Transfer toPERS UAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cigarette	24.4	21.4	21.2	18.4	17.4	16.8	16.3	15.9	15.3	14.8	14.5	14.1
Other Tobacco Products	30.3	29.4	26.8	20.4	26.3	25.2	24.1	23.2	22.4	21.6	21.1	20.6
Other Taxes	1.0	0.8	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Other Revenues												
Licenses and Fees	111.8	113.3	112.6	114.1	119.6	120.7	122.5	122.6	124.0	124.4	124.8	125.2
Charges for Services	6.4	6.4	8.1	8.1	8.9	8.9	9.8	9.8	10.7	10.7	11.8	11.8
Liquor Apportionment	160.0	172.3	178.9	149.3	136.6	145.6	147.9	157.7	157.6	168.1	179.2	191.0
Interest Earnings	40.0	262.5	413.0	245.6	168.8	128.2	130.8	133.4	136.4	139.5	142.5	145.6
Others	103.2	50.1	32.8	17.4	11.8	12.0	12.3	12.5	12.8	13.0	13.3	13.5
Gross General Fund	14,863.9	15,915.2	11,960.8	16,137.7	16,977.1	18,591.0	20,090.5	21,208.4	22,298.9	23,488.2	24,735.9	26,068.1
Net General Fund	14,837.7	15,759.2	11,927.8	15,937.6	16,944.5	18,412.5	20,057.0	21,021.6	22,271.3	23,316.1	24,727.4	25,889.2

Biennial Totals	**2021-23 BN**	*Change (%)*	**2023-25 BN**	*Change (%)*	**2025-27 BN**	*Change (%)*	**2027-29 BN**	*Change (%)*	**2029-31 BN**	*Change (%)*	**2031-33 BN**	*Change (%)*
Taxes												
Personal Income	25,683.5	*28.4%*	22,690.8	*-11.7%*	30,287.9	*33.5%*	35,825.7	*18.3%*	40,021.7	*11.7%*	44,600.7	*11.4%*
Corporate Excise & Income	3,157.0	*60.5%*	3,253.4	*3.1%*	3,439.8	*5.7%*	3,577.4	*4.0%*	3,786.5	*5.8%*	4,117.3	*8.7%*
Insurance	182.3	*14.5%*	122.8	*-32.6%*	197.2	*60.6%*	207.9	*5.4%*	218.7	*5.2%*	230.1	*5.2%*
Estate Taxes	623.0	*18.9%*	662.5	*6.3%*	694.4	*4.8%*	747.1	*7.6%*	786.7	*5.3%*	824.9	*4.9%*
Cigarette	45.8	*-17.0%*	39.5	*-13.6%*	34.2	*-13.6%*	32.3	*-5.6%*	30.2	*-6.4%*	28.6	*-5.3%*
Other Tobacco Products	59.8	*-2.5%*	47.2	*-21.0%*	51.6	*9.3%*	47.4	*-8.2%*	44.0	*-7.1%*	41.7	*-5.3%*
Other Taxes	1.9	*85.4%*	2.4	*28.4%*	2.0	*-15.2%*	2.0	*0.0%*	2.0	*0.0%*	2.0	*0.0%*
Other Revenues												
Licenses and Fees	225.1	*-9.7%*	226.7	*0.7%*	240.3	*6.0%*	245.1	*2.0%*	248.4	*1.4%*	250.0	*0.6%*
Charges for Services	12.7	*11.1%*	16.2	*26.7%*	17.8	*10.0%*	19.5	*10.0%*	21.5	*10.0%*	23.6	*10.0%*
Liquor Apportionment	332.4	*-2.5%*	328.2	*-1.3%*	282.2	*-14.0%*	305.6	*8.3%*	325.7	*6.6%*	370.2	*13.7%*
Interest Earnings	302.5	*225.5%*	658.6	*117.7%*	297.1	*-54.9%*	264.2	*-11.1%*	275.9	*4.4%*	288.1	*4.4%*
Others	153.3	*-17.5%*	50.2	*-67.2%*	23.8	*-52.7%*	24.8	*4.2%*	25.8	*4.0%*	26.8	*3.9%*
Gross General Fund	30,779.1	*30.1%*	28,098.5	*-8.7%*	35,568.1	*26.6%*	41,298.9	*16.1%*	45,787.1	*10.9%*	50,804.0	*11.0%*
Net General Fund	30,596.9	*30.0%*	27,865.4	*-8.9%*	35,357.0	*26.9%*	41,078.6	*16.2%*	45,587.5	*11.0%*	50,616.6	*11.0%*

Table B.3 – Summary of 2023 Legislative Session Adjustments

	23-25	25-27	27-29	Revenue Impact Statement
Personal Income Tax Impacts (millions)				
R&D Tax Credit – HB 2009	-$0.9	-$2.0	-$2.2	HB 2009
Gain Share (5-year extension)	$0.0	-$18.1	-$36.8	
Omnibus & Tax Credits – HB 2071	-$0.30	-$30.2	-$60.4	HB 2071
Child Tax Credit – HB 3235	-$71.5	-$74.1	-$77.5	HB 3235
Opportunity Grant Tax Credit – SB 129	$5.0	$0.1	$0.0	SB 129
Wildfire Deduction – HB 2812	-$0.6	-$0.2	$0.0	HB 2812
Film Tax Credit – HB 2093	Minimal			HB 2093
Reconnect – SB 141	Minimal			SB 141
SALT Workaround – HB 2083	Minimal			HB 2083
Personal Income Tax Total	**-$68.3**	**-$124.4**	**-$177.0**	
Corporate Income Tax Impacts (millions)				
R&D Tax Credit – HB 2009	-$24.0	-$53.6	-$61.3	HB 2009
Omnibus & Tax Credits – HB 2071	-$0.4	-$3.1	-$9.0	HB 2071
Opportunity Grant Tax Credit – SB 129	$8.7	$0.2	$0.0	SB 129
Film Tax Credit – HB 2093	Minimal			HB 2093
Reconnect – SB 141	Minimal			SB 141
Corporate Income Tax Total	**-$15.7**	**-$56.5**	**-$70.3**	
Other Tax/Revenue Impacts (millions)				
Estate Tax – SB 498	-$8.0	-$15.5	-$16.4	SB 498
Criminal Fine Account, Photo Radar – HB 2095	$5.2	$8.9	$8.5	HB 2095
OLCC, Alcohol Delivery – HB 3308	$3.9	$5.7	$6.0	HB 3308
Close Wildfire Account – HB 3215	$0.2	$0.0	$0.0	HB 3215
Program Change – SB 1049	$40.6	$0.0	$0.0	SB 1049
Forestland Tax Credit – HB 2161	Minimal			HB 2161
Other Tax Total	**$42.0**	**-$0.9**	**-$1.9**	

Table B.4 – Personal Income Tax Forecast

Table B.4 **September 2024**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
Withholding	1,748,844	1,836,249	2,011,564	1,851,177	7,447,834	1,925,880	2,039,120	2,079,900	1,999,015	8,043,914
%CHYA	4.4%	7.7%	9.6%	4.6%	6.6%	10.1%	11.0%	3.4%	8.0%	8.0%
Est. Payments	321,032	451,037	464,534	512,671	1,749,274	367,772	284,002	321,858	532,273	1,505,905
%CHYA	6.7%	41.3%	21.5%	13.9%	20.4%	14.6%	-37.0%	-30.7%	3.8%	-13.9%
Final Payments	92,364	169,785	174,096	878,587	1,314,832	104,644	156,592	225,515	1,385,562	1,872,312
%CHYA	-10.9%	17.7%	-0.6%	-4.4%	-2.0%	13.3%	-7.8%	29.5%	57.7%	42.4%
Refunds	133,143	266,467	686,100	610,486	1,696,196	140,701	335,635	546,225	445,573	1,468,133
%CHYA	-4.1%	4.6%	19.4%	34.2%	19.2%	5.7%	26.0%	-20.4%	-27.0%	-13.4%
Other	(192,251)	-	-	237,300	45,049	(237,300)	-	-	222,477	(14,823)
Total	**1,836,845**	**2,190,604**	**1,964,094**	**2,869,249**	**8,860,793**	**2,020,295**	**2,144,078**	**2,081,049**	**3,693,754**	**9,939,176**
%CHYA	7.7%	14.5%	8.0%	-0.2%	6.6%	10.0%	-2.1%	6.0%	28.7%	12.2%

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Withholding	2,059,715	2,223,410	2,183,444	1,997,661	8,464,230	2,127,124	2,291,161	2,321,603	2,266,779	9,006,667
%CHYA	6.9%	9.0%	5.0%	-0.1%	5.2%	3.3%	3.0%	6.3%	13.5%	6.4%
Est. Payments	413,316	296,072	376,127	428,769	1,514,284	497,544	292,601	432,742	701,877	1,924,764
%CHYA	12.4%	4.3%	16.9%	-19.4%	0.6%	20.4%	-1.2%	15.1%	63.7%	27.1%
Final Payments	131,560	195,074	159,708	330,328	816,671	758,710	142,228	220,765	1,500,229	2,621,931
%CHYA	25.7%	24.6%	-29.2%	-76.2%	-56.4%	476.7%	-27.1%	38.2%	354.2%	221.1%
Refunds	144,251	289,464	1,120,326	735,922	2,289,962	432,836	360,529	558,588	672,421	2,024,375
%CHYA	2.5%	-13.8%	105.1%	65.2%	56.0%	200.1%	24.6%	-50.1%	-8.6%	-11.6%
Other	(222,477)	-	-	175,167	(47,310)	(175,167)	-	-	194,880	19,713
Total	**2,237,864**	**2,425,092**	**1,598,954**	**2,196,004**	**8,457,914**	**2,775,375**	**2,365,460**	**2,416,522**	**3,991,345**	**11,548,702**
%CHYA	10.8%	13.1%	-23.2%	-40.5%	-14.9%	24.0%	-2.5%	51.1%	81.8%	36.5%

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Withholding	2,393,995	2,525,865	2,611,195	2,467,726	9,998,782	2,509,729	2,641,474	2,680,227	2,569,226	10,400,656
%CHYA	12.5%	10.2%	12.5%	8.9%	11.0%	4.8%	4.6%	2.6%	4.1%	4.0%
Est. Payments	495,468	340,639	508,064	904,746	2,248,917	659,287	713,409	575,127	789,444	2,737,267
%CHYA	-0.4%	16.4%	17.4%	28.9%	16.8%	33.1%	109.4%	13.2%	-12.7%	21.7%
Final Payments	153,160	208,665	255,615	2,115,965	2,733,405	162,621	255,669	349,752	1,658,281	2,426,323
%CHYA	-79.8%	46.7%	15.8%	41.0%	4.3%	6.2%	22.5%	36.8%	-21.6%	-11.2%
Refunds	162,428	300,852	1,062,458	960,617	2,486,355	293,038	559,280	822,472	720,282	2,395,072
%CHYA	-62.5%	-16.6%	90.2%	42.9%	22.8%	80.4%	85.9%	-22.6%	-25.0%	-3.7%
Other	(194,880)	-	-	183,017	(11,863)	(183,017)	-	-	284,139	101,122
Total	**2,685,315**	**2,774,318**	**2,312,417**	**4,710,837**	**12,482,887**	**2,855,581**	**3,051,273**	**2,782,635**	**4,580,808**	**13,270,296**
%CHYA	-3.2%	17.3%	-4.3%	18.0%	8.1%	6.3%	10.0%	20.3%	-2.8%	6.3%

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Withholding	2,622,334	2,773,397	2,861,267	2,778,879	11,035,878	2,639,937	2,733,097	3,062,776	2,923,396	11,359,206
%CHYA	4.5%	5.0%	6.8%	8.2%	6.1%	0.7%	-1.5%	7.0%	5.2%	2.9%
Est. Payments	577,023	524,217	493,608	825,136	2,419,984	580,357	442,162	602,397	803,732	2,428,648
%CHYA	-12.5%	-26.5%	-14.2%	4.5%	-11.6%	0.6%	-15.7%	22.0%	-2.6%	0.4%
Final Payments	195,731	260,845	273,319	962,274	1,692,169	157,723	167,802	270,009	1,814,466	2,410,001
%CHYA	20.4%	2.0%	-21.9%	-42.0%	-30.3%	-19.4%	-35.7%	-1.2%	88.6%	42.4%
Refunds	339,947	574,864	2,773,723	2,265,639	5,954,173	683,654	806,523	1,132,886	897,816	3,520,879
%CHYA	16.0%	2.8%	237.2%	214.5%	148.6%	101.1%	40.3%	-59.2%	-60.4%	-40.9%
Other	(284,139)	-	-	240,108	(44,031)	(240,108)	-	-	302,696	62,588
Total	**2,771,003**	**2,983,595**	**854,471**	**2,540,758**	**9,149,827**	**2,454,256**	**2,536,537**	**2,802,296**	**4,946,474**	**12,739,563**
%CHYA	-3.0%	-2.2%	-69.3%	-44.5%	-31.1%	-11.4%	-15.0%	228.0%	94.7%	39.2%

Note: Other includes July withholding accrued to June (30 Day Number)

Table B.4 **December 2024**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Withholding	3,018,510	3,211,104	3,227,654	3,066,126	12,523,394	3,182,211	3,385,168	3,411,395	3,241,656	13,220,430
%CHYA	*8.6%*	*7.0%*	*5.6%*	*5.4%*	*6.6%*	*5.4%*	*5.4%*	*5.7%*	*5.7%*	*5.6%*
Est. Payments	708,577	554,127	626,452	934,676	2,823,833	737,637	576,853	653,332	988,197	2,956,019
%CHYA	*13.2%*	*18.6%*	*6.3%*	*4.1%*	*9.4%*	*4.1%*	*4.1%*	*4.3%*	*5.7%*	*4.7%*
Final Payments	334,045	328,165	282,225	1,431,764	2,376,197	252,939	248,902	330,999	2,070,919	2,903,759
%CHYA	*84.2%*	*68.4%*	*-13.7%*	*-29.8%*	*-13.4%*	*-24.3%*	*-24.2%*	*17.3%*	*44.6%*	*22.2%*
Refunds	(272,407)	(454,503)	(1,454,636)	(1,213,170)	(3,394,716)	(348,307)	(633,650)	(1,189,558)	(979,085)	(3,150,599)
%CHYA	*-66.4%*	*-42.5%*	*34.5%*	*40.7%*	*-4.3%*	*27.9%*	*39.4%*	*-18.2%*	*-19.3%*	*-7.2%*
Other	(257,855)	-	-	271,828	13,973	(271,828)	-	-	287,393	15,565
Total	**3,530,870**	**3,638,893**	**2,681,695**	**4,491,223**	**14,342,681**	**3,552,652**	**3,577,274**	**3,206,168**	**5,609,080**	**15,945,174**
%CHYA	*39.2%*	*26.7%*	*-7.2%*	*-14.3%*	*5.9%*	*0.6%*	*-1.7%*	*19.6%*	*24.9%*	*11.2%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Withholding	3,364,405	3,578,997	3,621,446	3,442,891	14,007,739	3,573,292	3,801,229	3,818,071	3,626,693	14,819,286
%CHYA	*5.7%*	*5.7%*	*6.2%*	*6.2%*	*6.0%*	*6.2%*	*6.2%*	*5.4%*	*5.3%*	*5.8%*
Est. Payments	779,875	609,884	691,116	1,049,562	3,130,437	828,304	647,756	733,315	1,105,556	3,314,931
%CHYA	*5.7%*	*5.7%*	*5.8%*	*6.2%*	*5.9%*	*6.2%*	*6.2%*	*6.1%*	*5.3%*	*5.9%*
Final Payments	334,224	330,196	390,239	2,220,792	3,275,450	374,103	367,531	400,738	2,346,208	3,488,581
%CHYA	*32.1%*	*32.7%*	*17.9%*	*7.2%*	*12.8%*	*11.9%*	*11.3%*	*2.7%*	*5.6%*	*6.5%*
Refunds	(296,007)	(518,358)	(1,221,694)	(1,012,778)	(3,048,837)	(292,763)	(528,444)	(1,298,225)	(1,076,580)	(3,196,012)
%CHYA	*-15.0%*	*-18.2%*	*2.7%*	*3.4%*	*-3.2%*	*-1.1%*	*1.9%*	*6.3%*	*6.3%*	*4.8%*
Other	(287,393)	-	-	305,240	17,846	(305,240)	-	-	321,524	16,285
Total	**3,895,104**	**4,000,719**	**3,481,107**	**6,005,706**	**17,382,636**	**4,177,697**	**4,288,073**	**3,653,900**	**6,323,401**	**18,443,070**
%CHYA	*9.6%*	*11.8%*	*8.6%*	*7.1%*	*9.0%*	*7.3%*	*7.2%*	*5.0%*	*5.3%*	*6.1%*

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Withholding	3,763,996	4,004,055	4,027,597	3,826,367	15,622,016	3,971,242	4,224,527	4,249,992	4,037,719	16,483,480
%CHYA	*5.3%*	*5.3%*	*5.5%*	*5.5%*	*5.4%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*
Est. Payments	872,494	682,314	772,585	1,166,432	3,493,826	920,537	719,885	815,143	1,230,862	3,686,426
%CHYA	*5.3%*	*5.3%*	*5.4%*	*5.5%*	*5.4%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*
Final Payments	388,262	383,300	438,586	2,485,888	3,696,036	419,692	413,786	462,879	2,622,922	3,919,279
%CHYA	*3.8%*	*4.3%*	*9.4%*	*6.0%*	*5.9%*	*8.1%*	*8.0%*	*5.5%*	*5.5%*	*6.0%*
Refunds	(311,911)	(562,557)	(1,363,837)	(1,130,750)	(3,369,054)	(325,577)	(589,192)	(1,438,928)	(1,193,047)	(3,546,743)
%CHYA	*6.5%*	*6.5%*	*5.1%*	*5.0%*	*5.4%*	*4.4%*	*4.7%*	*5.5%*	*5.5%*	*5.3%*
Other	(321,524)	-	-	339,228	17,704	(339,228)	-	-	357,966	18,738
Total	**4,391,317**	**4,507,113**	**3,874,932**	**6,687,165**	**19,460,528**	**4,646,665**	**4,769,007**	**4,089,086**	**7,056,422**	**20,561,181**
%CHYA	*5.1%*	*5.1%*	*6.0%*	*5.8%*	*5.5%*	*5.8%*	*5.8%*	*5.5%*	*5.5%*	*5.7%*

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Withholding	4,190,597	4,457,875	4,484,679	4,260,677	17,393,829	4,421,997	4,704,033	4,735,325	4,499,138	18,360,493
%CHYA	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.6%*	*5.6%*	*5.6%*
Est. Payments	971,384	759,649	860,167	1,298,828	3,890,028	1,025,023	801,596	907,740	1,371,525	4,105,884
%CHYA	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.6%*	*5.5%*
Final Payments	442,934	436,725	488,770	2,768,097	4,136,526	467,619	461,041	515,645	2,920,846	4,365,151
%CHYA	*5.5%*	*5.5%*	*5.6%*	*5.5%*	*5.5%*	*5.6%*	*5.6%*	*5.5%*	*5.5%*	*5.5%*
Refunds	(343,533)	(621,680)	(1,518,466)	(1,259,000)	(3,742,680)	(362,559)	(656,078)	(1,602,287)	(1,328,498)	(3,949,422)
%CHYA	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*
Other	(357,966)	-	-	377,733	19,766	(377,733)	-	-	398,875	21,142
Total	**4,903,416**	**5,032,569**	**4,315,150**	**7,446,335**	**21,697,470**	**5,174,347**	**5,310,593**	**4,556,423**	**7,861,885**	**22,903,248**
%CHYA	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.5%*	*5.6%*	*5.6%*	*5.6%*

Note: Other includes July withholding accrued to June (30 Day Number)

Table B.5 – Corporate Income Tax Forecast

Table B.5 **December 2024**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
Advance Payments	179,603	185,787	182,395	303,835	851,619	222,891	249,768	158,748	264,445	895,852
%CHYA	31.4%	-13.9%	77.7%	55.5%	30.9%	24.1%	34.4%	-13.0%	-13.0%	5.2%
Final Payments	42,600	66,460	46,270	108,539	263,869	74,735	102,942	68,818	174,861	421,355
%CHYA	-4.8%	-28.9%	-11.3%	32.6%	-3.1%	75.4%	54.9%	48.7%	61.1%	59.7%
Refunds	-72,225	-129,963	-122,291	-54,224	-378,702	-43,428	-167,871	-128,586	-50,616	-390,501
%CHYA	82.0%	-22.0%	67.4%	-6.1%	12.4%	-39.9%	29.2%	5.1%	-6.7%	3.1%
Total	**149,978**	**122,285**	**106,374**	**358,149**	**736,786**	**254,199**	**184,839**	**98,979**	**388,690**	**926,707**
%CHYA	5.8%	-14.2%	30.1%	63.2%	25.8%	69.5%	51.2%	-7.0%	8.5%	25.8%

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Advance Payments	236,341	346,651	137,782	263,138	983,912	260,668	378,192	249,855	381,413	1,270,128
%CHYA	6.0%	38.8%	-13.2%	-0.5%	9.8%	10.3%	9.1%	81.3%	44.9%	29.1%
Final Payments	67,657	105,446	66,346	111,149	350,598	114,684	98,371	78,356	263,524	554,934
%CHYA	-9.5%	2.4%	-3.6%	-36.4%	-16.8%	69.5%	-6.7%	18.1%	137.1%	58.3%
Refunds	-73,866	-247,403	-91,312	-86,858	-499,439	-62,538	-254,020	-154,026	-153,392	-623,975
%CHYA	70.1%	47.4%	-29.0%	71.6%	27.9%	-15.3%	2.7%	68.7%	76.6%	24.9%
Total	**230,133**	**204,694**	**112,816**	**287,429**	**835,071**	**312,814**	**222,542**	**174,186**	**491,545**	**1,201,087**
%CHYA	-9.5%	10.7%	14.0%	-26.1%	-9.9%	35.9%	8.7%	54.4%	71.0%	43.8%

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Advance Payments	356,491	494,937	288,546	416,777	1,556,751	428,034	568,160	406,675	468,642	1,871,512
%CHYA	36.8%	30.9%	15.5%	9.3%	22.6%	20.1%	14.8%	40.9%	12.4%	20.2%
Final Payments	56,491	96,179	115,111	261,579	529,361	72,368	50,907	83,324	304,427	511,026
%CHYA	-50.7%	-2.2%	46.9%	-0.7%	-4.6%	28.1%	-47.1%	-27.6%	16.4%	-3.5%
Refunds	-49,631	-255,602	-197,775	-44,052	-547,060	-116,377	-247,875	-320,324	-92,796	-777,372
%CHYA	-20.6%	0.6%	28.4%	-71.3%	-12.3%	134.5%	-3.0%	62.0%	110.7%	42.1%
Total	**363,352**	**335,513**	**205,883**	**634,305**	**1,539,052**	**384,025**	**371,192**	**169,676**	**680,273**	**1,605,166**
%CHYA	16.2%	50.8%	18.2%	29.0%	28.1%	5.7%	10.6%	-17.6%	7.2%	4.3%

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Advance Payments	378,791	584,136	336,447	492,579	1,791,954	403,947	575,251	308,112	463,842	1,751,152
%CHYA	-11.5%	2.8%	-17.3%	5.1%	-4.3%	6.6%	-1.5%	-8.4%	-5.8%	-2.3%
Final Payments	106,469	77,027	85,407	357,338	626,241	102,069	130,858	106,184	336,301	675,412
%CHYA	47.1%	51.3%	2.5%	17.4%	22.5%	-4.1%	69.9%	24.3%	-5.9%	7.9%
Refunds	-63,414	-297,105	-260,296	-175,571	-796,387	-102,686	-305,381	-267,689	-119,173	-794,930
%CHYA	-45.5%	19.9%	-18.7%	89.2%	2.4%	61.9%	2.8%	2.8%	-32.1%	-0.2%
Total	**421,846**	**364,058**	**161,557**	**674,346**	**1,621,808**	**403,330**	**400,727**	**146,607**	**680,970**	**1,631,634**
%CHYA	9.8%	-1.9%	-4.8%	-0.9%	1.0%	-4.4%	10.1%	-9.3%	1.0%	0.6%

Table B.5 **December 2024**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Advance Payments	449,801	635,100	324,087	477,737	1,886,726	462,682	648,385	330,189	487,595	1,928,851
%CHYA	11.4%	10.4%	5.2%	3.0%	7.7%	2.9%	2.1%	1.9%	2.1%	2.2%
Final Payments	89,664	135,407	112,706	354,282	692,059	93,901	139,666	117,057	362,988	713,612
%CHYA	-12.2%	3.5%	6.1%	5.3%	2.5%	4.7%	3.1%	3.9%	2.5%	3.1%
Refunds	-105,817	-376,964	-267,463	-120,313	-870,556	-106,987	-396,954	-281,377	-125,604	-910,922
%CHYA	3.0%	23.4%	-0.1%	1.0%	9.5%	1.1%	5.3%	5.2%	4.4%	4.6%
Total	**433,648**	**393,544**	**169,330**	**711,707**	**1,708,229**	**449,595**	**391,097**	**165,869**	**724,979**	**1,731,541**
%CHYA	7.5%	-1.8%	15.5%	4.5%	4.7%	3.7%	-0.6%	-2.0%	1.9%	1.4%

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Advance Payments	472,286	662,316	337,254	496,638	1,968,494	480,963	673,808	343,208	508,217	2,006,195
%CHYA	2.1%	2.1%	2.1%	1.9%	2.1%	1.8%	1.7%	1.8%	2.3%	1.9%
Final Payments	96,701	142,853	120,348	373,770	733,673	99,543	145,649	123,157	382,491	750,840
%CHYA	3.0%	2.3%	2.8%	3.0%	2.8%	2.9%	2.0%	2.3%	2.3%	2.3%
Refunds	-111,748	-404,637	-286,538	-127,898	-930,821	-113,825	-413,185	-293,015	-130,906	-950,931
%CHYA	4.4%	1.9%	1.8%	1.8%	2.2%	1.9%	2.1%	2.3%	2.4%	2.2%
Total	**457,239**	**400,532**	**171,064**	**742,510**	**1,771,346**	**466,681**	**406,271**	**173,350**	**759,802**	**1,806,104**
%CHYA	1.7%	2.4%	3.1%	2.4%	2.3%	2.1%	1.4%	1.3%	2.3%	2.0%

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Advance Payments	492,342	691,120	352,368	523,625	2,059,455	507,375	713,093	363,900	543,452	2,127,820
%CHYA	2.4%	2.6%	2.7%	3.0%	2.7%	3.1%	3.2%	3.3%	3.8%	3.3%
Final Payments	101,938	149,015	125,827	392,096	768,875	104,547	153,448	129,347	404,089	791,430
%CHYA	2.4%	2.3%	2.2%	2.5%	2.4%	2.6%	3.0%	2.8%	3.1%	2.9%
Refunds	-116,334	-420,624	-298,067	-133,325	-968,350	-118,548	-431,480	-305,858	-136,854	-992,740
%CHYA	2.2%	1.8%	1.7%	1.8%	1.8%	1.9%	2.6%	2.6%	2.6%	2.5%
Total	**477,946**	**419,511**	**180,129**	**782,395**	**1,859,980**	**493,374**	**435,061**	**187,389**	**810,687**	**1,926,511**
%CHYA	2.4%	3.3%	3.9%	3.0%	3.0%	3.2%	3.7%	4.0%	3.6%	3.6%

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Advance Payments	526,742	741,595	378,766	567,390	2,214,493	550,043	775,214	396,201	595,444	2,316,901
%CHYA	3.8%	4.0%	4.1%	4.4%	4.1%	4.4%	4.5%	4.6%	4.9%	4.6%
Final Payments	107,790	159,123	133,730	418,938	819,581	111,781	166,009	139,190	436,827	853,807
%CHYA	3.1%	3.7%	3.4%	3.7%	3.6%	3.7%	4.3%	4.1%	4.3%	4.2%
Refunds	-121,780	-445,165	-315,571	-141,226	-1,023,742	-125,829	-462,837	-328,214	-146,860	-1,063,740
%CHYA	2.7%	3.2%	3.2%	3.2%	3.1%	3.3%	4.0%	4.0%	4.0%	3.9%
Total	**512,752**	**455,553**	**196,925**	**845,102**	**2,010,332**	**535,995**	**478,386**	**207,177**	**885,411**	**2,106,969**
%CHYA	3.9%	4.7%	5.1%	4.2%	4.4%	4.5%	5.0%	5.2%	4.8%	4.8%

Table B.6 – Cigarette and Tobacco Tax Distribution

TABLE B.6 | **December 2024**

Cigarette & Tobacco Tax Distribution

Millions of dollars

	Cigarette Tax Distribution*								Other Tobacco Tax Distribution				Inhalent Delivery Distribution		
						Tobacco Use Reduction[2]									
	Total	General Fund	Health Plan	Mental Health	Health Authority[1]	Old	New	Cities, Counties & Public Transit	Total	General Fund	Health Plan	Tobacco Use Reduction	Total	Health Authority	Tobacco Use Reduction
2023-24	**297.6**	21.2	76.2	13.3	160.0	3.0	17.8	6.1	**50.0**	26.8	20.9	2.3	**29.7**	26.8	3.0
2024-25	**278.4**	18.4	71.7	12.5	150.5	2.9	16.7	5.7	**37.9**	20.4	15.8	1.8	**30.1**	27.1	3.0
2023-25 BN	**576.0**	39.5	147.9	25.9	310.5	5.9	34.5	11.8	**87.9**	47.2	36.7	4.1	**59.8**	53.8	6.0
2025-26	**263.6**	17.4	67.9	11.9	142.5	2.7	15.8	5.4	**48.9**	26.3	20.3	2.3	**30.3**	27.3	3.0
2026-27	**253.7**	16.8	65.3	11.4	137.1	2.6	15.2	5.2	**46.9**	25.2	19.5	2.2	**30.4**	27.4	3.0
2025-27 BN	**517.3**	34.2	133.2	23.3	279.6	5.3	31.1	10.6	**95.8**	51.6	39.8	4.4	**60.7**	54.7	6.1
2027-28	**247.4**	16.3	63.7	11.1	133.8	2.5	14.9	5.1	**44.8**	24.1	18.6	2.1	**30.6**	27.6	3.1
2028-29	**240.7**	15.9	62.0	10.8	130.1	2.5	14.5	4.9	**43.2**	23.2	17.9	2.0	**30.8**	27.7	3.1
2027-29 BN	**488.2**	32.3	125.7	22.0	263.9	5.0	29.3	10.0	**88.0**	47.4	36.5	4.1	**61.4**	55.3	6.1
2029-30	**232.3**	15.3	59.8	10.5	125.6	2.4	14.0	4.8	**41.5**	22.4	17.3	1.9	**31.0**	27.9	3.1
2030-31	**224.7**	14.8	57.9	10.1	121.5	2.3	13.5	4.6	**40.2**	21.6	16.7	1.9	**31.1**	28.0	3.1
2029-31 BN	**457.0**	30.2	117.7	20.6	247.0	4.7	27.4	9.4	**81.7**	44.0	33.9	3.8	**62.1**	55.9	6.2
2031-32	**218.7**	14.5	56.3	9.9	118.2	2.2	13.1	4.5	**39.2**	21.1	16.3	1.8	**31.3**	28.2	3.1
2032-33	**214.1**	14.1	55.1	9.6	115.7	2.2	12.9	4.4	**38.2**	20.6	15.9	1.8	**31.5**	28.4	3.2
2031-33 BN	**432.8**	28.6	111.4	19.5	233.9	4.4	26.0	8.9	**77.4**	41.7	32.1	3.6	**62.8**	56.5	6.3

[1] Includes the cigarette floor tax in FY21 of $27.7 million and FY22 of $1.6 million

[2] Old and New refer to pre- and post-Measure 108 (2020) taxes and programs

Table B.7 – Liquor Apportionment and Revenue Distribution to Local Government

TABLE B.7 December 2024

Liquor Apportionment and Revenue Distribution to Local Governments

Millions of dollars

	Liquor Apportionment Distribution								
					City Revenue				
	Total Liquor Revenue Available	General Fund (56%)	Mental Health[1]	Oregon Wine Board	Revenue Sharing	Regular	Total	Counties	Cigarette Tax Distribution[2]
2023-24	315.082	179.693	9.682	0.326	56.992	39.894	96.886	28.496	6.080
2024-25	261.054	149.315	8.615	0.384	53.497	37.448	90.944	26.748	5.719
2023-25 BN	**576.136**	**329.008**	**18.297**	**0.710**	**110.488**	**77.342**	**187.830**	**55.244**	**11.799**
2025-26	253.091	136.570	8.856	0.361	48.775	34.841	83.616	24.387	5.414
2026-27	269.825	145.599	9.441	0.384	52.000	37.145	89.144	26.000	5.210
2025-27 BN	**522.916**	**282.169**	**18.297**	**0.745**	**100.775**	**71.986**	**172.760**	**50.387**	**10.625**
2027-28	273.333	147.905	8.856	0.361	52.823	36.976	89.800	26.412	5.083
2028-29	291.404	157.684	9.441	0.384	56.316	39.421	95.737	28.158	4.945
2027-29 BN	**564.737**	**305.589**	**18.297**	**0.745**	**109.139**	**76.397**	**185.536**	**54.569**	**10.027**
2029-30	290.724	157.645	8.856	0.361	56.302	39.411	95.713	28.151	4.772
2030-31	309.946	168.067	9.441	0.384	60.024	42.017	102.041	30.012	4.616
2029-31 BN	**600.670**	**325.712**	**18.297**	**0.745**	**116.326**	**81.428**	**197.754**	**58.163**	**9.387**

[1] Mental Health Alcoholism and Drug Services Account, per ORS 471.810

[2] For details on cigarette revenues see Table B.6 on previous page

Table B.8 – Track Record for the September 2024 Forecast

Table B.8 Track Record for the September 2024 Forecast

Millions of Dollars for Quarter ending September 30, 2024

Personal Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Withholding	$2,780.4	$2,639.9	$140.5	5.3%	$2,622.3	$158.1	6.0%
Estimated Payments*	$626.0	$580.4	$45.6	7.9%	$577.0	$48.9	8.5%
Final Payments*	$181.3	$157.7	$23.6	15.0%	$195.7	-$14.4	-7.4%
Refunds	-$811.6	-$683.7	-$127.9	18.7%	-$339.9	-$471.6	138.7%
Other	-$240.1	-$240.1	$0.0	0.0%	-$284.1	$44.0	-15.5%
Total	**$2,536.0**	**$2,454.3**	**$81.8**	**3.3%**	**$2,771.0**	**-$235.0**	**-8.5%**

Corporate Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Advanced Payments	$403.9	$403.6	$0.3	0.1%	$378.8	$25.2	6.6%
Final Payments	$102.1	$71.3	$30.7	43.1%	$106.5	-$4.4	-4.1%
Refunds	-$102.7	-$86.9	-$15.8	18.2%	-$63.4	-$39.3	61.9%
Total	**$403.3**	**$388.1**	**$15.3**	**3.9%**	**$421.8**	**-$18.5**	**-4.4%**

Combined Personal and Corporate Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
SUM	**$2,939.4**	**$2,842.3**	**$97.0**	**3.4%**	**$3,192.8**	**-$253.5**	**-7.9%**

* Data separating estimated and other personal income tax payments is no longer available in the Department of Revenue's financial statements. Tracking represents estimates based on individual transations.

Table B.9 – Lottery Forecast

TABLE B.9
Summary of Lottery Resources

December 2024

(in millions of dollars)	2023-25 Current Forecast	2023-25 Change from Sep-24	2023-25 Change from COS 2023	2025-2027 Current Forecast	2025-2027 Change from Sep-24	2027-29 Current Forecast	2027-29 Change from Sep-24	2029-31 Current Forecast	2029-31 Change from Sep-24	2031-33 Current Forecast	2031-33 Change from Sep-24
LOTTERY EARNINGS											
Traditional Lottery	216.171	19.225	52.476	212.266	47.152	215.377	48.764	217.847	52.169	220.727	56.055
Video Lottery	1,559.982	(15.692)	(65.002)	1,704.576	(5.891)	1,848.561	(28.620)	2,000.101	(22.912)	2,162.731	(28.192)
Sports Betting[1]	60.529	(0.127)	16.215	70.836	(0.003)	74.767	(0.007)	77.509	(0.010)	80.310	(0.014)
Administrative Actions	42.882	33.730	42.882	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Available to Transfer	**1,879.565**	37.137	46.571	**1,987.678**	41.258	**2,138.705**	20.137	**2,295.457**	29.246	**2,463.768**	27.849
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	84.396	0.000	0.000	67.680	28.398	0.000	0.000	0.000	0.000	0.000	0.000
Transfers from Lottery	1,879.565	37.137	46.571	1,987.678	41.258	2,138.705	20.137	2,295.457	29.246	2,463.768	27.849
Other Resources[2]	7.685	0.000	5.685	2.000	0.000	2.000	0.000	2.000	0.000	2.000	0.000
Total Available Resources	**1,971.647**	37.137	52.256	**2,057.358**	69.655	**2,140.705**	20.137	**2,297.457**	29.246	**2,465.768**	27.849
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund[3]	334.248	2.611	4.309	269.219	51.713	389.684	8.342	260.052	(42.866)	278.755	6.643
Oregon Capital Matching Fund[3]	0.000	0.000	0.000	77.489	(33.218)	0.000	0.000	131.766	44.266	131.766	131.766
Parks and Natural Resources Fund[4]	281.935	5.570	6.986	298.152	6.189	320.806	3.021	344.319	4.387	369.565	4.177
Veterans' Services Fund[5]	28.193	0.557	0.699	29.815	0.619	32.081	0.302	34.432	0.439	36.957	0.418
Other Distributions											
Outdoor School Education Fund[6]	36.406	0.000	(20.000)	59.551	(0.383)	62.528	(0.377)	65.539	(0.391)	69.031	0.000
County Economic Development	59.982	0.000	0.000	65.353	(0.226)	70.874	(1.097)	76.684	(0.878)	82.919	(1.081)
HECC Collegiate Athletic & Scholarships[7]	18.330	0.000	0.000	19.877	0.413	21.387	0.201	22.955	0.292	24.638	0.278
Gambling Addiction [7]	18.473	0.000	0.143	19.877	0.413	21.387	0.201	22.955	0.292	24.638	0.278
County Fairs	3.828	0.000	0.000	5.744	1.916	6.073	2.245	6.350	2.522	6.650	2.822
Other Legislatively Adopted Allocations[8]	1,094.384	0.000	32.439	342.983	0.000	287.141	0.000	236.879	0.000	186.892	0.000
Employer Incentive Fund (PERS)[1]	28.186	0.000	0.000	46.792	(0.413)	48.808	(0.169)	51.490	0.116	53.678	(4.420)
Total Distributions	**1,903.966**	8.739	24.576	**1,234.853**	27.021	**1,260.768**	12.669	**1,253.420**	8.179	**1,265.487**	140.881
Ending Balance/Discretionary Resources	**67.680**	28.398	27.680	**822.505**	42.634	**879.937**	7.468	**1,044.037**	21.068	**1,200.282**	(113.032)

Note: Some totals may not foot due to rounding.
1. Sports Betting revenues are transferred to Economic Development Fund making them subject to the constitutional distributions, after which the remainder is transferred to the Employer Incentive Fund
2. Includes reversions (unspent allocations from previous biennium) and interest earnings on Economic Development Fund.
3. Eighteen percent of proceeds accrue to the Ed. Stability Fund, until the balance equals 5% of GF Revenues. Thereafter, 15% of proceeds accrue to the School Capital Matching Fund.
4. The Parks and Natural Resources Fund Constitutional amendment requires 15% of net proceeds be transferred to this fund.
5. Per Ballot Measure 96 (2016), 1.5% of net lottery proceeds are dedicated to the Veterans' Services Fund
6. Per Ballot Measure 99 (2016), the lesser of 4% of Lottery transfers or $22 million per year is transferred to the Outdoor Education Account. Adjusted annually for inflation.
7. Approximately one percent of net lottery proceeds are dedicated to each program. Certain limits are imposed by the Legislature.
8. Includes Debt Service Allocations, Allocations to State School Fund and Other Agency Allocations

Table B.10 –Budgetary Reserve Summary

Table B.10 **December 2024**

Budgetary Reserve Summary and Outlook

Rainy Day Fund

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$962.2	$1,353.5	$1,907.8	$2,554.5	$3,242.4	$4,012.5
Interest Earnings	$44.1	$157.5	$172.7	$161.3	$201.4	$247.1
Deposits[1]	$347.2	$396.3	$474.0	$526.6	$568.7	$627.6
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$1,353.4**	**$1,907.3**	**$2,554.5**	**$3,242.4**	**$4,012.5**	**$4,887.2**

Education Stability Fund[3]

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$414.6	$710.8	$1,009.2	$1,251.5	$1,602.2	$1,836.3
Interest Earnings[4]	$21.9	$89.8	$92.0	$80.7	$99.4	$113.0
Deposits[5]	$294.0	$300.8	$242.3	$350.7	$234.0	$250.9
Distributions	$19.8	$92.2	$92.0	$80.7	$99.4	$113.0
Oregon Education Fund	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Oregon Opportunity Grant	$19.8	$92.2	$92.0	$80.7	$99.4	$113.0
Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$710.8**	**$1,009.2**	**$1,251.5**	**$1,602.2**	**$1,836.3**	**$2,087.2**

Total Reserves

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Ending Balances	**$2,064.2**	**$2,916.5**	**$3,806.0**	**$4,844.7**	**$5,848.8**	**$6,974.4**
Percent of General Fund Revenues	6.7%	10.5%	10.8%	11.8%	12.8%	13.8%

Footnotes:
1. Includes transfer of ending General Fund balances up to 1% of budgeted appropriations as well as private donations. Assumes future appropriations equal to 98.75 percent of available resources. Includes forecast for corporate income taxes above rate of 6.6% for the biennium are deposited on or before Jun 30 of each odd-numbered year.
2. Available funds in a given biennium equal 2/3rds of the beginning balance under current law.
3. Excludes funds in the Oregon Growth and the Oregon Resource and Technology Development subaccounts.
4. Interest earnings are distributed to the Oregon Education Funds (75%) and the State Scholarship Fund (25%), provided there remains debt outstanding. In the event that debt is paid off, all interest earnings distributed to the State Scholarship Fund.
5. Contributions to the ESF are capped at 5% of the prior biennium's General Fund revenue total. Quarterly contributions are made until the balance exceeds the cap.

Table B.11 – Recreational Marijuana Forecast

TABLE B.11

Dec 2024

Summary of Marijuana Resources

(in millions of dollars)	2023-25 Current Forecast	2023-25 Change from Sep-24	2023-25 Change from COS 2023	2025-27 Current Forecast	2025-27 Change from Sep-24	2027-29 Current Forecast	2027-29 Change from Sep-24	2029-31 Current Forecast	2029-31 Change from Sep-24	20231-33 Current Forecast	20231-33 Change from Sep-24
MARIJUANA EARNINGS											
+ Tax Revenue [1]	311.874	*0.702*	*(4.986)*	327.949	*0.666*	351.620	0.877	383.119	0.967	417.922	1.060
+ Medical Marijuana Tax Revenue [2]	0.000	*0.000*	*0.000*	0.000	*0.000*	14.044	0.028	20.207	0.040	22.038	0.044
- Administrative Costs [3]	18.374	*0.000*	*0.000*	18.746	*0.000*	19.144	0.000	19.571	0.000	20.027	0.000
Net Available to Transfer	**293.500**	*0.702*	*(4.986)*	**309.203**	*0.666*	**332.476**	*0.905*	**383.756**	*1.007*	**419.932**	*1.104*
OREGON MARIJUANA ACCOUNT											
Beginning Balance	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Revenue Transfers	293.500	*0.702*	*(4.986)*	309.203	*0.666*	346.520	0.905	383.756	1.007	419.932	1.104
Other Resources	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Total Available Resources	**293.500**	*0.702*	*(4.986)*	**309.203**	*0.666*	**346.520**	*0.905*	**383.756**	*1.007*	**419.932**	*1.104*
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	191.624	*0.702*	*(4.986)*	200.708	*0.898*	232.426	0.803	264.594	1.029	295.410	1.137
State School Fund	40.751	*0.000*	*0.000*	43.398	*(0.093)*	45.638	0.041	47.665	(0.009)	49.809	(0.013)
Mental Health, Alcoholism, & Drug Services	20.375	*0.000*	*0.000*	21.699	*(0.046)*	22.819	0.020	23.832	(0.004)	24.904	(0.007)
State Police	15.281	*0.000*	*0.000*	16.274	*(0.035)*	17.114	0.015	17.874	(0.003)	18.678	(0.005)
Cities	10.188	*0.000*	*0.000*	10.849	*(0.023)*	11.409	0.010	11.916	(0.002)	12.452	(0.003)
Counties	10.188	*0.000*	*0.000*	10.849	*(0.023)*	11.409	0.010	11.916	(0.002)	12.452	(0.003)
Alcohol & Drug Abuse Prevention, Intervention & Treatment	5.094	*0.000*	*0.000*	5.425	*(0.012)*	5.705	0.005	5.958	(0.001)	6.226	(0.002)
Total Distributions	**293.500**	*0.702*	*(4.986)*	**309.203**	*0.666*	**346.520**	*0.905*	**383.756**	*1.007*	**419.932**	*1.104*
Ending Balance	**0.000**	*0.000*	*0.000*	**0.000**	*0.000*	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000

Note: Some totals may not foot due to rounding.

1. Retailers pay taxes monthly, however taxes are not available for distribution to recepient programs until the Department of Revenue receives and processes retailers' quarterly tax returns. As such, there is a one to two quarter lag between when the initial monthly payments are made and when monies be come available to distribute.

2. Medical marijuana being exempt from tax is an explicit tax expenditure per HB 2433 (2021). Tax expenditures sunset after 6 years, although they may be renewed at that time. Current law is that medical marijuana sales will be taxed beginning January 1, 2028.

3. Administrative Costs reflect monthly collection costs for the Department of Revenue in addition to distributions to the Criminal Justice Commission and OLCC per SB 1544 (2018)

4. The first $11.25 million per quarter ($45m per year) is distributed via forumula to the initial recipient programs. These distributions are adjusted for inflation. All additional revenues go to the Drug Treatment & Recovery Fund.

Table B.12 – Fund for Student Success (Corporate Activity Tax)

TABLE B.12
Summary of Corporate Activity Tax Resources

December 2024

(in millions of dollars)	2023-25 Current Forecast	2023-25 *Change from Sep-24*	2023-25 *Change from COS 2023*	2025-27 Current Forecast	2025-27 *Change from Sep-24*	2027-29 Current Forecast	2027-29 *Change from Sep-24*	2029-31 Current Forecast	2029-31 *Change from Sep-24*	2031-33 Current Forecast	2031-33 *Change from Sep-24*
Corporate Activity Tax											
+ Tax Revenue	2,788.709	(5.924)	*9.611*	3,125.566	(40.145)	3,471.434	*(63.068)*	3,823.722	*(91.512)*	4,188.778	*(118.602)*
- Administrative Costs	21.312	0.000	*0.000*	23.656	0.000	26.259	*0.000*	28.689	*0.000*	31.234	*0.000*
Net Available to Transfer	**2,767.397**	(5.924)	**9.611**	**3,101.910**	**(40.145)**	**3,445.176**	(63.068)	**3,795.033**	(91.512)	**4,157.544**	(118.602)
Fund for Student Success											
Beginning Balance	326.038	0.000	*7.511*	178.218	(7.860)	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Revenue Transfers	2,767.397	(5.924)	*9.611*	3,101.910	(40.145)	3,445.176	*(63.068)*	3,795.033	*(91.512)*	4,157.544	*(118.602)*
Other Resources	0.000	0.000	*0.000*	0.000	0.000	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Total Available Resources	**3,093.435**	(5.924)	**17.122**	**3,280.127**	**(48.005)**	**3,445.176**	(63.068)	**3,795.033**	(91.512)	**4,157.544**	(118.602)
ALLOCATION OF RESOURCES											
State School Fund	779.156	1.936	*77.202*	829.892	7.149	913.180	*9.586*	1,001.190	*11.995*	1,094.009	*14.581*
Student Investment Account	1,087.179	0.000	*0.000*	1,225.118	(27.577)	1,265.998	*(36.327)*	1,396.921	*(51.754)*	1,531.767	*(66.592)*
Statewide Education Initiative Account	548.451	0.000	*(8.945)*	735.071	(16.546)	759.599	*(21.796)*	838.153	*(31.052)*	919.060	*(39.955)*
Early Learning Account	500.430	0.000	*(29.352)*	490.047	(11.031)	506.399	*(14.531)*	558.769	*(20.701)*	612.707	*(26.637)*
Total Distributions	**2,915.217**	1.936	**38.904**	**3,280.127**	**(48.005)**	**3,445.176**	(63.068)	**3,795.033**	(91.512)	**4,157.544**	(118.602)
Ending Balance	**178.218**	(7.860)	**(21.782)**	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000

Note: The State School Fund distribution equals an estimate of the lost General Fund due to the Personal and Corporate Income Tax changes enacted in HB 3427. In addition, each biennium includes an additional $40 million dedicated to the High Cost Disabilities Account. The 2021-23 distribution equals the Legislatively Adopted Budget Other Fund limitation. The 2023-25 distribution includes a $28.13 million reconciling adjustment for the prior biennium.
Some totals may not foot due to rounding.

Table B.13 – Fund for Student Success Quarterly Revenues

Table B.13 **December 2024**

Corporate Activity Tax Collections By Quarter

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Estimated Payments	0	0	4,023	222,495	**226,518**	224,973	254,387	223,550	270,784	**973,693**
Final Payments	0	0	0	0	**0**	0	0	26,911	163,436	**190,348**
Refunds	0	0	0	0	**0**	0	0	-997	-14,657	**-15,654**
Total	**0**	**0**	**4,023**	**222,495**	**226,518**	**224,973**	**254,387**	**249,464**	**419,563**	**1,148,387**
%CHY								*6101%*	*88.6%*	***407.0%***

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Estimated Payments	271,858	389,810	230,942	279,349	**1,171,959**	292,325	391,140	251,283	285,645	**1,220,391**
Final Payments	15,153	41,892	41,950	168,644	**267,640**	59,490	75,201	65,187	173,094	**372,971**
Refunds	-16,356	-141,389	-15,151	-50,166	**-223,062**	-41,565	-170,978	-21,976	-20,314	**-254,833**
Total	**270,656**	**290,314**	**257,741**	**397,828**	**1,216,538**	**310,249**	**295,362**	**294,493**	**438,425**	**1,338,529**
%CHY	*20.3%*	*14.1%*	*3.3%*	*-5.2%*	***5.9%***	*14.6%*	*1.7%*	*14.3%*	*10.2%*	***10.0%***

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Estimated Payments	289,041	317,340	314,961	301,839	**1,223,181**	308,692	383,126	275,816	326,850	**1,294,483**
Final Payments	41,981	53,324	65,943	185,622	**346,870**	47,701	60,201	63,712	190,278	**361,891**
Refunds	-29,313	-56,912	-101,932	-38,258	**-226,416**	-30,480	-85,106	-56,833	-38,882	**-211,302**
Total	**301,708**	**313,753**	**278,972**	**449,203**	**1,343,635**	**325,913**	**358,220**	**282,694**	**478,245**	**1,445,073**
%CHY	*-2.8%*	*6.2%*	*-5.3%*	*2.5%*	***0.4%***	*8.0%*	*14.2%*	*1.3%*	*6.5%*	***7.5%***

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	323,981	403,418	290,672	345,295	**1,363,366**	342,524	426,554	307,380	364,294	**1,440,753**
Final Payments	53,116	64,096	66,913	198,136	**382,262**	55,389	66,717	70,190	209,123	**401,419**
Refunds	-33,028	-91,889	-61,316	-40,812	**-227,045**	-34,430	-94,747	-63,297	-42,715	**-235,189**
Total	**344,069**	**375,626**	**296,269**	**502,618**	**1,518,582**	**363,484**	**398,524**	**314,274**	**530,703**	**1,606,984**
%CHY	*5.6%*	*4.9%*	*4.8%*	*5.1%*	***5.1%***	*5.6%*	*6.1%*	*6.1%*	*5.6%*	***5.8%***

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	361,005	449,459	323,797	383,130	**1,517,391**	379,641	472,574	340,384	402,284	**1,594,883**
Final Payments	58,400	70,441	74,050	220,383	**423,274**	61,556	74,228	77,928	231,735	**445,446**
Refunds	-36,160	-100,065	-66,868	-45,055	**-248,148**	-38,126	-105,438	-70,441	-47,407	**-261,412**
Total	**383,245**	**419,835**	**330,979**	**558,458**	**1,692,517**	**403,071**	**441,363**	**347,871**	**586,612**	**1,778,917**
%CHY	*5.4%*	*5.3%*	*5.3%*	*5.2%*	***5.3%***	*5.2%*	*5.1%*	*5.1%*	*5.0%*	***5.1%***

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Estimated Payments	398,588	496,092	357,269	421,827	**1,673,776**	417,986	520,161	374,559	441,726	**1,754,431**
Final Payments	64,735	78,047	81,859	243,281	**467,922**	67,967	81,932	85,867	255,064	**490,830**
Refunds	-40,105	-110,858	-74,049	-49,793	**-274,804**	-42,114	-116,373	-77,721	-52,225	**-288,433**
Total	**423,219**	**463,280**	**365,080**	**615,315**	**1,866,894**	**443,839**	**485,720**	**382,704**	**644,565**	**1,956,828**
%CHY	*5.0%*	*5.0%*	*4.9%*	*4.9%*	***4.9%***	*4.9%*	*4.8%*	*4.8%*	*4.8%*	***4.8%***

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Estimated Payments	437,604	544,504	392,033	461,939	**1,836,081**	457,603	569,332	409,872	482,714	**1,919,521**
Final Payments	71,265	85,897	89,942	267,017	**514,122**	74,612	89,918	94,088	279,205	**537,824**
Refunds	-44,164	-122,002	-81,468	-54,698	**-302,332**	-46,245	-127,710	-85,268	-57,215	**-316,439**
Total	**464,706**	**508,399**	**400,508**	**674,259**	**2,047,871**	**485,970**	**531,540**	**418,692**	**704,705**	**2,140,906**
%CHY	*4.7%*	*4.7%*	*4.7%*	*4.6%*	***4.7%***	*4.6%*	*4.6%*	*4.5%*	*4.5%*	***4.5%***

Appendix C: Population Forecast Detail

Table C.1 Oregon's Population Forecasts and Component of Change 1990-2033

Year		Population Change		Births		Deaths		Natural	Net Migration	
(July 1)	Population	Number	Percent	Number	Rate/1000	Number	Rate/1000	Increase	Number	Rate/1000
1989-1990	2,860,400	69,800	2.50	42,008	14.87	24,763	8.76	17,245	52,555	18.60
1985-1990		**187,800**		**199,810**		**121,318**		**78,492**	**109,308**	
1990-1991	2,928,500	68,100	2.38	42,682	14.75	24,944	8.62	17,738	50,362	17.40
1991-1992	2,991,800	63,300	2.16	42,427	14.33	25,166	8.50	17,261	46,039	15.55
1992-1993	3,060,400	68,600	2.29	41,442	13.69	26,543	8.77	14,899	53,701	17.75
1993-1994	3,121,300	60,900	1.99	41,487	13.42	27,564	8.92	13,923	46,977	15.20
1994-1995	3,184,400	63,100	2.02	42,426	13.46	27,552	8.74	14,874	48,226	15.30
1990-1995		**324,000**		**210,464**		**131,769**		**78,695**	**245,305**	
1995-1996	3,247,100	62,700	1.97	43,196	13.43	28,768	8.95	14,428	48,272	15.01
1996-1997	3,304,300	57,200	1.76	43,625	13.32	29,201	8.91	14,424	42,776	13.06
1997-1998	3,352,400	48,100	1.46	44,696	13.43	28,705	8.62	15,991	32,109	9.65
1998-1999	3,393,900	41,500	1.24	45,188	13.40	29,848	8.85	15,340	26,160	7.76
1999-2000	3,431,100	37,200	1.10	45,534	13.34	28,909	8.47	16,625	20,575	6.03
1995-2000		**246,700**		**222,239**		**145,431**		**76,808**	**169,892**	
2000-2001	3,470,400	39,300	1.15	45,536	13.20	29,934	8.67	15,602	23,698	6.87
2001-2002	3,502,600	32,200	0.93	44,995	12.91	30,828	8.84	14,167	18,033	5.17
2002-2003	3,538,600	36,000	1.03	45,686	12.98	30,604	8.69	15,082	20,918	5.94
2003-2004	3,578,900	40,300	1.14	45,599	12.81	30,721	8.63	14,878	25,422	7.14
2004-2005	3,626,900	48,000	1.34	45,892	12.74	30,717	8.53	15,175	32,825	9.11
1995-2000		**195,800**		**227,708**		**152,804**		**74,904**	**120,896**	
2005-2006	3,685,200	58,300	1.61	46,946	12.84	30,771	8.42	16,175	42,125	11.52
2006-2007	3,739,400	54,200	1.47	49,404	13.31	31,396	8.46	18,008	36,192	9.75
2007-2008	3,784,200	44,800	1.20	49,659	13.20	32,008	8.51	17,651	27,149	7.22
2008-2009	3,815,800	31,600	0.84	47,960	12.62	31,382	8.26	16,578	15,022	3.95
2009-2010	3,837,300	21,500	0.56	46,256	12.09	31,689	8.28	14,567	6,933	1.81
2005-2010		**210,400**		**240,225**		**157,246**		**82,979**	**127,421**	
2010-2011	3,872,700	35,400	0.92	45,381	11.77	32,437	8.41	12,944	22,456	5.83
2011-2012	3,900,100	27,400	0.71	44,897	11.55	32,804	8.44	12,093	15,307	3.94
2012-2013	3,924,100	24,000	0.62	44,969	11.49	33,168	8.48	11,801	12,199	3.12
2013-2014	3,965,400	41,300	1.05	45,447	11.52	33,731	8.55	11,716	29,584	7.50
2014-2015	4,018,500	53,100	1.34	45,660	11.44	35,318	8.85	10,342	42,758	10.71
2010-2015		**181,200**		**226,354**		**167,458**		**58,896**	**122,304**	
2015-2016	4,093,200	74,700	1.86	45,647	11.25	35,339	8.71	10,308	64,392	15.88
2016-2017	4,147,200	54,000	1.32	44,602	10.83	36,773	8.93	7,829	46,171	11.21
2017-2018	4,183,400	36,200	0.87	42,906	10.30	36,268	8.71	6,638	29,562	7.10
2018-2019	4,216,000	32,599	0.78	42,220	10.05	36,622	8.72	5,598	27,001	6.43
2019-2020	4,236,615	20,615	0.49	40,920	9.68	37,821	8.95	3,099	17,516	4.14
2015-2020		**218,115**		**216,295**		**182,823**		**33,472**	**184,643**	
2020-2021	4,216,137	-20,478	-0.48	39,654	9.38	41,893	9.91	-2,239	-18,239	-4.32
2021-2022	4,230,711	14,574	0.35	40,470	9.58	46,351	10.97	-5,881	20,455	4.84
2022-2023	4,246,688	15,977	0.38	38,739	9.14	43,521	10.27	-4,782	20,759	4.90
2023-2024	4,259,132	12,444	0.29	39,122	9.20	43,650	10.26	-4,529	16,973	3.99
2024-2025	4,283,000	23,868	0.56	39,396	9.22	44,004	10.30	-4,608	28,476	6.67
2020-2025		**46,385**		**197,381**		**219,419**		**-22,039**	**68,424**	
2025-2026	4,307,700	24,699	0.58	39,814	9.27	44,578	10.38	-4,764	29,463	6.86
2026-2027	4,332,600	24,900	0.58	40,224	9.31	44,891	10.39	-4,667	29,567	6.84
2027-2028	4,357,700	25,100	0.58	40,657	9.36	45,840	10.55	-5,183	30,283	6.97
2028-2029	4,383,000	25,300	0.58	41,102	9.40	46,382	10.61	-5,280	30,580	7.00
2029-2030	4,408,800	25,800	0.59	41,590	9.46	46,775	10.64	-5,186	30,986	7.05
2025-2030		**125,800**		**203,387**		**228,466**		**-25,079**	**150,879**	
2030-2031	4,434,800	26,000	0.59	41,802	9.45	47,113	10.65	-5,311	31,311	7.08
2031-2032	4,460,800	26,000	0.59	42,050	9.45	47,600	10.70	-5,550	31,550	7.09
2032-2033	4,487,000	26,200	0.59	42,321	9.46	48,091	10.75	-5,769	31,969	7.15
2030-2033		**78,200**		**126,174**		**142,803**		**-16,630**	**94,829**	
1990-2000		**570,700**		**432,703**		**277,200**		**155,503**	**415,197**	13.10
2000-2010		**406,200**		**467,933**		**310,050**		**157,883**	**248,317**	6.83
2010-2020		**399,315**		**442,649**		**350,281**		**92,368**	**306,947**	7.61
2020-2030		**172,185**		**400,768**		**447,886**		**-47,118**	**219,303**	5.10
2030-2033		**78,200**		**126,174**		**142,803**		**-16,630**	**94,829**	5.33

Sources: 1980-2019 intercensal population estimates by the U.S. Census Bureau; 2020-2023 and 2024 (preliminary) population by Ppulation Resear Center, PSU; births and deaths 1990-2023: Oregon Center for Health Statistics. Forecaasts of population, births, deaths, and net migration are by the Oregon Office of Economic Analysis.

Table C.2 Population Forecasts by Age and Sex: 2010-2033

		2010			2020			2021			2022			2023	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	122,302	116,141	238,443	111,818	106,800	218,617	107,798	102,830	210,628	105,888	100,848	206,736	103,652	98,702	202,353
5- 9	121,563	116,455	238,018	124,531	118,293	242,824	122,309	116,862	239,171	120,819	115,406	236,225	118,963	113,438	232,401
10-14	124,611	118,821	243,432	132,080	125,008	257,089	130,847	124,021	254,867	130,030	122,945	252,976	128,712	121,445	250,156
15-19	131,215	124,664	255,879	130,432	125,454	255,886	128,686	122,425	251,111	130,325	123,455	253,780	132,404	125,385	257,789
20-24	128,737	124,919	253,656	135,004	131,992	266,996	134,019	131,876	265,894	134,088	132,282	266,370	133,819	131,652	265,471
25-29	133,819	131,522	265,341	145,476	141,886	287,362	139,942	136,833	276,775	137,816	134,287	272,103	136,843	132,940	269,783
30-34	131,483	128,253	259,736	152,540	148,773	301,314	151,138	148,083	299,221	152,748	149,111	301,859	153,435	149,153	302,588
35-39	128,103	123,715	251,818	150,138	147,954	298,092	150,093	147,224	297,317	150,508	147,597	298,105	151,077	148,177	299,254
40-44	125,961	122,930	248,891	138,035	136,372	274,407	140,759	139,214	279,973	143,817	142,711	286,528	146,197	145,721	291,918
45-49	130,755	132,549	263,304	129,927	127,205	257,133	128,018	125,684	253,702	128,320	126,634	254,954	130,421	129,081	259,503
50-54	135,069	141,566	276,635	125,433	125,664	251,097	127,407	126,867	254,274	129,144	128,237	257,380	129,672	128,615	258,287
55-59	132,995	140,775	273,769	128,222	134,573	262,794	124,646	129,880	254,527	121,848	126,409	248,258	119,933	123,830	243,763
60-64	115,186	121,047	236,233	130,229	142,864	273,093	128,354	140,468	268,822	126,871	138,841	265,712	125,468	136,935	262,404
65-69	81,837	87,957	169,794	125,028	139,082	264,110	124,872	139,790	264,661	124,653	140,238	264,891	123,811	139,803	263,614
70-74	56,945	63,006	119,950	102,834	114,381	217,215	106,708	119,327	226,035	108,754	122,479	231,233	110,197	125,106	235,303
75-79	40,954	50,138	91,091	65,255	75,486	140,741	68,417	79,341	147,759	73,171	84,887	158,058	78,275	90,928	169,203
80-84	30,391	42,761	73,152	37,998	46,621	84,619	39,580	48,634	88,213	41,602	51,338	92,941	44,412	54,882	99,294
85+	26,767	51,389	78,156	31,757	51,468	83,225	32,096	51,092	83,188	32,110	50,492	82,601	32,725	50,878	83,603
Total	1,898,693	1,938,607	3,837,300	2,096,738	2,139,877	4,236,615	2,085,686	2,130,451	4,216,137	2,092,513	2,138,198	4,230,711	2,100,016	2,146,672	4,246,688
Mdn. Age	37.2	39.4	38.3	38.9	40.8	39.8	39.3	41.2	40.2	39.5	41.5	40.5	39.7	41.8	40.7

		2024			2025			2026			2027			2028	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	102,084	97,077	199,161	101,561	96,596	198,158	101,844	96,826	198,670	101,816	96,781	198,596	102,885	97,781	200,665
5- 9	116,531	111,019	227,550	113,734	107,867	221,600	110,731	104,601	215,332	109,005	102,728	211,733	106,928	100,689	207,617
10-14	127,353	120,156	247,510	126,717	119,578	246,295	126,080	118,966	245,046	124,841	117,648	242,488	123,235	115,803	239,039
15-19	133,666	126,471	260,137	134,917	127,535	262,452	135,437	127,863	263,299	134,984	127,077	262,060	133,983	125,818	259,801
20-24	133,114	130,214	263,327	132,607	128,426	261,033	133,098	127,510	260,608	135,225	129,029	264,254	137,853	131,515	269,367
25-29	136,693	132,928	269,621	137,652	134,703	272,356	138,659	136,723	275,382	139,211	137,544	276,755	139,375	137,303	276,678
30-34	152,291	147,735	300,026	150,701	145,802	296,503	148,781	143,402	292,182	147,407	141,331	288,738	147,219	140,508	287,726
35-39	151,999	149,001	301,000	153,895	150,577	304,472	156,278	152,422	308,700	158,431	153,864	312,294	159,713	154,327	314,041
40-44	148,051	147,815	295,866	149,780	149,376	299,156	150,870	150,345	301,214	151,524	151,090	302,615	152,308	152,041	304,349
45-49	133,384	132,361	265,744	137,078	136,626	273,704	140,918	140,930	281,848	144,249	144,736	288,985	146,896	148,070	294,966
50-54	128,985	127,896	256,881	127,781	126,789	254,570	126,717	126,205	252,922	127,257	127,400	254,657	129,546	130,080	259,626
55-59	119,682	123,000	242,682	121,761	124,649	246,410	124,586	127,082	251,668	126,590	128,798	255,388	127,349	129,484	256,833
60-64	123,990	134,592	258,582	122,126	131,970	254,096	119,684	128,848	248,532	117,366	125,802	243,168	115,811	123,584	239,395
65-69	122,435	138,691	261,125	121,545	137,886	259,431	120,843	137,096	257,939	119,921	135,976	255,896	118,939	134,495	253,434
70-74	111,777	127,949	239,726	113,287	130,606	243,894	114,237	132,463	246,700	114,565	133,333	247,898	114,179	133,270	247,449
75-79	82,762	96,440	179,202	87,488	102,287	189,775	91,449	107,372	198,821	93,736	110,695	204,431	95,368	113,431	208,799
80-84	47,173	58,527	105,700	49,534	61,795	111,330	52,376	65,452	117,828	56,588	70,600	127,188	60,948	76,049	136,997
85+	33,677	51,613	85,290	34,968	52,798	87,766	36,472	54,535	91,007	38,409	57,046	95,454	40,786	60,132	100,918
Total	2,105,647	2,153,485	4,259,132	2,117,133	2,165,868	4,283,000	2,129,059	2,178,640	4,307,700	2,141,123	2,191,477	4,332,600	2,153,319	2,204,380	4,357,700
Mdn. Age	40.0	42.1	41.0	40.2	42.4	41.3	40.4	42.7	41.6	40.7	43.0	41.8	40.8	43.2	42.1

		2029			2030			2031			2032			2033	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	103,952	98,786	202,738	105,109	99,881	204,990	106,160	100,875	207,035	107,126	101,789	208,915	108,010	102,625	210,635
5- 9	105,587	99,231	204,818	105,093	98,771	203,864	105,419	99,028	204,447	105,420	99,005	204,424	106,557	100,046	206,603
10-14	121,158	113,557	234,715	118,317	110,369	228,686	115,237	107,050	222,287	113,489	105,156	218,645	111,362	103,087	214,450
15-19	133,043	124,824	257,867	132,461	124,284	256,745	131,857	123,696	255,552	130,628	122,381	253,008	129,005	120,514	249,519
20-24	139,854	133,297	273,151	141,270	134,525	275,794	141,883	134,942	276,825	141,491	134,187	275,678	140,513	132,919	273,432
25-29	139,198	136,412	275,610	138,763	134,637	273,400	139,341	133,736	273,076	141,645	135,397	277,042	144,476	138,065	282,541
30-34	148,102	141,259	289,361	149,333	143,280	292,613	150,585	145,535	296,120	151,360	146,522	297,883	151,677	146,349	298,027
35-39	159,632	153,595	313,227	158,155	151,702	309,857	156,279	149,282	305,561	154,970	147,213	302,183	154,879	146,432	301,311
40-44	153,587	153,387	306,974	155,587	155,106	310,694	158,058	157,081	315,139	160,300	158,644	318,945	161,666	159,190	320,856
45-49	149,134	150,658	299,792	150,978	152,341	303,319	152,162	153,397	305,559	152,903	154,226	307,129	153,767	155,257	309,025
50-54	132,774	133,682	266,456	136,555	138,071	274,626	140,473	142,489	282,962	143,883	146,411	290,294	146,616	149,858	296,474
55-59	126,990	129,148	256,138	125,942	128,140	254,082	125,028	127,647	252,675	125,691	128,955	254,646	128,083	131,764	259,846
60-64	115,944	123,225	239,169	118,143	125,032	243,175	121,052	127,604	248,656	123,149	129,447	252,597	124,037	130,248	254,285
65-69	117,951	132,693	250,644	116,383	130,278	246,660	114,255	127,350	241,606	112,240	124,494	236,734	110,964	122,459	233,423
70-74	113,391	132,684	246,075	112,832	132,129	244,962	112,446	131,579	244,025	111,847	130,706	242,553	111,198	129,488	240,686
75-79	97,187	116,416	213,603	98,809	119,092	217,902	99,951	121,043	220,994	100,557	122,105	222,662	100,568	122,351	222,920
80-84	64,834	81,050	145,884	68,792	86,194	154,986	72,191	90,730	162,921	74,380	93,900	168,280	76,147	96,675	172,823
85+	43,341	63,436	106,777	45,787	66,658	112,445	48,755	70,606	119,361	52,965	76,219	129,183	57,630	82,518	140,148
Total	2,165,661	2,217,339	4,383,000	2,178,310	2,230,490	4,408,800	2,191,131	2,243,668	4,434,800	2,204,043	2,256,757	4,460,800	2,217,155	2,269,845	4,487,000
Mdn. Age	41.0	43.5	42.3	41.2	43.8	42.5	41.5	44.0	42.7	41.7	44.3	43.0	42.0	44.5	43.2

Table C.3 Population of Oregon: 1990-2033

Year (July 1)	Total Population	Change from previous year Number	Percent
1990	2,860,400	-	-
1991	2,928,500	68,100	2.38%
1992	2,991,800	63,300	2.16%
1993	3,060,400	68,600	2.29%
1994	3,121,300	60,900	1.99%
1995	3,184,400	63,100	2.02%
1996	3,247,100	62,700	1.97%
1997	3,304,300	57,200	1.76%
1998	3,352,400	48,100	1.46%
1999	3,393,900	41,500	1.24%
2000	3,431,100	37,200	1.10%
2001	3,470,400	39,300	1.15%
2002	3,502,600	32,200	0.93%
2003	3,538,600	36,000	1.03%
2004	3,578,900	40,300	1.14%
2005	3,626,900	48,000	1.34%
2006	3,685,200	58,300	1.61%
2007	3,739,400	54,200	1.47%
2008	3,784,200	44,800	1.20%
2009	3,815,800	31,600	0.84%
2010	3,837,300	21,500	0.56%
2011	3,872,700	35,400	0.92%
2012	3,900,100	27,400	0.71%
2013	3,924,100	24,000	0.62%
2014	3,965,400	41,300	1.05%
2015	4,018,500	53,100	1.34%
2016	4,093,200	74,700	1.86%
2017	4,147,200	54,000	1.32%
2018	4,183,400	36,200	0.87%
2019	4,216,000	32,599	0.78%
2020	4,236,615	20,615	0.49%
2021	4,216,137	-20,478	-0.48%
2022	4,230,711	14,574	0.35%
2023	4,246,688	15,977	0.38%
2024	4,259,132	12,444	0.29%
2025	4,283,000	23,868	0.56%
2026	4,307,700	24,699	0.58%
2027	4,332,600	24,900	0.58%
2028	4,357,700	25,100	0.58%
2029	4,383,000	25,300	0.58%
2030	4,408,800	25,800	0.59%
2031	4,434,800	25,999	0.59%
2032	4,460,800	26,000	0.59%
2033	4,487,000	26,200	0.59%

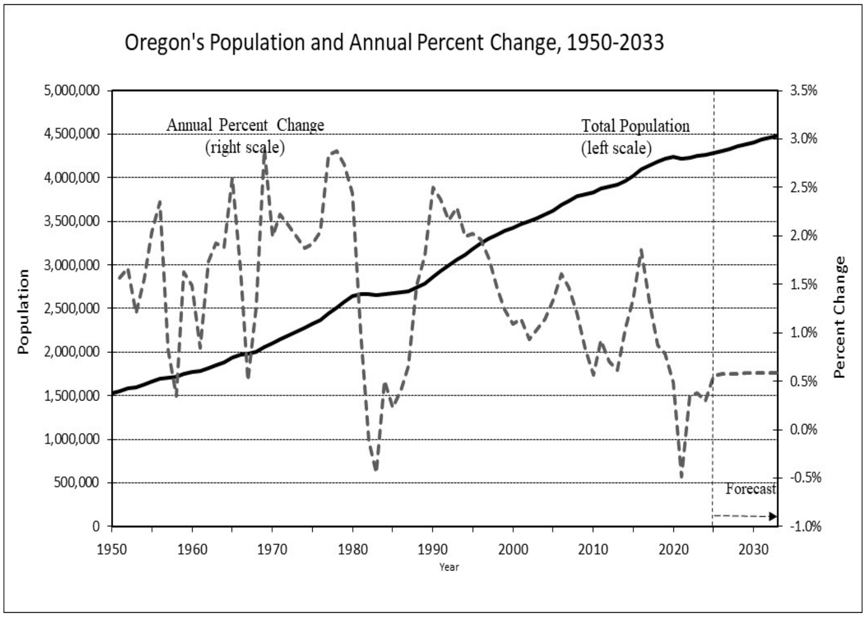


Table C.4 Children: Ages 0-4 / Table C.5 School Age Population: Ages 5-17 / Table C.6 Young Adult Population: Ages 18-24

Year (July 1)	C.4 Population	C.4 % Change from previous decade/yr. Number	C.4 Percent	C.5 Population	C.5 % Change from previous decade/yr. Number	C.5 Percent	C.6 Population	C.6 % Change from previous decade/yr. Number	C.6 Percent
1980	199,525	---	---	524,446	---	---	329,407	---	---
1990	209,638	10,113	5.07%	532,727	8,281	1.58%	268,134	-61,273	-18.60%
2000	223,207	13,569	6.47%	624,316	91,589	17.19%	330,328	62,194	23.20%
2010	238,443	15,236	6.83%	631,132	6,815	1.09%	359,854	29,526	8.94%
2011	237,025	-1,418	-0.59%	632,768	1,637	0.26%	362,539	2,685	0.75%
2012	233,718	-3,307	-1.40%	634,848	2,080	0.33%	364,881	2,342	0.65%
2013	230,245	-3,474	-1.49%	636,043	1,194	0.19%	367,398	2,517	0.69%
2014	229,266	-979	-0.43%	638,822	2,780	0.44%	369,948	2,550	0.69%
2015	229,564	298	0.13%	642,298	3,476	0.54%	372,011	2,063	0.56%
2016	231,814	2,250	0.98%	648,018	5,720	0.89%	374,147	2,136	0.57%
2017	232,124	310	0.13%	650,561	2,544	0.39%	375,736	1,588	0.42%
2018	229,135	-2,989	-1.29%	649,580	-982	-0.15%	376,274	539	0.14%
2019	224,616	-4,520	-1.97%	650,249	669	0.10%	375,249	-1,025	-0.27%
2020	218,617	-5,998	-2.67%	650,823	574	0.09%	371,972	-3,277	-0.87%
2021	210,628	-7,989	-3.65%	644,818	-6,005	-0.92%	366,226	-5,747	-1.54%
2022	206,736	-3,892	-1.85%	642,495	-2,323	-0.36%	366,857	631	0.17%
2023	202,353	-4,383	-2.12%	638,644	-3,851	-0.60%	367,174	317	0.09%
2024	199,161	-3,192	-1.58%	632,550	-6,094	-0.95%	365,974	-1,199	-0.33%
2025	198,158	-1,004	-0.50%	625,159	-7,391	-1.17%	366,222	247	0.07%
2026	198,670	513	0.26%	616,017	-9,142	-1.46%	368,269	2,047	0.56%
2027	198,596	-74	-0.04%	608,167	-7,850	-1.27%	372,368	4,100	1.11%
2028	200,665	2,069	1.04%	599,297	-8,870	-1.46%	376,526	4,158	1.12%
2029	202,738	2,073	1.03%	591,527	-7,770	-1.30%	379,024	2,498	0.66%
2030	204,990	2,252	1.11%	584,478	-7,049	-1.19%	380,612	1,588	0.42%
2031	207,035	2,045	1.00%	578,102	-6,376	-1.09%	381,009	397	0.10%
2032	208,915	1,879	0.91%	572,128	-5,974	-1.03%	379,627	-1,382	-0.36%
2033	210,635	1,720	0.82%	566,411	-5,717	-1.00%	377,592	-2,035	-0.54%

Table C.7 Criminally At Risk Population (males): Ages 15-39

Table C.8 Prime Wage Earners: Ages 25-44

Table C.9 Older Wage Earners: Ages 45-64

Year	C.7	% Change from previous decade/yr.		C.8	% Change from previous decade/yr.		C.9	% Change from previous decade/yr.	
(July 1)	Population	Number	Percent	Population	Number	Percent	Population	Number	Percent
1980	561,931	---	---	790,750	---	---	491,249	---	---
1990	544,738	-17,193	-3.06%	926,326	135,576	17.15%	531,181	39,932	8.13%
2000	616,988	72,250	13.26%	996,500	70,174	7.58%	817,510	286,329	53.90%
2010	653,357	36,370	5.89%	1,025,787	29,287	2.94%	1,049,941	232,431	28.43%
2011	654,254	897	0.14%	1,032,760	6,973	0.68%	1,060,368	10,428	0.99%
2012	656,074	1,820	0.28%	1,038,435	5,675	0.55%	1,055,522	-4,846	-0.46%
2013	659,512	3,437	0.52%	1,044,222	5,787	0.56%	1,049,177	-6,345	-0.60%
2014	667,013	7,502	1.14%	1,054,896	10,674	1.02%	1,050,631	1,454	0.14%
2015	676,749	9,735	1.46%	1,068,810	13,914	1.32%	1,056,585	5,954	0.57%
2016	690,908	14,159	2.09%	1,092,436	23,627	2.21%	1,067,462	10,876	1.03%
2017	701,566	10,657	1.54%	1,114,454	22,017	2.02%	1,066,781	-681	-0.06%
2018	707,231	5,666	0.81%	1,132,587	18,133	1.63%	1,059,475	-7,306	-0.68%
2019	712,352	5,120	0.72%	1,148,691	16,104	1.42%	1,051,630	-7,845	-0.74%
2020	713,591	1,239	0.17%	1,161,175	12,484	1.09%	1,044,117	-7,513	-0.71%
2021	703,877	-9,714	-1.36%	1,153,285	-7,890	-0.68%	1,031,324	-12,793	-1.23%
2022	705,485	1,608	0.23%	1,158,596	5,310	0.46%	1,026,304	-5,020	-0.49%
2023	707,578	2,093	0.30%	1,163,543	4,948	0.43%	1,023,956	-2,348	-0.23%
2024	707,762	184	0.03%	1,166,513	2,969	0.26%	1,023,890	-66	-0.01%
2025	709,772	2,009	0.28%	1,172,487	5,974	0.51%	1,028,780	4,890	0.48%
2026	712,252	2,480	0.35%	1,177,479	4,992	0.43%	1,034,970	6,190	0.60%
2027	715,257	3,005	0.42%	1,180,402	2,923	0.25%	1,042,198	7,228	0.70%
2028	718,142	2,885	0.40%	1,182,794	2,392	0.20%	1,050,820	8,621	0.83%
2029	719,830	1,687	0.23%	1,185,173	2,379	0.20%	1,061,555	10,735	1.02%
2030	719,981	152	0.02%	1,186,563	1,390	0.12%	1,075,202	13,647	1.29%
2031	719,945	-37	-0.01%	1,189,896	3,333	0.28%	1,089,852	14,650	1.36%
2032	720,094	149	0.02%	1,196,053	6,157	0.52%	1,104,665	14,814	1.36%
2033	720,550	457	0.06%	1,202,735	6,682	0.56%	1,119,629	14,964	1.35%

Table C.10 Elderly Population by Age Group

Year (July 1)	Ages 65+	%Change from previous decade/yr.	Ages 65-74	%Change from previous decade/yr.	Ages 75-84	%Change from previous decade/yr.	Ages 85+	%Change from previous decade/yr.
1980	305,841	---	185,863	---	91,137	---	28,841	---
1990	392,369	28.29%	224,772	20.93%	128,813	41.34%	38,784	34.48%
2000	439,239	11.95%	218,997	-2.57%	162,187	25.91%	58,055	49.69%
2010	532,145	21.15%	289,744	32.31%	164,244	1.27%	78,156	34.62%
2011	547,239	2.84%	302,099	4.26%	165,476	0.75%	79,664	1.93%
2012	572,696	4.65%	324,844	7.53%	167,189	1.04%	80,663	1.25%
2013	597,016	4.25%	346,105	6.55%	169,663	1.48%	81,248	0.72%
2014	621,837	4.16%	366,153	5.79%	174,052	2.59%	81,632	0.47%
2015	649,233	4.41%	388,002	5.97%	179,353	3.05%	81,878	0.30%
2016	679,324	4.63%	410,279	5.74%	186,278	3.86%	82,767	1.09%
2017	707,545	4.15%	430,698	4.98%	194,088	4.19%	82,759	-0.01%
2018	736,350	4.07%	448,385	4.11%	205,211	5.73%	82,754	-0.01%
2019	765,566	3.97%	465,975	3.92%	216,829	5.66%	82,762	0.01%
2020	789,910	3.18%	481,325	3.29%	225,360	3.93%	83,225	0.56%
2021	809,856	2.53%	490,696	1.95%	235,972	4.71%	83,188	-0.05%
2022	829,724	2.45%	496,124	1.11%	250,999	6.37%	82,601	-0.70%
2023	851,018	2.57%	498,918	0.56%	268,497	6.97%	83,603	1.21%
2024	871,044	2.35%	500,852	0.39%	284,902	6.11%	85,290	2.02%
2025	892,195	2.43%	503,325	0.49%	301,105	5.69%	87,766	2.90%
2026	912,295	2.25%	504,638	0.26%	316,649	5.16%	91,007	3.69%
2027	930,867	2.04%	503,794	-0.17%	331,619	4.73%	95,454	4.89%
2028	947,597	1.80%	500,883	-0.58%	345,796	4.28%	100,918	5.72%
2029	962,983	1.62%	496,719	-0.83%	359,487	3.96%	106,777	5.81%
2030	976,955	1.45%	491,622	-1.03%	372,888	3.73%	112,445	5.31%
2031	988,906	1.22%	485,631	-1.22%	383,915	2.96%	119,361	6.15%
2032	999,412	1.06%	479,287	-1.31%	390,942	1.83%	129,183	8.23%
2033	1,009,999	1.06%	474,108	-1.08%	395,742	1.23%	140,148	8.49%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1304

December 30, 2024

Collective Bargaining Agreement

A vested interest in a successful future.

Effective: June 1, 2024 – May 31, 2028

2024 Collective Bargaining Agreement
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COLLECTIVE BARGAINING AGREEMENT

THIS COLLECTIVE BARGAINING AGREEMENT, hereinafter called “Agreement,” is entered into on June 1, 2024, between NORTHWEST NATURAL GAS COMPANY, a corporation, its successors or assigns, hereinafter called “the Company” or “the Employer,” and OFFICE AND PROFESSIONAL EMPLOYEES INTERNATIONAL UNION, LOCAL 11, AFL-CIO, hereinafter called “the Union,” collectively referred to as “the parties,” to promote a balance between the needs of the employees and those of the Employer while fostering an environment of mutual respect and cooperation.

COLLABORATIVE MISSION STATEMENT

The Union and the Company will work together to:

- Achieve collaborative and transparent relationships at all levels of the organization;
- Resolve concerns at the lowest level possible;
- Foster an environment in which employees are valued and supported in their development, engagement and success; and
- Promote NW Natural’s core values and continued success.

ARTICLE 1
GUARANTEES AND FLEXIBILITY

Section 1.1 Introduction

To support our ability to acquire and serve customers, and to outperform our competitors, thereby promoting employment security and enhancing job opportunities, the parties share responsibility for developing and rewarding a flexible and skilled work force. To successfully compete requires the ability to quickly adjust our products, services and processes.

Section 1.2 Flexibility

The parties agree that during the term of this Agreement, the Company has the flexibility to redesign and change its business operations, the work and the workforce. In exchange, the Company agrees that certain employees shall have Employment Security and Pay Guarantees, as defined in Section 1.4 and Section 1.5 of this Article.

Section 1.3 Involvement

It is the Company's right and responsibility to make business decisions, including such matters as redesigns, changes in business operations, the work and workforce. The Company acknowledges its obligation to bargain employee impacts with the Union.

The Company will meet quarterly with Union Representative to review the number of contractor personnel working, the type of work performed, and the current and projected workload to discuss the feasibility of increasing the bargaining unit work force or using overtime when practical and economical as an alternative.

Section 1.4 Employment Security

1.4.1 The parties agree that during the term of this Agreement there will be no layoff of any regular employee whose current period of employment was on or before May 31, 2023. Probationary and Term Employees are not eligible for employment security.

1.4.2 Employees without employment security are subject to layoff for any reason. However, the Company will not contract work to others that would cause employees with employment security to be laid off. The Company will eliminate individual, third-party contract workers, and temporary and Term employees who are performing the same bargaining unit duties in the impacted location and workgroup prior to laying off full or part-time employees. This excludes elimination of contract workers doing non-routine work that customarily uses contractors. Non-routine work performed by contractors will be reviewed by the parties to determine if regular employees can perform the work before laying off full or part-time employees.

1.4.3 The Company agrees to meet with the Union if it is considering laying off bargaining unit employees for any reason.

Section 1.5 Pay Guarantee

Pay for regular employees in jobs that are affected by work redesign, regional lack of work, or certain disability situations, will be guaranteed at no less than their current rate of pay, as provided for in Section 11.4 within this Agreement.

ARTICLE 2
GENERAL PROVISIONS

Section 2.1 Application and Coverage

2.1.1 **Definition of Bargaining Unit**

This Agreement applies to and covers NW Natural Gas Company individuals who are employed in the jobs shown in the Job Titles by Group list of this Agreement. The terms of this Agreement do not extend to any NW Natural affiliate.

2.1.1.1 It is not the intent to have Supervisors perform the job duties of bargaining unit employees except in circumstances such as training, testing, inspection(s)/QA, a threat to public safety or emergency (e.g., inclement weather, volcanic eruption, earthquake, hazardous material release, or other natural or man-made disaster or employee absenteeism; excluding scheduled PTO), or in occasional circumstances where needed to support the continuity of local business operations.

2.1.1.2 The Parties agree to a standard process by which all new jobs will be evaluated for inclusion in the bargaining unit.

- This process applies to newly created jobs that do not exist at the Company as of June 1, 2024. This does not apply to the creation of additional numbers of existing jobs (or positions). The Parties will consider the definitions which describe inclusion as a bargaining unit position in the National Labor Relations Act (NLRA) found on the website www.nlrb.gov.

- New jobs at these levels are excluded from possible inclusion in the Bargaining Unit: Executives, Directors, Managers, and Supervisors with direct reports as well as jobs that require advanced formal education (e.g., Financial Analysts, Attorneys, Human Resource Professionals). New jobs involving a high level of confidentiality will be excluded from consideration. Company-sensitive strategic, financial, and working with private individual employee data are examples of types of confidentiality.

- The Company will meet with the Union to review its analysis of the new jobs and to obtain the Union's input following the requirements of

2.1.1.2 of this agreement. However, it is ultimately the Company who will make the decision as to whether the new jobs should be included in the bargaining unit and will inform the Union of the final decision. If the Union disagrees with the Company's decision, they may pursue any avenue already available.

2.1.2 Employee and Other Worker Definitions

2.1.2.1 Employee

An employee is a common-law employee of the Employer whose job is within the bargaining unit as defined in 2.1.1 to this Article.

2.1.2.2 Regular Employee

A regular employee is an employee who is employed by the Employer to work on a full or part-time basis.

- A Full-Time regular employee is a regular employee who is employed by the Employer to work an average of forty (40) or more hours per work week.

- A Part-Time regular employee is a regular employee who is employed by the Employer to fill a continuing work requirement that averages less than forty (40) hours per work week.

- A Job-Share employee is a part-time regular employee who is employed by the Employer to share the responsibilities of one (1) full-time position with one (1) other job-share employee.

    - The incumbent in a job-share position will have a share of a full-time position determined by Management to be appropriate for a job-share arrangement.

    - Both job-share employees must meet the bidding and performance qualifications for the shared position.

    - Work schedules will be agreed to between the job-share employees and will be subject to approval by the workgroup Supervisor.

    - When a job-share vacancy occurs, the position will be first posted as a job-share arrangement. If the job-share vacancy cannot be filled from the posting, then the remaining incumbent will be offered a full-time position. If that is refused, a full-time position will be posted. The remaining incumbent will then be placed into redeployment.

2.1.2.3 **Probationary Employee**

A Probationary Employee is a newly hired or rehired employee in their first year of employment (three hundred and sixty-five [365] calendar days) with the Company. Probationary employees who are regular employees retain all rights and benefits of regular employees under the Collective Bargaining Agreement; except as limited in 4.3.2 and Section 20.1 within this Agreement.

Probationary employees who are term employees retain only the rights and benefits provided to term employees.

If a probationary employee uses protected leave for thirty (30) calendar days or more, the Company may exercise its sole discretion to extend the employee's probationary period by the same number of calendar days.

2.1.2.4 **Term Employee**

A Term Employee is an employee engaged for a limited duration to complete a special project as specifically defined in their Term Employment Agreement. An Intern is a type of employee hired for a limited duration to work in a structured internship program as a BU Term Employee as specifically defined in their Term Employee Agreement. Term employees have only those benefits and rights expressly defined in their Term Employment Agreement.

- The Company will not hire Term employees for the purpose of replacing or restricting the hiring of regular employees for ongoing work. The Company will ensure that Term positions do not limit the advancement opportunities of regular employees. Unless mutually agreed by the LMC Co-Chairs, the duration of a Term position shall not exceed twelve (12) months.

- Term employees do not have regular employee bidding rights. When seeking a regular position, term employees will be considered as external applicants and will be required to complete the full external bargaining unit selection process even if they are seeking a position involving the same type of work as that done while a Term employee.

- Term employees shall be provided the benefits of regular employees only as defined in the Term Employee Agreement.

2.1.2.5 Temporary Worker

A temporary worker is an external agency worker engaged for an assignment lasting for one hundred and eighty (180) or fewer calendar days. Temporary workers are not employees of the Company and do not have Union membership rights or employee benefits. Any extension of a temporary worker on the same assignment beyond one hundred and eighty (180) calendar days requires the mutual agreement of the Parties. The Company may not rotate temporary employees into the position or assignment where there is a need to create a regular position and hire a regular employee.

Any person working in a position covered by this Agreement as a temporary worker must obtain a working permit from the Union after each thirty (30) days worked.

2.1.3 Union Security and Recognition

The Company recognizes the Union as the exclusive bargaining agent for all employees who are classified by the Company in the Job Titles (Schedule A) covered by this Agreement.

2.1.4 Union Membership Requirements

It shall be a condition of employment that all employees covered by this document shall pay dues to OPEIU Local 11, and all new employees shall, on the last calendar day of the month following the beginning of such employment, begin payment of dues and such initiation fee as is customary to the Union.

Upon receipt of a written request signed by an employee, the Company will deduct and remit to the Union dues and other fees from the pay of the employee once in each month and an accounting for such deductions. Such form will be provided by the Union.

In case any Employee shall fail to tender the initiation fee and periodic dues uniformly required as a condition of acquiring or retaining membership (which payment of fees and dues shall be a condition of continued employment), the Union will notify the executives responsible for labor relations. A Company representative will then notify the delinquent employee in writing by the end of their next workday that, unless the executives responsible for labor relations receive from the Union office notification of the employee’s tender of required dues, the employee will be terminated within the next ten (10) working days.

Section 2.2 Management Rights

The Company retains all rights to manage its business and direct its work force, except as those rights are limited by the express and specific language of this Agreement. The Company's rights include, but are not limited to, the right and flexibility to redesign and change its business operations, the work and the workforce; determine the number and nature of positions needed across the Company and by work location; protect and preserve Company property; open and close work locations; contract work*; set schedules; assign and direct work; define work duties, including duties performed within any job description or job family; implement and utilize existing and new automation and technologies; and require that work be performed, including overtime.

*It is the intent and preference of the Company to use women and minority-owned contractors as well as utilize Union contractors whenever practical.

Job descriptions will be maintained for all jobs and positions in the bargaining unit. The Company has the right to change and create jobs and position descriptions. If requested by the Union, the Parties will meet to discuss and determine the impacts to the bargaining unit.

Management's right to contract work out is further described in Section 1.4 within this Agreement. While it is Management's right and responsibility to make business decisions, it is agreed that the Company will discuss the impact of the Company's decision on employees as described in Section 1.3 within this Agreement.

Section 2.3 No Strike, No Lockout

There shall be no strike, work stoppage, work slowdown, sympathy strike, lockout, or other interruption of work during the life of this Agreement. The Union shall take every reasonable means within its power to prevent such occurrences and induce employees engaged in or supporting any such prohibited conduct to cease such activity.

Any member of OPEIU Local 11 employed by the Company who recognizes a lawful primary picket line sanctioned by OPEIU Local 11 shall not be disciplined for recognizing that picket line, notwithstanding the provisions of this Article, provided that such employee shall have no greater rights under law or contract than does a striking employee.

Section 2.4 Union Member Time Off

The Union's Stewards shall be allowed time off with pay to investigate and present issues/grievances as necessary to fulfill their duty of fair representation. Whenever possible, such time shall be scheduled in advance with the Steward's Supervisor to minimize the impact on business operations.

The Parties shall meet with the Union Stewards and Management representatives after the ratification of this Agreement to provide joint training on all modifications of this Agreement.

Upon written request from the Union, members shall be given short-term leaves of absence to transact Union business and be paid by the Union. An employee covered by this Agreement who is elected, appointed or hired to an office in the Union requiring a long-term leave of absence from the Company, shall, upon two (2) weeks' written notice, be granted a voluntary leave of absence without pay not to exceed two (2) years.

Section 2.5 Union Bulletin Boards

The Company will make available space on its bulletin boards for the posting of Union notices and bulletins.

Section 2.6 Compliance with Laws Governing the Workplace

The Union shares the Company's commitment to maintaining a business in compliance with all applicable laws governing the workplace, ensuring an environment free from discrimination, harassment or retaliation and supporting business and workplace decisions promoting diversity.

The Company agrees not to discriminate or retaliate against any member of the Union for their activity on behalf of or because of membership in the Union.

The Company promptly investigates and addresses complaints regarding discrimination, retaliation, or harassment. The Union recognizes the importance of the prompt and effective investigation and resolution of such complaints and will support and cooperate with the Company in the Company's investigation and resolution of such complaints.

Section 2.7 Modifications and Agreements

2.7.1 The Parties with mutual agreement have the right to renegotiate the Agreement in the event there are external events or significant business changes which in the opinion of either party require renegotiation of the Agreement. Amendments to this Agreement are made by a Memorandum of Agreement (MOA), must be in writing, agreed to, and signed by both parties.

The language described above does not have the intention of opening the entire Collective Bargaining Agreement for negotiations.

2.7.2 Interpretations regarding this Agreement are outlined and assigned at the direction of the LMC Co-Chairs. This assignment shall be given to bargaining unit members, management, and subject matter experts; who shall review the contract language and clarify the intent within the Agreement; and which shall be submitted to the Company and Union Leadership for approval.

2.7.3 A Memorandum of Agreement is a written document signed by both the Union and the Company Executive Sponsors that states what the Union and the Company agree to when they reach agreement on something other than what is stated within the Collective Bargaining Agreement. Memorandums of Agreement can remain in effect for the duration of the current Agreement or may be limited to a specific period of time, or incorporated into the Collective Bargaining Agreement upon opening for negotiations.

2.7.4 Except as expressly noted otherwise, this Agreement supersedes all prior CBAs, Joint Accords, Joint Accord Guidelines (JAGs), Interpretations, and Memorandums of Agreement. To the extent the terms of this Agreement were to conflict with any other agreement, the terms of this Agreement control.

Section 2.8 Labor/Management Committee

The Labor/Management Committee or LMC shall be organized for the purpose of addressing contract issues, clarifying the intent of the labor contract, monitoring for unanticipated consequences of the labor contract and anticipating change. The LMC will consist of up to ten (10) members from the Union and ten (10) members of from the Company. Members are inclusive of the LMC Leadership Team, Management employees, Stewards, and Chief Stewards. The Committee shall meet monthly at a mutually agreed location, time, and date, and with an outlined agenda set by the LMC Co-Chairs. Meetings may be cancelled by the mutual agreement of the LMC Co-Chairs. The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the contract.

ARTICLE 3
SENIORITY

Section 3.1 Company Seniority

Company seniority is established on the date of hire or rehire as a regular employee. When multiple regular employees are hired on the same day, Company seniority is then established based on name at date of hire in ascending alphabetical order of last name, then first name.

Any previous regular employee who was separated due to disability (industrial or non-industrial) and is subsequently awarded or placed in a position under Article 15 within this Agreement is eligible for adjusted seniority abridgement of Company seniority.

Section 3.2 Job Seniority

Job seniority is based on the days that a particular job is held. When multiple regular employees have the same number of days the job was held, the ranking will be based on Company seniority. Job seniority is only accumulated for jobs that are not in a Line of Progression.

Section 3.3 Line of Progression Seniority

Line of Progression seniority is based on the days that any job within that Line of Progression is held. When multiple regular employees have the same number of days in the Line of Progression, the ranking will be based on Company seniority. For jobs in a Line of Progression, job seniority is not accumulated.

Section 3.4 Term and Intern Employee Seniority

3.4.1 Term and Intern Employees do not accrue seniority while in Term employment status; however, if subsequently hired as a Regular Employee with no break in service, Company Seniority will be established on the date of hire as a Term or Intern Employee.

3.4.2 Job or Line of Progression seniority (as applicable) is calculated for positions involving the same type of work as that done as a Term or Intern Employee.

Section 3.5 Job and Line of Progression Seniority Accumulation

Accumulation of seniority is based on straight-time days of employment. For full-time regular employees, this is equivalent to five (5) eight-hour workdays per seven (7) calendar days. For part-time regular employees, seniority will be accumulated at seventy-five percent (75%) of the rate of full-time regular employees.

Section 3.6 Seniority Retained

Seniority accumulated by a regular employee in a job or in a Line of Progression is retained. Any employee who leaves the bargaining unit or ends employment will not retain any job, Line of Progression, or Company seniority. Any previous regular employee who was separated due to disability (industrial or non-industrial) and is subsequently awarded or placed in a position under Article 15 within this Agreement is eligible for adjusted seniority abridgement of Company seniority.

Section 3.7 Application of Seniority

For the application of seniority, refer to the appropriate articles within this Agreement.

Section 3.8 Line of Progression and Job Seniority Calculations

The process of seniority calculations related to the definitions under this Agreement shall be as follows:

3.8.1 Name changes after the date of hire will not impact a regular employee’s seniority ranking or subsequent seniority calculations.

3.8.2 Regular employees who receive a fourteen (14) calendar day award will earn seniority in both the new job and the old job until they start in the new job.

3.8.3 Regular employees who hold a Combo Position earn seniority in each distinct job that makes up their Combo Position.

3.8.4 Regular employees who fail to qualify for a job for reasons within their control (e.g., bidding to another job or failing to qualify) will not earn any seniority for that job.

3.8.5 Regular employees on a Long-Term Special Assignment (LTSA) earn seniority in the temporary job and continue to earn seniority in their regular job.

3.8.6 Regular employees on a Short-Term Assignment only earn seniority in their regular job.

3.8.7 Regular employees on a Temporary Development Opportunity (TDO) do not earn seniority in their regular job.

3.8.8 During a leave of absence, a regular employee will continue to earn seniority.

3.8.9 A temporary, unplanned reduction in work resulting in an interruption of paid status will not interrupt a regular employee's seniority calculation.

3.8.10 Regular employees in redeployment due to a work redesign or a bump will continue to earn seniority in the job from which they were redeployed until they secure a new regular job.

3.8.11 Positions that become obsolete or honored will be mapped to a current job or Line of Progression and applicable seniority credited to regular employees who hold those positions accordingly.

3.8.12 Regular employees who exercise a right to return will not earn seniority in either the new job or the old job to which they return for the duration of the transfer to the new job in accordance with Article 4 within this Agreement.

ARTICLE 4
SELECTION AND ASSIGNMENT

Section 4.1 General

This Article describes the selection and assignment provisions and processes for regular employees. Term employees are not eligible for these provisions or processes, as explained in the Term Employee Agreement.

Section 4.2 Definitions

All bargaining unit job descriptions, including general task bars, will be maintained by the Company. The Company has the right to change and create job descriptions. Upon completion, the Company will notify the Union of substantive changes to existing job descriptions and newly created job descriptions. Substantive changes will follow the review process outlined in Section 11.3. All job descriptions and General Task Bars are made available on the Company intranet site.

- Job: A paid role of employment.

- Job Title: Describes the occupation, function, and, if applicable, the level of a job if part of a larger job family.

- Job Description: Written documentation of a job title that may include general purpose, job requirements, position specific essential functions, and requirements for a particular job.

- Job Family: A group of jobs that are related because of similar job content, skill requirements, and/or career paths.

- General Task Bar: A list of tasks that everyone in a Job Family can be expected to perform, with training, as needed.

- Position: Role within the organization that is assigned a job title and used for headcount management. All employees are assigned to a position and job title.

Section 4.3 Postings and Consideration of Bids

4.3.1 When a position has been approved, the position will be posted Company-wide for seven (7) calendar days. Open and available positions are posted on the Company's intranet. It is every employee's responsibility to check the intranet on a regular basis for postings upon which they may want to bid. The intranet shall be available to access at all resource centers or remotely on the Company device/application.

4.3.2 All applications received from regular employees* prior to the expiration of a posting shall be considered in accordance with the Position Posting and Bidding Company policies, processes and procedures. Probationary employees will only be allowed to apply as external candidates.

*Regular employees already in the Construction line of progression at the resource center where a posted position in Construction is located are considered auto-bidders and automatically included in the bidding process. If an auto-bidder declines an award, must sign a Progression Waiver (existing rate retention will be forfeited). When bidding between Distribution and Transmission Construction, auto bidding does not apply.

4.3.3 The internal bidding and selection process applies for bidding and/or selection of non-probationary regular employees to fill regular, term and Long-Term Special Assignment (LTSA) bargaining unit positions that have been approved by the Company. This process applies to the bidding and selection process for non-probationary regular employees bidding on internal bargaining unit positions. This process is also used to determine if displaced employees meet bidding qualifications when being assigned/placed into a bargaining unit position through redeployment and/or when an employee is bumping into a position.

4.3.4 The Parties agree to use and continue to refine the currently agreed to internal bidding and selection processes as outlined in the Internal Bidding and Selection Process Company policies, processes and procedures.

4.3.5 Employees who are off on Paid Time Off (PTO), Short-Term Disability, Long-Term Disability, Workers' Compensation, unpaid active status, or protected leave as defined under Federal, State or local law; or by Company policy for an entire posting period shall be eligible to submit a bid on any posted position within the seven (7) calendar days following the expiration of the posting period in accordance with the Position Bidding and Award Eligibility for Regular Employees Company policies, processes and procedures.

Section 4.4 Position Awards

Seniority and qualifications will be considerations in awarding a posted position. With agreement between the Parties, certain positions will be awarded based on qualifications first and then seniority. Bidders will be considered for posted positions regardless of their currently assigned Company-based location except as provided for in Section 4.9 of this Article.

Position awards will be published within fourteen (14) calendar days of acceptance by the employee. Employees will be moved to the new position as soon as possible, usually within twenty-one (21) calendar days of accepting the award.

- Extensions to the above timelines from twenty-two (22) calendar days up to a maximum of one hundred and twenty (120) calendar days may be made after discussion with the employee and upon mutual agreement between the releasing and receiving Supervisors.

- Employees not in the new position after fourteen (14) calendar days from the position award will receive any applicable pay increases and begin accumulating either Job seniority or Line of Progression seniority as of the fourteenth (14th) calendar day from the employee's acceptance of the award.

The following are the principles that apply when awarding positions for: Open Jobs, Line of Progression Jobs, and Jobs involving Progression without Bidding (unless otherwise agreed that the position is selected on qualifications first and then seniority).

4.4.1 **Open Positions**

An open position is one that, if posted, all regular employees are eligible to bid. These positions do not include those within a Line of Progression or Progression without Bidding except at the entry level. Qualified bidders will be awarded positions based on seniority in the following order:

- Job seniority for the position posted for bid, then
- Company seniority.

4.4.2 Line of Progression (LoP) Jobs

A LoP is a sequence of specifically related jobs that require successively higher skills to advance sequentially to the next higher position. The following are the currently recognized LoPs:

- Construction (2, 3, 4)
- Customer Field Service (2, 3, 4)

LoP jobs may be added to, or removed from, or changed with mutual agreement of management and the Union during the life of the contract.

Qualified bidders will be awarded positions based on seniority in the following order:

- Line of Progression seniority in the line of the position posted for bid, then
- Company seniority.

Advancing in a LoP requires that a regular employee meet all the qualifications, certifications, and training for the current level prior to being eligible to move into a vacant and available position at the next level. Regular employees in a LoP earn days toward rate retention when they work up.

4.4.3 Qualification Based Progression

Certain jobs are posted based on business need and awarded based on qualifications regardless of Company, Job, or Line of Progression seniority. Additional jobs may be added to the qualifications based process by mutual agreement between management and the Union. The parties agree that when filling vacancies or promotional opportunities, the goal is to encourage growth and opportunity for advancement from within and to hire the most qualified candidate for the position. When, in the judgment of the hiring manager and Human Resources Department, sufficient candidates who apply from within the Company are qualified, available and interested, the recruitment may be restricted to internal candidates.

The current jobs are:

- Accounting 4
- Customer Service 4
- Construction 4
- Customer Field Service 4
- Gas Storage 1
- General Services 4
- Transportation 3
- Transportation 4
- Welding & Fabrication 4

4.4.4 **Jobs Involving Progression without Bidding**

Employees will progress based on meeting the qualifications and performance standards for the higher-level job. Jobs may be added to, removed, or changed by mutual agreement between management and the Union. Progression may be limited by position availability. In this case, the most senior qualified person will progress, based on seniority in the following order:

- Job seniority in the lower position, then
- Company seniority.

The jobs involving Progression without Bidding are:

- Accounting = Accounting 2 to 3
- Account Services = Accounting 2 to 3
- Customer Field Service 2 to 3 in Astoria / Warrenton, Coos Bay, The Dalles, Lincoln City
- Customer Service 2 to 3
- Distribution Arc Welder 1 to 2
- Electronic Technician 1 to 2
- Gas Storage 1 to 2
- GIS Tech 1 to 2; 2 to 3
- Specialty Construction 1 to 2
- System Operations 1 to 2
- Technical Coordinator 2 to 3
- Transmission Maintenance 1 to 2
- Transportation 1 to 2

Some of the above workgroups have specific rules for progression without bidding. In the absence of such rules, the default criteria for progression will be the accumulation of working two hundred and sixty (260) days at the higher-level position with satisfactory performance.

4.4.5 **Qualifying Standards**

An employee awarded a new position must satisfy the Performance Qualifying Standards during the established qualifying period per Article 5 within this Agreement.

Section 4.5 Right to Return to Former Position

Employees have sixty (60) calendar days after reporting to a new and different position to voluntarily return to their former position. This right provides a one-time ability to return for any reason. An employee wanting to return to a former position must have previously qualified in order to return to that position. Any subsequent request to return to their former position within a rolling five (5) year period from the date of award must be mutually agreed upon by the

Parties. Employees who exercise their right to return within five (5) workdays will not be subject to the five (5) year restriction. An employee may relinquish their right to return at any time. Written notification will be sent to Human Resources (Talent Acquisition).

An employee still retains the right to bid on any position posting at any time. The employee will not continue to accumulate Job or Line of Progression seniority while they are away from the former position.

Right to return to former position does not apply to situations where movement is to the same position at any location.

Section 4.6 Waivers

A waiver is a mechanism for an employee to voluntarily return to a former position or to forego advancement. In all cases of waiver, the employee will be paid the applicable rate for the position waiving into, and is waiving rate retention and all days currently earned towards rate retention.

In a Lack of Work situation, restrictions on returning to a waived position are removed. There are two (2) types of waivers: Progression (Advancement) Waivers and Position Waivers. The waiver definitions and processes are as described herein.

4.6.1 **Progression (Advancement) Waiver**

An employee elects to forego advancement (move up and/or work up). An employee who waives advancement is also waiving working up. When exercised, the employee waives the right to advance to a specific opening, but does not waive the right to advance should a subsequent posting/work-up opportunity occur. For convenience, this waiver is considered in effect until “pulled” by the employee (by notifying their Department and Human Resources in writing). For Progression Waivers related to a declined auto-bid award, there is a minimum of one (1) year term before the waiver can be pulled. There is no duration requirement for other Progression Waivers.

4.6.2 **Position Waiver**

An employee elects to vacate a position to return to a lower rated position at the same resource center for which they previously qualified. A Position Waiver has a minimum one (1) year term. After one (1) year, the waiver remains in effect until “pulled” by the employee (by notifying their Department and Human Resources in writing). Employees who wish to return to the waived position may bid (or progress in the case of Progression Without Bidding or Qualification Based Progression) to an opening of that position.

The Chief Steward and Manager for the requesting employee approve this waiver and shall meet to discuss.

Section 4.7 Workplace Location Exchange

Employees may request a workplace location exchange by completing a “Workplace Location Exchange Request” form. Human Resources will notify the Chief Stewards and the Union office of the finalized exchange including the nature of the exchange (lateral or non-lateral), qualifying periods, pay rates, and effective dates.

Section 4.8 Retention of Higher Rate

4.8.1 Jobs awarded based on qualifications are not eligible for rate retention.

4.8.2 When an employee in a Line of Progression position is working up a grade, the employee will be paid at the entry level rate for the first two hundred and sixty (260) working days. Once an employee in a Line of Progression position has worked up a grade for two hundred and sixty (260) working days, the employee will continue to receive the higher rate of pay at the experienced level, until such employee leaves their position or signs a Progression Waiver.

4.8.3 When an employee with less seniority in a Line of Progression works up a grade ahead of a senior employee in the same Line of Progression at the same Company-based location, the most senior employee will also be paid entry level at the higher rate for the day, except when the less senior employee is working up into a qualifications-based job (e.g., Construction 4).

4.8.4 If a less senior employee at the same Company-based location reaches rate retention prior to a senior employee at the same Company-based location in the same Line of Progression because the senior employee was on a Short-Term Assignment, the senior employee will be designated as rate retained.

4.8.5 When working up into qualification-based jobs, only the employee working up is paid the higher rate for the day.

Section 4.9 Temporary Positions / Internal Assignment of Employees

4.9.1 **Short-Term Assignment of Employees**

Employees may be temporarily assigned for one hundred and eighty (180) calendar days or less per calendar year to a position for which they qualify or may be trained based on Company needs. Any individual employee assignment longer than one hundred and eighty (180) calendar days shall be by mutual agreement of the Parties. The Chief Stewards and Union will be notified by management no later than the start of any Short-Term Assignment expected to last longer than seven (7) calendar days.

An employee who is assigned to perform a higher-grade position will be compensated at the higher of the employee’s current or assigned rate for the hours worked at that rate up to four (4) hours of the day. An employee who works four (4) hours or more is paid for the full day at the higher rate.

Employees will continue to accumulate Job or Line of Progression seniority in their regular position during such assignments.

An employee returning from an authorized leave of absence may be temporarily assigned to other work regardless of seniority.

4.9.2 **Long-Term Special Assignment**

A Long-Term Special Assignment (LTSA) is a posted special, voluntary work opportunity that is up to twelve (12) months in length. Requests for extensions beyond the initial term will be mutually reviewed and agreed upon by the Parties. All LTSAs are subject to the following:

- An LTSA is not a replacement for a vacant regular position. Recurring LTSAs shall be reviewed by the Parties to determine whether there is a need for a regular position; the Union may include a Chief Steward for the review. The term “voluntary,” as used here, means that either the employee or the Company may end the LTSA at any time for any reason.

- Because an LTSA goes through the post, bid and award process, the pay rate for the LTSA will apply in all situations. If the LTSA is a lateral move, the employee will retain their current pay rate. An employee bidding from a higher paying position will not retain that higher pay rate while in the LTSA position; they will receive the experienced level of the lower position.

- At the conclusion of the LTSA, the employee will return to their original position. While in the LTSA, the employee will be included in any work redesign, as it may occur, that might affect their regular position.

- If there are no qualified bidders, the position will be temporarily assigned based on this Article.

4.9.3 **Assignment to Non-Bargaining Position - Temporary Development Opportunity (TDO)**

The Company’s TDO procedure applies with respect to the assignment. The employee will continue to retain Union membership status (including benefits) and pay Union dues. Per 3.8.7, Regular Employees on a TDO do not earn seniority in their regular job. The Company will notify the Chief Stewards and the Union no later than the start of the non-bargaining assignment.

ARTICLE 5
PERFORMANCE QUALIFYING STANDARDS

Section 5.1 General

Employees must acquire and maintain Performance Qualifying Standards per these four (4) following processes:

- Failure to Qualify During Qualifying Period
- Failure to Maintain Performance Qualifying Standards
- Field Operations Testing Failure to Qualify
- Welding Procedure to Recertify

Section 5.2 Failure to Qualify During Qualifying Period

5.2.1 **Application**

The process outlined below applies when a regular employee is failing to meet performance-qualifying standards during the qualifying period for that position.

5.2.2 **Process**

5.2.2.1 Employees may exercise their right to return per Section 4.5 within this Agreement.

5.2.2.2 Employees ineligible for a right to return may:

- Return to original position if previously qualified and position is still vacant.
- Return to previous status when outside of a regular position (e.g., redeployment, leave of absence due to Failure to Maintain Performance Qualifying Standards). If original status was a leave of absence resulting from Failure to Maintain Performance Qualifying Standards or a third Testing Failure, employee's leave of absence will be restarted from the point at which it had been paused at the time of the employee's successful bid (See Failure to Maintain Performance Qualifying Standards and Field Operations Testing Failure to Qualify process within this Article).
- Return to the department if the position is not vacant and the department can absorb the employee, as determined by Management.

5.2.2.3 If no job is available, the employee will be placed in the redeployment process at the pay group and pay rate of the job in which the employee last qualified, or Pay Group O Experienced Pay Rate if never previously qualified, or Pay Group M Experienced Pay Rate if prior status was a third testing failure on a new task or content area and Paid Time Off (PTO) is exhausted (See Redeployment Process in Section 7.3 within this Agreement).

Section 5.3 Failure to Maintain Performance Qualifying Standards

5.3.1 Application

This process applies to regular employees who have successfully completed the qualifying period and who are subsequently unable to maintain performance qualifying standards for a position.

For failure to qualify situations involving Operator Qualifications or welding, refer to the Field Operations Testing Failure to Qualify process within this Article or Welding Procedure to Recertify within this Article, as appropriate.

5.3.2 Process

After the employee has received coaching and direct performance feedback, which may include a Performance Development Plan (PDP), and still does not maintain performance qualifying standards, the following occurs:

5.3.2.1 A Failure to Maintain Performance Qualifying Standards Disciplinary Action Plan (DAP) will be utilized and will specify:

- The changes that must occur for the employee to meet standards;
- The timeline for the employee to accomplish those changes. (The DAP should generally be no longer than the qualifying period for the employee’s position. If the DAP is longer than the qualifying period for the employee’s position, it must be approved by the LMC Co- Chairs and must be signed by the Manager and Union Representative.); and
- Consequences if the employee does not meet the requirements of the DAP.

5.3.2.2 The employee may:

- Bid on any open positions (if any are available) for which they meet bidding qualifications; and/or
- Apply for a position waiver in accordance with Section 4.6 within this Agreement.

5.3.3 If the employee does not successfully complete the DAP:

- The employee will be placed on leave for a period equivalent to one (1) month per year of service during which time they may bid to an open posted position (other than the position from which they were disqualified) for which they meet bidding qualifications; and

- The employee will use Paid Time Off (PTO) until PTO is exhausted; then the employee will be placed on leave without pay; and

- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

Section 5.4 Field Operations Testing Failure to Qualify

5.4.1 **Application**

This Section outlines the process to be followed when a field operations employee fails to pass required testing for their current job, including but not limited to testing related to Operator Qualifications (OQ).

5.4.1.1 This process covers:

- The consequences after each failure of a required test;

- The criteria that must be met before an employee can attempt to retest;

- The time intervals between testing opportunities; and

- The resources available to the employee.

5.4.1.2 This process does not apply to:

- Testing that is part of initial position training (Refer to the Failure to Qualify During Qualifying Period process within this Article or department guidelines);or

- Performance issues identified on the job (Refer to the Failure to Maintain Performance Qualifying Standards process within this Article or Failure to Qualify During Qualifying Period process within this Article, as appropriate); or

- Weld testing (Refer to the Welding Procedure to Recertify within this Article, as appropriate).

5.4.1.3 Certification testing provided by outside agencies may be covered by this Article as determined appropriate.

5.4.2 **Process**

At any point during this process, the regular employee has the option to do any of the following, if applicable:

- Bid to an open position, if available, for which they meet bidding Qualifications;
- Apply for a Waiver per Section 4.6 within this Agreement, as available, or
- Exercise their right to return to a former position per Section 4.5 within this Agreement.

5.4.3 **First Failure**

5.4.3.1 Employee is immediately restricted from performing the task or associated task(s) (e.g., tasks connected to a failed Abnormal Operating Condition [AOC]), unless directed by a qualified worker, as permitted and approved by management. If the employee will not be directed by a qualified worker, the employee will be assigned work that does not involve performing the associated task(s) for which they are now unqualified, if such work is available.

5.4.3.2 The employee will be provided focused training on the tasks or AOCs, which may include individual review, training, and/or time to practice or study as deemed appropriate by a training representative, with consideration of input from the employee. Training will be documented on the FTQ Training Documentation form.

5.4.3.3 On the day of first failure:

- Employee may be afforded additional time to prepare (e.g., receive training or study) for retesting, as necessary.
- Employee may choose to utilize PTO or leave without pay, as appropriate, for rest of shift. Such PTO will be approved without penalty.

5.4.3.4 The employee must be scheduled to retest at a minimum next shift and maximum of fourteen (14) calendar days, excluding scheduled PTO or approved leave. Within this timeframe and with regard to input from the employee, a training representative will schedule retesting. Any exceptions to minimum or maximum time to retest must be approved by the Training Manager or designee.

5.4.4 **Second Failure**

5.4.4.1 Employee restriction from performing the associated task(s) continues, unless directed by a qualified worker, as permitted and approved by management. If the employee will not be directed by a qualified worker, the employee will continue to be assigned work that does not involve performing the task(s) for which they are now unqualified, if such work is available.

5.4.4.2 Prior to retraining, the employee will have a meeting with their Supervisor, a Union Steward if one is requested, and a representative from Human Resources (HR) to review this Article and discuss concerns and options.

5.4.4.3 The employee will be provided focused training on the tasks or AOCs, which may include individual review, training, and/or time to practice or study as deemed appropriate by a training representative, with consideration of input from the employee. The employee may request to waive the focused training session. Training will be documented on the FTQ Training Documentation form.

5.4.4.4 The employee must be scheduled to retest at a minimum seven (7) calendar days and maximum of thirty (30) calendar days, excluding scheduled PTO or approved leave. Within this timeframe and with regard to input from the employee, a training representative will schedule retesting. Any exceptions to minimum or maximum time to retest must be approved by the Training Manager or designee.

5.4.5 **Third Failure**

5.4.5.1 If the employee is in their qualifying period, see Failure to Qualify During Qualifying Period process within this Article. If the previous position held by the employee requires the same task, then the employee moves into redeployment.

5.4.5.2 If the employee is not in their qualifying period:

- Following third failure of a required test for requalification (i.e., employee has previously passed testing and was “qualified”).

- Employee will be placed on leave for a period equivalent to one (1) month per full year completed from date of hire, during which time they may bid to an open position (other than the position for which they were disqualified) for which they meet bidding qualifications.

- Employee will use all accrued and banked PTO until PTO is exhausted; then employee will continue on leave without pay.

- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

Following third failure of a required test on a new task or content area introduced to an incumbent's position:

- Employee will be placed on leave for a period equivalent to one (1) month per full year completed from date of hire, during which time they may bid to an open position (other than the position for which they were disqualified) for which they meet bidding qualifications.

- While on leave, the employee may be assigned to temporary work, as available. Assignments of temporary work will not exceed one (1) month per year of service up to a maximum of twelve (12) months from the date of the third (3rd) failure. Days assigned to temporary work do not extend the length of the leave of absence.

- Employee will use all accrued and banked PTO until PTO is exhausted; then the employee will continue on leave without pay.

- Once PTO is exhausted, the employee is removed from their current position and will be reclassified to Pay Group M, Experienced Pay Rate. Employee continues to accumulate only Company seniority.

- While performing temporary work, additional PTO will be accrued at Pay Group M. When temporary work is not available, the employee will use additional accrued PTO until PTO is exhausted; then the employee will be returned to leave without pay.

- Employee will not be eligible for preferential bidding, redeployment, or bumping as a result of this process.

- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

5.4.6 An employee who has successfully bid to another job or exercised the waiver option at any point during this process may reapply for the position (if available) after a period of one (1) year if the employee can demonstrate that a substantial change has occurred making it possible for the employee to qualify, based upon management's approval.

Section 5.5 Welding Procedure to Recertify

5.5.1 **Application**

This procedure applies to all regular employees who are required to maintain Welding qualifications. This procedure covers failure on any of the following Welding tests:

- Requalification Testing
- Probable Cause Testing
- Random Testing

It is the employee's responsibility to actively participate in this process.

5.5.2 **First Failure**

- Employee is immediately restricted from performing the task.
- Employee is issued Welding Documented Verbal Warning.
- Employee does not earn days toward Experienced rate, if at Entry rate.
- Employee is provided a minimum of eight (8) hours of formal, paid, documented training.
- The minimum time to retest is the second (2nd) business day after failure. Maximum time to retest is fourteen (14) calendar days after failure. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.5.3 **Second Failure**

- Employee restriction from performing the task continues.
- Refer to "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" process. Employee issued Welding DAP.
- Employees at the Experienced rate return to Entry rate of their current grade.
- Employee is provided a minimum of eight (8) hours of formal, paid, documented training.
- The minimum time to retest is fourteen (14) calendar days after failure. Maximum time to retest is thirty (30) calendar days after failure. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.5.4 **Third Failure**

- Refer to “Failure to Maintain Performance Qualifying Standards” or “Failure to Qualify During Qualifying Period” processes within this Article.
- Loss of position.
- One (1) year minimum from loss of position to bid on open Welding position.

ARTICLE 6
WORKING CONDITIONS

Section 6.1 Schedules and Overtime

This Article recognizes the fact that the Company must provide uninterrupted continuous service to our customers, twenty-four (24) hours per day, seven (7) days per week, as a matter of public safety and health. In accordance with Article 2 within this Agreement, the Company retains the right to manage the business and direct the work and workforce, including the right to determine schedules and require overtime, subject to the rules listed below.

6.1.1 **General Definitions and Rules**

6.1.1.1 Workweek: For the purposes of calculating overtime and establishing schedules, the seven (7) day workweek for all employees begins at 12:01 a.m. on Monday.

6.1.1.2 Work Schedule: For most employees, a regular full-time schedule will be five (5) workdays of eight (8) hours duration; including two (2) consecutive days off. Some work groups have alternate schedules which may be required by Management based on business needs. Work schedules define the workdays and shifts and shall be documented by each department and/or workgroup as appropriate and will be made available to all employees on the Company intranet.

Employee selection process guidelines for work outside a typical schedule, such as 6th and 7th day, night work, or out of town work, will include recognition and application of Job Seniority, and will be made available to all employees on the Company intranet.

6.1.1.3 Workday: Each employee’s workday begins at the start of their shift and continues for twenty-four (24) hours or until the beginning of their next shift, whichever is sooner. For payroll purposes, all hours worked on a workday will be paid based on the start of the shift.

6.1.1.4 Shift: An employee's shift is defined as scheduled working hours within a workday.

6.1.1.5 Shift types are defined based on the scheduled start time as follows:

Shift Type	Start Time
Day Shift	06:00 a.m. – 9:59 a.m.
Swing Shift	10:00 a.m. – 5:59 p.m.
Graveyard	06:00 p.m. – 5:59 a.m.

6.1.1.6 For work groups that operate a 24/7 schedule, starting times will be rotated as equitably as practicable between members of the same position.

6.1.1.7 Work groups that offer shift bid opportunities will do so at least annually to eligible workers in Job Seniority order. Processes will be developed and documented by department and/or work group as appropriate and will be made available to all employees on the Company intranet.

6.1.1.8 The Parties agree that there shall be a minimum of an eight (8) hour period between scheduled shifts.

6.1.1.9 An employee who reports for work on a regularly scheduled workday and is then sent home for lack of work shall be paid for their entire scheduled shift at the rate such employee would have received if they worked.

6.1.1.10 Unless otherwise stated within the Agreement, overtime is calculated on actual hours worked, not hours paid. The calculation of time worked for overtime purposes shall include paid leave, paid rest period, holidays, floating holidays, and PTO used.

6.1.1.11 If pay is due to an employee under two (2) or more provisions under this Article, only the highest payment required under any provision of this Article shall be paid. This should only be used when a situation is ambiguous and all Articles within the Agreement have been reviewed.

6.1.1.12 Employees will not be required or expected to perform any work before their designated start time or after the end of their shift without compensation.

6.1.2 Flexible Schedules/Work Arrangements

6.1.2.1 An employee may work a flexible work schedule (e.g., four [4] ten-hour days), flex start and end times of their shift, and/or make up lost time in their work schedule within the same workweek if mutually agreed upon by the employee and Management. Not every Flexible Schedule/Work Arrangement option will be available for every work group, position, or employee and approval of a flexible schedule/work arrangement will be at the Manager's discretion. Company policies and department guidelines will define specific and/or additional requirements for a flexible schedule/work arrangement.

6.1.2.2 If an employee requests a temporary flexible work schedule, this temporary schedule is not considered a regularly scheduled workweek and Saturday/Sunday and Shift Work premiums will not apply for the shift(s) impacted by the temporary schedule change.

6.1.2.3 Remote Work. An employee may request to work remotely, which allows a reporting location off Company property. An employee who is working remotely must log in to the appropriate Company software systems at the employee's scheduled start time. The remote work location is not considered a fixed official work location/station. Remote work will not be available for every work group, position, or employee. Hybrid work schedules will be approved on a case-by-case basis. Flexible Work Company policy and department guidelines will define specific and/or additional requirements for working remotely and will be made available to all employees on the Company intranet.

6.1.3 **Unplanned Schedule and Shift Changes**

6.1.3.1 **Unplanned Schedule Changes**

Changes in an employee's scheduled workdays affecting the employee's scheduled days off made with less than forty-eight (48) hours advance notice are considered Unplanned Schedule Changes and hours worked shall be paid at the applicable overtime rate.

6.1.3.2 **Unplanned Shift Changes**

Changes in an employee's scheduled working hours (i.e., shift) made with less than twelve (12) hours notification prior to the start of the new shift are considered Unplanned Shift Changes and include:

- When an employee meets the conditions for a rest period under 6.1.6 within this Article and is required to return to work before the end of the employee's eight (8) hour rest period, all hours worked are considered an Unplanned Shift Change and paid per 11.5.1.

- After the start of an employee's shift, if an employee is released and rescheduled for a later start time, all hours worked are considered an Unplanned Shift Change and paid per 11.5.1.

6.1.3.3 Unplanned Shift Changes are not eligible for schedule-based premium pay rates.

6.1.3.4 It is not an Unplanned Shift Change when a Call-In extends into the regularly scheduled shift.

6.1.4 **On-Call Assignment**

6.1.4.1 On-Call Assignments shall be filled between the qualified resource center, department and/or workgroup employees as equitably as practicable; qualified employees are those identified by Management as having the necessary skills to handle emergency response work.

6.1.4.2 If employees are assigned a Company vehicle for the purposes of emergency response when On-Call, travel to and from work is not considered commuting for the purposes of 6.1.3.2 nor is it considered paid time. Employees working On-Call Assignment are required to accept any Call-Ins.

6.1.4.3 Employees are responsible for the accuracy of their contact information. On-Call guidelines shall be documented by each department and/or workgroup as applicable and will be made available to all employees on the Company intranet.

6.1.4.4 An On-Call Assignment on an employee’s regularly scheduled workday begins at the end of the employee’s regular work shift including overtime worked beyond the end of the employee’s regular shift and ends at the start of the employee’s next shift the following day. An On-Call Assignment on an employee’s scheduled days off begins at their normal shift start time and ends after twenty-four (24) hours or the start of the employee’s next regular shift.

6.1.4.5 If an employee has an On-Call Assignment for which the Company provides lodging, the Company will provide a minimum of eight (8) hours work for the employee on the assigned day. Current guidelines for establishing On-Call Assignments will be utilized.

6.1.4.6 Pay for On-Call Assignment will be in accordance with 11.5.3 within this Agreement.

6.1.5 **Call-In**

6.1.5.1 When an Employee is notified to report for emergency, immediate or unplanned work either before or after completion of the employee’s shift, or on a scheduled day off, the time worked shall be considered a Call-In.

6.1.5.2 For Call-Ins that extend into a regularly scheduled shift, the Call-In rate will be paid until the start of the regular scheduled shift or for a minimum of 2 hours, whichever is greater. The regular scheduled shift will be worked and paid at the regular rate of pay.

6.1.5.3 Employees may be required to work through to the end of their original shift and may be required to work additional overtime.

6.1.5.4 Call-Ins are not eligible for schedule based premium pay rates.

6.1.5.5 It is not a Call-In when:

- An employee is requested to extend hours in conjunction with a regular shift.
- An employee is requested at least twelve (12) hours in advance to work additional hours on a scheduled day off. A minimum of two (2) hours at the appropriate overtime rate will apply and the work time shall start at the reporting location.

6.1.5.6 **Call-In Procedure.** Call-In procedures shall be developed and documented by each department and/or workgroup as appropriate and will be made available to all employees on the Company intranet.

6.1.5.7 For immediate response (unplanned), paid time for the Call-In begins when the employee is notified when On-Call or accepts the work for a Call-In.

6.1.5.8 For non-immediate response (planned), paid time for the Call-in begins at the agreed upon start time.

6.1.5.9 Call-Ins that do not extend into a regularly scheduled shift end upon completion of work and return to the reporting location unless an employee is assigned a Company vehicle during this time period, in which case time ends when the employee returns to their originating location.

6.1.5.10 Employees called in will be paid a minimum of two (2) hours at two (2) times their rate of pay. All subsequent Call-Ins that begin on the same scheduled day off or workday will be paid at two (2) times the employee's rate of pay for actual hours worked. Employees called in are obligated to remain in contact and be available to work for the full two (2) hours that they are being compensated.

6.1.6 **Excused Rest Period**

When an employee is called into work and the last Call-In ends less than eight (8) hours before start of the employees' next scheduled shift, the employee will be given eight (8) hours of rest if:

- The Call-In totals six (6) or more hours duration (consecutive or aggregate); or

- The employee has three (3) or more Call-Ins within the twelve (12) hour period before the start of their next scheduled shift.

6.1.6.1 Additionally, for safety reasons, following unscheduled work and/or Call-Ins prior to a regularly scheduled shift, Management reserves the right to excuse an Employee for some or all of the employee's regularly scheduled shift in accordance with the established Company policy and procedure and the shift will be paid per 6.1.6.3.

6.1.6.2 An employee that does not qualify for a rest period or after a rest period feels they cannot safely perform their assigned duties may request to be excused for the beginning or remainder of their shift not to exceed more than one half of the regular scheduled shift. Available PTO must be used prior to leave without pay.

6.1.6.3 Hours excused from original shift shall be paid at the straight-time rate and shall be counted as time worked for the purpose of calculating overtime.

6.1.7 **Paid Transition Time**

At Management's discretion, when transitioning from scheduled nights to days, or scheduled days to nights, the employee may receive pay per 6.1.6.3 in lieu of working a shift to ensure appropriate rest.

Section 6.2 Work Reporting Methods

6.2.1 **General**

Work reporting methods, including facility-based reporting, jobsite reporting and telecommuting, are defined below. All employees have a work reporting method, in addition to a Company-based location, both of which are determined and assigned by the Company. The Company may change employees' Company-based location and work reporting method based on business needs.

6.2.1.1 Work reporting methods contained in Section 6.2 do not address mileage reimbursement or compensation for time spent traveling in accordance with provisions outlined in this Article.

6.2.1.2 When a work reporting method other than facility-based reporting is utilized, department/workgroup guidelines addressing the application of the method will be established and utilized.

6.2.2 **Facility-Based Reporting Method**

The facility-based reporting method establishes a location to which the employee reports (e.g., resource center, corporate office or storage facility). Under this method, the Company-based location is the reporting location. The employee must be at that reporting location and ready to work at the employee's scheduled start time.

6.2.3 **Travel When Facility-Based Reporting**

Employees beginning and ending their shift at a temporary location within thirty (30) miles of their Company-based location will travel to and from the temporary location on their own time.

- Employees beginning and ending their shift at a temporary location greater than thirty (30) miles from their Company-based location will be compensated for travel time.
- Employees beginning and ending their shift at a temporary location will be paid mileage based on the distance between their Company-based location and the temporary location, unless a Company vehicle or other transportation is provided.

6.2.4 **Jobsite Reporting Method**

The jobsite reporting method establishes varying reporting locations (e.g., job sites, facilities or geographic work areas) to which the employee reports. The employee must be at the employee's reporting location and ready to work at their scheduled start time. Additionally, the employee must be at the employee's reporting location at the end of their shift, unless otherwise directed. Under this method, the Company-based location is not considered the fixed official work location/station.

6.2.5 **Travel When Jobsite Reporting**

For jobsite reporting, the region is defined as the geographic area within a forty-five (45) mile radius of the Company-based location.

For travel within the region:

- Time spent traveling to and from the reporting location is considered personal commuting time and is not time worked.
- If an employee uses a personal vehicle to commute to and from the reporting location, there will be no mileage reimbursement for that commute.

For travel outside the region:

- Time spent traveling to and from the reporting location will be compensated as time worked based on the calculated travel time from the employee's Company-based location to the reporting location.

- If an employee uses a personal vehicle to commute to and from the reporting location, mileage reimbursement will be provided for that commute based on the calculated mileage between the employee's Company-based location and the reporting location.

Section 6.3 Health and Safety

6.3.1 It is the Company's responsibility to provide a safe work environment and to operate its system safely. The parties mutually agree to promote safe work and stop work practices, which include providing appropriate personnel and equipment to meet health and safety obligations. Personal Protective Equipment (PPE) allowances provided by the Company shall be in accordance with Section 17.8 within this Agreement; unless otherwise required by applicable law.

6.3.2 All employees are subject to the Company's Drug and Alcohol policies.

Section 6.4 Emergency Operations

If adverse or emergency conditions exist, employees may be given alternative work assignments, schedules, shifts, and/or work locations. The Parties agree that the Company will maintain safe operation in their service territory.

Mutual Aid/Assistance. In the event of mutual aid requested by another utility, the employee selection process will include recognition and application of Job Seniority and will be made available to all employees on the Company intranet.

Section 6.5 Dash Camera

The vehicle dash cameras are to be used for triggering events such as collisions, litigation around collisions, and public complaints or other triggering events such as hard braking. Video footage from a triggering event will first be reviewed by a third party. The Company and the Union recognize the intent of the dash cameras is to improve driving habits and the overall safety of our employees, customers, and the communities in which they drive.

The camera will only upload video footage for viewing when there has been a triggering event or as requested by the Company. The cameras will not be used for real-time video or audio surveillance of employees, or to track employee work performance.

At no time will the device be used for audio voice recording of employees.

The use of cab facing cameras are not considered discipline. The cab facing cameras will only be activated in conjunction with discipline related to violations of Company Driving Policies. Activation of cab facing cameras longer than one hundred and eighty (180) calendar days must be signed by the Manager and the Union Representative. Forward facing cameras will continue to be used.

ARTICLE 7
EMPLOYEE DISPLACEMENT

Section 7.1 General

Employee displacement includes work redesign, redeployment, lack of work, bumping process, and layoff.

Section 7.2 Work Redesign

Work redesign may occur within a department, a workgroup, a resource center, or company-wide resulting in employee position status change or displacement from position. Before a work redesign, the Company will bargain the impact of the redesign and identify issues that are covered under this Agreement or are considered mandatory subjects of bargaining and must be resolved before the application of the Company's Work Redesign Job Allocation Process. When a redesign has projected reductions in occupied positions or changes in Company-based location, the Company agrees to inform the Union in accordance with Section 7.3 to this Article and Company processes.

7.2.1 **Acceptance or Declination Timelines**

Regarding position selection, the employee shall be given a minimum of forty-eight (48) hours (two [2] complete workdays) from point of notification to make their decision.

Failure or refusal by a regular employee to complete the documents within the agreed timeframe will be considered a declination.

7.2.2 **Position Reinstatement**

An eliminated position in the impacted group that is reinstated within one (1) year of a regular employee's displacement date will be offered in Company seniority order to those regular employees displaced by this redesign provided that the reinstated position is not in a location declined by that employee. This reinstatement applies to regular employees displaced due to the initial redesign only and not regular employees displaced due to any subsequent assignments or bumps.

Section 7.3 Redeployment

7.3.1 Redeployment is a process utilized to retain a regular employee whose job has been eliminated due to work redesign, or may be used in a regional lack of work if mutually agreed upon by the Union and the Company. This process may also be used as a result of Failure to Qualify During Qualifying Period as defined in Section 5.2 within this Agreement.

7.3.2 This process shall include preferential consideration for the displaced regular employee in the bidding and selection process for equivalent or lower grade positions for which the employee meets bidding qualifications. As an alternative to bumping, the Company may assign such employee to a position for which the employee meets bidding qualifications. Refer to the Redeployment Process and Failure to Qualify During Qualifying Period in accordance with Article 5 within this Agreement.

Section 7.4 Lack of Work

7.4.1 If the Company declares a regional lack of work in a location or workgroup, regular employees may be permanently assigned from one work location to another. Regular employees involved in regional lack of work will have their pay guaranteed per Section 1.5 within this Agreement. Once the Company has declared a regional lack of work, the impact and application of that determination shall be mutually agreed upon by the Union and the Company.

7.4.2 If the Company declares a Company-wide lack of work, the bumping process shall be applied per Section 7.5 to this Article.

7.4.3 The Parties agree that in the case of unforeseen events that could cause the need for a temporary reduction in the amount of work available either Company-wide, in a location, or workgroup, the Parties will meet to determine the method by which they may meet the challenges of the unforeseen event(s). Before any forced reduction in available work hours is initiated, the Parties will exhaust as many voluntary options as appropriate that meet the joint interests of the parties. Situations covered under this Section are not considered a permanent event and will not be subject to other provisions of this agreement such as layoff or bumping rights.

Section 7.5 Bumping

Bumping, as described in 7.5.1 to this Article, General Bumping Principles, and in the Company process, may be available for use in the following circumstances:

- Redeployment resulting from work redesign (refer to the Redeployment Process in accordance with Section 7.3 within this Agreement)

- Company-declared lack of work.

7.5.1 **General Bumping Principles**

An employee:

- Cannot bump an employee who has more Company seniority.
- Cannot bump into a higher graded job.
- Cannot bump into a job for which bidding qualifications are not met as defined in Article 4 within this Agreement.
- Cannot bump into a previously declined job at any location due to Work Redesign.
- Cannot bump into a previously declined job at that specific location due to assignment in redeployment.
- Can decline to bump into positions that change their employment status (FT, PT>20, PT<20). In such cases, the Parties will convene a Committee to provide oversight on significant redeployment and bumping activities. The process will be based on seniority, and the Committee will also consider employee preference for work location, current job held, previous jobs worked and maintaining group.
- Can bump into a different employment status (FT, PT>20, PT<20), but must elect to change employment status accordingly.

Section 7.6 Layoff

The parties agree that a layoff will only occur when the Company determines a need to reduce its workforce. The Company may layoff any employee who has not earned employment security as defined in Section 1.4 within this Agreement.

Regular employees shall be given ten (10) working days' advance notice before a layoff expected to last longer than ten (10) working days.

ARTICLE 8
PERFORMANCE DEVELOPMENT AND MANAGEMENT

Section 8.1 Performance Appraisal

Management will maintain an appraisal system to determine if performance requirements have been or continue to be satisfied for the Probationary period and the Qualifying period.

Line of Progression

Advancing within Line of Progression jobs requires a regular employee currently meet all the standards for the previous job prior to being eligible to move into the next job.

Section 8.2 Performance Development Plan

A Performance Development Plan (PDP) shall be used for incumbent regular employees who have been assessed as “not meeting” performance qualifying standards. However, Performance Development Plans are not to be used for term employees, probationary regular employees, and regular employees in their qualifying period, or situations warranting immediate use of the progressive discipline process. The Performance Development Plan will be kept in Human Resources (HR) in the employee’s personnel file.

Successful completion of the Performance Development Plan does not change anniversary dates for pay progression timelines.

8.2.1 Responsibility of the Supervisor

Using a Performance Development Plan, Supervisors shall provide monitoring of regular employees so that the employees are aware of any standards they are not meeting, and what they need to do to meet the standard.

8.2.2 Responsibility of the Employee

Regular employees on a Performance Development Plan have the responsibility to follow through on the agreed plan, including any training or use of tools/resources provided by the Supervisor, and to inform the Supervisor if there are any barriers to completing the plan. Regular employees who know they are not meeting an essential function may ask Supervisors for a Performance Development Plan to help ensure that they can meet the standards.

Section 8.3 Statement of Expectations

A Statement of Expectations is a non-disciplinary coaching tool a Supervisor may use to outline and help an employee understand the Supervisor’s expectations of the employee.

At times a Supervisor may choose to provide an Employee with a Statement of Expectations to further communicate or document expectations. A Statement of Expectations may be retained in the employee’s personnel file.

Section 8.4 Relationship to the Disciplinary Process

A Performance Development Plan or Statement of Expectations **cannot** be construed as the first step of the disciplinary process and cannot be used or referenced in any future disciplinary documents. All disciplinary action must be conducted as described in Article 20 within this Agreement.

ARTICLE 9
ATTENDANCE

Section 9.1 General

The Union and the Company agree that employees' regular and reliable attendance is critical to the success of the Company. The Parties further agree that late arrivals to work, early departures from work, and other unscheduled and unapproved absences are disruptive and should be avoided. Employees are expected to be at work each scheduled workday, on time and ready and able to work and all employees are expected to have regular, reliable and punctual attendance. Appropriate use of Paid Time Off (PTO), disability benefits (Short-Term Disability, Long-Term Disability and Workers' Compensation), and protected forms of leave as defined by Company policy are essential to employee well-being, a healthy work environment, and a committed workforce, which are integral factors in Company performance.

Section 9.2 Relationship to Paid Time Off

Employees may use Paid Time Off (PTO) per Article 12 within this Agreement for vacation, illness, accident, family illness, medical appointments or personal business.

Section 9.3 Attendance Guidelines

9.3.1 **Definitions**

9.3.1.1 Time away from scheduled work is:

- **Absence**: one (1) hour or more of time away is considered one (1) absence. This includes late arrivals and early departures as well as full day absences.

- **Tardy**: Late arrivals or returns and early departures of less than one (1) hour. This includes late arrivals or returns from breaks or meal periods.

- **Days Off**: Negotiated days off such as PTO, holidays, floating days, bereavement leave, etc.

9.3.1.2 **Approved**: Time away will be considered approved when the time away is:

- Protected leave, defined under applicable local, state or federal laws (i.e., FMLA, OFLA, WFLA, *Oregon and Washington Paid Sick Leave), or relevant leave laws. Protected leave is applied before absences are determined to be unapproved. Employees need to work with Matrix or current leave administrator and the Human Resources team to determine whether any particular absence is covered by protected leave.

* As of June 1, 2024, Oregon Paid Sick Leave is 40 hours of protected leave and Washington State Sick Leave is 50 hours of protected leave. Subject to change, refer to Company Policy.

- Discipline or retaliation based on an employee's use of protected leave is not permitted by law. Employees are responsible for providing appropriate notice and documentation of protected leave as described in the Company's Family Medical Leave policy.

- Approved bereavement leave (per Article 13 within this Agreement), approved military leave, protected leave (as defined in Company policy), jury duty, witness duty on behalf of NW Natural, and approved absences due to industrially related injuries or illnesses.

- Granted approval with at least forty-eight (48) hours' notice, e.g., floating days, PTO, appointments. *

  *Requests for time away from work with less than forty-eight (48) hours' notice may be considered approved. This is an exception and the decision is at the sole discretion of the Supervisor/Manager/designated approving authority.

9.3.1.3 **Unapproved:** An absence will be considered unapproved when the time away from work does not meet the criteria for approved absence within this Article or if the employee failed to notify their department's designated approving authority or failed to follow the applicable department reporting procedures for the absence, tardy, or early departure before the start of the scheduled shift or as soon as practicable upon the employee's knowledge that they would be late or absent.

9.3.1.4 **Use of PTO for Unapproved Absence:** Employees may use their accrued Paid Time Off (PTO) for unanticipated absences with less than forty-eight (48) hours' advance notice, but the time away is not considered approved just because the employee has PTO available to cover the time they were away from work.

9.3.1.5 **Unacceptable Amounts/Patterns of Unapproved Absences:** An unacceptable pattern of unapproved absence is demonstrated generally by the following:

- Except as provided in 9.3.1.2 to this Article, after five (5) unapproved absences within a rolling twelve (12) month period measured backward from the date of the most recent unapproved absence.

- Unacceptable amounts/patterns of unapproved absence may be subject to discipline per Article 20 within this Agreement. The Company has discretion to assess an employee's overall attendance record as it relates to unapproved absences to determine if there is an unacceptable pattern and, if so, the appropriate level of discipline.

9.3.1.6 **No Call/No Show:** An employee is considered a No Call/No Show when the employee fails to report for work without contacting their Supervisor (or the Supervisor's documented designee, or if no documented designee, the next level of Supervision) or without following any applicable department-level procedures for absence notification. After three (3) or more consecutive workdays in which a No Call/No Show has occurred, an employee is considered to have voluntarily abandoned employment with the Company.

ARTICLE 10
ISSUE RESOLUTION

Section 10.1 Introduction

The Issue Resolution Process is the agreed to method to address questions, conflicts and disputes, regarding any provisions of this Agreement, at the lowest level possible prior to going through the Grievance Process. The Issue Resolution Process is not intended to be a substitute for direct dialogue between employee and Supervisor. The objective of the Issue Resolution Process is to promote open and continuous communication to determine what's right, not who's right, regarding concerns in the workplace. This process is established on the premise of trust, respect and the mutual goal of resolving issues at the earliest opportunity and appropriate level.

Section 10.2 Issue Resolution Process

Step One

Prior to filing a formal issue (OPEIU Local 11 form), the employee and the Supervisor should first meet informally to discuss and attempt to resolve the issue(s).

Step Two

In the event there is no resolution, the Steward, the employee and the Supervisor should meet and discuss the issue(s) and attempt to resolve the issue(s) informally.

Section 10.3 The Issue Resolution Committee

Step Three

Should the issue not get resolved between the employee, the Steward and the Supervisor, it shall be presented to an Issue Resolution Committee, hereinafter referred to as the "Committee," for consideration.

10.3.1 An Issue Resolution Committee is organized on an as needed basis for the purpose of dealing with possible conflict(s) with the Agreement and in accordance with Section 10.1 to this Article. The Committee shall not have the authority to change, delete, or modify any terms and conditions of the Agreement.

10.3.2 The Committee shall be comprised of two (2) bargaining unit members from the current list of Stewards and Chief Stewards appointed by the Union and two (2) management employees appointed by the Company. These Committee members will be mutually agreed upon by the LMC Co-Chairs. The appointed Committee members with mutual agreement may at their discretion bring in a subject matter expert (SME).

10.3.3 For any single topic the Committee may meet for up to three (3) hours total.

The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the Agreement or bylaws of the Committee.

The Committee resolution decisions will be made by consensus and the Committee shall submit their findings and decision to the employee, Supervisor, and the LMC Co-Chairs. Resolutions that are changes to work rules/conditions or other items that may impact other workgroups or employees shall be submitted to the LMC Co-Chairs for review, approval, and communication to members and/or workgroups impacted.

Should these four (4) Committee members not reach consensus within fourteen (14) calendar days, they shall immediately communicate this to the LMC Co-Chairs for resolution or movement to the grievance process.

All timelines above may be extended by mutual agreement of the Parties. If extended, notification will generally be provided to all parties along with status and anticipated action within three (3) working days of the decision to extend or as soon as possible thereafter.

Nothing in this language precludes a party from withdrawing an issue at any time with notification to the Union office and Human Resources.

ARTICLE 11
WAGES

Section 11.1 Compensation

The parties agree to ensure that there will be a compensation system that supports business operations while maintaining internal and external equity.

11.1.1 **Pay Rates.** Each job will be placed in a pay group. Each pay group will have at least two (2) pay steps.

11.1.2 **Entry Rate.** This rate of pay is one step below the Experienced Rate.

11.1.2.1 An employee entering a position which has only two (2) pay steps shall receive the Entry Rate when:

- Entering a new position in a higher pay grade,
- Entering a new position in the same grade when an employee is currently receiving the entry pay rate,
- Entering the same or lower position and an employee has never received the Experienced Rate for either position.

11.1.3 **Experienced Rate.** This is the top rate of pay an employee will receive for that grade.

11.1.3.1 In order to receive the Experienced Rate an employee must first successfully complete all of the following:

- Any applicable in training programs or required certifications.
- Receive the Entry Rate for the new position for a period not less than two hundred and sixty (260) working days (credit towards the two hundred and sixty [260] working days will be given for any previous days worked in the same or higher grade at the entry rate). The parties agree for absences of twenty (20) workdays or more, the Company may, at its sole discretion, extend the two hundred and sixty (260) day timeframe by the same number of workdays missed.
- The qualifying period for the position.

11.1.3.2 Employees who have previously held the same or higher grade and who have received the experience rate for the same or higher grade shall also be paid the experienced rate.

11.1.4 **Additional Pay Steps**

11.1.4.1 Under certain circumstances, positions may have additional pay steps. These positions must be mutually agreed to and have formal In-Training programs and as defined below.

11.1.4.2 An employee entering a position with these additional pay steps will receive the appropriate rate of pay in accordance with the provisions within this

Article. The starting rate shall not be less than eighty percent (80%) of the Experienced Rate.

11.1.4.3 A formal In-Training program is required for a position to have additional pay steps. Not all positions with a formal training program will have additional pay steps. The starting step for any such position shall not be less than eighty percent (80%) of the experienced rate as deemed appropriate by the Company.

11.1.4.4 **Positions with Approved Additional Pay Steps**

Currently, the following positions have additional pay steps. The pay steps are tied to timeframes and not to completion of training phases or qualifying periods. During the life of this Agreement, positions with additional pay steps may be added to, removed from or changed by mutual agreement between Management and the Union.

- Corrosion Technician
- Construction 2
- Service Technician (CFS 2)
- Mechanic Welder (Welding & Fabrication 4)

11.1.4.5 Time starts on the date of hire for external hires and rehires or first day of training for internal hires. Employees shall progress through Steps 1 through 4 in accordance with the schedule below.

Employees may progress from Step 4 to Step 5 (Experienced Rate), after successfully meeting all the conditions as described in 11.1.3.1 to this Article and receiving satisfactory performance evaluations. Steps as a percentage of Experienced Pay Rate are listed below:

Step	Time in Program	% of Experienced Pay Rate
1	0 months	80%
2	6 months	85%
3	12 months	90%
4	24 months	96% (Entry)
5	36 months	100%

Pay rates for internal employees entering an In-Training program will be determined as follows:

- When promoting into a job with a higher pay grade the employee shall be placed at the Step closest to their current rate of pay that results in a pay increase.

- When bidding into a job in the same pay grade, they shall be placed at the same Step the employee currently holds, except in the case of an employee who currently holds the Experienced Rate where it will be the Step below the Experienced Rate.

- When bidding into a job with a lower pay grade they shall be placed at the Step below the Experienced Rate which results in the least reduction in pay.

11.1.4.6 Internal employees entering an In-Training program at a step higher than Step 1 will advance to the next Step within the timeframes as defined in the above chart. For example, an employee who enters at Step 3 will move to the Step 4 pay rate after twelve (12) months.

11.1.4.7 **Benchmark-based Progression**

At Management's discretion, with mutual agreement from the employee, benchmark-based progression may be used for the following workgroups:

- Weld & Fab 4
- Corrosion Technician

Benchmark-based progression would allow an employee to advance to the next step/pay scale as described in 11.1.4.5, not to exceed Step 4, by completing the required testing ahead of the time-based progression. In the absence of benchmark-based progression, the employee will follow the additional step/pay scale schedule.

Section 11.2 Scheduled Annual Increases and Wage Adjustments

Increases to wages are incorporated into "Schedule B – Wage Scale" within this Agreement. These negotiated rates were achieved utilizing the guiding principle of alignment with market practices and internal equity considerations. This principle was applied to comparable companies, surveys and job matches. Internal equity ranking shall be applied by mutual agreement in comparison to peer utilities. Market matches and internal equity shall both be considered when achieving alignment.

11.2.1 An employee's rate of pay shall be adjusted depending upon the employee's current rate of pay as follows:

- Effective June 1, 2024, all bargaining unit employees shall be moved to the appropriate rate for their job group in accordance with "Schedule A – Job Titles by Pay Group" to this Agreement.

- Employees in positions covered by pay guarantees in Section 1.5 within this Agreement are covered in Section 11.4 to this Article below.

11.2.2 For Employees whose current rate of pay is equal to that contained in "Schedule B – Wage Scale," the minimum Scheduled Annual Increase is specified in the table below.

Scheduled Annual Increases	
Effective Date	**Percentage Increase**
June 1, 2024	6.0 %
December 1, 2024	4.0 %
December 1, 2025	4.0 %
December 1, 2026	4.0 %
December 1, 2027	4.0 %

Section 11.3 Job Compensation and Approval Process

11.3.1 **Human Resources Professional Review**

When a new bargaining unit job is established or if there is a substantive change, initiated by the Human Resource Compensation Professional or submission of the Job Compensation Evaluation Form, to the job that requires changing the job match used in the market evaluation as determined by the Human Resources Compensation Professional, the Company shall conduct a market evaluation of wages using the same comparable companies, surveys, job matches, and methodology used in the negotiations for this Agreement. For purposes of determining whether there is a substantive change to a job, the Company's Human Resources Compensation professional will make the ultimate determination which will focus on whether there is a material change in job duties that significantly affect the nature and level of the work being performed and using the process described below.

11.3.2 **Labor Management Committee Review**

The Labor Management Committee Leadership Team (LMC LT) will review and approve recommended changes to Job Matches, Pay Groups, Wage Rates and Adjustments as described in this Article and presented by the Company Compensation Professional following the Job Compensation Evaluation Form, which will be made available to all employees on the Company intranet. The LMC LT reserves the right to bring in subject matter experts to inform their decisions.

11.3.3 Changes and additions of a significant nature to “Position Specific Essential Functions” will follow these steps:

(1) Employee(s) shall submit the Job Compensation Evaluation to their department Manager for consideration. The manager will consult with the HR Compensation Professional prior to approving a request for job description changes or evaluation. If after review with the HR Compensation Professional it is determined there are changes of a substantive nature to the job description that would warrant a review (material change of job duties that significantly affect the nature and level of the work), the manager will approve the job evaluation form and compensation will notify the employee that a review is pending and will be presented to the LMC-LT.

(2) If the HR Compensation Professional determines there is not a substantive change to the job to warrant a review, the HR Compensation Professional will inform the manager and requesting employee that a market review will not be completed. The HR Compensation Professional will inform the LMC Co-Chairs of the request, and non-substantive changes to the job description. The LMC Co-Chairs have the option to request a deeper review if other material information is presented to the HR Compensation Professional that was not included in the initial request.

(3) The HR Compensation Professional is responsible for communicating decisions on review requests to the LMC-LT, the requesting manager, and employee(s).

(4) The effective date of any change will be the date of the decision by the LMC-LT. If the compensation review has taken an extended period of time (i.e., more than three (3) months), the LMC-LT will agree on an appropriate effective date.

Section 11.4 Honored Pay Rate Employees

11.4.1 Effective June 1, 2024, and for the term of this Agreement, Honored Pay Rate employees shall receive a lump sum equal to the scheduled annual increase. This lump sum payment shall continue until the difference between their current rates of pay prior to the scheduled annual increase is less than three percent (3%) more than the rate of the “Schedule B – Wage Scale.” At that time, they will receive that percentage amount necessary for their current wage to equal that in the “Schedule B – Wage Scale” with the difference between that amount and the scheduled annual increase in a lump sum*.

* Lump sums owed under these provisions shall be calculated based on the employee’s regular and overtime earnings for pay periods ending in the preceding

twelve (12) months period prior to the increase, and shall be paid on the employee's second pay check in the month the increase was issued.

11.4.2 In the event an Honored Pay Rate employee bids into a position with a Wage Scale rate lower than the pay rate for the position the employee was placed or preferentially bid into that resulted in the pay guarantee, the employee's pay shall be decreased to the rate contained in the Wage Scale for the position into which the employee bid.

Section 11.5 Premium Pay Rates

11.5.1 **Overtime Pay**

11.5.1.1 An employee shall be paid at one and one-half (1.5) times the regular rate, including applicable premiums for:

- The first twelve (12) hours worked on the first scheduled day off for any time worked.
    - The first twelve (12) hours worked on an Unplanned Schedule Change or an Unplanned Shift Change except as provided for in 11.5.1.2 to this Article.
- Hours worked in excess of an employee's shift (minimum eight [8] hours) when working a regular full-time schedule.
- Hours worked in excess of forty (40) regular hours in a workweek, when working a regular full-time, flexible or part-time schedule.

11.5.1.2 An employee shall be paid at two (2) times the employee's regular rate, including applicable premiums for:

- More than four (4) hours worked in excess of an employee's shift (minimum eight [8] hours), or hours worked in excess of forty (40) regular hours plus twenty (20) time-and-one-half hours in a workweek.
- All hours worked on the second scheduled day off in a workweek when no schedule change is involved. This applies only if an employee works at least eight (8) hours on the first scheduled day off.
- All hours worked on a Sunday that is a scheduled day off.
- Call-Ins as provided for in 6.1.5 within this Agreement.
- All hours worked on holidays as provided for in Section 14.5 within this Agreement.

11.5.2 **Pay for On-Call Assignment**

- Sixty-nine dollars and fifty-three cents ($69.53) for each On-Call Assignment on an employee's regularly scheduled workday,

- One hundred four dollars and twenty-nine cents ($104.29) for each On-Call Assignment on an employee's scheduled days off, and

- One hundred thirty-five dollars and forty-six cents ($135.46) for each On-Call Assignment that begins on an actual (not an Observed) holiday as defined in Section 14.1 within this Agreement.

Effective June 1, 2024, the amounts listed in this Section above will be increased annually at the same time and percentage as the scheduled annual increase in accordance with 11.2.2 to this Article.

11.5.3 **Recognition for On-Call Assignments**

11.5.3.1 Employees who have eighty (80) to one hundred four (104) On-Call Assignments in a calendar year will receive a payment of one and a half percent (1.5%) of that Employee's regular and overtime earnings for that same calendar year payable in a lump sum on the second regularly scheduled paycheck in January of the next year. An employee who retires or separates employment prior to the end of the calendar year and has earned the On-Call Assignment Recognition Incentive shall be paid the on-Call Assignment Incentive with their final paycheck.

11.5.3.2 Employees who have one hundred five (105) or more On-Call Assignments in a calendar year will receive a payment of two and a half percent (2.5%) of that Employee's regular and overtime earnings for that same calendar year payable in a lump sum on the second regularly scheduled paycheck in January of the next year. An employee who retires or separates employment prior to the end of the calendar year and has earned the On-Call Assignment Recognition Incentive shall be paid the on-Call Assignment Incentive with their final paycheck.

11.5.3.3 Call-In pay is in addition to On-Call Assignment pay as provided in 6.1.5 within this Agreement. On-Call Assignment periods are not to be counted as time worked for the purpose of calculating overtime.

11.5.4 **Schedule Based Premium Pay**

11.5.4.1 **Saturday/Sunday Pay.** Hours worked on Saturday and/or Sunday as part of the employee's regularly scheduled workweek; as defined in Article 6 within this Agreement; shall be compensated an additional four dollars ($4.00) per hour.

11.5.4.2 **Shift Work Pay.** Hours worked on Swing and/or Graveyard shift as part of the employee's regularly scheduled workweek shall be compensated an additional two dollars ($2.00) per hour for Swing shift and three dollars ($3.00) per hour for Graveyard shift.

11.5.5 **Skill Based Premium Pay**

11.5.5.1 **HAZWOPER Work Pay.** Employees trained to perform duties identified by the Company as HAZWOPER (Hazardous Waste Operations and Emergency Response) will receive an additional three dollars and fifty cents ($3.50) per hour for the entire shift when performing such duties.

11.5.5.2 **Bilingual Pay.** All hours worked by an employee who is qualified for and participating in an approved Bilingual Program shall be compensated an additional two dollars ($2.00) per hour.

11.5.5.3 **High Angle Work Pay.** Employees identified, trained and certified in high angle work and rescue skills shall be paid an additional three dollars and fifty cents ($3.50) per hour when performing such duties.

When an employee is eligible and earning premium pay under any of the categories listed in this Section, that premium pay will be included when calculating the employee's overtime rate.

Section 11.6 Accurate Timekeeping

It is the Company's intention to perform accurate timekeeping and payroll entry. In the event of a discrepancy with an employee's submitted time, the employee will be contacted as soon as possible to identify and correct the discrepancy.

ARTICLE 12
PAID TIME OFF (PTO)

Section 12.1 General

Paid Time Off (PTO) benefits are available to employees and may be used for vacation, illness, accident, family illness, medical appointments, or other personal business. PTO shall accrue according to Length of Service with the Company as defined in Section 12.3 to this Article.

12.1.1 **Guidelines for PTO Scheduling**

Established PTO selection groups based on a department, work group or resource center with more than one (1) bargaining unit employee may create their own guidelines for PTO scheduling.

These guidelines shall be made available to all employees on the Company intranet and:

- Include signatures of the department Manager and the Union Representative.
- Include date the guidelines were completed or reviewed.
- Be reviewed no more than once each calendar year, and changes must be finalized sixty (60) days prior to the start of the department's PTO selection process.

12.1.2 Unless otherwise defined in an employee's department, work group or resource center guidelines, scheduling of available PTO will be as follows:

- During the first round of scheduling, full work weeks, including weeks with holidays, and consecutive weeks may be scheduled.
- During the second round, partial weeks and single days can be scheduled.
- Carry over PTO hours accrued in previous years may be scheduled once all employees have been afforded the opportunity to schedule their current year accrual.
- Groups without guidelines will review the need for guidelines not more than annually and if mutually agreed to, then, the group can continue to operate without guidelines.

12.1.3 Employees will be required to take a minimum number of PTO hours annually (Annual Minimum Usage) as described in 12.2.2 to this Article, but will otherwise be able to carry over accrued but unused PTO up to a total of four hundred and eighty (480) PTO hours.

All other PTO provisions of the Agreement apply (i.e., requests must be made forty-eight [48] hours in advance, etc.).

12.1.4 **Previously Approved PTO Scheduling When Awarded a Position**

Once a position has been awarded, the awarding group will accommodate the PTO requests that were previously approved, subject to availability and approval. If an employee exercises the right of return, the group that the employee is returning to will attempt to accommodate the PTO request that was previously approved, subject to availability and returning Supervisor approval.

12.1.5 The LMC Co-Chairs may approve payout of annual minimum usage time not taken that otherwise would be forfeited due to the inability to schedule the minimum because of a disability or protected leave. In all other cases, for employees who do not take the full annual minimum usage of PTO, the PTO will be forfeited.

12.1.6 **Annual Minimum PTO Usage Exceptions**

12.1.6.1 Employees are responsible to schedule and take annual minimum PTO within department guidelines.

12.1.6.2 For employees whose medical disability time off or protected leave does not allow them to schedule their entire annual minimum PTO usage hours, unused minimum hours may be paid out rather than rolled over. In these cases, employees need to make their request via email to the LMC Co-Chairs prior to December 31st. Requests are reviewed on a case-by-case basis; approval is not automatic. Employees will be advised via email of the final decision.

12.1.6.3 On a voluntary basis, employees may donate up to 40 PTO hours annually to other employees. Donated time does not count towards minimum usage for either the giver or the recipient and must be scheduled in accordance with 12.1.1 and 12.1.2. The recipient must have satisfied their probationary period.

Section 12.2 Accrual

12.2.1 Regular employees begin to accrue PTO benefits from the first day of regular employment. PTO benefits are credited to the employee's account at the end of each pay period.

12.2.2 The rate of PTO accrual is based on a regular employee's Length of Service as follows:

Length of Service	Annual PTO Accrual	Annual Accrual In Hours	Annual Minimum PTO Usage
0 to less than 1 year	16 days	128 Hours	0 Hours
1 to less than 5 years	16 days	128 Hours	40 Hours
5 to less than 13 years	21 days	168 Hours	80 Hours
13 to less than 22 years	26 days	208 Hours	120 Hours
22 years and more	31 days	248 Hours	160 Hours

12.2.3 During the year in which an increase in annual PTO accrual occurs, the change will take place during the pay period of the regular employee's anniversary date and will be prorated for the calendar year.

12.2.4 Term and Intern Employees accrue PTO only as provided for in their Term Employment Agreement.

12.2.5 Employees who qualify for Short-Term Disability (STD), Workers' Compensation (WC), or protected leave as defined in Company policy will continue to accrue PTO during their first six (6) months of absence.

12.2.6 Employees do not accrue PTO while on Long-Term Disability (LTD) or after six (6) months on WC or protected leave as defined in Company policy, unless otherwise required by applicable law.

12.2.7 PTO will not accrue during a voluntary unpaid leave of absence of any duration (See Section 12.7 to this Article).

12.2.8 Employees may borrow PTO in advance up to their current year annual accrual. An employee who terminates employment with a negative PTO balance will be required to reimburse the Company for the PTO advanced to the employee. Employees agree and understand that this reimbursement will be deducted from the employee's final paycheck and that such deduction is specifically authorized as a term of this Agreement.

12.2.9 PTO accrual for part-time regular employees will be prorated based on the actual hours worked as compared to a full-time year of two thousand eighty (2,080) hours.

Section 12.3 Length of Service

12.3.1 Length of Service for purposes of determining PTO accrual shall be defined to include:

- The time during which the regular employee was an employee and received income (pay) or income replacement (e.g., STD, LTD, WC), regardless of whether that previous service was as a regular, Term, or Intern employee; and

- An approved period of absence without pay that is less than sixty (60) consecutive calendar days. In such a circumstance, the regular employee will retain their original hire date for the calculation of the Length of Service.

12.3.2 Length of Service does not include periods of absence without pay of sixty (60) or more consecutive calendar days, unless otherwise required by applicable law.

12.3.3 Regular employees who have a break in service may be eligible for an adjusted PTO abridgement date for PTO accrual if their prior eligible Length of Service is greater than the time they were not an employee of the Company. If so eligible for abridgement date, the duration of the break in service will not be credited toward

Length of Service. The determination of this adjustment will be done at the time of rehire.

12.3.4 Section 12.3 to this Article addresses Length of Service for purposes of determining PTO accrual. Length of Service may be defined differently in other benefits plans including, for example, the Retirement Plan for bargaining unit employees. In such cases, the terms of the individual plan(s) control.

Section 12.4 Buy Back Provision

Employees may request a buy back of their annual PTO accrual which exceeds the minimum usage requirement. Requests for buy back will be permitted so long as the PTO balance is not reduced below thirty-two (32) hours. The thirty-two (32) hour buy back restriction does not apply to the scheduling of PTO (i.e., PTO can be scheduled to a zero [0] balance, but not sold below the thirty-two [32] hour balance).

In all buy back instances, the calculation of pay for buy back requests refers to the current rate of pay at the time of the buy back, which means the rate of pay contained in the Wage Scale for the current awarded position. If rate retained, the higher rate applies. This applies only to situations of PTO buy back and has no impact on the language contained in Section 12.5 to this Article.

All PTO buy back shall be in accordance with IRS rules and Company guidelines and will be made available to all employees on the Company intranet.

Section 12.5 Rate of Pay

The rate of pay for PTO shall be computed at the employee's wage rate for the employee's current awarded position. If rate retained, this higher rate applies. In addition, the rate of pay shall include the appropriate shift work pay and other premium pay if the employee works (is scheduled to work) shift work and/or receives premium pay every working day.

Section 12.6 Scheduling of PTO

12.6.1 Except for emergencies, bereavement and PTO for unanticipated illness as described in Section 15.1 within this Agreement, requests for PTO for full or partial day absences must be made forty-eight (48) hours in advance and require prior Supervisor approval. The minimum increment of time that may be used for PTO is fifteen (15) minutes.

12.6.2 Employees will schedule PTO on a Company seniority basis according to workgroup, department or resource center guidelines and in accordance with this Article. Guidelines will be made available to all employees on the Company intranet.

Section 12.7 Voluntary Leave of Absence without Pay

A voluntary unpaid leave of absence is a leave of absence without pay that does not fall within any category of protected leave as defined in Company policy. Employees are eligible for a voluntary unpaid leave of absence only as provided for in Company policy. Annual PTO accrual must be exhausted before an employee may take a voluntary unpaid leave of absence and PTO will not accrue during a voluntary unpaid leave of absence of any duration. Under certain business conditions the Executive Officer responsible for Human Resources may waive the requirement to use the annual PTO accrual prior to allowing voluntary leave without pay.

Section 12.8 PTO Counts as Time Worked

Any PTO used by an employee shall be treated as if it were time worked for the purpose of computing overtime.

Section 12.9 PTO at Separation

At the time an employee retires or separates employment, all accrued and unused PTO will be paid to the employee with their final paycheck. Accrued PTO is not intended to be used to extend employment prior to retirement or separation, therefore, employees shall not schedule more than a maximum of one (1) month of PTO just prior to their retirement or separation date.

ARTICLE 13
PAID BEREAVEMENT LEAVE

Section 13.1 General

13.1.1 Employees are eligible for Paid Bereavement Leave in the event of the death of a covered family member. Eligible employees may take up to a maximum of three (3) workdays of Paid Bereavement Leave for each death of a covered family member to grieve and attend to matters related to the loss. A covered family member is defined in the Company's Bereavement Leave policy.

13.1.2 Employees must notify the Company as soon as practical when taking Paid Bereavement Leave or any extension of bereavement leave covered by PTO in accordance with departmental absence reporting practices. Employees may be required to provide documentation.

Section 13.2 Rate of Pay

The rate of pay for Paid Bereavement Leave shall be computed in the same manner as PTO as described in Section 12.5 within this Agreement.

ARTICLE 14
HOLIDAYS

Section 14.1 Holidays Defined

14.1.1 **Paid Holidays**

New Year's Day
Martin Luther King Jr. Day
Memorial Day
Independence Day
Labor Day
Veterans Day
Thanksgiving Day
Day after Thanksgiving
Christmas Day
Three (3) Floating Days per calendar year
One (1) Additional Designated Holiday

14.1.2 **Paid Holidays Falling on a Saturday and/or Sunday**

Any Holiday which falls on a Sunday shall be observed on the following Monday; any Holiday which falls on a Saturday shall be observed on the Friday before. However, for employees with regular schedules that include scheduled workdays of Saturday and/or Sunday, the holiday shall be recognized on the actual date of the Holiday and not on the Observed Holiday.

Section 14.2 Holiday Pay

14.2.1 Full-Time regular employees shall receive holiday pay based upon an eight (8) hour day regardless of assigned shift (e.g., ten [10] or twelve [12] hours) and will be paid at the employee's regular straight time pay. For remaining hours beyond eight (8) hours, employee may use PTO or Leave without Pay.

14.2.2 Part-Time regular employees receive holiday pay based on the actual hours compensated in the two (2) full pay periods prior to the pay period in which the Holiday occurs as compared to a normal two (2) full pay periods of one hundred sixty (160) hours.

Section 14.3 Floating Days

14.3.1 Floating days are additional paid days off which are not defined holidays and during which the Company will remain open. Employees are eligible for three (3) floating days per calendar year. Floating days must be used within the calendar year or they are forfeited. Floating days will be made available by Management to the limit required by the department to assure appropriate business staffing. Employees must schedule their floating days within these limits with the mutual agreement of their Supervisor.

14.3.2 Employees in their first year of employment will be eligible for floating days during that calendar year as follows:

Hire Date	Floating Days Qualified For
January 1 through April 30	Three (3) 8-hour days
May 1 through September 30	Two (2) 8-hour days
October 1 through November 30	One (1) 8-hour day
December 1 through December 31	0 days

14.3.3 Scheduled floating days qualify as a holiday for pay. Part-Time regular employees receive pay for floating days per 14.2.2 within this Article.

Section 14.4 Additional Designated Holiday

Employees will be given one (1) additional designated holiday to be used on the workday before or after Christmas or New Year's Day. The day or days available for scheduling the additional designated holiday will be based upon staffing requirements as determined by the department Manager, which may vary by employee if the department is not closed. Date(s) to be determined and communicated before annual PTO scheduling.

Scheduled additional designated holidays qualify as a holiday for pay.

Section 14.5 Holiday Allowance for Work on a Holiday

Employees who are scheduled to work during a holiday (actual and/or observed), additional designated holiday, or on a previously scheduled floating day shall be paid at two (2) times the employee's regular rate and the rate of pay shall include the shift differential and other applicable premium pay if the employee works or is scheduled to work an alternate shift and/or receives premium pay every working day. In addition, the employee will receive eight (8) hours of holiday pay.

Section 14.6 Holiday Pay if Absent

14.6.1 Employees who are absent are eligible for holiday pay when on:

- Approved PTO or absences, including State(s) Paid Sick Leave, the scheduled workday before or scheduled workday after a holiday;
- Paid status for a continuous absence for a period of not more than six (6) months and when the pay is in some form directly from the Company;
- Unpaid status in conjunction with a protected leave; or
- Short-Term Disability (STD). The employee receives holiday pay to supplement the portion of the employee's earnings not paid through STD,

calculated at the employee's regular straight-time rate not to exceed a total of one hundred percent (100%) of the employee's regular pay.

14.6.2 Employees are not eligible for paid holiday(s) when the employee is:

- Absent the scheduled workday before or the scheduled workday after the scheduled holiday(s) and the absence is unapproved, and in accordance with 9.3.1.4 within this Agreement*;

- On Workers' Compensation (Industrial Disability) paid leave. The Employee will continue to receive time loss payments from the Workers' Compensation carrier;

- Absent for six (6) months or more;

- On a voluntary unpaid leave of absence of any duration;

- On a period of absence for which the employee is already receiving full pay from the Company; or,

- On Long-Term Disability (LTD). The employee receives LTD pay through the LTD provider and is not eligible for holiday pay.

*When an employee has an unapproved absence due to treatment at a healthcare provider (doctor's office), urgent care facility, emergency room, or admission to a hospital and the employee provides documentation of such treatment, the employee shall be eligible for holiday pay.

Section 14.7 Holiday Counts as Time Worked

Paid holidays shall be counted as time worked for the purposes of computing overtime if the holiday falls on an employee's scheduled workday. If the holiday falls on an employee's scheduled day off, it shall be treated the same as a Saturday and be paid at the employee's regular straight time pay.

ARTICLE 15
DISABILITY

Section 15.1 Non-Industrial Disability

15.1.1 **Short-Term Disability (Non-Industrial)**

Short-Term Disability (STD) benefits are available to eligible regular employees.

Qualified absences for eligible full-time regular employees that exceed four (4) consecutive or non-consecutive workdays in a consecutive fourteen (14) calendar day period for the same non-industrial illness or injury are covered under STD subject to the provisions and eligibility requirements of the NW Natural Short-Term Disability Income Protection Plan (STD Plan). For part-time regular employees the elimination period will be prorated based on the actual hours compensated in the two (2) full pay periods prior to the pay period in which the initial absence occurs as compared to a normal two (2) full pay periods of one hundred sixty (160) hours.

STD income replacement is based on a regular employee's Length of Service, as defined in Section 12.3 within this Agreement, and as follows:

Length of Service	Percentage of Income Replacement
0 to less than 10 years	70%
10 to less than 15 years	80%
15 years and more	85%
Date of hire 1994 and earlier (honored)	100%

STD benefits are provided to eligible regular employees for as long as the employee(s) have an accepted disability claim supported by the employee's health care provider, and determined by the disability carrier. However, the maximum period for a STD claim is one hundred eighty (180) consecutive calendar days. All STD requests require documentation from a qualified healthcare provider supporting the illness/injury. A period of short-term disability may require the employee's qualified healthcare provider's release to return to work when directed by the third-party STD Plan Administrator.

While an employee is on company paid STD Plan, the Company will continue to contribute to the employee's retirement plan(s), transfer Union dues, and contribute Company portion of the Health & Welfare premium share.

While an employee is receiving benefits from a State Paid Leave Program the Company will continue to pay the employer share of the Health and Welfare premium.

Regular employees may elect to supplement their STD income replacement up to one hundred percent (100%) of their regular rate of pay by drawing on their PTO account.

For more details regarding STD, including eligibility requirements and coordination with State Paid Leave Laws, refer to the STD Plan summary plan description or contact Human Resources. All plan descriptions will be made available to all employees on the Company intranet.

15.1.2 Long-Term Disability (Non-Industrial)

Long-Term Disability (LTD) benefits are available to eligible regular employees. A qualified disability for eligible regular employees that extends beyond one hundred eighty (180) calendar days will be covered under LTD subject to the provisions and eligibility requirements of the bargaining unit Group Long Term Disability Insurance Program (LTD Plan). The LTD Plan provides income continuation at sixty percent (60%) of the regular employee’s pay for as long as disabled, until the regular employee reaches the Maximum Duration of Benefits as outlined in the LTD Plan. Each period of Long-Term Disability requires a qualified healthcare provider’s release to return to work as coordinated through the third-party LTD Plan Administrator. For more details regarding LTD, including eligibility requirements, refer to the LTD Plan or contact Human Resources.

A regular employee’s employment will end on the anniversary date of the first day of absence, as defined in Consecutive Disability Period (per Section 15.5 to this Article). LTD benefits may continue as described above and per the terms of the LTD Plan. Nothing in Article 15 is intended to indicate a guarantee of employment; employment may be ended for other reasons during the year, subject to other provisions of this Agreement.

A regular employee whose employment has ended as described in this Article will retain the right to apply for an open and available position as an internal bidder for a time period equal to two (2) years or one (1) month per full year completed from date of hire, whichever is greater, from the date of first absence related to the disability. The employee’s Company, Job and/or Line of Progression seniority accumulated as of the last day of employment will be used for bids and awards per Article 4 within this Agreement.

Section 15.2 Workers’ Compensation (Industrial Disability)

If an employee is injured on the job, the employee may be eligible for Workers’ Compensation benefits, including industrial disability pay. If injured on the job, the employee will contact their Supervisor immediately to report the injury and complete any required form(s) in a timely manner. In no case shall an employee receive non-industrial disability pay and industrial disability pay for the same period(s) of time. If for any reason an employee’s Workers’ Compensation claim is denied, the employee may apply for coverage of the disability using the non-industrial disability programs outlined in 15.1.1 and 15.1.2 to this Article.

Section 15.3 Workers’ Compensation (Industrial Disability) Supplemental Pay Allowance

Industrial disability pay or “time loss” in connection with a Workers’ Compensation claim generally begins following a waiting period (currently three [3] days). The Company will compensate the employee during the waiting period with a supplemental allowance equal to the employee’s statutory rate of sixty-six and sixty-seven hundredths’ percent (66.67%) of an employee's regular straight time pay on a tax-free basis.

Section 15.4 Reemployment and Reinstatement Arising from Industrial Disability

15.4.1 If it is determined that a regular employee has ongoing restrictions which prevent them from returning to their current regular job, the Parties will consider applicable ADA (Americans with Disabilities Act) reasonable accommodations and/or state workers' compensation reemployment or reinstatement provisions to explore options for that employee.

15.4.1.1 Employees on permanent restrictions due to Industrial Disability are encouraged to seek open positions that fit with their restrictions and must follow the bidding process per Article 4 within this Agreement.

15.4.1.2 With joint Union and Management agreement, these employees may be placed into an open position without posting the open position.

15.4.2 If a regular Employee exceeds one (1) year of Consecutive Disability Period (as defined in Section 15.5 to this Article) related to the covered industrial disability, the employee's employment will end. Workers' Compensation benefits may continue, subject to eligibility in accordance with applicable Workers' Compensation laws. The regular employee also retains the right to apply for any open and available position for which they meet bidding qualifications as an internal bidder for a time period equal to two (2) years from date of separation of employment. The employee's Company, Job and/or Line of Progression seniority accumulated as of the last day of employment will be used for bids and awards per Article 4 within this Agreement.

15.4.3 A regular employee who is placed, awarded, or reemployed in a lower classification per Section 15.4 to this Article shall have their pay administered as an Honored Pay Rate Employee subject to provisions in Section 11.4 within this Agreement.

15.4.4 A regular employee whose employment is ended per 15.4.2 to this Article will be eligible for a COBRA (Consolidated Omnibus Budget Reconciliation Act) subsidy equivalent to the amount and duration provided through the LTD Plan. This subsidy will be adjusted to match the LTD benefit as needed.

Section 15.5 Consecutive Disability Period (Industrial and Non-Industrial)

The Consecutive Disability Period starts with the first day of absence for the covered disability and includes time off on STD and/or LTD and/or Workers' Compensation. Any return to work for twenty-nine (29) calendar days or less, excluding PTO, does not restart or extend this Consecutive Disability Period.

The Consecutive Disability Period ends when an employee returns to work, without restriction (with or without accommodation), for a period of thirty (30) or more consecutive calendar days, excluding PTO, in either the employee's original position or a new regular position. Any subsequent absence related to the same initial disability would start a new Consecutive Disability Period.

Section 15.6 Family and Medical Leave Act and Americans with Disabilities Act (ADA)

As detailed in Section 2.6 within this Agreement, the parties strive to comply with all applicable laws, rules and regulations governing the workplace, including but not limited to the Family and Medical Leave Act (and applicable state law) and the Americans with Disabilities Act (and applicable state law). To the extent applicable laws include exceptions for parties in a collectively bargained relationship, this Section does not address or waive the application of such exceptions.

15.6.1 **Family and Medical Leave Act (and Related State Laws)**

Federal and State laws permit eligible employees to take unpaid leave in certain circumstances. These laws include, for example, the federal Family and Medical Leave Act (FMLA), the Oregon Family Leave Act (OFLA), the Washington State Family Leave Act (WFLA), the Washington State Family Care Act (WFCA), and the Washington State Military Family Leave Act (WMFLA).

15.6.2 **Americans with Disabilities Act (and Related State Laws)**

Employees must be able to perform essential job functions with or without reasonable accommodation.

ARTICLE 16
HEALTHCARE

Section 16.1 Employees

The Company shall pay into the Western States Health & Welfare Trust Funds of the OPEIU, hereinafter the Welfare Trust Fund, the costs necessary to establish and maintain coverage for medical, dental, vision, and life insurance benefits for eligible employees through the Welfare Trust Fund, including that percentage specified in 16.1.1.3 to this Article as the responsibility of the employee. The terms and conditions of coverage are set forth in the Welfare Trust Fund’s plan documents and are not the subject of negotiation between the Parties.

16.1.1 **General**

16.1.1.1 These Company payments will be made only for eligible employees who are regularly scheduled to work twenty (20) or more hours per week. Term employees are eligible only for the benefits identified in their Term Employee Agreement.

16.1.1.2 For the term of this Agreement the Company will share in the cost of benefits with employees as necessary to provide benefits under the Welfare Trust Fund, on the effective dates and in the amounts described below.

16.1.1.3 Effective with the benefit year beginning January 1, 2025, and for the term of the Agreement, eligible employees shall be responsible for fifteen percent (15%) of the cost of the premium. The premium share payments for the Company and employees described above are based on composite rates provided by the Welfare Trust Fund and will apply regardless of the number of dependents that the employee enrolls. If the Trustees of the Welfare Trust Fund make alternate rates available during the term of this Agreement, the Parties agree to negotiate the impact of any alternate rates.

The Company is authorized to deduct from each eligible employee's wages the percentage amount described above as the employee's cost of premium in such amount that is necessary to maintain coverage under the Welfare Trust Fund.

16.1.2 **Spouses or Partners Both Working for NW Natural**

An employee who is married to, or in a domestic partnership with, a current or former Company employee who is eligible for Company payments to the Welfare Trust Fund will not be required to opt out of coverage, but may elect to opt out. In which case, the employee will be covered under the voluntary provisions of 16.1.3 to this Article.

16.1.3 **Opt Out Due to Other Coverage**

Employees eligible for Company payments to the Welfare Trust Fund may voluntarily opt out of Welfare Trust Fund medical, dental, and vision coverage, provided that they produce evidence of other such coverage. Employees who opt out of coverage will receive a cash payment of three hundred dollars ($300.00) per month in lieu of Company payments to the Welfare Trust Fund. This monthly cash payment can be applied to other benefits offered by the Company (such as additional life insurance or additional life insurance or additional LTD, subject to the terms of those benefits), deferred into the RKSP 401(k) Plan, taken as cash, and/or directed into the Flexible Spending Account.

16.1.4 **Timing of Elections**

In any case where an employee can elect a cash payment in lieu of Company payments to the Welfare Trust Fund, the employee's election must be made under, and in compliance with, a cafeteria plan under Section 125 of the Internal Revenue Code, as amended (Code). The provisions of Section 16.1 to this Article shall be interpreted and applied in a manner that complies with Section 125 of the Code.

Section 16.2 Retirees

16.2.1 **General.** A covered retiree is a former employee who (i) is eligible for and elects to retire at or after age sixty (60) with a total of fifteen (15) years of service, or at or after age fifty-eight (58) with a total of twenty (20) years of service, under the Retirement Plan and (ii) enrolls in retiree coverage through the Welfare Trust Fund. A covered retiree may enroll their eligible dependents (as defined by the Welfare Trust Fund). Retiree medical coverage through the Welfare Trust Fund ends when the covered retiree becomes Medicare eligible, currently age sixty-five (65). The Company's obligations under this Agreement are to make payments to the Welfare Trust Fund for retiree medical coverage through the term of this Agreement.

16.2.2 Effective through the term of this Agreement, the premium necessary to maintain benefits for each covered retiree under the Welfare Trust Fund shall be paid by the Company and covered retiree, as of the effective date of this Agreement (seventy-five percent [75%] Company/twenty- five percent [25%] Covered Retiree).

16.2.3 The premium share payments for the Company and covered retirees are based on composite rates and will apply regardless of the number of dependents (if any) that the covered retiree enrolls. If the Trustees of the Welfare Trust Fund make alternate rates available during the term of this Agreement, the parties agree to negotiate the impact of any alternate rates.

16.2.4 **Exclusion of Certain Employees**

Employees hired on or after January 1, 2010, are not eligible for retiree medical coverage under the Welfare Trust Fund or for Company payments to the Welfare Trust Fund. Employees who terminate employment with the Company and who are rehired on or after January 1, 2010, are not eligible for retiree medical coverage under the Welfare Trust Fund or for Company payments to the Welfare Trust Fund. This exclusion applies regardless of the length of the rehired employee's break in Company employment and regardless of whether the rehired employee previously would have been eligible for retiree medical benefits.

Section 16.3 Retirees with Spouses or Partners Eligible for Company Paid Benefits

A Company retiree who is eligible for coverage under the Welfare and Trust Fund will not be required to opt out of coverage but may elect to opt out. In which case, the company retiree will be covered under the voluntary provisions of 16.1.3 to this Article.

ARTICLE 17
OTHER BENEFITS

Section 17.1 Meal Stipend

17.1.1 **Meal Stipend.** Employees, except for those on per diem, shall be provided a meal stipend for any of the listed situations:

a. Working three (3) or more hours in addition to the assigned shift duration (minimum eight [8] hour shift);

b. Each four (4) hours of continuous overtime beyond the original three (3) hours;

c. Unplanned Shift Change or Call-In without at least three (3) hours advance notice to provide for a meal; or,

d. After four (4) consecutive hours of work on a Call-In.

17.1.2 **Time Stipend.** Employees who meet the criteria of 17.1.1 (a), including those on per diem, shall be paid the amount equivalent of thirty (30) minutes of time at one and one-half (1.5) times the regular rate. The thirty (30) minutes will be paid one (1) time per continuous work period and shall not be counted as time worked for the purpose of calculating overtime.

17.1.3 Effective November 1, 2023, the meal stipend is twenty-three dollars and sixty cents ($23.60). The meal stipend will be adjusted annually by the same percentage adjustment made to the per diem rate, if any. The dollar amount of meals will be recalculated annually by indexing it to the Government Services Administration's per diem rate for the State of Oregon as described in 17.2.2 of this Article.

Section 17.2 Per Diem

17.2.1 An employee shall be provided per diem for each day the employee is temporarily assigned job duties away from the regular work area which requires an overnight stay, including the first and last scheduled workdays. Such allowance shall include all personal expenses other than lodging and travel, and is provided to cover such items as meals, tips, personal phone calls, and local transportation. Meal stipends are not provided when the employee receives per diem.

17.2.2 Effective December 1, 2023, the per diem rate is sixty-six dollars ($66.00). The per diem rate will be adjusted annually by averaging the Government Services Administration's State of Oregon rates as published on the website (www.gsa.gov). This per diem rate will be adjusted not less than thirty (30) days after publication by averaging the Meals and Incidental rate column for the close of the government fiscal year, published approximately October of each year for the following twelve (12) month period.

Section 17.3 Compensation for Travel

Employees will be compensated for travel and mileage. Federal applicable state wage and hour regulations apply as a minimum in these situations, absent an agreement between the Parties.

17.3.1 Paid Travel Guidelines

Paid travel is to be completed during regular scheduled working hours if possible. With the appropriate advance notice, an employee's schedule can be changed to accommodate travel time. (To determine if an Unplanned Shift/Schedule change, see 6.1.3 within this Agreement).

- Paid travel at a time other than the employee's regular scheduled working hours must be pre-approved by Management.
- Paid travel time shall be counted as time worked for the calculation of overtime. To determine appropriate pay, refer to 11.5.1 within this Agreement for overtime calculation with the exception that travel on Sundays or holidays is not automatically paid at two (2) times the regular rate.
- Paid travel time is eligible for applicable premium pay.
- For standard travel times and mileage between Company-based locations, refer to the Hub. Travel times and mileage between locations other than Company-based locations will be calculated by management utilizing the method used by the Labor/Management Committee (LMC) [e.g., currently GoogleMaps]. Time exceeding those calculated will be reported to Management for compensation.
- When applicable, mileage reimbursement will be paid in accordance with the Company's Mileage Reimbursement Policy and will be made available to all employees on the company intranet.
- A Company vehicle may be temporarily or permanently assigned to employees for "drive home" use based on business needs.

17.3.2 Travel within Company Territory Requiring Overnight Stay

The Company will provide lodging when an overnight stay is required. The Company is responsible for all associated costs of lodging prior to travel. Employees will not be responsible for any out-of-pocket expenses for lodging, excluding incidentals. Employees may be required to provide personal credit card to cover incidentals.

- If the employee requests and Management agrees, the employee may travel on a normal day off ahead of the desired reporting day to the temporary reporting location. Under these circumstances, the Company will provide lodging for that day and time spent traveling to the temporary location will be compensated as time worked based on the calculated travel time from the employee's Company-based location to the temporary reporting location. Per diem will not be provided for that day.

- Employees returning home on the last day of a work assignment will be paid for time worked that day including the standard time to drive from the temporary reporting location to the employee's Company-based location. They will also receive per diem for that day.

- If an employee uses a personal vehicle to commute to and from the temporary reporting location, mileage reimbursement will be provided for that commute based on the standard mileage between the employee's Company-based location and the temporary reporting location.

17.3.3 **Travel Outside Company Territory**

The Company may ask employees to travel to training or other events outside of the territory. Such travel can normally be completed within an eight (8) hour timeframe, but due to unforeseen circumstances (e.g., weather or mechanical delays) may exceed this time.

- All travel arrangements, including scheduled travel day, and itinerary, are to be mutually agreed to by the employee and Management prior to travel. The Company is responsible for all associated costs of lodging prior to travel. Employees will not be responsible for any out-of-pocket expenses for lodging, excluding incidentals. Employees may be required to provide personal credit card to cover incidentals.

- Paid travel time for travel outside of scheduled working hours shall be up to a maximum of eight (8) hours per day in addition to any time already worked that day, unless otherwise required by applicable law. Employees will also receive per diem for that day.

- Travel time is only those hours spent in transit to or from the travel destination.

- Company Policy "Business Travel Procurement and Expense Reimbursement" also applies for travel arrangements outside NWN territory.

17.3.4 **Voluntary Travel Alternatives**

Travel alternatives at the employee's discretion (mode of travel, early arrival or late departure for personal reasons) must be mutually agreed upon by the employee and Management. Such travel should be cost neutral to the Company.

When voluntary travel arrangements result in missed workdays, those days will be charged to Paid Time Off (PTO).

Section 17.4 Transportation

17.4.1 **Basis of Allowance**

Employees who use their personal vehicles for Company business shall be compensated at the rate authorized by the Company, taking into consideration the rate established by the Internal Revenue Service (IRS). The current rate will be made available to all employees on the Company intranet.

17.4.2 **Parking**

The Company has no obligation to provide employee parking, but will make parking available to the extent possible. A parking Flexible Spending Account (FSA) will be available to employees to allow for pre-tax benefit account that can be used to pay or get reimbursed for qualified parking expenses.

17.4.3 **Transit Passes**

Transit passes will be made available to Headquarters-based bargaining unit employees at no cost to the employee. Oregon residents will be provided a TriMet pass. Washington residents who are reporting at 250 Taylor two (2) or more times per week will be provided a C-Tran pass upon request.

In the event of a personal emergency, the Company may provide accommodations to transport the employee to their destination.

Section 17.5 Jury Duty

17.5.1 Employees will receive their regular straight-time rate of pay while serving on jury duty, provided the employee has:

- Promptly notified a designated Company representative and presented a legally enforceable subpoena,
- Requested a transfer to a Monday through Friday Day Shift schedule, if applicable, and

- Called a designated Company representative on weekdays when excused from jury duty to determine whether to report to work.

17.5.2 Employees shall retain any compensation paid by the court while performing this civic function.

Section 17.6 Recognition Programs

In recognition of employee flexibility and support of continuous operations, departments or workgroups may develop recognition programs. Any new recognition programs are subject to approval of the LMC Leadership Team.

Section 17.7 Paid Parental Leave

Regular employees who are regularly scheduled to work twenty (20) or more hours per week are eligible for Paid Parental Leave following the birth, adoption of a child, or foster care placement. Eligible full-time employees qualify for one hundred and twenty (120) hours of pay at their regular rate of pay.

Eligible employees who are typically scheduled to work between twenty (20) to thirty-nine (39) hours per week will receive a pro-rated benefit, based on their weekly schedule. Additional details are provided in the Company's Paid Parental Leave policy.

17.7.1 If and when any new state or federal laws are passed that include a requirement for employers to provide additional paid or unpaid leave, the parties agree to meet and discuss total paid leave allocation. Paid Parental Leave will run concurrently with leave taken under the Oregon Family Leave Act, the federal Family and Medical Leave Act, and/or paid leave provided under any state law when applicable.

17.7.2 Eligible employees should provide thirty (30) days' advance notice or as much advance notice as practicable under the circumstances when requesting paid parental leave. Any paid parental leave provided will run concurrently with leave taken under applicable state or federal leave laws.

17.7.3 **Rate of Pay**

The rate of pay for Paid Parental Leave shall be computed in the same manner as PTO as described in Section 12.5 within this Agreement.

Section 17.8 Personal Protective Equipment (PPE) Allowances

PPE allowances will be reviewed annually and adjusted as necessary based on Tyndale's average price increase.

17.8.1 **FR (Fire Resistant) Clothing Allowance**

- Newly hired or rehired field employees who are required to wear FR clothing shall receive two thousand one hundred seventy-five dollars ($2,175.00) for the purchase of approved FR clothing by the end of the calendar year.

- All field employees who are required to wear FR clothing shall receive an annual allowance of nine hundred dollars ($900.00) for the purchase of approved FR clothing, effective January 1st, 2025.

- Employees have the obligation to take reasonable care of FR clothing. Employees are responsible for laundering. Employees may receive replacement of damaged FR clothing due to unanticipated work-related situations with Supervisor approval.

17.8.2 **Footwear Protection Allowance**

Employees required to wear safety footwear shall be provided up to three hundred dollars ($300.00) per calendar year for either purchase or refurbishment of boots (e.g., boot rebuilds or toe guards).

17.8.3 **Prescription Safety Glasses**

Employees requiring prescription safety glasses receive up to four hundred fifty dollars ($450.00) for two (2) pairs of prescription safety glasses during their initial year in the program, and thereafter an annual allowance of up to two hundred twenty-five dollars ($225.00) for replacement prescription safety glasses.

ARTICLE 18
RETIREMENT PLANS

Section 18.1 Bargaining Unit Employees' Retirement Plan

The Company shall continue to maintain the NW Natural Gas Company Retirement Plan. The Company will make contributions to the Retirement Plan in amounts determined by the Company in consultation with an enrolled actuary, that are sufficient on a sound actuarial basis to provide for the payment of benefits.

18.1.1 Regular employees employed on or before December 31, 2009, are eligible to participate in the Retirement Plan to the extent provided for in the written terms and conditions of the Retirement Plan. Term employees are eligible only for the benefits described in the Term Employee Agreement. Term employees are not eligible to participate in the Retirement Plan.

18.1.2 Regular employees hired on or after January 1, 2010, are not eligible to participate in the Retirement Plan. Regular employees who terminate employment with the Company and who are rehired on or after January 1, 2010, are not eligible to participate in, or to accrue any additional benefits under, the Retirement Plan. This exclusion applies regardless of the length of the rehired employee's break in Company employment and regardless of whether the rehired employee previously participated in the Retirement Plan.

18.1.3 Western States Pension Plan (Western States Plan B)

Upon establishment of the plan, the Company will perform its due diligence for acceptance. Company and Trust Representatives will present the Western States Pension Plan B to the NW Natural RKSP Committee and to the NW Natural Board of Directors for approval. If approval is given the Company will make contributions to the Western States Office and Professional Employees Pension Fund on behalf of each eligible Regular Employee beginning the first of the calendar year following approval.

For employees hired or rehired on or after January 1, 2010, the Company will contribute four percent (4%) of the employee's compensation including overtime. Benefits are determined by the Board of Trustees of the Western States Plan and are not subject to negotiation between the Company and the Union.

If the plan is not approved in order to commence contribution on January 1, 2025, 18.1.3 will be opened to renegotiate.

Section 18.2 Retirement K Savings Plans (401(k) Plan)

18.2.1 **Retirement K Savings Plan (RKSP 401(k) Plan)**

Except as provided in this Agreement, all bargaining unit employees shall be eligible to participate in the RKSP 401(k) Plan under the terms and conditions set forth in the RKSP 401(k) Plan document. For purposes of Section 18.2 to this Article, employees participating in the RKSP 401(k) Plan shall be referred to as "RKSP Participants." During the term of this Agreement, the Company will make a cash matching contribution each pay period on behalf of each RKSP Participant who has made elective deferrals to the RKSP 401(k) Plan during that pay period.

- During the term of this Agreement, the matching contribution shall be equal to fifty percent (50%) of the RSKP participant's elective deferrals (excluding catch-up contributions under Code Section 414(v)) for the pay period, but disregarding elective deferrals exceeding eight percent (8%) of the RKSP Participant's compensation, as defined in the RKSP 401(k) Plan, for the pay period.

- Term employees are eligible only for the benefits identified in their Term Agreements.

18.2.2 **Enhanced RKSP 401(k) Plan Contributions for Employees Hired or Rehired On or after January 1, 2010**

For employees hired or rehired on or after January 1, 2010, who are eligible to participate in the RKSP 401(k) Plan, the Company will separately contribute four percent (4%) of the employee's compensation for each plan year to the RKSP 401(k) Plan account (Enhanced RKSP 401(k) Plan Benefit). This Enhanced RKSP 401(k) Plan Benefit is available only to employees hired or rehired on or after January 1, 2010, as they are not eligible to participate in the NW Natural Gas Company Retirement Plan.

Pursuant to 18.1.3, the Enhanced RKSP 401(k) plan contribution will be redirected to Western State Pension Plan B in the same manner as the Enhanced Contributions are structured. Employees that are not eligible to enroll in the Western State Pension Plan will continue to participate in the Enhanced RKSP 401(k) plan.

ARTICLE 19
EMPLOYEE STOCK PURCHASE PLAN

Employees are eligible to participate in the Company's Employee Stock Purchase Plan ("ESPP") according to the terms and conditions set forth in the written ESPP document. The Company shall continue to have sole discretion to determine the terms and conditions of the ESPP applicable to employees, including contributions, benefits, and administrative provisions. The Company retains the right to terminate the ESPP at any time and will notify the Union of such decision prior to its implementation. Term employees are eligible only for the benefits identified in their Term Agreements.

ARTICLE 20
PROGRESSIVE DISCIPLINE

Section 20.1 General

The Company may discipline or terminate any employee for Just Cause and will determine the appropriate level of discipline based on the facts and circumstances presented. The Company shall conduct investigations and issue all discipline in an expedient manner. Notwithstanding the inclusion of Just Cause, the Union and the Company agree to a reasonable person standard to determine what's right, not who's right, in matters of discipline. To ensure the reasonable person standard is adhered to, discipline defense based purely on Just Cause must be approved by the Executive Secretary-Treasurer of OPEIU Local 11 or their designee.

20.1.1 **New Hire Probationary Periods**

Any probationary new employee can be terminated for any reason without intervention by the Union and without right of appeal to the Grievance and Mediation/Arbitration Process in Article 21 within the Agreement.

20.1.2 **Progressive Discipline**

Regular employees may be disciplined in the form of a Documented Verbal Warning, Disciplinary Action Plan, suspension, or termination for Just Cause. Discipline should be progressive to allow the employee the opportunity for improvement prior to moving to a higher level of discipline.

Section 20.2 Definitions

20.2.1 **Documented Verbal Warning (DVW)**

A disciplinary document a Manager or Supervisor may use that identifies in writing an employee's performance problems or other conduct that requires correction.

20.2.2 **Disciplinary Action Plan (DAP)**

A written disciplinary document a Manager or Supervisor may use that states specific performance problems or conduct requiring correction and requires that the employee fully correct the problem within a specified period of time.

20.2.3 **Suspension**

A disciplinary suspension is unpaid and may be used by a Manager or Supervisor in conjunction with a DVW or DAP.

20.2.4 **Last Chance Agreement (LCA)**

A written disciplinary document a Manager or Supervisor may use that states that employee misconduct could have led to termination, but the employee is being offered one final opportunity. An LCA is not subject to the grievance process.

Section 20.3 Disciplinary and Investigatory Meetings

During a disciplinary or investigatory meeting, an employee shall be afforded Union representation as associated with Weingarten Rights, upon the employee's request. The Company shall notify the appropriate representative of the Union (e.g., Steward, Chief Steward, Union Representative) and provide a reasonable period of time to be available for the meeting.

Employees shall be advised of their right to Union representation during any investigatory interview or meeting which could reasonably be expected to lead to disciplinary action.

Section 20.4 Process

Progressive discipline shall normally include the following steps:

20.4.1 **Documented Verbal Warning (DVW):** Supervisor is to keep the original in the supervisory file. A copy will be provided in accordance with Section 20.5 to this Article. Documented Verbal Warnings shall remain in effect for no more than two (2) years, at which time they shall be considered removed from the employee's supervisory file.

20.4.2 **Disciplinary Action Plan (DAP):** Copies of the DAP will be sent to Human Resources to be placed in the employee's personnel file and copies provided in accordance with Section 20.5 to this Article. Typically, a DAP will be in effect for up to one hundred and eighty (180) calendar days. Duration of DAPs longer than one hundred and eighty (180) calendar days must be signed by the Manager and the Union Representative.

Three (3) years after the satisfactory completion of a DAP, it will be considered moved from the employee's personnel file to the employee's "employee history file," provided no additional DAPs have been issued to the employee. This "employee history file" will be retained in Human Resources and will be considered a part of the employee's personnel record.

20.4.3 **Suspension:** In case of a suspension, the Company agrees that the employee and the Union shall be provided written documentation setting forth the reason(s) for such action, and in accordance with Section 20.5 of this Article. Employees are entitled to Union representation at such meetings.

To avoid undue burden on the workgroup the date(s) that the employee will be away from work for disciplinary suspension will be determined by applicable PTO guidelines. For work group(s) that do not have documented PTO scheduling guidelines the accepted departmental process will apply; if the suspension dates are not selected and agreed to within five (5) working days management will assign the dates.

For suspensions that are three (3) days or fewer, the date(s) will not be adjacent to employee's regular scheduled day(s) off. No suspension days will be taken adjacent to an observed Holiday. Unpaid dates will occur within sixty (60) days from the date of discipline.

20.4.4 **Last Chance Agreement (LCA):** Copies of the LCA will be sent to Human Resources to be placed in the employee's personnel file permanently and copies will be provided in accordance with Section 20.5 of this Article.

20.4.5 Employees will be required to acknowledge receipt in writing of any disciplinary action; which the employee's signature shall not be construed as agreement or concurrence with the discipline; and in accordance with Section 20.5 of this Article.

Section 20.5 Distribution of Documents

The Company will provide copies of DVWs, DAPs, LCAs, and Terminations to the employee, Human Resources, Union Office, and Steward or Chief Steward. Sensitive information (e.g., LCAs) may be only shared with the Union Office to ensure privacy for the employee.

Section 20.6 Repetition of Infraction

Repetition of the infraction or failure to complete an action plan within the time specified may lead to further discipline up to and including termination.

Section 20.7 Discipline

As stated in Section 20.1 of this Article, any infraction may also warrant an immediate DAP, suspension, or termination.

Section 20.8 Bidding

Bidding on positions, advancing in a Line of Progression, or Progression without Bidding may be affected as a condition of progressive discipline.

Section 20.9 Grievance

The employee may file a written grievance appealing disciplinary action per Article 21 within this Agreement.

ARTICLE 21
GRIEVANCE AND MEDIATION / ARBITRATION PROCESS

Section 21.1 Introduction

The Grievance Process is limited to matters of discipline and unresolved Issue Resolution items, and in accordance with Section 21.3 to this Article. This Grievance Process is established on the premise of trust, respect and the mutual goal of resolving differences at the earliest opportunity and appropriate level. It is not intended to be a substitute for direct dialogue between employee and Supervisor or to be used for events covered by the Issue Resolution Process as per Article 10 to this Agreement.

Section 21.2 Timelines

When computing timelines under this Article, the day which triggers the grievance (contract violation, receipt of grievance, etc.) shall not be included. “Working days” means Monday through Friday, excluding holidays. Filing and response time limits shall be met by mailing, e-mail, hand delivery or facsimile transmission. Receipt shall be considered to be the date of actual receipt.

The time limits prescribed herein may be waived or extended by mutual agreement, in writing by the Steward, Chief Steward, or the Union, and the appropriate Company representative at each step.

A grievance not brought within the time limit prescribed for every step shall be considered settled on the basis of the Company's last decision received by the Steward, Chief Steward, or the Union. A grievance or complaint not responded to by the Company representative may be moved to the next step in the procedure.

Section 21.3 Written Grievances

A written grievance shall be documented on the official OPEIU Local 11 Grievance form and must be signed and dated and indicate the step at which it is being filed. Grievances not meeting the requirements of this Section shall not be considered officially filed or may not be moved to the next step until missing information is provided. Grievances or responses to grievances missing information may be referred to the LMC Co-Chairs or timelines can be extended in accordance with Section 21.2 to this Article. Written grievances and responses at all levels shall address, at a minimum, the following points:

- The statement of the grievance/response and the facts upon which it is based;
- Signed by the grievant and the represented parties involved;
- A statement of the specific provision(s) of the Agreement that is (are) the basis of the grievance/response;
- The manner in which the provision is purported to have been violated, misapplied, or misinterpreted (or in which the provision supports the response);
- The date or dates on which the alleged violation, misinterpretation, or misapplication occurred; and
- The specific remedy sought or offered.

Section 21.4 Grievance Process

A grievance can be initiated in the following ways:

- If the concern is about discipline, it should start at Level 1 in the grievance process.
- If the grievance is related to an employee's involuntary termination, Level 1 and Level 2 of the grievance process will be bypassed and the grievance process will start at Level 3 in accordance with this Article.
- The concern may be referred from the issue resolution process at the discretion of the LMC Co-Chairs. In these instances, the LMC Co-Chairs may elect to bypass Levels 1 and 2 of the grievance processes.

Grievances may necessitate meeting more than once at any particular level or obtaining information from additional sources; however, each level will be addressed in an expedient manner.

For grievances that start in the Grievance Resolution Process, the Steward and the Supervisor should first meet informally to understand and potentially resolve the unfiled grievance.

For grievances referred through the Issue Resolution Process, it is required that the Issue Resolution Committee write up what was agreed to, what the parties were unable to agree to, and narrowly describe the open question that has not been resolved.

21.4.1 **Level 1 – Process**

Participants: Employee, Steward(s) or the Union Representative, and the first line Supervisor or their designee.

Procedure: The Union Steward has twenty (20) working days to file a formally documented grievance for the employee(s) or on behalf of the employee(s) from the event or knowledge of the event and should be submitted to the Supervisor of the employee(s).

The Supervisor will schedule a meeting with the Steward to occur within ten (10) working days of receiving the documented grievance to potentially resolve the grievance or to provide additional background information. Resolved and unresolved outcomes of the grievance resolution meeting will be documented.

It is the intent of the Parties to strive to resolve grievances at this level.

Copies will be sent to the Union office and the Chief Steward by the Steward, and to Human Resources and the Manager by the Supervisor within ten (10) working days from the Level 1 meeting. Unresolved Grievances will enter the Level 2 process.

21.4.2 **Level 2 – Process**

Participants: Individuals involved in Level 1 plus Chief Steward and Manager(s) responsible for department (or representative) and any Subject Matter Expert (SME) needed to reach resolution.

Procedure: Within ten (10) working days of receipt of the unresolved Level 1 grievance filing, the Manager (or designee) will schedule a meeting with the Chief Steward; this meeting is to occur at a mutually agreeable time.

Resolved outcomes of the grievance resolution meeting between the Chief Steward and the Manager will be documented. Copies will be sent to the Union office by the Chief Steward and to Human Resources by the Manager within ten (10) working days from the Level 2 meeting.

Unresolved grievances, within ten (10) working days from the Level 2 meeting, will be documented with recommendations and forwarded by the Manager and Chief Steward to the LMC Co-Chairs (or designee) for review and recommended action prior to entering the Level 3 process.

21.4.3 **Level 3 – Process**

Participants: LMC Co-Chairs; and as needed, the Chief Steward and the Department Manager.

Procedure: LMC Co-Chairs shall review the grievance, and meet to discuss said grievance within ten (10) working days of receipt of the grievance, and determine a resolution within fifteen (15) working days of receiving the Level 2 grievance meeting documentation. If the grievance is not resolved by the LMC Co-Chairs, it shall be submitted in writing to the LMC Executive Sponsors within five (5) business days from the Level 3 grievance meeting for continued discussion or consideration of next steps. All Level 3 documented resolutions must be approved by the Company's Executives responsible for labor relations and the Executive Secretary-Treasurer of OPEIU Local 11, or their designees. Resolutions reached at this level will be final and binding on both parties and documentation will be forwarded to the filing parties within ten (10) working days of the decision.

All timelines above may be extended by mutual agreement of the Parties. If extended, notification will generally be provided to all parties along with status and anticipated action within three (3) working days of the decision to extend, or as soon as possible thereafter.

Section 21.5 Mediation and Arbitration

If the grievance cannot be resolved at Level 3, the Parties may, by mutual agreement, seek the assistance of the Federal Mediation and Conciliation Service in a non-binding attempt to resolve the dispute. Mediation communications are not admissible in arbitration.

In the event the grievance has not been settled, the Union or the Company may seek arbitration. The Arbitrator shall be selected by Union and Company representatives from a panel obtained from the Federal Mediation and Conciliation Service or as otherwise mutually agreed by the parties. The authority of the Arbitrator is limited to interpreting the express provisions of this Agreement or related terms and conditions of employment of covered employees. The decision of such arbitrator shall be final and binding upon both parties. The parties shall each pay their own fees and costs, and each shall pay one-half (½) of the Arbitrator's fees and any other joint costs of the arbitration.

Nothing in this Article precludes a party from withdrawing a grievance at any time with written notification to the Union office and to Human Resources.

ARTICLE 22
SEPARABILITY OF PROVISIONS

If any provision of this Agreement shall be found to be invalid by any court having jurisdiction in respect thereof, such finding as to such provision shall not affect the remainder of this Agreement, and all other terms and provisions hereof shall continue in full force and effect as set forth herein. If the provision is found to be invalid by the court having final jurisdiction in respect thereof, the parties shall promptly negotiate and endeavor to reach agreement upon a suitable substitute for said provision.

Nothing in this Collective Bargaining Agreement shall be interpreted or enforced to cause a violation of any applicable Federal, State, or local law or regulation.

ARTICLE 23
TERM OF THE AGREEMENT AND METHOD OF REOPENING

The Collective Bargaining Agreement and all terms and provisions hereof shall be and continue in effect from and after the date first written hereof until midnight on May 31, 2028, and until May 31st from year to year thereafter until and unless either party shall have served written notice to the other party at least sixty (60) calendar days prior to said May 31, 2028, or prior to any May 31st thereafter stating that it desires to negotiate modifications or to terminate this Agreement.

IN WITNESS WHEREOF, the parties have caused this Collective Bargaining Agreement to be executed in duplicate by their respective officers, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

By

Larry R. Buchanan

Cari L. Colton

James C. Hart

Darcy D. Noxon

Joseph S. Karney, LMC LT Executive Sponsor

Michelle L. Ewaniec, LMC LT Co-Chair

Melinda B. Rogers, LMC LT Executive Sponsor
VP, Chief HR & Diversity Officer

David Anderson, Chief Executive Officer

Justin Palfreyman, President

Mardilyn Saathoff
Senior VP, General Counsel & Regulation

OFFICE & PROFESSIONAL EMPLOYEES INTERNATIONAL UNION, LOCAL-11, AFL-CIO

By

Jonathan P. Hughes

Michael K. Jamison

Christine N. Jelbmann

Konswaylu S. Nelson

Ernest H. Pech

Aron P. Ruljancich

Jordan Fosdick, LMC LT Co-Chair

Howard Bell, LMC LT Executive Sponsor
Executive Secretary-Treasurer

SCHEDULE A – JOB TITLES BY PAY GROUP

Pay Group	Job Title *(Position Title)*	Pay Group	Job Title *(Position Title)*
A1	Construction 4 *(Transmission Foreman/woman)* Electronic Technician 2 Journeyman Electrician Journeyman Millwright	F	Accounting 4 Customer Service 4 Specialty Construction 1 Stores 3 *(Head Storekeeper)* Stores 3 *(Storekeeper - Delivery)* Stores 3 *(Storekeeper - Transportation)*
A	System Ops 2 Transmission Maintenance 2 *Weld & Fab 4 *(Mechanic Welder)*	G	GIS Tech 2 Stores 2 *(Storekeeper)* Technical Coordinator 3 Weld & Fab 1 *(Body Repair Tech)*
B	Construction 3 *(Distribution Foreman/woman)* *Corrosion Technician Customer Field Service 4 *(Industrial Tech)* Electronic Technician 1 Gas Storage 2 *(Chief Operator)* Instrumentation Technician	H	Accounting 3 Computer Support 1 Customer Service 3 GIS Tech 1 Operational Support 3 Technical Coordinator 2 Transportation 2 (Lube Tech Specialist) Utility Support 3 *(Field Maint Worker)*
C	Customer Field Service 3 (Commercial Tech) Distribution Arc Welder 2 Field Support 3 (Field Engineering Tech) General Services 4 (Sr Machinist) Leakage Inspector System Ops 1 Transportation 4 (Auto Shop Foreman/Woman) Transmission Maintenance 1	I	*Currently No Positions*
		J	Accounting 2 Customer Service 2 Office Services 2
D	Construction 2 - Honored *Customer Field Service 2 (Service Tech) Distribution Arc Welder 1 Field Support 2 (Field Measurement Tech) Gas Storage 1 (Plant Operator) Specialty Construction 2 Transportation 3 (Auto Mechanic) Weld & Fab 3 (Sr Fabricator)	K	Operational Support 2 Transportation 1 *(Garage Attendant)*
		L	Accounting 1 General Services 1 *(Delivery Driver)* Office Services 1 Stores 1 *(Warehouse Worker)*
E	*Construction 2 Field Support 1 *(Field Data Tech)* Fire & Safety Technician General Services 2 *(Maintenance Tech)* GIS Tech 3 Meter & Reg Shop 2 Semi & Crane Weld & Fab 2 *(Fabricator)*	M	Customer Service 1 Utility Support 2 *(AMR Driver)*
		N	*Currently No Positions*
		O	Utility Support 1 *(Motor Messenger)*

* Designates job titles with additional pay steps

SCHEDULE B – WAGE SCALES

Pay Group	Step Description	June 2024 Wage Rate with 6.0% Increase	December 2024 Wage Rate with 4.0% Increase	December 2025 Wage Rate with 4.0% Increase	December 2026 Wage Rate with 4.0% Increase	December 2027 Wage Rate with 4.0% Increase
A1	Experienced	$57.00	$59.28	$61.65	$64.11	$66.67
A1	Entry	$54.72	$56.90	$59.18	$61.54	$64.00
A	Experienced	$55.26	$57.47	$59.76	$62.15	$64.63
A	Entry	$53.04	$55.17	$57.36	$59.66	$62.04
A	3 - Training	$49.73	$51.72	$53.78	$55.93	$58.16
A	2 - Training	$46.97	$48.84	$50.79	$52.82	$54.93
A	1 - Training	$44.20	$45.97	$47.80	$49.72	$51.70
B	Experienced	$53.53	$55.67	$57.89	$60.20	$62.60
B	Entry	$51.38	$53.44	$55.57	$57.79	$60.09
B	3 - Training	$48.17	$50.10	$52.10	$54.18	$56.34
B	2 - Training	$45.50	$47.31	$49.20	$51.17	$53.21
B	1 - Training	$42.82	$44.53	$46.31	$48.16	$50.08
C	Experienced	$50.28	$52.29	$54.38	$56.55	$58.81
C	Entry	$48.26	$50.19	$52.20	$54.28	$56.45
D	Experienced	$47.21	$49.09	$51.05	$53.09	$55.21
D	Entry	$45.32	$47.12	$49.00	$50.96	$53.00
D	3 - Training	$42.48	$44.18	$45.94	$47.78	$49.68
D	2 - Training	$40.12	$41.72	$43.39	$45.12	$46.92
D	1 - Training	$37.76	$39.27	$40.84	$42.47	$44.16
E	Experienced	$44.33	$46.10	$47.94	$49.85	$51.84
E	Entry	$42.55	$44.25	$46.02	$47.85	$49.76
E	3 - Training	$39.89	$41.49	$43.14	$44.86	$46.65
E	2 - Training	$37.68	$39.18	$40.74	$42.37	$44.06
E	1 - Training	$35.46	$36.88	$38.35	$39.88	$41.47
F	Experienced	$41.62	$43.28	$45.01	$46.81	$48.68
F	Entry	$39.95	$41.54	$43.20	$44.93	$46.73
G	Experienced	$39.10	$40.66	$42.28	$43.97	$45.72
G	Entry	$37.53	$39.03	$40.58	$42.21	$43.89
H	Experienced	$36.54	$38.00	$39.52	$41.10	$42.74
H	Entry	$35.07	$36.48	$37.93	$39.45	$41.03

Pay Group	Step Description	June 2024 Wage Rate with 6.0% Increase	December 2024 Wage Rate with 4.0% Increase	December 2025 Wage Rate with 4.0% Increase	December 2026 Wage Rate with 4.0% Increase	December 2027 Wage Rate with 4.0% Increase
I	Experienced	$34.15	$35.51	$36.93	$38.40	$39.93
I	Entry	$32.78	$34.08	$35.45	$36.86	$38.33
J	Experienced	$31.89	$33.16	$34.48	$35.85	$37.28
J	Entry	$30.61	$31.83	$33.10	$34.41	$35.78
K	Experienced	$29.55	$30.73	$31.95	$33.22	$34.54
K	Entry	$28.36	$29.50	$30.67	$31.89	$33.15
L	Experienced	$27.36	$28.45	$29.58	$30.76	$31.99
L	Entry	$26.26	$27.31	$28.39	$29.52	$30.71
M	Experienced	$25.32	$26.33	$27.38	$28.47	$29.60
M	Entry	$24.30	$25.27	$26.28	$27.33	$28.41
N	Experienced	$23.43	$24.36	$25.33	$26.34	$27.39
N	Entry	$22.49	$23.38	$24.31	$25.28	$26.29
O	Experienced	$21.69	$22.55	$23.45	$24.38	$25.35
O	Entry	$20.82	$21.64	$22.51	$23.40	$24.33

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1305

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1306

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE / CAPITAL EXPENDITURES EXHIBIT 1307

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

December 30, 2024

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of John J. Spanos

DEPRECIATION
EXHIBIT 1400

December 30, 2024

EXHIBIT 1400 – DIRECT TESTIMONY– DEPRECIATION

Table of Contents

I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your position in the firm?

A. I am President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a Past President and member of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes. I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Will you outline your experience in the field of depreciation?

A. Yes. I have over 38 years of depreciation experience which includes giving expert testimony in more than 480 cases before 46 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 900 other depreciation or valuation assignments. Please refer to Appendix A (Exhibit NW Natural/1401, Spanos) for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

Q. What is the purpose of your testimony?

A. My testimony is in support of the gas depreciation study conducted under my direction and supervision for Northwest Natural Gas Company (the “Company”). Based upon the study, I am recommending that new depreciation accrual rates be adopted by the Company.

II. OVERVIEW

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. Please describe the contents of the Depreciation Study.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, contains statements with respect to the plan of the report and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life and net salvage studies. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics, presents the statistical analysis of service life estimates. Part VIII, Net Salvage Statistics, sets forth the statistical indications of net salvage percents.

Part IX, Detailed Depreciation Calculations, presents the detailed tabulations of annual depreciation.

The table on Pages VI-5 through VI-8 of the Depreciation Study present the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2023, the book depreciation reserve and the calculated annual depreciation accrual amount and rate for each account or subaccount. The section beginning on Page VII-2 of the Depreciation Study presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on Page VIII-2 of the Depreciation Study presents the results of the net salvage analysis. The section beginning on Page IX-2 of the Depreciation Study presents the depreciation calculations related to surviving original cost as of December 31, 2023.

In the study that I performed, and which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life procedure to develop recommended depreciation accrual rates. The total annual depreciation is based on a system of depreciation accounting which aims to distribute the cost of fixed capital assets over the estimated useful life of the unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391.10, 391.20, 391.21, 392.22, 393.00, 394.00, 397.00, 397.10, 397.20, 397.30, 397.40, 397.50, 398.10, 398.20, 398.30, 398.40 and 398.50 for gas assets, I used the straight line method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. Have you prepared an exhibit presenting the results of your study?

A. Yes. The report titled, "2023 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2023," which has been marked Exhibit NW Natural/1402, Spanos, sets forth the results of my depreciation study.

Q. How did you determine the recommended annual depreciation accrual rates?

A. The determination of annual depreciation accrual rates consists of two phases. In the first phase, service life and net salvage characteristics are estimated for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, the annual depreciation accrual rates are calculated based on the service life and net salvage estimates determined in the first phase.

III. ESTIMATION OF SERVICE LIFE AND NET SALVAGE

Q. Please describe the first phase of each study, that is, the manner in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life studies consisted of compiling historical data from records related to the Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning the Company's practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of the Company's plant?

A. The data consisted of the entries made by the Company to record plant transactions through 2023. The transactions included additions, retirements, transfers and the related balances. The Company, in accordance with my instructions, classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. Was there any emphasis on other factors in this study?

A. Yes. First, we focused on the results from the last depreciation study in 2022 and some of the compromises agreed to in the Stipulation in docket UM 2312 that the Commission adopted in its Order No. 24-302, entered August 29, 2024. Second and more critically, we considered some of the key drivers for future life characteristics for asset classes. This was a reason for some of the slightly shorter lives for the mains and services accounts as these long-lived assets will not have as long a life cycle into the future.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method. That method is the most appropriate when aged retirement data are available, because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type of survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve as plotted from the life table represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa-type survivor curves were used in these interpretations.

Q. What is an "Iowa-type survivor curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type survivor curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa survivor curves were developed at the Iowa State University College of Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired. Iowa-type survivor curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa survivor curves and truncated Iowa survivor curves were used in the Depreciation Study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. As I will explain, the use of truncated curves is appropriate to reflect retirements of plant components that may not be fully depreciated at the time a plant is retired.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 58-R2 indicates an average service life of fifty-eight years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. What approach did you use to estimate the lives of significant facilities such as storage facilities?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occurs during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has this approach been adopted in other regulatory proceedings?

A. Yes. My firm has used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada, including this Commission.

Q. What are the bases for the probable retirement years that you have estimated for each facility?

A. The bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar facilities. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. Have you physically observed the Company's plants and equipment as part of your depreciation work?

A. Yes. The most recent field review of the Company's property was on September 28 and 29, 2021 in order to observe representative portions of plant. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar plants and meet with operations personnel at other companies. The knowledge accumulated from those visits and meetings provide me useful information that I can draw on to confirm or challenge my numerical analyses concerning plant condition and remaining life estimates.

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, *e.g.,* one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of a $10,000 regulator will include not only the $10,000 of original cost, but also, on average, $550 to remove the regulator at the end of its life and $50 in salvage value. In this example, the net salvage component is negative $500 ($50 - $550), and the net salvage percent is negative 5 percent (($50 - $550)/$10,000).

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages based on judgment. In doing so, for most accounts, I incorporated analyses of the historical data for the period 1993 through 2023 for gas plant and considered estimates for other gas companies. In the historical analyses, the net salvage, cost of removal and gross salvage amounts were expressed as percents of the original cost retired. These percents were calculated on annual and three-year moving average bases for the 1993-1995 through 2021-2023 periods.

IV. CALCULATION OF DEPRECIATION

Q. Please describe the second phase of the process that you used, that is, the calculation of annual depreciation accrual rates.

A. After I estimated the service life and net salvage characteristics for each depreciable group, I calculated annual depreciation accrual rates for each group in accordance with the straight line remaining life method, using the average service life procedure. The annual depreciation accrual rates were developed as of December 31, 2023.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and this rate is applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the sum of the future book accruals is divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. Please briefly describe the amortization of certain General Plant accounts.

A. For General Plant Accounts 391.10, 391.20, 391.21, 392.22, 393.00, 394.00, 397.00, 397.10, 397.20, 397.30, 397.40, 397.50, 398.10, 398.20, 398.30, 398.40

and 398.50 for gas assets, I used the straight line method of amortization. General Plant Accounts include a large number of units but represent slightly less than three percent of depreciable gas plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period.

V. <u>DESCRIPTION OF REPORT</u>

Q. Please use an example to illustrate the manner in which the studies were presented in the report.

A. I will use Account 380.00, Services, as my example because it is the largest depreciable mass account and represents 23 percent of the depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data were compiled from 1919 through 2023 and analyzed for periods that best represent the overall service life of this property. The life tables for the 1919-2023, 1976-2015 and 1981-2015 experience bands are presented on pages VII-102 through VII-110 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-102 shows $2,348,906 retired during age interval 0.5-1.5 with $1,024,432,762 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0023 ($2,348,906/$1,024,432,762) and the surviving ratio is 0.9977 (1-.00023). The percent surviving at age 0.5 of 0.9990 percent is multiplied by the survivor ratio of 99.77 to derive the percent surviving at age 1.5 of 99.67 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1919-2023. The resultant life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 60-R2.5 on page VII-101. The 60-R2.5 reflected the overall expected shorter life cycle into the future than what has been statistically experienced in the past.

The net salvage percent is presented on pages VIII-4 and VIII-5 for Account 380.00. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1993 through 2023. The 31-year period experienced $51,864,733 (($108,345)-$51,756,388) in negative net salvage for $48,143,634 plant retired. The result is negative net salvage of 108 percent ($51,864,733/$48,143,634) on the statistics for the account for the entire 31-year period. The three-year rolling averages and the most recent five-year averages trend to more negative net salvage, however, based on the current net salvage estimate and the industry averages, the recommended net salvage for gas services is negative 108 percent.

My calculation of the annual depreciation related to the original cost of Account 380.00, Services, as of December 31, 2023, is presented on pages IX-73 through IX-75 of the report. The calculation is based on the 60-R2.5 survivor curve, 108 percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-7.

VI. RECOMMENDATION

Q. What is your recommendation regarding annual depreciation accrual rates for the Company?

A. I recommend that the Company use a composite annual depreciation accrual rate for gas accounts or subaccounts. My recommended depreciation accrual rates, based on the depreciation study, are set forth for each account in column 9 of Table 1 on pages VI-5 through VI-8 of Exhibit NW Natural/1402, Spanos. In my opinion, these are reasonable and appropriate depreciation accrual rates for the Company.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of John J. Spanos

DEPRECIATION
EXHIBITS 1401 – 1402

December 30, 2024

EXHIBITS 1401–1402 – DEPRECIATION

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BEFORE THE

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Exhibit of John J. Spanos

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EXHIBIT 1401

December 30, 2024

Appendix A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the

Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:

"Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2019	HI PUC	Docket No. 2019-0117	Young Brothers, LLC	Depreciation
331.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
334.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
335.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
336.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
337.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
338.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
340.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
341.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
342.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
343.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
344.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
345.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
346.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
347.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
348.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
349.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
350.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
351.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery	Depreciation
352.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
353.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
354.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
355.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
356.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
357.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
358.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
359.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
360.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
361.	2021	NC Util.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
362.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
363.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
364.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
365.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
366.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
367.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
368.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
369.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
370.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
371.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
372.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
373.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
374.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
375.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation
377.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
378.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
379.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
380.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
381.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
382.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
383.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
384.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
385.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
386.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
387.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
388.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
389.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
390.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
391.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
392.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
393.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
395.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
396.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
397.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
398.	2022	PA PUC	R-2022-3031672; R-2022-3031673	Pennsylvania-American Water Company	Depreciation
399.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
400.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
401.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power	Depreciation
402.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
403.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
404.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
405.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
406.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation
407.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
408.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
409.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
410.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
412.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
413.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
414.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
415.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
416.	2022	NC Util Com	Docket No. E-22, Sub 493	Virginia Electric and Power Company	Depreciation
417.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
418.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
419.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
420.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
421.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
422.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
423.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
424.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
425.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison	Depreciation
426.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
427.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
428.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
429.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
430.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
431.	2023	MD PSC	Case No. 9695	The Potomac Edison Company	Depreciation
432.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
433.	2023	FERC	Docket No. ER23-1629-000	PPL Electric Utilities	Depreciation
434.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
435.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
436.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
437.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
438.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
439.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
440.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
441.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
442.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation
443.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
444.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
445.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation
446.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
447.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation
448.	2023	NY PSC	Case No. 23-G-0627	National Fuel Gas Distribution Corporation	Depreciation
449.	2023	IN URC	Cause No. 45990	Southern Indiana Gas and Electric Company d/b/a Centerpoint Energy Indiana South	Depreciation
450.	2023	PA PUC	Docket No. R-2023-3044549	Peoples Natural Gas Company LLC	Depreciation
451.	2023	OR PUC	Docket No. UM-2312	Northwest Natural Gas Company	Depreciation
452.	2023	AZ PCC	Docket No. WS-21182A-23-2092	Northwest Natural Water Company, LLC	Depreciation
453.	2023	SC PSC	Docket No. 2023-388-E	Duke Energy Carolinas	Depreciation
454.	2024	FERC	Docket No. ER24-768-000	Duke Energy Progress	Depreciation
455.	2024	FERC	Docket No. ER24-2057	Duke Energy Carolina	Depreciation
456.	2024	FERC	Docket No. SPP-0007	Evergy Metro, Inc. and Evergy Missouri West, Inc.	Depreciation
457.	2024	NJ BPU	Docket No. WR24010057	Aqua New Jersey, Inc.	Depreciation
458.	2024	ILL CC	Docket No. 24-0044	Aqua Illinois, Inc.	Depreciation
459.	2024	PA PUC	Docket No. R-2024-3046519	NiSource – Columbia Gas of Pennsylvania, Inc.	Depreciation
460.	2024	KY PSC	Case No. 2024-00092	NiSource – Columbia Gas of Kentucky, Inc.	Depreciation
461.	2024	VA SCC	Case No. PUR-2024-00030	NiSource – Columbia Gas of Virginia, Inc.	Depreciation
462.	2024	IA Util Bd	Docket No. RPU-2023-0002	Alliant - Interstate Power and Light Company	Depreciation
463.	2024	PA PUC	Docket No. R-2024-3047068	FirstEnergy Pennsylvania – Metropolitan Edison; Pennsylvania Electric; Pennsylvania Power; West Penn Power	Depreciation
464.	2024	PA PUC	Docket No. R-2024-3046523	Duquesne Light Company	Depreciation
465.	2024	NCUC	Docket No. E-22, Sub 694	Dominion Energy North Carolina	Depreciation
466.	2024	IN URC	IURC Cause No. 46038	Duke Energy Indiana	Depreciation
467.	2024	NJ BPU	Docket Nos. ER23120924 and GF 23120925	Public Service Electric and Gas Company	Depreciation
468.	2024	CO PUC	Docket No. 24-AL-0275E	Black Hills Colorado Electric, LLC	Depreciation
469.	2024	OH PUC	Case No. 24-0468-EL-AIR, Case No. 24-0469-EL-ATA, Case No. 24-0470-EL-AAM, Case No. 24-0471-EL-UNC	FirstEnergy Ohio	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
470.	2024	SD PUC	Docket No. NG24-005	Northwestern Energy	Depreciation
471.	2024	PA PUC	Docket No. R-2024-3047822	Aqua Pennsylvania, Inc	Depreciation
472.	2024	PA PUC	Docket No. R-2024-3047824	Aqua Pennsylvania Wastewater, Inc	Depreciation
473.	2024	NH PUC	Docket No. DE 24-070	Eversource Energy - Public Service of New Hampshire	Depreciation
474.	2024	VA SCC	Case No. PUR-2024-00048	Virginia Natural Gas Company	Depreciation
475.	2024	WV PSC	Case No. 24-0678-G-D	Hope Gas, Inc.	Depreciation
476.	2024	MO PSC	ER-2024-0319	Ameren Missouri	Depreciation
477.	2024	PA PUC	Docket No. R-2024-3050208	Newtown Artesian Water Company	Depreciation
478.	2024	PA PUC	Docket No. RP-24-1106-00	Adelphia Gateway	Depreciation
479.	2024	OH PUC	Case No. 24-0832-GA-AIR	Centerpoint Energy Ohio	Depreciation
480.	2024	MT PSC	Docket 2024-05-053	Northwestern Energy	Depreciation
481.	2024	MD PSC	Case No. 9754	NiSource – Columbia Gas of Maryland	Depreciation
482.	2024	IURC	Cause No. 46120	Northern Indiana Public Service Company LLC	Depreciation
483.	2024	MO PSC	GR-2024-0369	Ameren Missouri	Depreciation
484.	2024	PUCO	Case No. 24-1009-EL-AIR, Case No. 24-1010-El-AAM, Case No. 24-1011-El-ATA	The Dayton Power and Light Company d/b/a AES Ohio	Depreciation
485.	2024	KY PSC	Case No. 2024-00092	Duke Energy Kentucky	Depreciation
486.	2024	MO PSC	GR-2025-0107	Spire Missouri, Inc.	Depreciation

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of John J. Spanos

DEPRECIATION
EXHIBIT 1402

December 30, 2024

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF DECEMBER 31, 2023

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

NORTHWEST NATURAL GAS COMPANY
Portland, Oregon

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Camp Hill, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
207 Senate Avenue
Camp Hill, PA 17011
P 717.763.7211 | **F** 717.763.8150

gannettfleming.com

December 9, 2024

Northwest Natural Gas Company
250 SW Taylor Street
Portland, OR 97204

Attention: Zachary Kravitz
Rates and Regulatory Affairs

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of Northwest Natural Gas Company as of December 31, 2023. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC.

John J Spanos

JOHN J. SPANOS
President

Fredrick B. Johnston Jr.

FREDERICK B. JOHNSTON, JR.
Senior Analyst

JJS:mle

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NORTHWEST NATURAL GAS COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Northwest Natural Gas Company's ("NWNat" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the gas plant of NWNat as of December 31, 2023. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, and forecasted net salvage characteristics for each depreciable group of assets.

NWNat's accounting policy for plant assets has not changed since the last depreciation study was prepared. However, there have been changes to the plant in service due to system improvements and there are some expected changes to future life characteristics which has created new depreciation rates.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of December 31, 2023 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $154.7 million when applied to depreciable plant balances as of December 31, 2023. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2023	PROPOSED RATE	PROPOSED EXPENSE
Intangible Plant	$ 294,039,083.04	8.90	$ 26,162,477
Oil Gas Facilities	21,398.00	-	0
Other Production Facilities	628,802.00	-	0
Underground Storage Plant	239,087,512.56	2.05	4,896,830
Local Storage Plant	109,378,540.95	4.31	4,718,667
Transmission Plant	419,723,299.63	1.93	8,083,905
Distribution Plant	2,841,263,523.03	3.16	89,708,499
General Plant	369,421,300.49	5.85	21,611,140
General Plant Reserve Amortization	-	-	(434,015)
Total	**$4,273,563,459.70**	**3.62**	**$154,747,503**

PART I. INTRODUCTION

NORTHWEST NATURAL GAS COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Northwest Natural Gas Company ("Company"), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas plant as of December 31, 2023. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to gas plant in service as of December 31, 2023

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2023, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other gas companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and methods used in the service life study. Part III, Service Life Considerations, presents the results of the average service life analysis. Part IV, Net Salvage Considerations, presents the results of the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is 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 which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization accounting.

Both types of calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

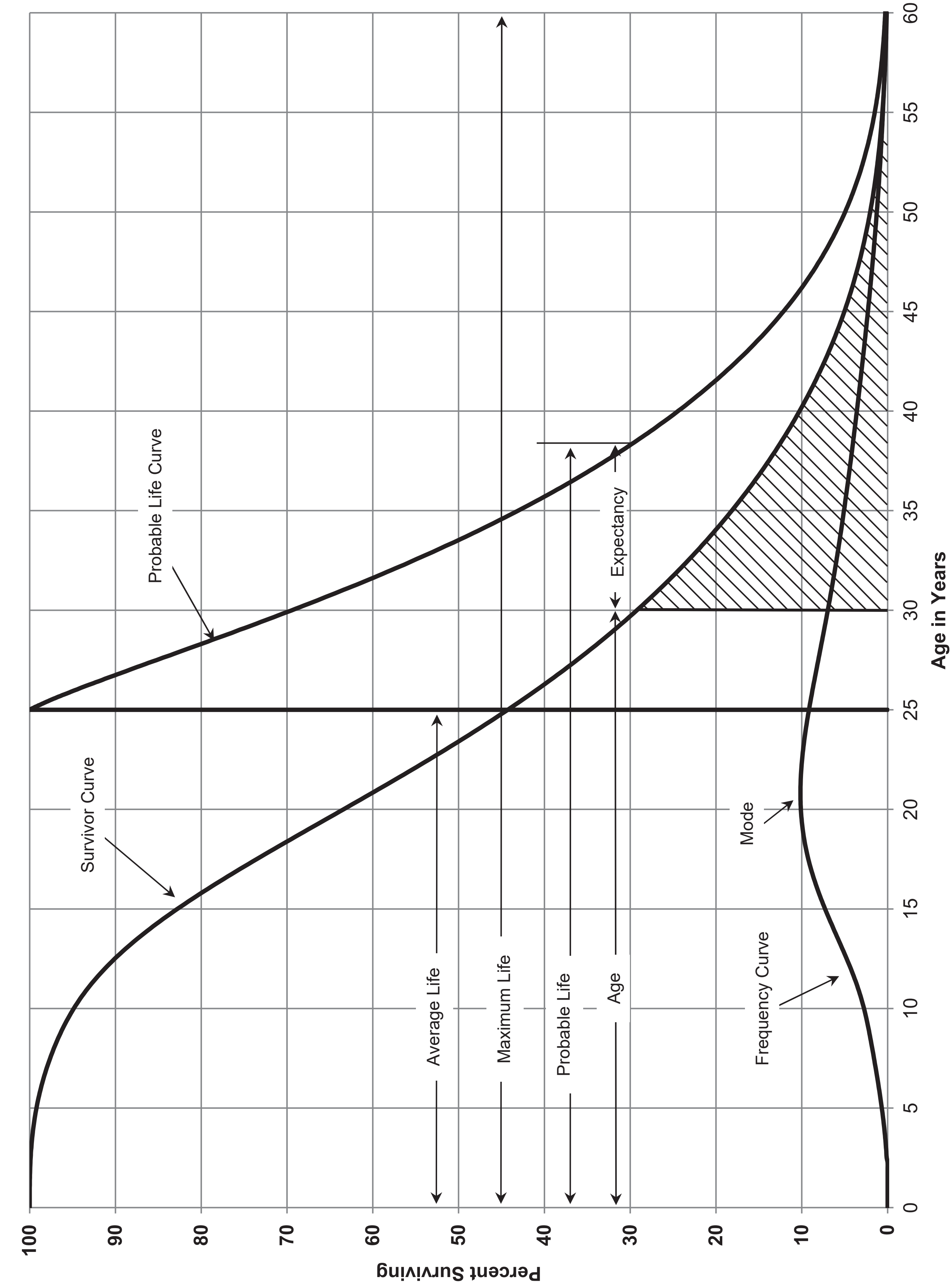

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

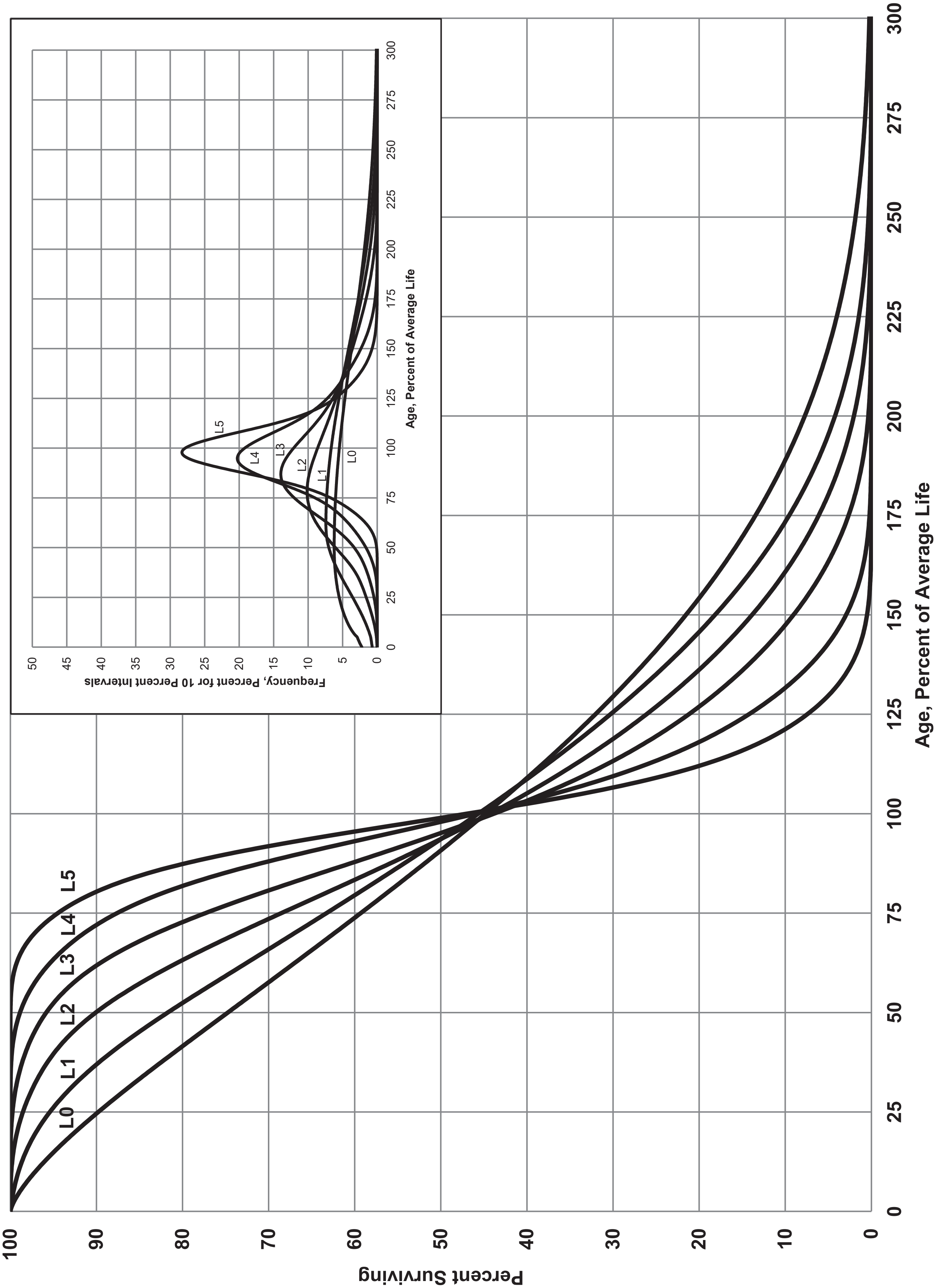

FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

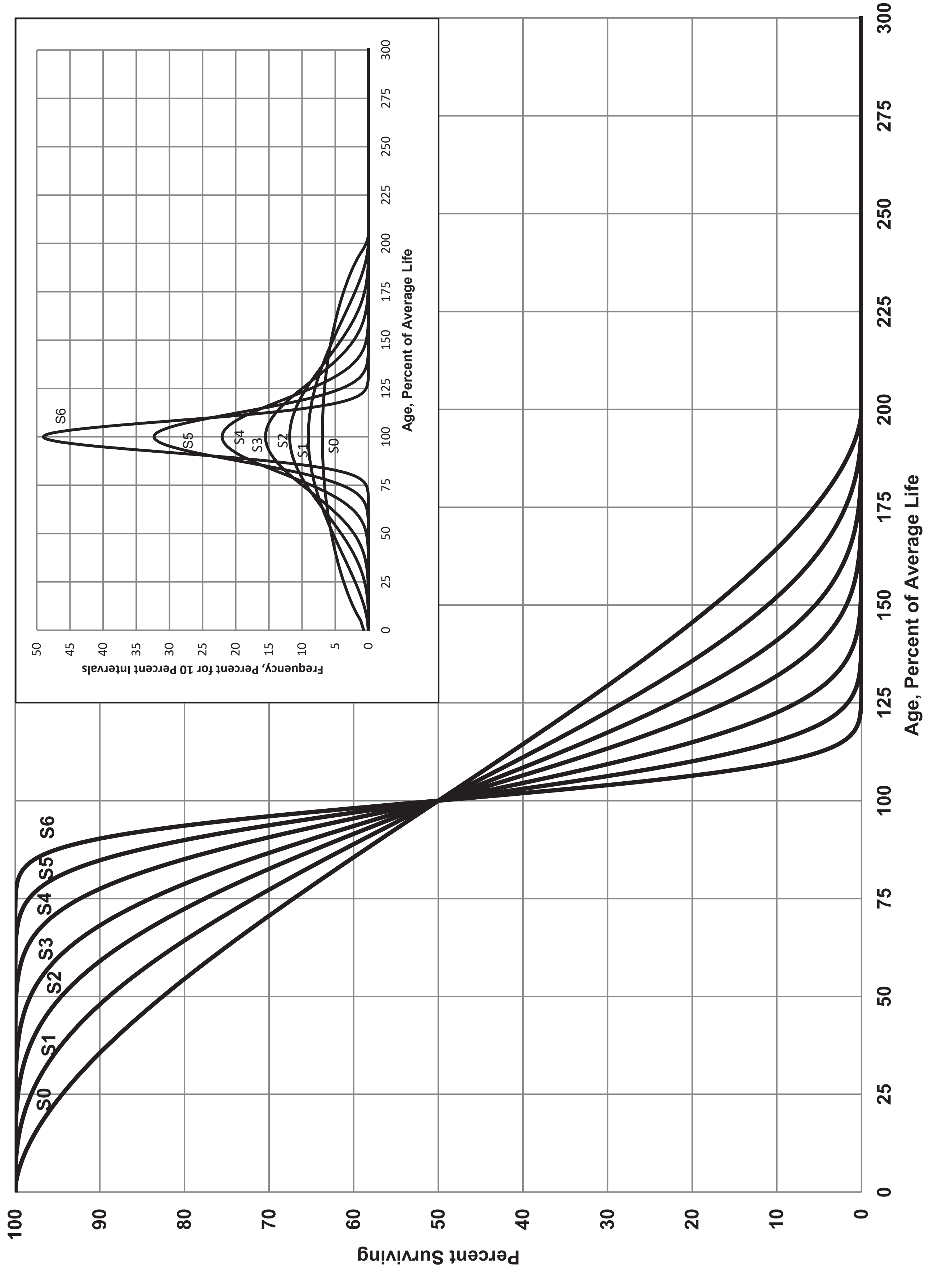

FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

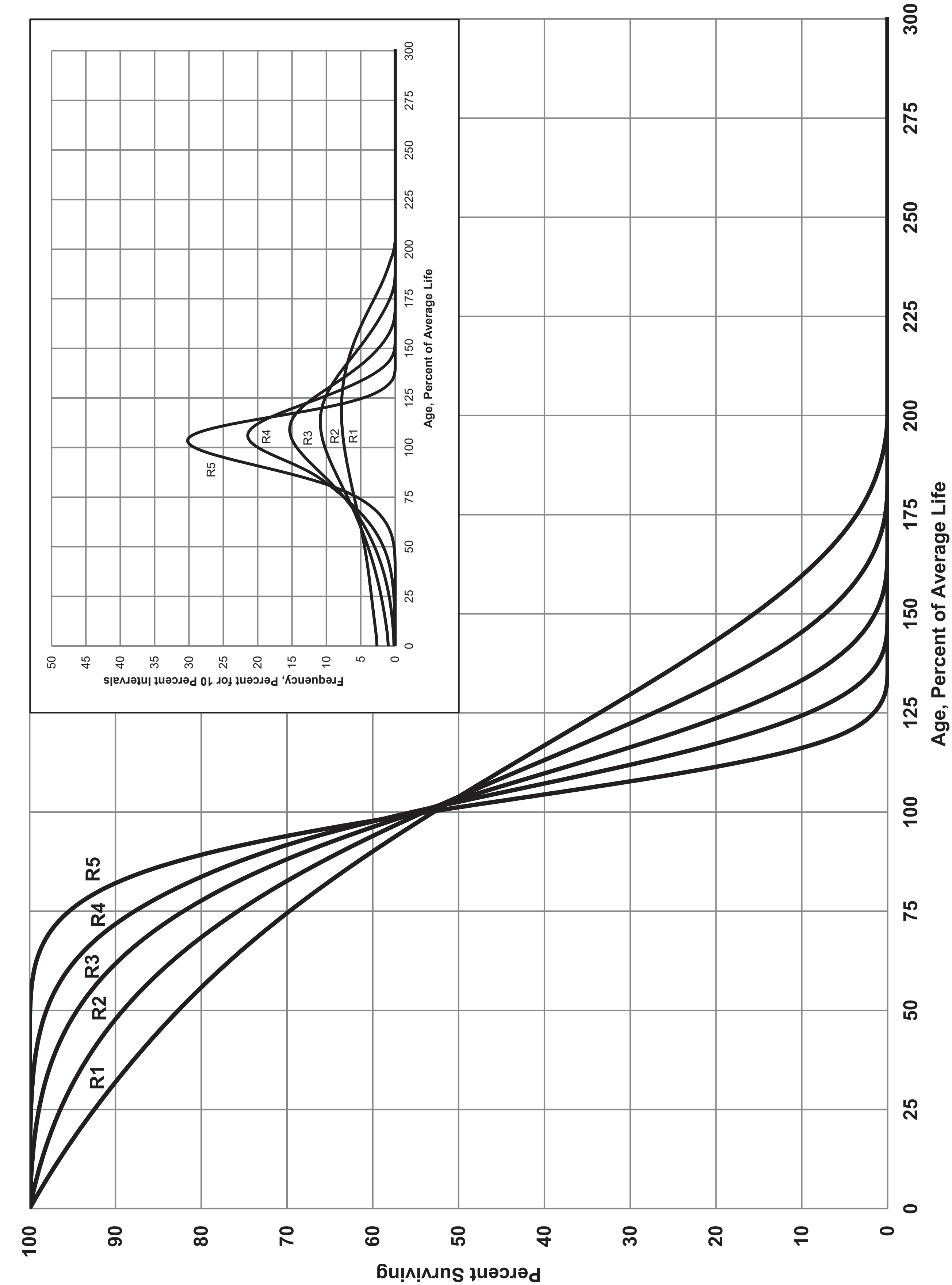

FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

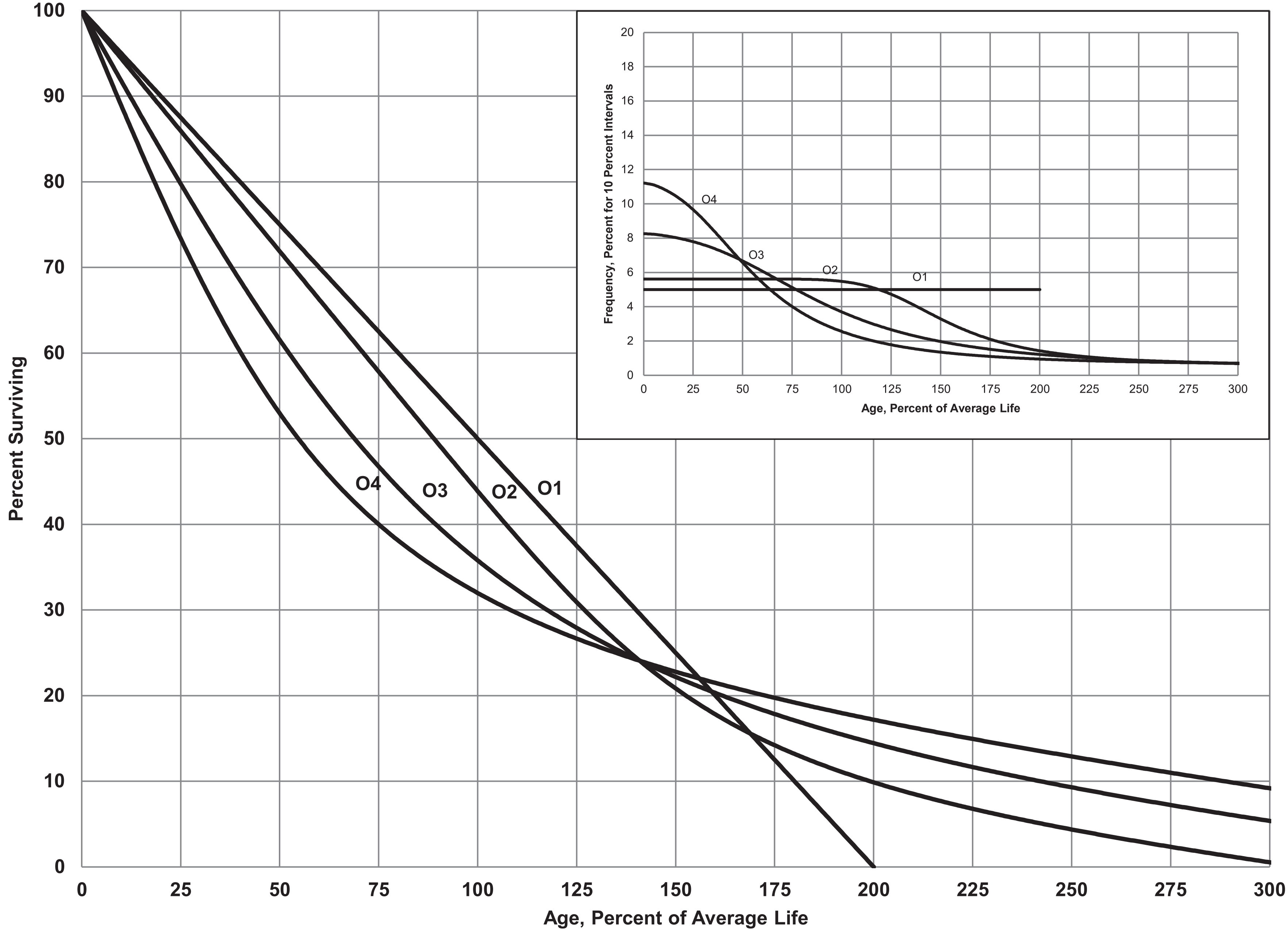

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2014-2023 for which there were placements during the years 2009-2023. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2009 were retired in 2014. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2014 retirements of 2009 installations and ending with the 2023 retirements of the 2018 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 Placement Band 2009-2023

Year	Retirements, Thousands of Dollars											
	During Year										Total During	Age
Placed	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2010	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2011	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2012	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2013	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2014	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2015		5	11	12	13	14	15	16	18	20	113	7½-8½
2016			6	12	13	15	16	17	19	19	124	6½-7½
2017				6	13	15	16	17	19	19	131	5½-6½
2018					7	14	16	17	19	20	143	4½-5½
2019						8	18	20	22	23	146	3½-4½
2020							9	20	22	25	150	2½-3½
2021								11	23	25	151	1½-2½
2022									11	24	153	½-1½
2023										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 | Placement Band 2009-2023

	Acquisitions, Transfers and Sales, Thousands of Dollars											
	During Year											
Year Placed (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)	2018 (6)	2019 (7)	2020 (8)	2021 (9)	2022 (10)	2023 (11)	Total During Age Interval (12)	Age Interval (13)
2009	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2010	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2011	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2012	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2013	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2014	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2015		-	-	-	-	-	-	-	-	-	6	7½-8½
2016			-	-	-	-	-	-	-	-	-	6½-7½
2017				-	-	-	-	(12)[b]	-	-	-	5½-6½
2018					-	-	-	-	22[a]	-	-	4½-5½
2019						-	-	(19)[b]	-	-	10	3½-4½
2020							-	-	-	-	-	2½-3½
2021								-	-	(102)[c]	(121)	1½-2½
2022									-	-	-	½-1½
2023											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2014 through 2023 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2019 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 Placement Band 2009-2023

Year Placed	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total at Beginning of Age Interval	Age Interval
	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year											
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2010	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2011	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2012	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2013	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2014	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2015		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2016			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2017				580[a]	574	561	546	530	501	482	3,057	5½-6½
2018					660[a]	653	639	623	628	609	3,789	4½-5½
2019						750[a]	742	724	685	663	4,332	3½-4½
2020							850[a]	841	821	799	4,955	2½-3½
2021								960[a]	949	926	5,719	1½-2½
2022									1,080[a]	1,069	6,579	½-1½
2023										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2014-2023, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2014-2023 Placement Band 2009-2023

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

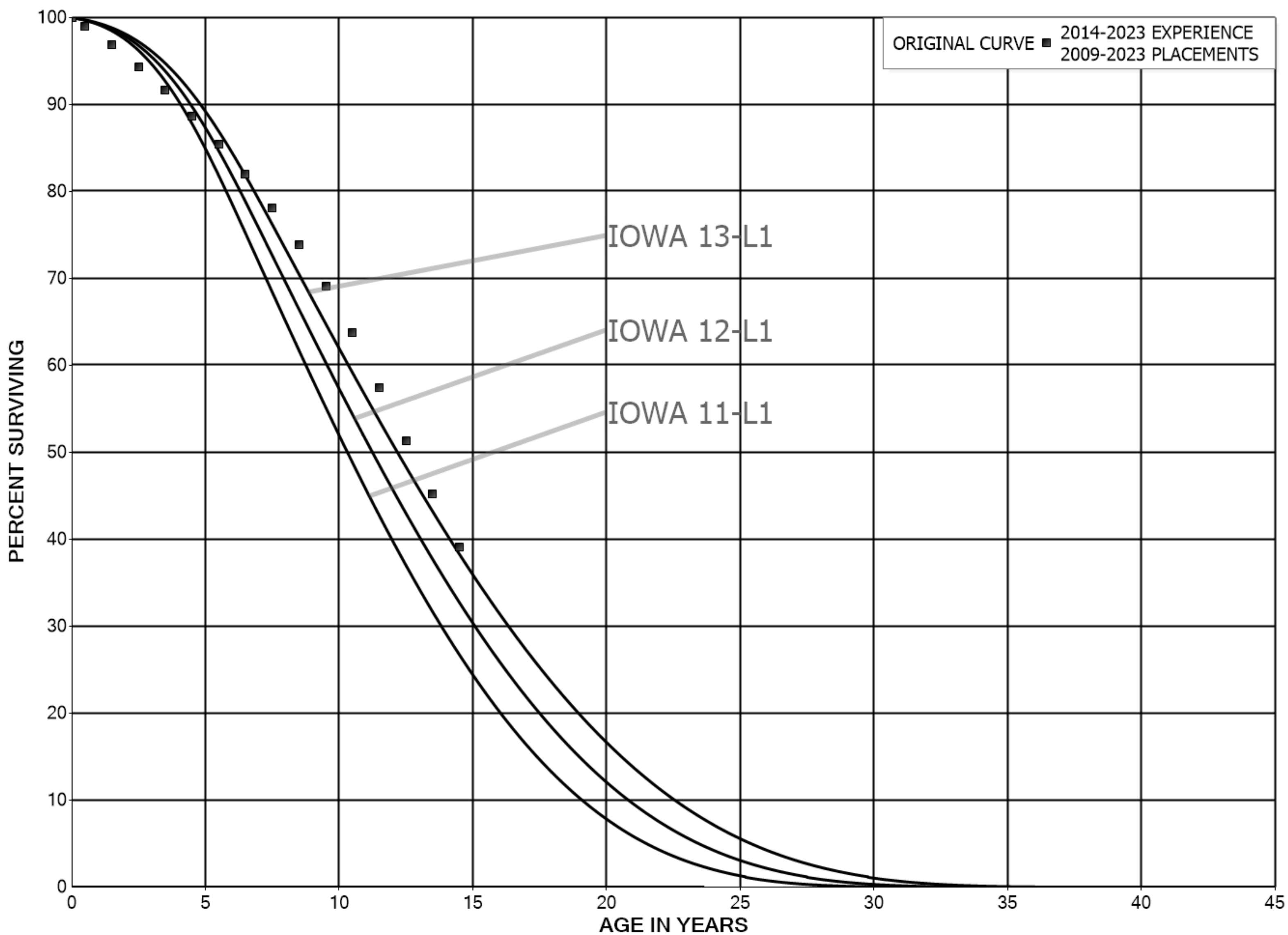


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

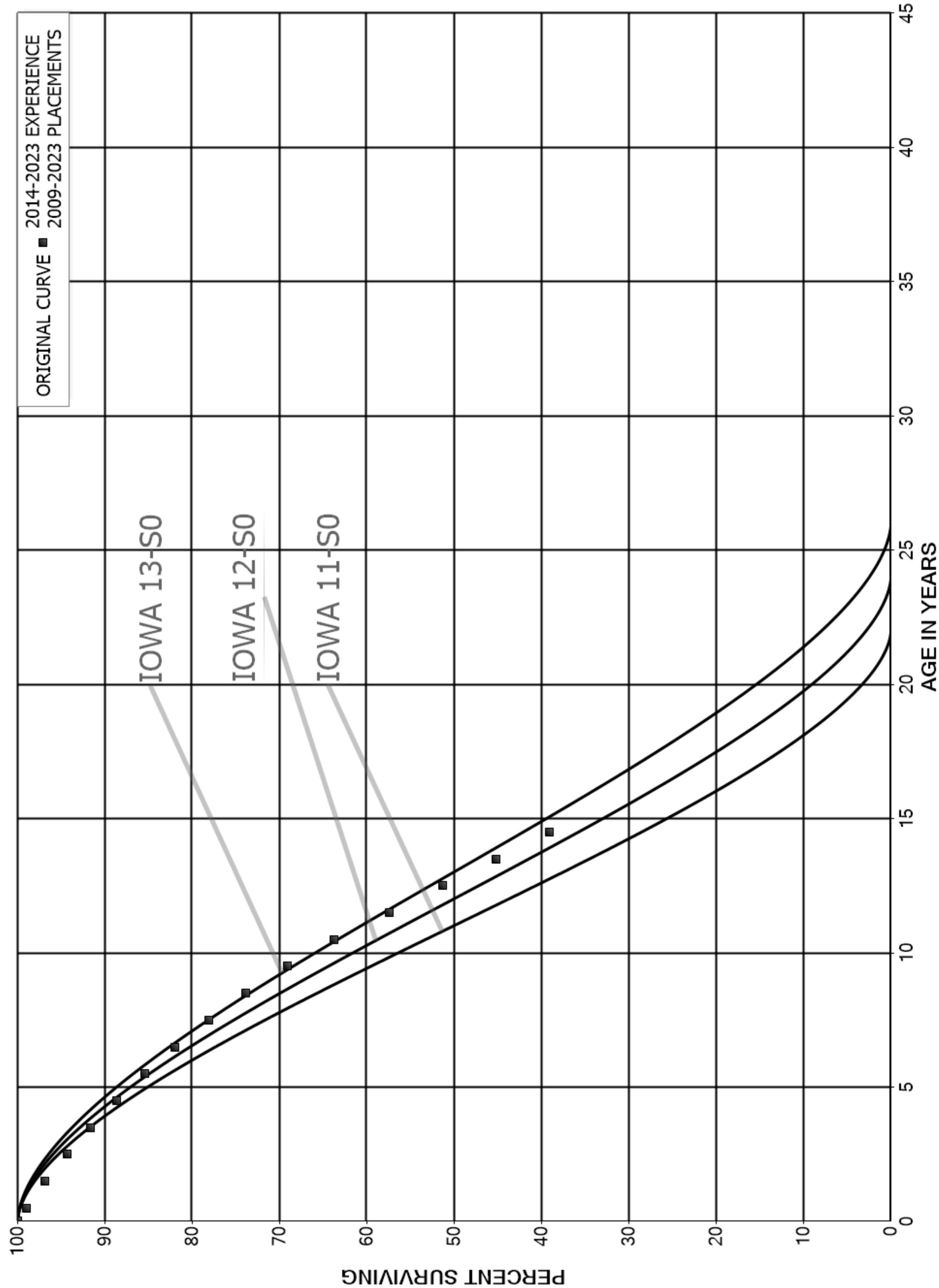


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

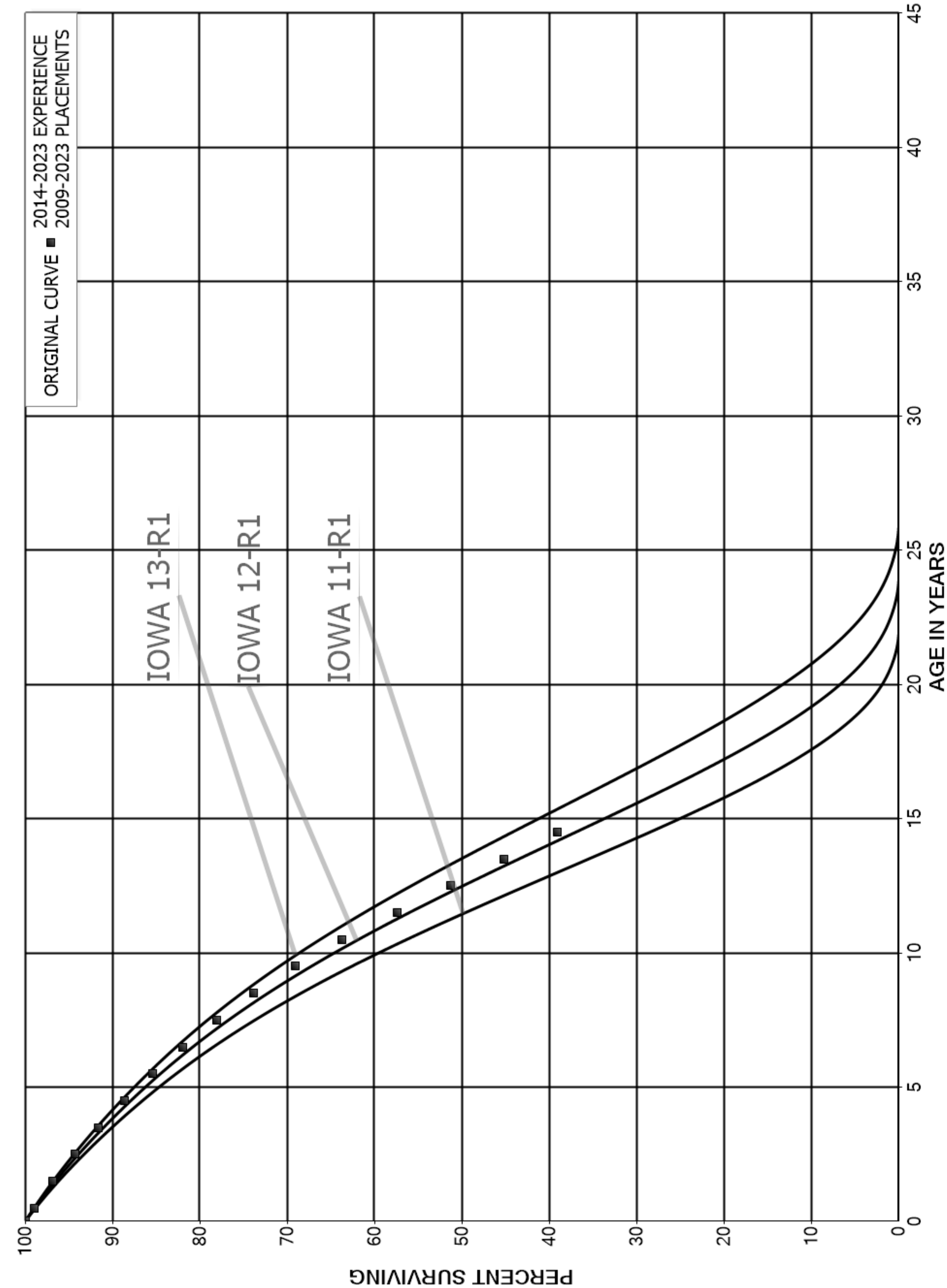
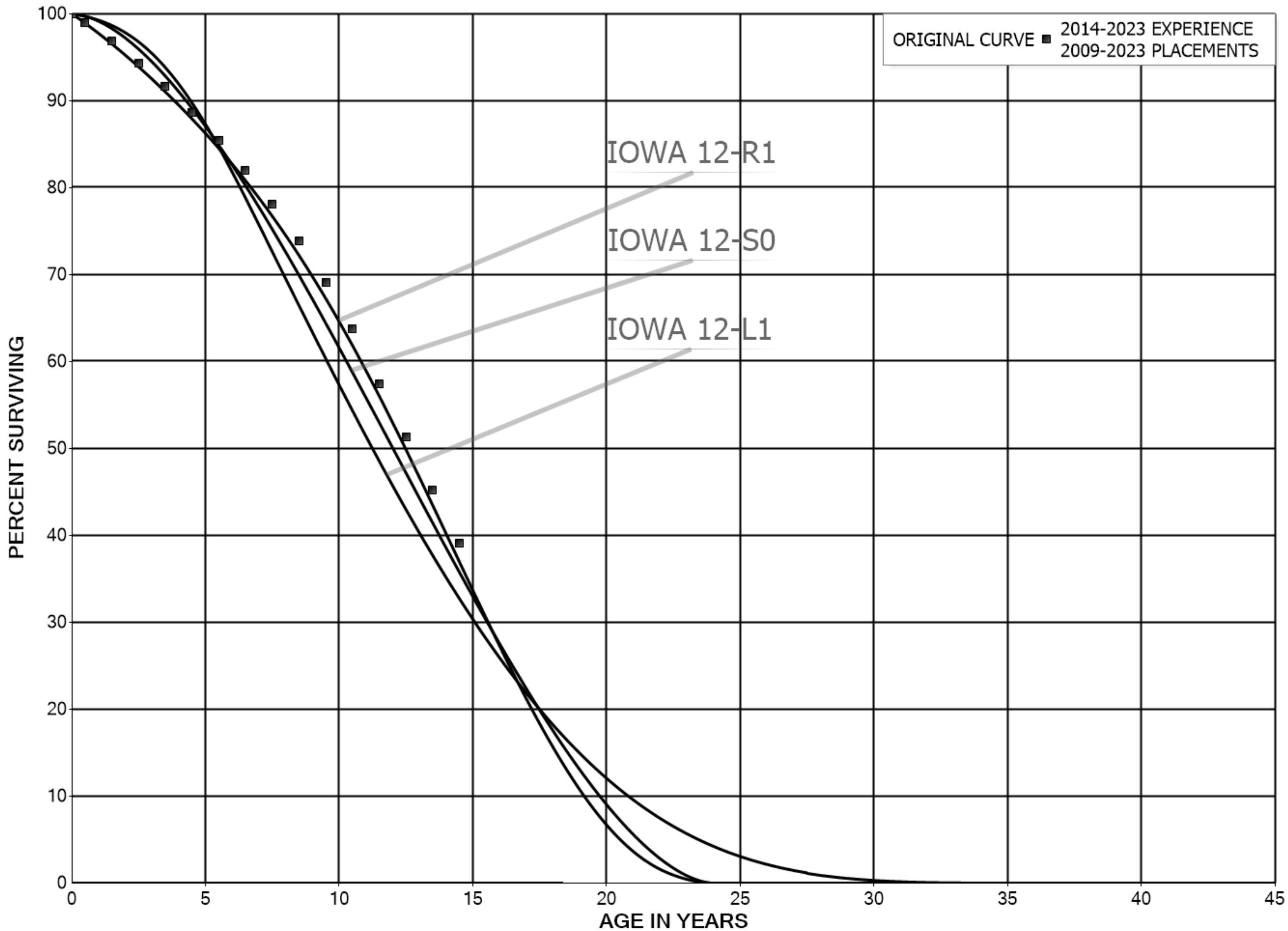


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted during past studies. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trip.

September 28-29, 2021
North Mist Compressor Station
Injection Well 44-03-65
Mist (Miller Station) Compressor Station
Sauvie Island City Gate Station
Gasco Mixer Station (Measuring & Regulating Station)
Linnton (Portland) LNG Plant
Jean Road Regulating Station
Sherwood Service Center

SERVICE LIFE ANALYSIS

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 71 percent of depreciable plant. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

OIL GAS FACILITIES
305.50 Structures and Improvements - Other

OTHER PRODUCTION FACILITIES

305.11	Structures and Improvements – Gas Production
305.17	Structures and Improvements – Mixing Station

LOCAL STORAGE PLANT

361.00	Structures and Improvements
363.20	Vaporizing Equipment
363.50	CNG Refueling Facilities

DISTRIBUTION PLANT

375.00	Structures and Improvements
376.11	Mains – HP 4" and Less
376.12	Mains – HP 4" and Over
380.00	Services
381.00	Meters
381.10	Meters – Electric
381.20	Meters – ERT
382.00	Meter Installations
382.10	Meter Installations – Electric
382.20	Meter Installations – ERT
386.00	Other Property on Customers' Premises

GENERAL PLANT

390.00	Structures and Improvements
390.10	Structures and Improvements – Source Control Plant
392.00	Transportation Equipment
396.00	Power Operated Equipment

The combined analysis of Accounts 376.11 - Mains, HP 4" and Less; and 376.12, Mains – HP 4" and Over, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. The combined Accounts 376.11 and 376.12 represent 35 percent of the total depreciable plant. Aged plant accounting data have been compiled for the years 1910 through 2023. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the period 1910 through 2023 and 1961 through 2023. The Iowa 65-R3 is an excellent fit of the original survivor curve. The 65-year service life is within the typical service life range of 55 to 70 years for mains. The 65-year life reflects the Company’s plans and practices of the past and next few years. The previous estimate was the Iowa 67-R3.

The survivor curve estimate for Account 380.00, Services, is based on the statistical analyses of historical retirement experience for the periods 1919-2023, 1976-2015 and 1981-2015. The 60-R2.5 estimate for Account 380.00, Services, is a good fit of the original survivor curve developed from historical plant retirements for the period 1919 through 2023. However, the lack of recorded retirements in the last few years are not expected to continue so emphasis on the level of retirements through 2015 are expected into the future. The 60-R2.5 survivor curve sets forth the constant rates of retirement through approximately age 76. The 60-year average service life is above the upper end of the typical range of 40-55 years for services. The previous estimate was the Iowa 65-R1.5

The survivor curve estimates for the remaining accounts in the preceding list were based on similar statistical analyses and previous studies for this and other gas utilities. The remaining accounts were based primarily on judgment and estimates of other gas utilities.

Life Span Estimates

Inasmuch as production plant consists of large units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for local storage plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1961 through 2023.

The depreciable life span estimates for storage facilities were the result of considering experienced life spans of similar facilities, the age of surviving plants, general operating characteristics of the station, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the stations.

The estimated survivor curves for local storage plant reflect the life span or forecast concept of life estimation. In the life span concept, an interim survivor curve is selected to describe the rates of retirement between installation and the final concurrent retirement of all facilities at a location. The forecast life span for the Linnton and Newport plants in the local storage plant accounts, is set forth in years from the date of their initial major installation. Although the Company currently does not have plans to replace these plants in the foreseeable future, the forecast retirement dates represent the midpoint of a range of dates during which significant replacement of the facilities presently in service will be required due to their age and improvements in technology.

	Probable Retirement Date	Initial Major Installation	Life Span
Local Storage			
Linnton	2036	1969,2016	67,20
Newport	2042	1977,2017	55,25

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other gas companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled for the years 1993 through 2023. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled "Net Salvage Statistics" for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 1993 through 2023 contributed significantly toward the net salvage estimates for 11 plant accounts, representing 70 percent of the depreciable plant, as follows:

DISTRIBUTION PLANT

376.11	Mains – HP 4” and Less
376.12	Mains – HP 4” and Over
380.00	Services
381.00	Meters
381.20	Meters – ERT
382.00	Meter Installations
382.20	Meter Installations – ERT

GENERAL PLANT

390.00	Structures and Improvements
390.10	Structures and Improvements – Source Control Plant
392.00	Transportation Equipment
396.00	Power Operated Equipment

The combined analyses of Account 376.11, Mains – HP 4” and Less and Account 376.12, Mains – HP 4” and Over, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 1993 through 2023 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1993-1995 through 2021-2023 periods were computed to smooth the annual amounts.

Cost of removal fluctuated considerably during the 31-year period, 1993-2023. The practices for assigning labor costs to removing pipe versus installing new pipe had not changed in recent years however, there is a plan to allocate more to installation of the new asset and slightly less to cost of removal as compared to the retirement cost. Cost of removal for the most recent five years averaged 199 percent.

Gross salvage has been minimal throughout the period with a slight increase in recent years due to a few projects. The most recent five-year average of 12 percent gross salvage reflects moderate salvage value for pipe.

The net salvage percent based on the overall period 1993 through 2023 is 91 percent negative net salvage. The range of estimates made by other gas companies for mains is negative 15 to negative 75 percent. Because the overall statistical indications are above the upper end of the industry range and the most recent five-year period is well above the upper end of the range, the statistical indication of negative 65 percent was selected for the Company's mains. This also considers the expected reduction due to less cost of removal being assigned to main replacement projects.

The net salvage estimates for the remaining accounts were based on judgment incorporating estimates of previous studies of this and other gas utilities.

The net salvage estimates for the remaining plant accounts were estimated using the above-described process of historical indications, judgment and reviewing the typical range of estimates used by other gas companies. The results of the net salvage for each plant account are presented in account sequence beginning in the section titled "Net Salvage Statistics", page VIII-2.

Generally, the net salvage estimates for remaining general plant accounts were zero percent, consistent with amortization accounting.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a \$1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4\ +\ 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000\left(1\ -\ \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2023, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2023, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391.10	Office Furniture and Equipment	20
391.20	Office Furniture and Equipment – Computers	5
391.21	Office Furniture and Equipment – Computers Horizon	10
391.22	Office Furniture and Equipment – Computers TSA Security Directive	10
393.00	Stores Equipment	25
394.00	Tools, Shop and Garage Equipment - Non Specific	25
395.00	Laboratory Equipment	20
397.00	Communication Equipment	15
397.10	Communication Equipment – Mobile	10
397.20	Communication Equipment – Non Mobile and Telemeter	15
397.30	Communication Equipment – Telemeter Other	15
397.40	Communication Equipment – Telemeter Microwave	15
397.50	Communication Equipment – Telephone	10
398.10	Miscellaneous Equipment – Print Shop	15
398.20	Miscellaneous Equipment – Kitchen	15

398.30	Miscellaneous Equipment – Janitorial	20
398.40	Miscellaneous – Leased Buildings	20
398.50	Miscellaneous Equipment - Other	20

For the purpose of calculating annual amortization amounts as of December 31, 2023, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the gas plant in service as of December 31, 2023. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2023, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The analyses of net salvage data are presented in the section titled, “Net Salvage Statistics”. The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DETAILED TABULATIONS

A summary of the results of the study, as applied to the original cost of gas plant as of December 31, 2023, is presented on pages VI-5 through VI-8 of this report. The schedule sets forth the original cost, the book depreciation reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to gas plant.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2023 are presented in account sequence starting on page IX-2 of the supporting documents. The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
DEPRECIABLE GAS PLANT									
INTANGIBLE PLANT									
303.10 MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE		15-SQ	0	128,050,933.02	26,336,695	101,714,238	9,791,008	7.65	10.4
303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON		10-SQ	0	46,726,994.21	4,141,642	42,585,352	5,010,041	10.72	8.5
303.12 MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE		10-SQ	0	22,242,163.51	1,789,927	20,452,237	2,403,337	10.81	8.5
303.20 MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM		15-SQ	0	32,409,597.11	32,398,798	10,799	1,963	0.01	5.5
303.30 MISCELLANEOUS INTANGIBLE PLANT - INDUSTRIAL AND COMMERCIAL		10-SQ	0	4,146,951.00	4,146,951	0	0	-	-
303.70 MISCELLANEOUS INTANGIBLE PLANT - CRMS		5-SQ	0	33,207,967.40	11,320,431	21,887,536	5,597,274	16.86	3.9
303.71 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON		10-SQ	0	24,096,593.68	3,203,067	20,893,527	2,458,062	10.20	8.5
303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE		5-SQ	0	3,157,883.11	0	3,157,883	900,792	28.53	3.5
TOTAL INTANGIBLE PLANT				**294,039,083.04**	**83,337,511**	**210,701,572**	**26,162,477**	**8.90**	
OIL GAS FACILITIES									
305.50 STRUCTURES AND IMPROVEMENTS - OTHER		40-S1	(5)	13,156.00	13,814	0	0	-	-
311.70 LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5	(5)	4,033.00	8,066	(3,831)	0	-	-
311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5	(5)	4,209.00	6,585	(2,166)	0	-	-
TOTAL OIL GAS FACILITIES				**21,398.00**	**28,465**	**(5,997)**	**0**	**-**	
OTHER PRODUCTION FACILITIES									
305.11 STRUCTURES AND IMPROVEMENTS - GAS PRODUCTION		40-S1	(5)	8,320.00	8,736	0	0	-	-
305.17 STRUCTURES AND IMPROVEMENTS - MIXING STATION		40-S1	(5)	46,587.00	51,246	(2,330)	0	-	-
318.30 LIGHT OIL REFINING		45-S2.5	(5)	144,896.00	152,141	0	0	-	-
318.50 TAR PROCESSING		45-S2.5	(5)	243,551.00	255,729	0	0	-	-
319.00 GAS MIXING EQUIPMENT		30-R0.5	(5)	185,448.00	194,720	0	0	-	-
TOTAL OTHER PRODUCTION FACILITIES				**628,802.00**	**662,572**	**(2,330)**	**0**	**-**	
UNDERGROUND STORAGE PLANT									
350.20 LAND RIGHTS		70-R4	0	109,624.94	38,249	71,376	1,545	1.41	46.2
351.00 STRUCTURES AND IMPROVEMENTS		60-R4	0	14,554,925.77	3,598,479	10,956,447	232,069	1.59	47.2
352.00 WELLS		50-S4	0	63,027,620.00	20,130,011	42,897,609	1,219,313	1.93	35.2
352.10 STORAGE LEASEHOLDS AND RIGHTS		55-S3	0	3,939,511.52	2,053,886	1,885,626	65,283	1.66	28.9
352.20 RESERVOIRS		55-S3	0	10,834,054.54	4,520,124	6,313,931	191,859	1.77	32.9
352.30 NONRECOVERABLE GAS		55-R4	0	6,440,889.82	4,055,238	2,385,652	97,235	1.51	24.5
353.00 LINES		55-S3	(15)	12,955,423.07	4,880,336	10,018,401	267,129	2.06	37.5
354.10 COMPRESSOR STATION EQUIPMENT - TURBINE 1		50-R3	(10)	7,885,231.22	3,244,668	5,429,086	150,255	1.91	36.1
354.20 COMPRESSOR STATION EQUIPMENT - TURBINE 2		50-R3	(10)	4,154,699.00	3,255,359	1,314,810	67,461	1.62	19.5
354.30 COMPRESSOR STATION EQUIPMENT - TURBINE 3		50-R3	(10)	21,084,256.03	8,324,605	14,868,077	420,517	1.99	35.4
354.40 COMPRESSOR STATION EQUIPMENT - TURBINE 4		50-R3	(10)	16,396,554.18	7,211,285	10,824,925	325,593	1.99	33.2
354.50 COMPRESSOR STATION EQUIPMENT - TURBINE 5		50-R3	(10)	3,739,476.97	1,231,783	2,881,642	76,801	2.05	37.5
354.60 COMPRESSOR STATION EQUIPMENT - TURBINE 6		50-R3	(10)	260,041.78	55,162	230,884	5,531	2.13	41.7
355.00 MEASURING AND REGULATING EQUIPMENT		45-S2	(10)	39,474,567.00	9,593,627	33,828,397	944,101	2.39	35.8
356.00 PURIFICATION EQUIPMENT		45-S2.5	(5)	28,968,864.51	1,837,162	28,580,146	694,183	2.40	41.2
357.00 OTHER EQUIPMENT		35-R4	0	5,261,772.21	1,404,487	3,857,285	137,955	2.62	28.0
TOTAL UNDERGROUND STORAGE PLANT				**239,087,512.56**	**75,434,461**	**176,344,294**	**4,896,830**	**2.05**	
LOCAL STORAGE PLANT									
361.00 STRUCTURES AND IMPROVEMENTS									
LINNTON	06-2036	60-R2.5 *	(5)	12,498,961.89	5,008,053	8,115,857	658,612	5.27	12.3
NEWPORT	06-2042	60-R2.5 *	(5)	12,196,541.26	5,148,646	7,657,722	428,309	3.51	17.9
OTHER		60-R2.5	(5)	26,757.00	14,191	13,904	399	1.49	34.8
TOTAL STRUCTURES AND IMPROVEMENTS				24,722,260.15	10,170,890	15,787,483	1,087,320	4.40	14.5

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

DEPRECIABLE GROUP (1)	PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2023 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
362.00 GAS HOLDERS									
LINNTON	06-2036	60-R3 *	(20)	4,556,064.35	3,122,790	2,344,487	197,281	4.33	11.9
NEWPORT	06-2042	60-R3 *	(20)	5,927,103.82	6,422,031	690,494	44,938	0.76	15.4
OTHER		60-R3	(20)	1,600.14	1,312	608	15	0.94	40.5
TOTAL GAS HOLDERS				10,484,768.31	9,546,133	3,035,589	242,234	2.31	12.5
363.10 LIQUEFACTION EQUIPMENT									
LINNTON	06-2036	50-R2.5 *	(5)	3,911,724.33	2,906,482	1,200,829	98,779	2.53	12.2
NEWPORT	06-2042	50-R2.5 *	(5)	22,700,560.02	8,398,821	15,436,767	890,918	3.92	17.3
TOTAL LIQUEFACTION EQUIPMENT				26,612,284.35	11,305,303	16,637,596	989,697	3.72	16.8
363.20 VAPORIZING EQUIPMENT									
LINNTON	06-2036	40-R4 *	(5)	4,458,618.00	2,707,111	1,974,438	179,030	4.02	11.0
NEWPORT	06-2042	40-R4 *	(5)	6,718,208.96	1,307,093	5,747,026	320,797	4.78	17.9
TOTAL VAPORIZING EQUIPMENT				11,176,826.96	4,014,204	7,721,464	499,827	4.47	15.5
363.30 COMPRESSOR EQUIPMENT									
LINNTON	06-2036	35-R1.5 *	(5)	1,362,753.51	218,613	1,212,278	102,046	7.49	11.9
NEWPORT	06-2042	35-R1.5 *	(5)	7,731,229.09	2,477,597	5,640,194	333,389	4.31	16.9
TOTAL COMPRESSOR EQUIPMENT				9,093,982.60	2,696,210	6,852,472	435,435	4.79	15.7
363.40 MEASURING AND REGULATING EQUIPMENT									
LINNTON	06-2036	50-R4 *	(5)	7,882,786.81	1,490,295	6,786,631	559,147	7.09	12.1
NEWPORT	06-2042	50-R4 *	(5)	15,384,423.80	1,109,662	15,043,983	819,145	5.32	18.4
TOTAL MEASURING AND REGULATING EQUIPMENT				23,267,210.61	2,599,957	21,830,614	1,378,292	5.92	15.8
363.50 CNG REFUELING FACILITIES		31-R3	(5)	3,281,734.97	1,831,291	1,614,531	83,959	2.56	19.2
363.60 LNG REFUELING FACILITIES		45-S2.5	(5)	739,473.00	741,913	34,534	1,903	0.26	18.1
TOTAL LOCAL STORAGE PLANT				**109,378,540.95**	**42,905,901**	**73,514,283**	**4,718,667**	**4.31**	
TRANSMISSION PLANT									
365.20 LAND RIGHTS		75-R4	0	6,455,176.86	2,600,382	3,854,795	83,004	1.29	46.4
366.30 STRUCTURES AND IMPROVEMENTS		55-R3	0	1,546,072.61	494,039	1,052,034	26,760	1.73	39.3
367.00 MAINS		70-R3	(40)	243,891,349.30	46,553,265	294,894,624	4,855,298	1.99	60.7
367.21 MAINS - NORTH MIST		70-R3	(40)	1,994,582.39	1,342,849	1,449,566	32,816	1.65	44.2
367.22 MAINS - SOUTH MIST		70-R3	(40)	14,949,264.00	12,154,663	8,774,307	230,439	1.54	38.1
367.23 MAINS - SOUTH MIST		70-R3	(40)	34,881,341.36	17,859,027	30,974,851	657,235	1.88	47.1
367.24 MAINS - 11.7M S MIST		70-R3	(40)	17,466,181.89	7,804,954	16,647,701	330,574	1.89	50.4
367.25 MAINS - 12M NORTH S MIST		70-R3	(40)	18,613,651.15	8,025,389	18,033,723	355,046	1.91	50.8
367.26 MAINS - 38M NORTH S MIST		70-R3	(40)	68,232,675.58	29,590,611	65,935,135	1,298,659	1.90	50.8
368.00 COMPRESSOR STATION EQUIPMENT		45-R3	(5)	7,723,454.21	3,373,630	4,735,997	156,458	2.03	30.3
369.00 MEASURING AND REGULATING EQUIPMENT		50-R2.5	(10)	3,969,550.28	2,062,022	2,304,483	57,616	1.45	40.0
TOTAL TRANSMISSION PLANT				**419,723,299.63**	**131,860,831**	**448,657,216**	**8,083,905**	**1.93**	
DISTRIBUTION PLANT									
374.20 LAND RIGHTS		75-R4	0	1,886,180.64	1,725,171	161,010	2,499	0.13	64.4
375.00 STRUCTURES AND IMPROVEMENTS		35-S1	0	1,587,598.32	239,253	1,348,345	62,819	3.96	21.5
376.11 MAINS - HP 4" AND LESS		65-R3	(65)	733,069,799.15	396,483,311	813,081,858	18,030,844	2.46	45.1
376.12 MAINS - HP 4" AND OVER		65-R3	(65)	779,378,528.59	297,942,649	988,031,923	20,420,234	2.62	48.4
377.00 COMPRESSOR STATION EQUIPMENT		30-S3	(5)	860,686.82	719,546	184,175	14,348	1.67	12.8
378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		50-R3	(25)	55,197,805.30	16,175,076	52,822,181	1,415,068	2.56	37.3
379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		50-R2.5	(25)	22,002,640.72	4,561,996	22,941,305	527,644	2.40	43.5
380.00 SERVICES		60-R2.5	(100)	1,004,062,014.54	486,777,081	1,521,346,948	35,336,053	3.52	43.1
381.00 METERS		30-S0	0	111,544,967.20	16,523,475	95,021,492	4,465,795	4.00	21.3
381.10 METERS - ELECTRIC		16-S4	0	1,696,938.46	1,461,577	235,361	35,878	2.11	6.6
381.20 METERS - ERT		15-R0.5	0	48,095,881.00	16,345,841	31,750,040	3,304,178	6.87	9.6
382.00 METER INSTALLATIONS		22-L1	0	67,194,266.99	3,463,742	63,730,525	5,491,694	8.17	11.6
382.10 METER INSTALLATIONS - ELECTRIC		15-L3	0	481,019.77	298,351	182,669	33,953	7.06	5.4
382.20 METER INSTALLATIONS - ERT		18-R2.5	0	9,455,364.18	5,948,353	3,507,011	404,405	4.28	8.7
383.00 HOUSE REGULATORS		30-S2.5	0	3,244,766.96	695,743	2,549,024	115,310	3.55	22.1

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP (1)	PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF DECEMBER 31, 2023 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
386.00	OTHER PROPERTY ON CUSTOMERS' PREMISES		14-S0	0	1,162,110.41	753,163	408,947	43,878	3.78	9.3
387.10	OTHER EQUIPMENT - CATHODIC PROTECTION TESTING		25-S4	0	173,858.98	150,855	23,004	3,899	2.24	5.9
387.20	OTHER EQUIPMENT - CALORIMETERS AT GATE STATION		23-S0.5	0	96,424.00	96,424	0	0	-	-
387.30	OTHER EQUIPMENT - METER TESTING EQUIPMENT		25-S4	0	72,671.00	72,671	0	0	-	-
TOTAL DISTRIBUTION PLANT					**2,841,263,523.03**	**1,250,434,278**	**3,597,325,818**	**89,708,499**	**3.16**	
GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		48-S0	(5)	147,048,661.54	21,709,798	132,691,297	3,132,793	2.13	42.4
390.10	STRUCTURES AND IMPROVEMENTS - SOURCE CONTROL PLANT		48-S0	(5)	23,033,564.87	7,427,058	16,758,185	417,789	1.81	40.1
391.10	OFFICE FURNITURE AND EQUIPMENT									
	FULLY ACCRUED				150,625.11	150,625	0	0	-	-
	AMORTIZED		20-SQ	0	18,089,789.51	5,849,675	12,240,115	904,546	5.00	13.5
	TOTAL ACCOUNT 391.10				18,240,414.62	6,000,300	12,240,115	904,546	4.96	13.5
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS									
	FULLY ACCRUED				0.14	0	0	0	-	-
	AMORTIZED		5-SQ	0	45,049,654.91	26,473,140	18,576,515	9,008,263	20.00	2.1
	TOTAL ACCOUNT 391.20				45,049,655.05	26,473,140	18,576,515	9,008,263	20.00	2.1
391.21	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON		10-SQ	0	2,190,419.85	328,563	1,861,857	219,042	10.00	8.5
391.22	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE		10-SQ	0	9,141,168.44	1,370,558	7,770,610	914,117	10.00	8.5
392.00	TRANSPORTATION EQUIPMENT		13-L2	15	57,500,630.35	22,116,078	26,759,458	3,192,238	5.55	8.4
393.00	STORES EQUIPMENT		FULLY ACCRUED		119,406.00	119,406	0	0	-	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	23,892,668.61	7,467,894	16,424,775	955,705	4.00	17.2
396.00	POWER OPERATED EQUIPMENT		15-L1.5	20	16,250,386.19	3,432,764	9,567,545	893,134	5.50	10.7
397.00	COMMUNICATION EQUIPMENT		15-SQ	0	49,718.14	34,803	14,915	3,314	6.67	4.5
397.10	COMMUNICATION EQUIPMENT - MOBILE		10-SQ	0	5,340,779.26	1,977,185	3,363,594	534,079	10.00	6.3
397.20	COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER		15-SQ	0	9,957.65	6,970	2,988	664	6.67	4.5
397.30	COMMUNICATION EQUIPMENT - TELEMETER OTHER									
	FULLY ACCRUED				53,241.79	53,242	0	0	-	-
	AMORTIZED		15-SQ	0	13,964,358.75	3,160,000	10,804,359	931,795	6.67	11.6
	TOTAL ACCOUNT 397.30				14,017,600.54	3,213,242	10,804,359	931,795	6.65	11.6
397.40	COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE									
	FULLY ACCRUED				61,119.78	61,120	0	0	-	-
	AMORTIZED		15-SQ	0	7,009,279.04	2,127,101	4,882,178	467,288	6.67	10.4
	TOTAL ACCOUNT 397.40				7,070,398.82	2,188,221	4,882,178	467,288	6.61	10.4
397.50	COMMUNICATION EQUIPMENT - TELEPHONE		10-SQ	0	340,671.19	300,650	40,021	34,146	10.00	1.2
398.10	MISCELLANEOUS EQUIPMENT - PRINT SHOP		15-SQ	0	4,359.31	3,923	436	291	6.67	1.5
398.20	MISCELLANEOUS EQUIPMENT - KITCHEN		15-SQ	0	28,864.84	15,277	13,588	1,924	6.67	7.1
398.30	MISCELLANEOUS EQUIPMENT - JANITORIAL		FULLY ACCRUED		14,873.00	14,873	0	0	-	-
398.40	MISCELLANEOUS EQUIPMENT - LEASED BUILDINGS		FULLY ACCRUED		10,120.00	10,120	0	0	-	-
398.50	MISCELLANEOUS EQUIPMENT - OTHER									
	FULLY ACCRUED				66,739.00	66,739	0	0	-	-
	AMORTIZED		20-SQ	0	243.22	12	231	12	5.00	19.2
	TOTAL ACCOUNT 398.50				66,982.22	66,751	231	12	0.02	19.3
TOTAL GENERAL PLANT					**369,421,300.49**	**104,277,574**	**261,772,667**	**21,611,140**	**5.85**	

NORTHWEST NATURAL GAS COMPANY

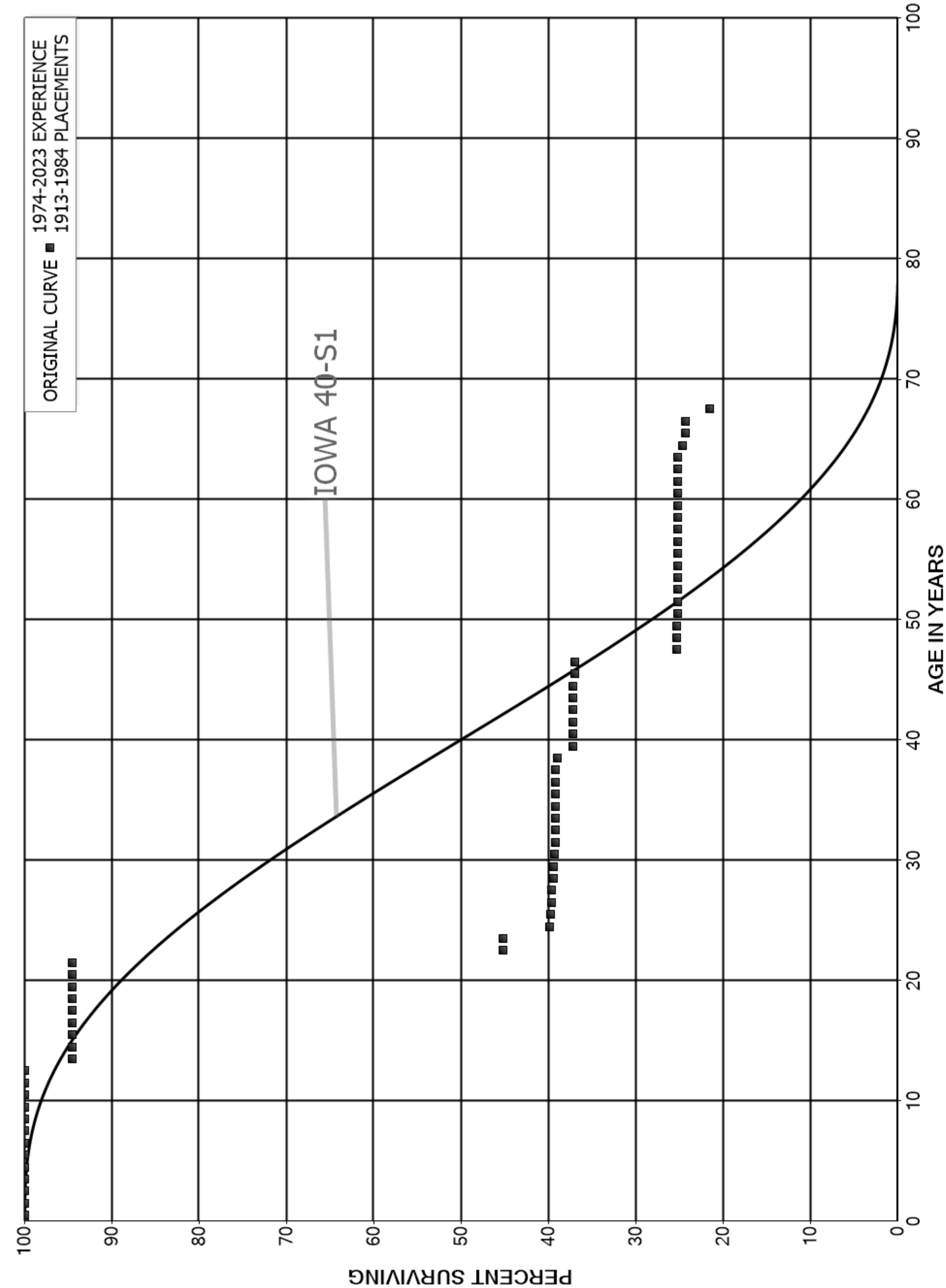
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
RESERVE ADJUSTMENT FOR AMORTIZATION									
391.10 OFFICE FURNITURE AND EQUIPMENT					1,342,419		(268,484) **		
391.20 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS					(85,000)		17,000 **		
391.21 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON					218,417		(43,683) **		
391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE					961,928		(192,386) **		
394.00 TOOLS, SHOP AND GARAGE EQUIPMENT					485,356		(97,071) **		
395.00 LABORATORY EQUIPMENT					(35)		7 **		
397.00 COMMUNICATION EQUIPMENT					5,944		(1,189) **		
397.10 COMMUNICATION EQUIPMENT - MOBILE					(104,997)		20,999 **		
397.20 COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER					(59,219)		11,844 **		
397.30 COMMUNICATION EQUIPMENT - TELEMETER OTHER					(318,519)		63,704 **		
397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE					(330,997)		66,199 **		
397.50 COMMUNICATION EQUIPMENT - TELEPHONE					57,055		(11,411) **		
398.10 MISCELLANEOUS EQUIPMENT - PRINT SHOP					(1,527)		305 **		
398.20 MISCELLANEOUS EQUIPMENT - KITCHEN					(744)		149 **		
398.50 MISCELLANEOUS EQUIPMENT - OTHER					(12)		2		
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION					**2,170,069**		**(434,015)**		
TOTAL DEPRECIABLE GAS PLANT				**4,273,563,459.70**	**1,691,111,662**	**4,768,307,523**	**154,747,503**	**3.62**	
NONDEPRECIABLE GAS PLANT									
301.00 ORGANIZATION				1,174.00	0				
302.00 FRANCHISES AND CONSENTS				83,621.00	0				
304.10 LAND				24,998.00	0				
350.10 LAND				106,549.00	0				
360.11 LAND - LNG LINNTON				83,598.00	0				
360.12 LAND - LNG NEWPORT				536,433.00	(242)				
360.20 LAND - OTHER				106,557.00	0				
365.10 LAND				1,015,597.00	0				
374.10 LAND				211,692.00	0				
389.00 LAND				13,118,401.00	426,129				
ROU UTILITY LEASE				0.00	15,856,270				
FIN UTILITY LEASE				0.00	199,716				
TOTAL NONDEPRECIABLE GAS PLANT				**15,288,620.00**	**16,481,873**				
TOTAL GAS PLANT IN SERVICE				**4,288,852,079.70**	**1,707,593,535**				

* INDICATES INTERIM SURVIVOR CURVE. EACH UNIT HAS A UNIQUE TERMINAL DATE.
** 5 YEAR AMORTIZATION OF RESERVE RELATED TO AMORTIZATION ACCOUNTING.

PART VII. SERVICE LIFE STATISTICS

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-1984 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,156		0.0000	1.0000	100.00
0.5	13,156		0.0000	1.0000	100.00
1.5	13,156		0.0000	1.0000	100.00
2.5	13,156		0.0000	1.0000	100.00
3.5	13,156		0.0000	1.0000	100.00
4.5	13,156		0.0000	1.0000	100.00
5.5	13,156		0.0000	1.0000	100.00
6.5	14,409		0.0000	1.0000	100.00
7.5	16,221		0.0000	1.0000	100.00
8.5	16,221		0.0000	1.0000	100.00
9.5	16,221		0.0000	1.0000	100.00
10.5	24,541		0.0000	1.0000	100.00
11.5	22,729		0.0000	1.0000	100.00
12.5	22,729	1,253	0.0551	0.9449	100.00
13.5	21,476		0.0000	1.0000	94.49
14.5	21,476		0.0000	1.0000	94.49
15.5	34,048		0.0000	1.0000	94.49
16.5	34,048		0.0000	1.0000	94.49
17.5	87,775		0.0000	1.0000	94.49
18.5	88,093		0.0000	1.0000	94.49
19.5	88,420		0.0000	1.0000	94.49
20.5	163,371		0.0000	1.0000	94.49
21.5	163,715	85,500	0.5222	0.4778	94.49
22.5	78,108		0.0000	1.0000	45.14
23.5	78,545	9,163	0.1167	0.8833	45.14
24.5	69,586	211	0.0030	0.9970	39.88
25.5	69,375	327	0.0047	0.9953	39.75
26.5	94,601		0.0000	1.0000	39.57
27.5	94,601	344	0.0036	0.9964	39.57
28.5	94,257		0.0000	1.0000	39.42
29.5	94,257	437	0.0046	0.9954	39.42
30.5	93,820	204	0.0022	0.9978	39.24
31.5	94,256		0.0000	1.0000	39.15
32.5	98,581		0.0000	1.0000	39.15
33.5	98,581		0.0000	1.0000	39.15
34.5	98,581		0.0000	1.0000	39.15
35.5	98,671		0.0000	1.0000	39.15
36.5	98,671		0.0000	1.0000	39.15
37.5	98,720	640	0.0065	0.9935	39.15
38.5	98,353	4,325	0.0440	0.9560	38.90

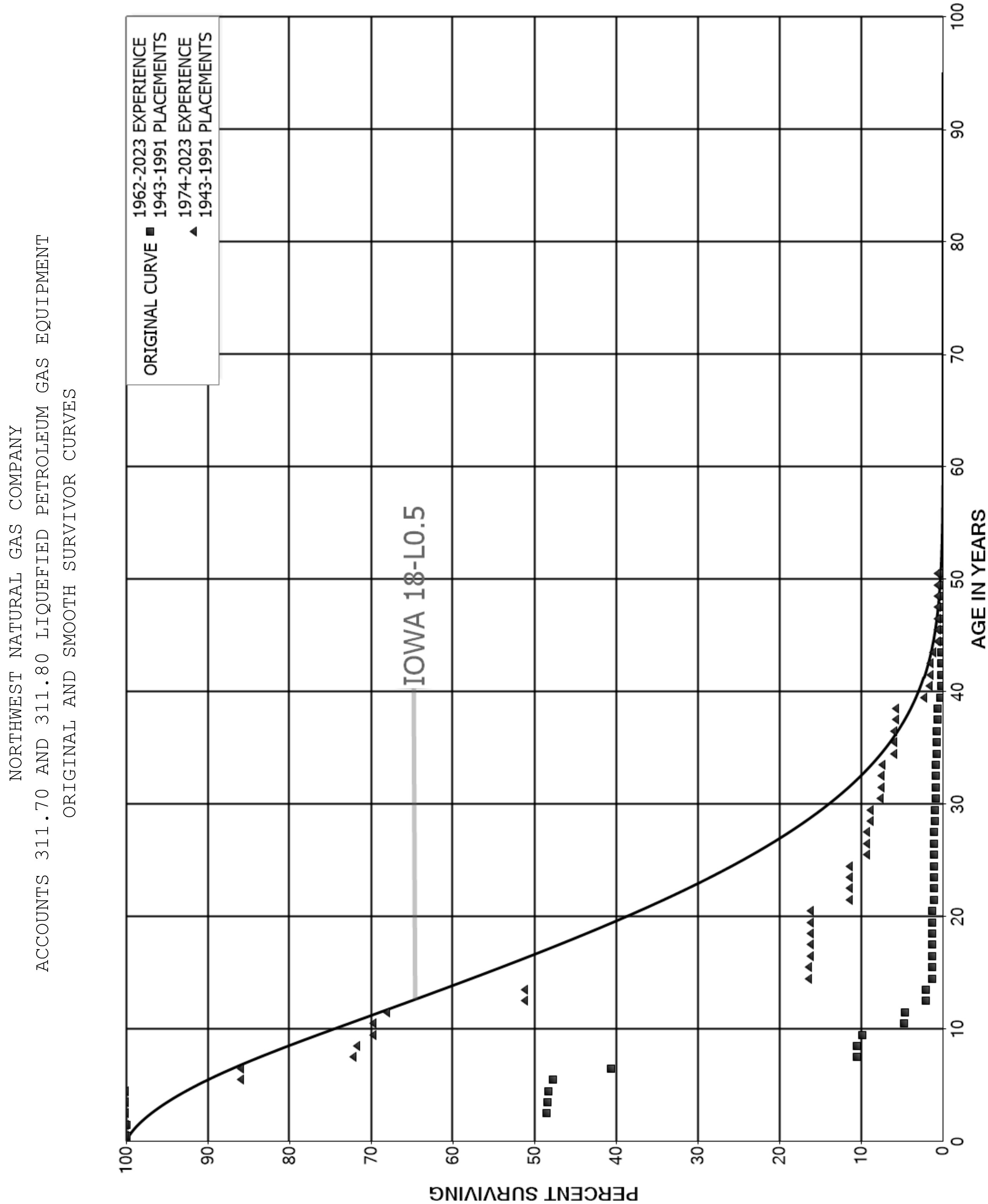
NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1984 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80,872		0.0000	1.0000	37.19
40.5	80,872		0.0000	1.0000	37.19
41.5	80,872	90	0.0011	0.9989	37.19
42.5	83,479		0.0000	1.0000	37.15
43.5	83,749	49	0.0006	0.9994	37.15
44.5	83,700	273	0.0033	0.9967	37.13
45.5	83,427		0.0000	1.0000	37.01
46.5	80,730	25,553	0.3165	0.6835	37.01
47.5	55,177		0.0000	1.0000	25.29
48.5	55,239		0.0000	1.0000	25.29
49.5	55,239	270	0.0049	0.9951	25.29
50.5	54,969		0.0000	1.0000	25.17
51.5	54,969		0.0000	1.0000	25.17
52.5	54,969		0.0000	1.0000	25.17
53.5	54,969		0.0000	1.0000	25.17
54.5	54,986	62	0.0011	0.9989	25.17
55.5	54,924		0.0000	1.0000	25.14
56.5	54,924		0.0000	1.0000	25.14
57.5	55,941		0.0000	1.0000	25.14
58.5	56,791		0.0000	1.0000	25.14
59.5	56,791		0.0000	1.0000	25.14
60.5	54,110	17	0.0003	0.9997	25.14
61.5	54,093		0.0000	1.0000	25.13
62.5	54,093		0.0000	1.0000	25.13
63.5	54,093	1,017	0.0188	0.9812	25.13
64.5	53,076	850	0.0160	0.9840	24.66
65.5	50,203		0.0000	1.0000	24.27
66.5	50,203	5,639	0.1123	0.8877	24.27
67.5					21.54


NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1962-2023 EXPERIENCE
1943-1991 PLACEMENTS
▲ 1974-2023 EXPERIENCE
1943-1991 PLACEMENTS
IOWA 18-L0.5
PERCENT SURVIVING
AGE IN YEARS

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1962-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	63,128		0.0000	1.0000	100.00
0.5	68,628		0.0000	1.0000	100.00
1.5	141,412	72,784	0.5147	0.4853	100.00
2.5	75,680	200	0.0026	0.9974	48.53
3.5	70,180	150	0.0021	0.9979	48.40
4.5	87,543	1,077	0.0123	0.9877	48.30
5.5	89,904	13,319	0.1481	0.8519	47.70
6.5	90,123	66,829	0.7415	0.2585	40.64
7.5	91,254	203	0.0022	0.9978	10.50
8.5	106,323	6,441	0.0606	0.9394	10.48
9.5	106,542	55,848	0.5242	0.4758	9.85
10.5	106,855	1,207	0.0113	0.9887	4.68
11.5	201,105	109,727	0.5456	0.4544	4.63
12.5	91,708		0.0000	1.0000	2.10
13.5	264,428	101,568	0.3841	0.6159	2.10
14.5	172,942		0.0000	1.0000	1.30
15.5	173,374	513	0.0030	0.9970	1.30
16.5	173,767	47	0.0003	0.9997	1.29
17.5	174,013		0.0000	1.0000	1.29
18.5	196,426		0.0000	1.0000	1.29
19.5	196,426	368	0.0019	0.9981	1.29
20.5	196,058	26,365	0.1345	0.8655	1.29
21.5	169,693	136	0.0008	0.9992	1.12
22.5	169,557		0.0000	1.0000	1.12
23.5	169,557		0.0000	1.0000	1.12
24.5	169,557	12,335	0.0727	0.9273	1.12
25.5	157,222		0.0000	1.0000	1.03
26.5	157,222		0.0000	1.0000	1.03
27.5	157,222	7,052	0.0449	0.9551	1.03
28.5	150,170		0.0000	1.0000	0.99
29.5	150,170	17,363	0.1156	0.8844	0.99
30.5	132,807	2,361	0.0178	0.9822	0.87
31.5	130,446	219	0.0017	0.9983	0.86
32.5	130,227	1,131	0.0087	0.9913	0.86
33.5	129,096	25,301	0.1960	0.8040	0.85
34.5	103,795	219	0.0021	0.9979	0.68
35.5	103,576	313	0.0030	0.9970	0.68
36.5	103,263	3,205	0.0310	0.9690	0.68
37.5	100,058	180	0.0018	0.9982	0.66
38.5	99,878	62,202	0.6228	0.3772	0.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1962-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,676	11,900	0.3159	0.6841	0.25
40.5	25,776	432	0.0168	0.9832	0.17
41.5	25,344	393	0.0155	0.9845	0.17
42.5	24,951	6,196	0.2483	0.7517	0.16
43.5	18,755	10,513	0.5605	0.4395	0.12
44.5	8,242		0.0000	1.0000	0.05
45.5	8,242		0.0000	1.0000	0.05
46.5	8,242		0.0000	1.0000	0.05
47.5	8,242		0.0000	1.0000	0.05
48.5	4,033		0.0000	1.0000	0.05
49.5	4,033		0.0000	1.0000	0.05
50.5	627		0.0000	1.0000	0.05
51.5	627		0.0000	1.0000	0.05
52.5	627		0.0000	1.0000	0.05
53.5	627		0.0000	1.0000	0.05
54.5	627		0.0000	1.0000	0.05
55.5	627		0.0000	1.0000	0.05
56.5	627		0.0000	1.0000	0.05
57.5	627		0.0000	1.0000	0.05
58.5	627		0.0000	1.0000	0.05
59.5	403		0.0000	1.0000	0.05
60.5					0.05

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,209		0.0000	1.0000	100.00
0.5	13,115		0.0000	1.0000	100.00
1.5	13,115		0.0000	1.0000	100.00
2.5	13,115		0.0000	1.0000	100.00
3.5	7,615		0.0000	1.0000	100.00
4.5	7,615	1,077	0.1414	0.8586	100.00
5.5	7,615		0.0000	1.0000	85.86
6.5	7,983	1,285	0.1610	0.8390	85.86
7.5	34,348	203	0.0059	0.9941	72.04
8.5	34,484	980	0.0284	0.9716	71.61
9.5	34,708		0.0000	1.0000	69.58
10.5	50,793	1,207	0.0238	0.9762	69.58
11.5	63,128	15,682	0.2484	0.7516	67.92
12.5	47,446		0.0000	1.0000	51.05
13.5	149,014	101,568	0.6816	0.3184	51.05
14.5	54,498		0.0000	1.0000	16.25
15.5	54,498	513	0.0094	0.9906	16.25
16.5	71,861	47	0.0007	0.9993	16.10
17.5	74,222		0.0000	1.0000	16.09
18.5	74,441		0.0000	1.0000	16.09
19.5	75,572	368	0.0049	0.9951	16.09
20.5	90,273	26,365	0.2921	0.7079	16.01
21.5	64,127	136	0.0021	0.9979	11.34
22.5	64,304		0.0000	1.0000	11.31
23.5	64,509		0.0000	1.0000	11.31
24.5	64,839	12,335	0.1902	0.8098	11.31
25.5	123,656		0.0000	1.0000	9.16
26.5	133,738		0.0000	1.0000	9.16
27.5	134,170	7,052	0.0526	0.9474	9.16
28.5	127,511		0.0000	1.0000	8.68
29.5	127,757	17,363	0.1359	0.8641	8.68
30.5	132,807	2,361	0.0178	0.9822	7.50
31.5	130,446	219	0.0017	0.9983	7.37
32.5	130,227	1,131	0.0087	0.9913	7.35
33.5	129,096	25,301	0.1960	0.8040	7.29
34.5	103,795	219	0.0021	0.9979	5.86
35.5	103,576	313	0.0030	0.9970	5.85
36.5	103,263	3,205	0.0310	0.9690	5.83
37.5	100,058	180	0.0018	0.9982	5.65
38.5	99,878	62,202	0.6228	0.3772	5.64

NORTHWEST NATURAL GAS COMPANY

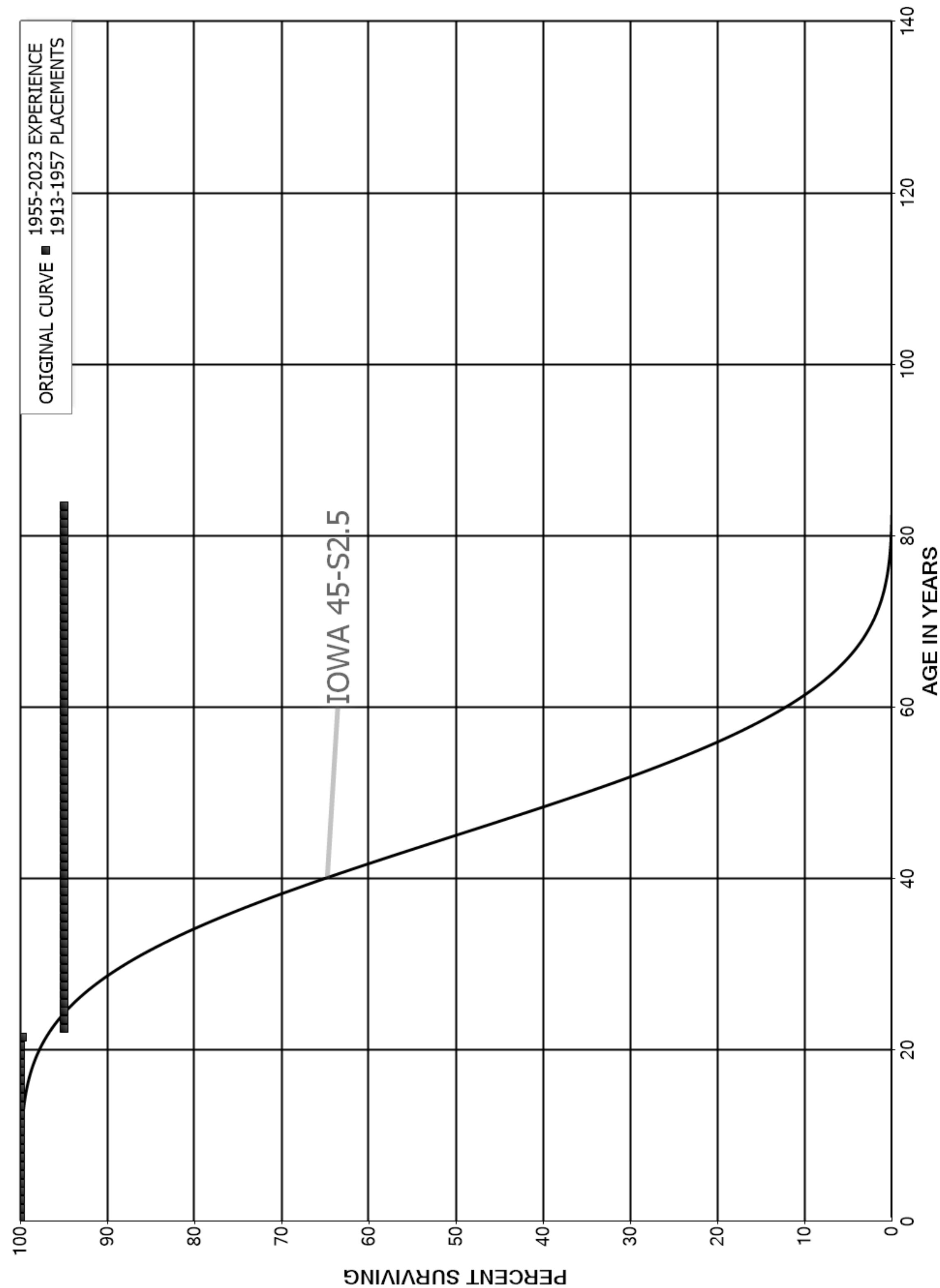
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,676	11,900	0.3159	0.6841	2.13
40.5	25,776	432	0.0168	0.9832	1.46
41.5	25,344	393	0.0155	0.9845	1.43
42.5	24,951	6,196	0.2483	0.7517	1.41
43.5	18,755	10,513	0.5605	0.4395	1.06
44.5	8,242		0.0000	1.0000	0.47
45.5	8,242		0.0000	1.0000	0.47
46.5	8,242		0.0000	1.0000	0.47
47.5	8,242		0.0000	1.0000	0.47
48.5	4,033		0.0000	1.0000	0.47
49.5	4,033		0.0000	1.0000	0.47
50.5	627		0.0000	1.0000	0.47
51.5	627		0.0000	1.0000	0.47
52.5	627		0.0000	1.0000	0.47
53.5	627		0.0000	1.0000	0.47
54.5	627		0.0000	1.0000	0.47
55.5	627		0.0000	1.0000	0.47
56.5	627		0.0000	1.0000	0.47
57.5	627		0.0000	1.0000	0.47
58.5	627		0.0000	1.0000	0.47
59.5	403		0.0000	1.0000	0.47
60.5					0.47

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,115		0.0000	1.0000	100.00
0.5	17,541		0.0000	1.0000	100.00
1.5	233,776		0.0000	1.0000	100.00
2.5	264,524		0.0000	1.0000	100.00
3.5	320,746		0.0000	1.0000	100.00
4.5	349,818		0.0000	1.0000	100.00
5.5	351,000		0.0000	1.0000	100.00
6.5	364,722		0.0000	1.0000	100.00
7.5	480,536		0.0000	1.0000	100.00
8.5	480,536		0.0000	1.0000	100.00
9.5	480,536		0.0000	1.0000	100.00
10.5	496,810		0.0000	1.0000	100.00
11.5	600,028		0.0000	1.0000	100.00
12.5	600,028		0.0000	1.0000	100.00
13.5	730,592		0.0000	1.0000	100.00
14.5	777,670		0.0000	1.0000	100.00
15.5	777,670		0.0000	1.0000	100.00
16.5	777,670		0.0000	1.0000	100.00
17.5	777,670	263	0.0003	0.9997	100.00
18.5	777,407		0.0000	1.0000	99.97
19.5	777,407		0.0000	1.0000	99.97
20.5	777,407	2,294	0.0030	0.9970	99.97
21.5	775,113	36,343	0.0469	0.9531	99.67
22.5	738,770		0.0000	1.0000	95.00
23.5	738,770		0.0000	1.0000	95.00
24.5	738,770		0.0000	1.0000	95.00
25.5	738,770		0.0000	1.0000	95.00
26.5	738,770		0.0000	1.0000	95.00
27.5	738,770		0.0000	1.0000	95.00
28.5	752,250		0.0000	1.0000	95.00
29.5	752,250		0.0000	1.0000	95.00
30.5	752,250		0.0000	1.0000	95.00
31.5	768,838		0.0000	1.0000	95.00
32.5	768,838		0.0000	1.0000	95.00
33.5	768,838		0.0000	1.0000	95.00
34.5	768,838		0.0000	1.0000	95.00
35.5	768,838		0.0000	1.0000	95.00
36.5	768,838		0.0000	1.0000	95.00
37.5	768,838		0.0000	1.0000	95.00
38.5	768,838		0.0000	1.0000	95.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	768,838		0.0000	1.0000	95.00
40.5	768,838		0.0000	1.0000	95.00
41.5	776,894		0.0000	1.0000	95.00
42.5	776,894		0.0000	1.0000	95.00
43.5	776,894		0.0000	1.0000	95.00
44.5	776,894		0.0000	1.0000	95.00
45.5	776,894		0.0000	1.0000	95.00
46.5	776,894		0.0000	1.0000	95.00
47.5	776,894		0.0000	1.0000	95.00
48.5	776,894		0.0000	1.0000	95.00
49.5	776,894		0.0000	1.0000	95.00
50.5	776,894		0.0000	1.0000	95.00
51.5	776,894		0.0000	1.0000	95.00
52.5	776,894		0.0000	1.0000	95.00
53.5	776,894		0.0000	1.0000	95.00
54.5	776,894		0.0000	1.0000	95.00
55.5	776,894		0.0000	1.0000	95.00
56.5	776,894		0.0000	1.0000	95.00
57.5	776,894		0.0000	1.0000	95.00
58.5	776,894		0.0000	1.0000	95.00
59.5	776,894		0.0000	1.0000	95.00
60.5	776,894		0.0000	1.0000	95.00
61.5	776,894		0.0000	1.0000	95.00
62.5	776,894		0.0000	1.0000	95.00
63.5	776,894		0.0000	1.0000	95.00
64.5	776,894		0.0000	1.0000	95.00
65.5	776,894		0.0000	1.0000	95.00
66.5	774,988		0.0000	1.0000	95.00
67.5	774,662		0.0000	1.0000	95.00
68.5	771,042		0.0000	1.0000	95.00
69.5	761,910		0.0000	1.0000	95.00
70.5	582,018		0.0000	1.0000	95.00
71.5	551,270		0.0000	1.0000	95.00
72.5	495,048		0.0000	1.0000	95.00
73.5	465,976		0.0000	1.0000	95.00
74.5	464,794		0.0000	1.0000	95.00
75.5	451,072		0.0000	1.0000	95.00
76.5	335,258		0.0000	1.0000	95.00
77.5	335,258		0.0000	1.0000	95.00
78.5	335,258		0.0000	1.0000	95.00

NORTHWEST NATURAL GAS COMPANY

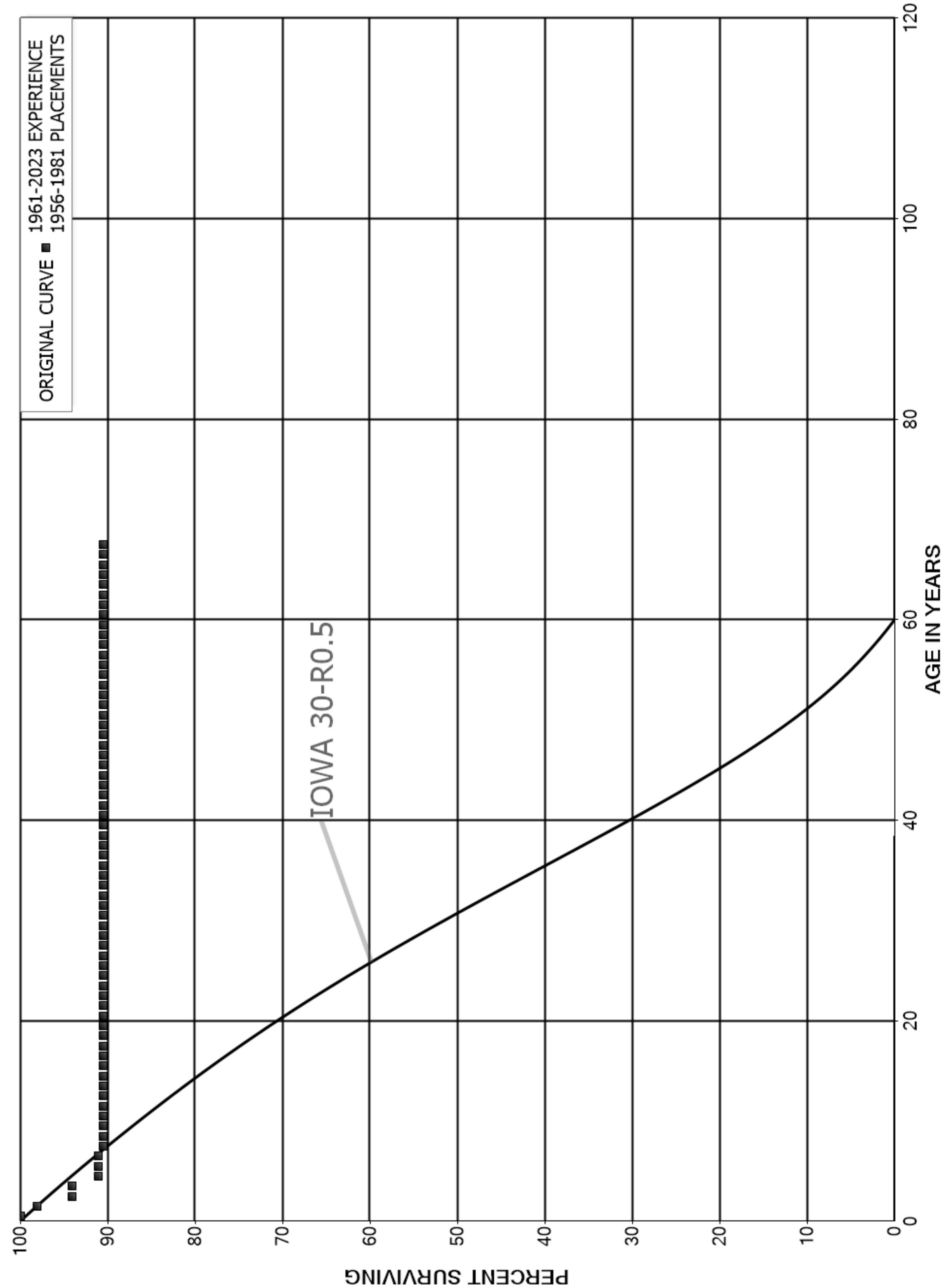
ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	318,984		0.0000	1.0000	95.00
80.5	215,766		0.0000	1.0000	95.00
81.5	215,766		0.0000	1.0000	95.00
82.5	85,202		0.0000	1.0000	95.00
83.5	38,124		0.0000	1.0000	95.00
84.5	38,124		0.0000	1.0000	95.00
85.5	38,124		0.0000	1.0000	95.00
86.5	38,124		0.0000	1.0000	95.00
87.5	38,124		0.0000	1.0000	95.00
88.5	38,124		0.0000	1.0000	95.00
89.5	38,124		0.0000	1.0000	95.00
90.5	38,124		0.0000	1.0000	95.00
91.5	38,124		0.0000	1.0000	95.00
92.5	38,124		0.0000	1.0000	95.00
93.5	38,124		0.0000	1.0000	95.00
94.5	38,124		0.0000	1.0000	95.00
95.5	38,124		0.0000	1.0000	95.00
96.5	38,124		0.0000	1.0000	95.00
97.5	24,644		0.0000	1.0000	95.00
98.5	24,644		0.0000	1.0000	95.00
99.5	24,644		0.0000	1.0000	95.00
100.5	8,056		0.0000	1.0000	95.00
101.5	8,056		0.0000	1.0000	95.00
102.5	8,056		0.0000	1.0000	95.00
103.5	8,056		0.0000	1.0000	95.00
104.5	8,056		0.0000	1.0000	95.00
105.5	8,056		0.0000	1.0000	95.00
106.5	8,056		0.0000	1.0000	95.00
107.5	8,056		0.0000	1.0000	95.00
108.5	8,056		0.0000	1.0000	95.00
109.5	8,056		0.0000	1.0000	95.00
110.5					95.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 319.00 GAS MIXING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 319.00 GAS MIXING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-1981 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,655		0.0000	1.0000	100.00
0.5	18,932	376	0.0199	0.9801	100.00
1.5	19,149	770	0.0402	0.9598	98.01
2.5	24,885		0.0000	1.0000	94.07
3.5	40,405	1,300	0.0322	0.9678	94.07
4.5	185,448		0.0000	1.0000	91.05
5.5	185,448		0.0000	1.0000	91.05
6.5	185,448	1,025	0.0055	0.9945	91.05
7.5	185,448		0.0000	1.0000	90.54
8.5	185,448		0.0000	1.0000	90.54
9.5	185,448		0.0000	1.0000	90.54
10.5	185,448		0.0000	1.0000	90.54
11.5	185,448		0.0000	1.0000	90.54
12.5	185,448		0.0000	1.0000	90.54
13.5	185,448		0.0000	1.0000	90.54
14.5	185,448		0.0000	1.0000	90.54
15.5	185,448		0.0000	1.0000	90.54
16.5	185,448		0.0000	1.0000	90.54
17.5	185,448		0.0000	1.0000	90.54
18.5	185,448		0.0000	1.0000	90.54
19.5	185,448		0.0000	1.0000	90.54
20.5	185,448		0.0000	1.0000	90.54
21.5	185,448		0.0000	1.0000	90.54
22.5	185,448		0.0000	1.0000	90.54
23.5	185,448		0.0000	1.0000	90.54
24.5	185,448		0.0000	1.0000	90.54
25.5	185,448		0.0000	1.0000	90.54
26.5	185,448		0.0000	1.0000	90.54
27.5	185,448		0.0000	1.0000	90.54
28.5	185,448		0.0000	1.0000	90.54
29.5	185,448		0.0000	1.0000	90.54
30.5	185,448		0.0000	1.0000	90.54
31.5	185,448		0.0000	1.0000	90.54
32.5	185,448		0.0000	1.0000	90.54
33.5	185,448		0.0000	1.0000	90.54
34.5	185,448		0.0000	1.0000	90.54
35.5	185,448		0.0000	1.0000	90.54
36.5	185,448		0.0000	1.0000	90.54
37.5	185,448		0.0000	1.0000	90.54
38.5	185,448		0.0000	1.0000	90.54

NORTHWEST NATURAL GAS COMPANY

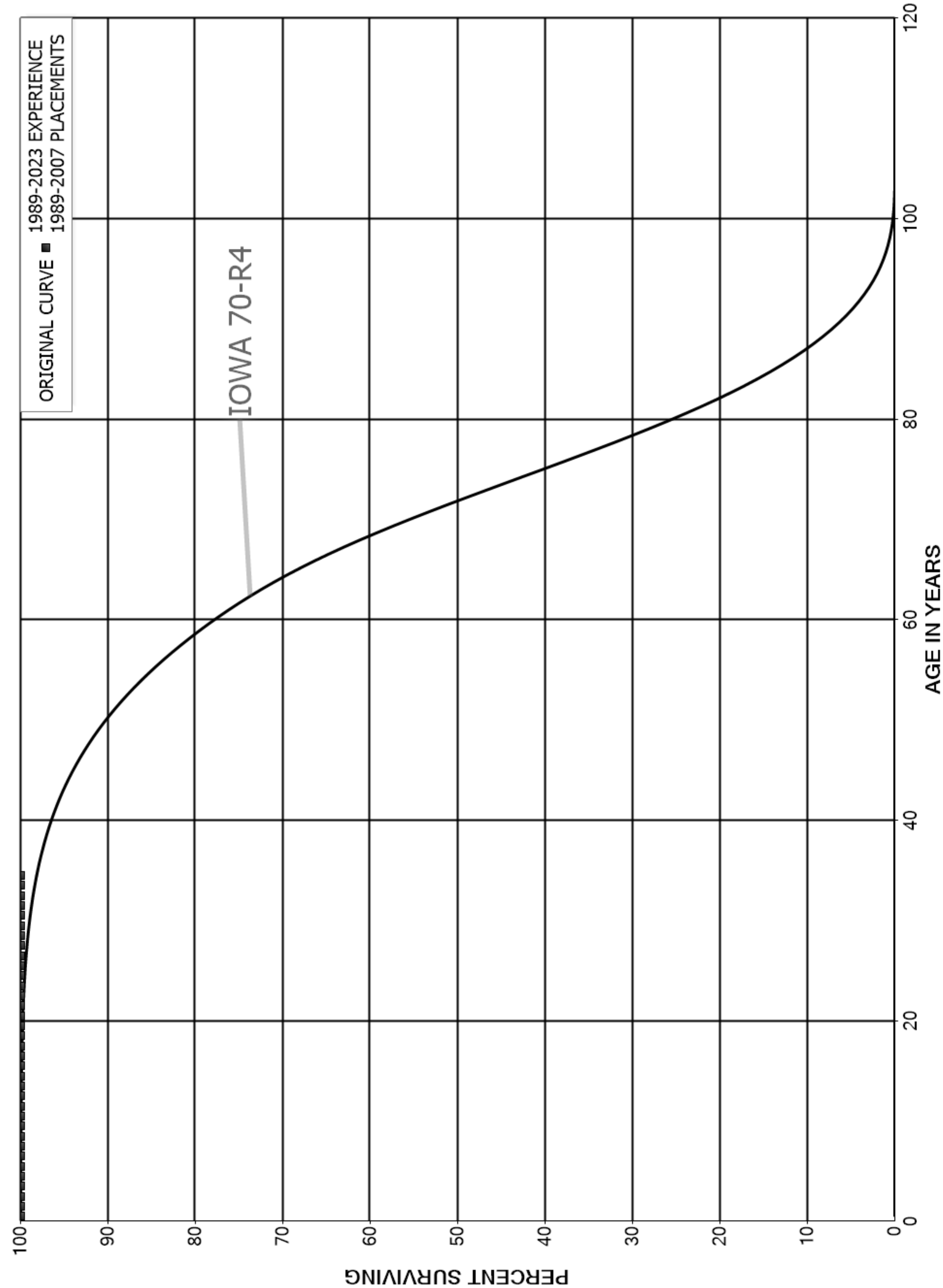
ACCOUNT 319.00 GAS MIXING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-1981 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	185,448		0.0000	1.0000	90.54
40.5	185,448		0.0000	1.0000	90.54
41.5	185,448		0.0000	1.0000	90.54
42.5	181,891		0.0000	1.0000	90.54
43.5	169,470		0.0000	1.0000	90.54
44.5	169,470		0.0000	1.0000	90.54
45.5	169,470		0.0000	1.0000	90.54
46.5	169,470		0.0000	1.0000	90.54
47.5	169,470		0.0000	1.0000	90.54
48.5	169,470		0.0000	1.0000	90.54
49.5	169,470		0.0000	1.0000	90.54
50.5	169,470		0.0000	1.0000	90.54
51.5	169,470		0.0000	1.0000	90.54
52.5	169,470		0.0000	1.0000	90.54
53.5	169,470		0.0000	1.0000	90.54
54.5	169,470		0.0000	1.0000	90.54
55.5	169,470		0.0000	1.0000	90.54
56.5	169,381		0.0000	1.0000	90.54
57.5	169,381		0.0000	1.0000	90.54
58.5	169,381		0.0000	1.0000	90.54
59.5	168,460		0.0000	1.0000	90.54
60.5	168,460		0.0000	1.0000	90.54
61.5	166,793		0.0000	1.0000	90.54
62.5	166,793		0.0000	1.0000	90.54
63.5	166,516		0.0000	1.0000	90.54
64.5	166,299		0.0000	1.0000	90.54
65.5	160,563		0.0000	1.0000	90.54
66.5	145,043		0.0000	1.0000	90.54
67.5					90.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 350.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

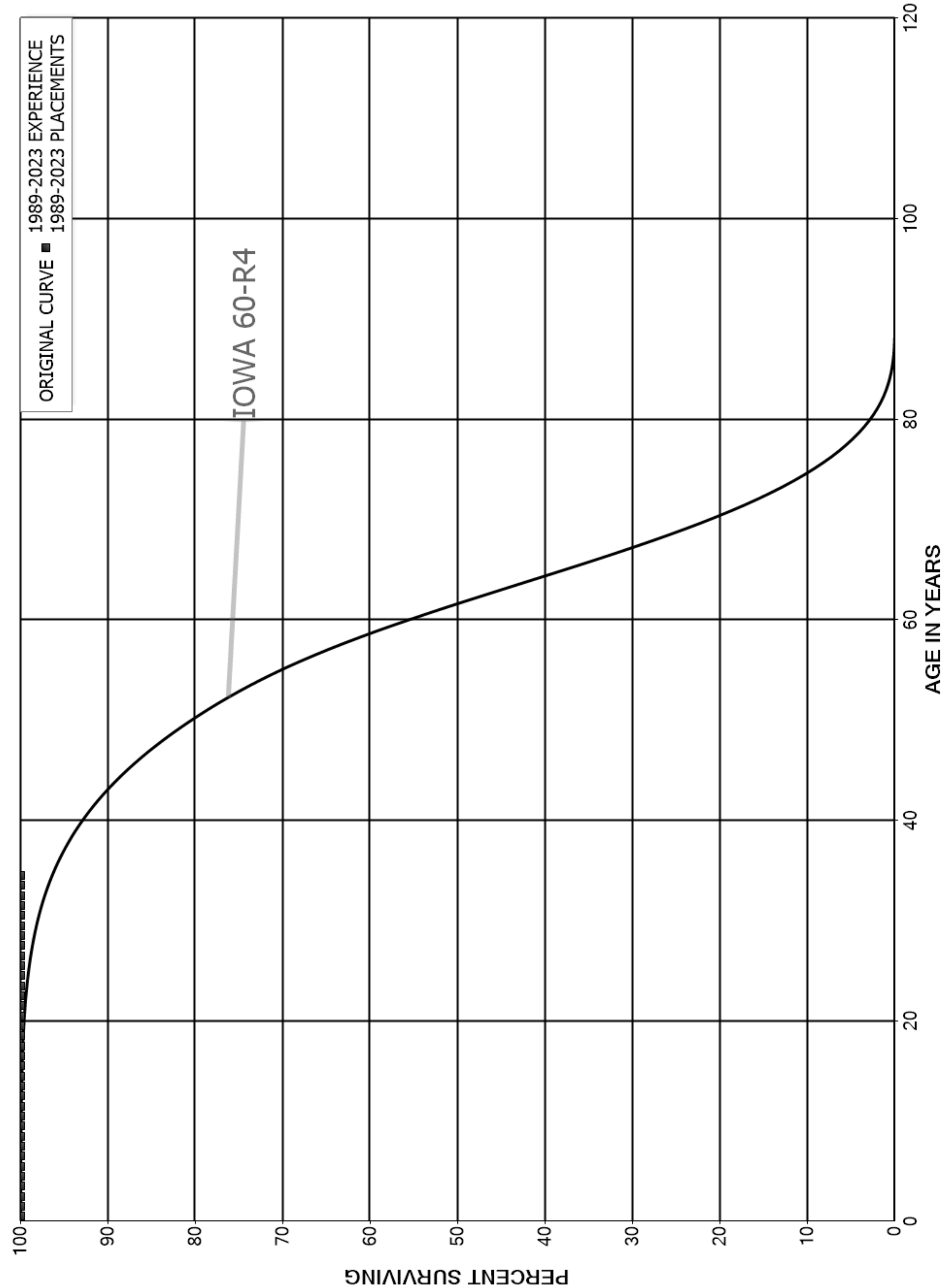
ACCOUNT 350.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2007 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	109,625		0.0000	1.0000	100.00
0.5	109,625		0.0000	1.0000	100.00
1.5	109,625		0.0000	1.0000	100.00
2.5	109,625		0.0000	1.0000	100.00
3.5	109,625		0.0000	1.0000	100.00
4.5	109,625		0.0000	1.0000	100.00
5.5	109,625		0.0000	1.0000	100.00
6.5	109,625		0.0000	1.0000	100.00
7.5	109,625		0.0000	1.0000	100.00
8.5	109,625		0.0000	1.0000	100.00
9.5	109,625		0.0000	1.0000	100.00
10.5	109,625		0.0000	1.0000	100.00
11.5	109,625		0.0000	1.0000	100.00
12.5	109,625		0.0000	1.0000	100.00
13.5	109,625		0.0000	1.0000	100.00
14.5	109,625		0.0000	1.0000	100.00
15.5	109,625		0.0000	1.0000	100.00
16.5	51,122		0.0000	1.0000	100.00
17.5	51,122		0.0000	1.0000	100.00
18.5	51,122		0.0000	1.0000	100.00
19.5	51,122		0.0000	1.0000	100.00
20.5	51,122		0.0000	1.0000	100.00
21.5	51,122		0.0000	1.0000	100.00
22.5	47,318		0.0000	1.0000	100.00
23.5	47,318		0.0000	1.0000	100.00
24.5	47,318		0.0000	1.0000	100.00
25.5	46,690		0.0000	1.0000	100.00
26.5	46,505		0.0000	1.0000	100.00
27.5	46,505		0.0000	1.0000	100.00
28.5	46,505		0.0000	1.0000	100.00
29.5	46,105		0.0000	1.0000	100.00
30.5	40,841		0.0000	1.0000	100.00
31.5	40,841		0.0000	1.0000	100.00
32.5	40,841		0.0000	1.0000	100.00
33.5	40,841		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



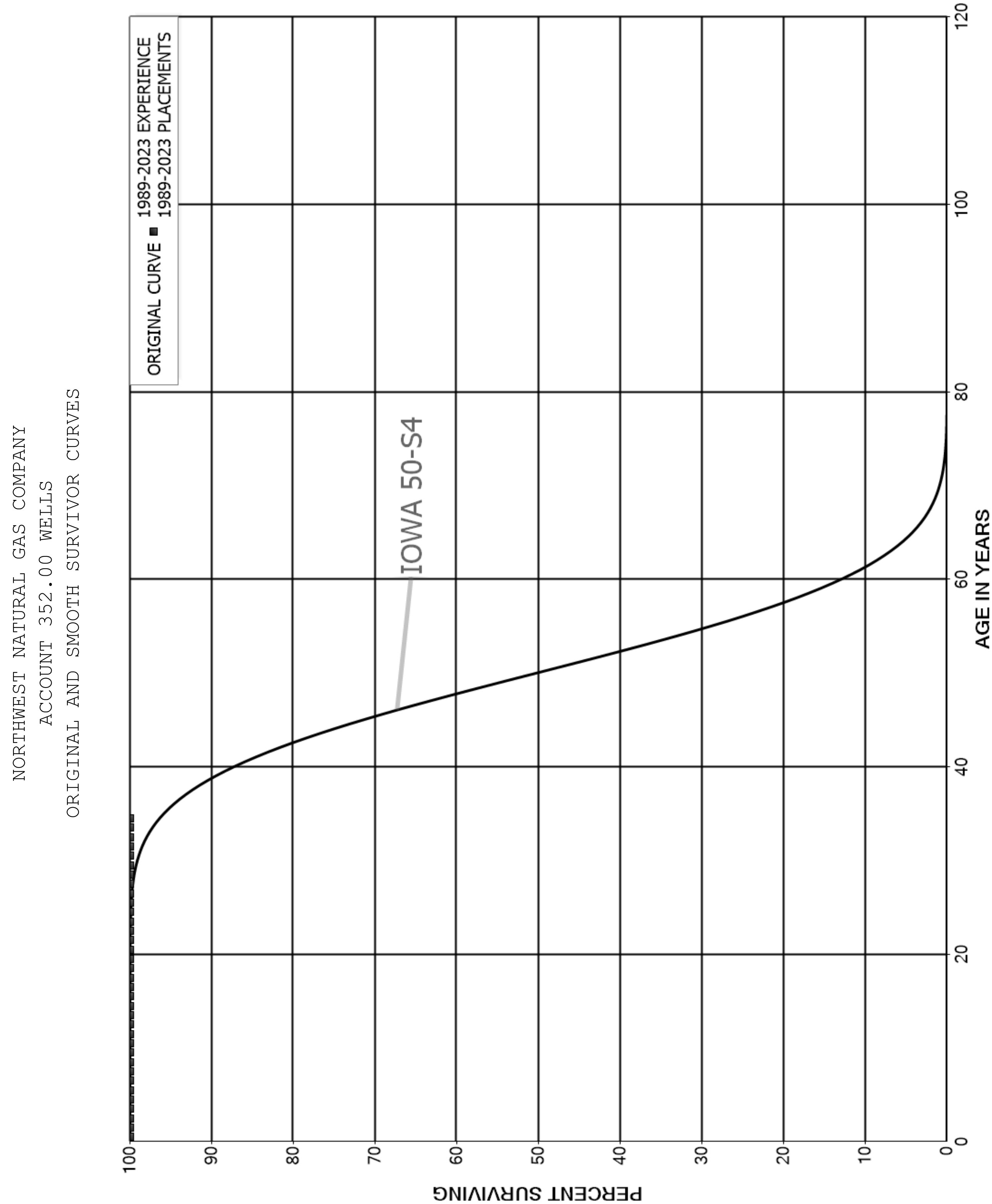
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,571,122		0.0000	1.0000	100.00
0.5	9,167,746		0.0000	1.0000	100.00
1.5	8,919,522		0.0000	1.0000	100.00
2.5	8,634,151		0.0000	1.0000	100.00
3.5	8,634,151		0.0000	1.0000	100.00
4.5	8,634,151		0.0000	1.0000	100.00
5.5	7,382,069		0.0000	1.0000	100.00
6.5	7,208,245		0.0000	1.0000	100.00
7.5	7,208,245		0.0000	1.0000	100.00
8.5	7,141,840		0.0000	1.0000	100.00
9.5	6,715,064		0.0000	1.0000	100.00
10.5	6,715,064		0.0000	1.0000	100.00
11.5	6,555,425		0.0000	1.0000	100.00
12.5	6,555,425		0.0000	1.0000	100.00
13.5	6,542,426		0.0000	1.0000	100.00
14.5	6,538,592		0.0000	1.0000	100.00
15.5	6,247,670		0.0000	1.0000	100.00
16.5	6,247,670		0.0000	1.0000	100.00
17.5	6,247,670		0.0000	1.0000	100.00
18.5	6,247,546		0.0000	1.0000	100.00
19.5	6,173,312		0.0000	1.0000	100.00
20.5	6,156,413		0.0000	1.0000	100.00
21.5	5,913,514		0.0000	1.0000	100.00
22.5	5,029,273		0.0000	1.0000	100.00
23.5	4,996,462		0.0000	1.0000	100.00
24.5	4,991,499		0.0000	1.0000	100.00
25.5	2,516,340		0.0000	1.0000	100.00
26.5	2,516,340		0.0000	1.0000	100.00
27.5	2,516,340		0.0000	1.0000	100.00
28.5	2,480,692		0.0000	1.0000	100.00
29.5	2,467,430		0.0000	1.0000	100.00
30.5	2,464,204		0.0000	1.0000	100.00
31.5	2,422,299		0.0000	1.0000	100.00
32.5	2,146,801		0.0000	1.0000	100.00
33.5	2,101,010		0.0000	1.0000	100.00
34.5					100.00


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.00 WELLS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1989-2023 EXPERIENCE
1989-2023 PLACEMENTS
IOWA 50-S4
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

NORTHWEST NATURAL GAS COMPANY

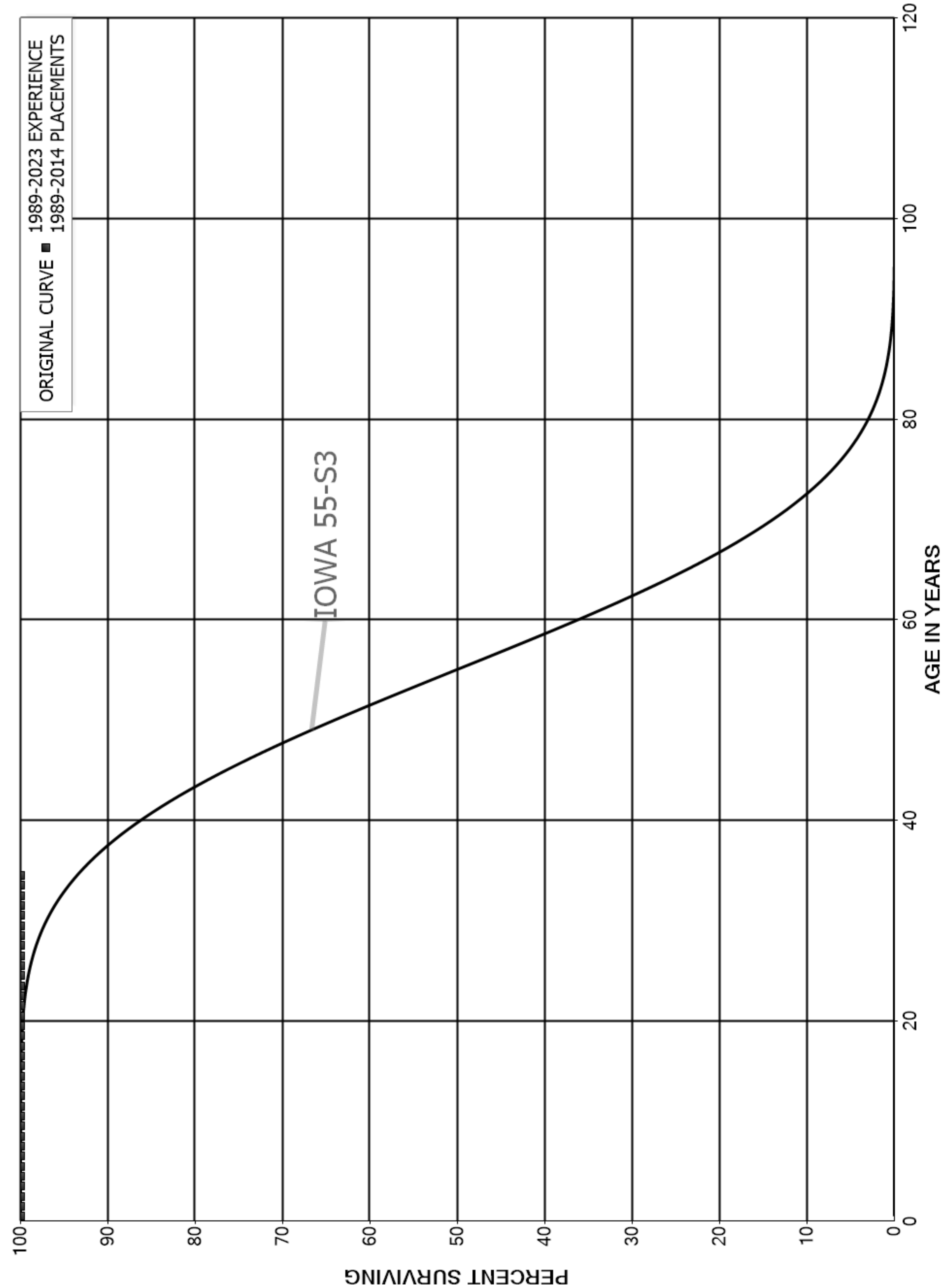
ACCOUNT 352.00 WELLS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	64,838,832		0.0000	1.0000	100.00
0.5	57,556,369		0.0000	1.0000	100.00
1.5	52,423,569		0.0000	1.0000	100.00
2.5	48,356,358		0.0000	1.0000	100.00
3.5	43,804,325		0.0000	1.0000	100.00
4.5	40,316,037		0.0000	1.0000	100.00
5.5	36,987,527		0.0000	1.0000	100.00
6.5	36,987,527		0.0000	1.0000	100.00
7.5	36,987,527		0.0000	1.0000	100.00
8.5	36,987,527		0.0000	1.0000	100.00
9.5	36,987,527		0.0000	1.0000	100.00
10.5	36,987,527		0.0000	1.0000	100.00
11.5	36,970,027		0.0000	1.0000	100.00
12.5	36,970,027		0.0000	1.0000	100.00
13.5	36,970,027		0.0000	1.0000	100.00
14.5	36,138,659		0.0000	1.0000	100.00
15.5	36,138,659		0.0000	1.0000	100.00
16.5	27,363,189		0.0000	1.0000	100.00
17.5	27,363,189		0.0000	1.0000	100.00
18.5	23,510,122		0.0000	1.0000	100.00
19.5	18,383,091		0.0000	1.0000	100.00
20.5	18,338,288		0.0000	1.0000	100.00
21.5	18,338,288		0.0000	1.0000	100.00
22.5	18,138,203		0.0000	1.0000	100.00
23.5	18,138,203		0.0000	1.0000	100.00
24.5	18,138,203		0.0000	1.0000	100.00
25.5	11,810,679		0.0000	1.0000	100.00
26.5	11,810,679		0.0000	1.0000	100.00
27.5	11,810,679		0.0000	1.0000	100.00
28.5	11,810,679		0.0000	1.0000	100.00
29.5	11,808,321		0.0000	1.0000	100.00
30.5	11,625,429		0.0000	1.0000	100.00
31.5	11,474,852		0.0000	1.0000	100.00
32.5	9,469,844		0.0000	1.0000	100.00
33.5	8,933,762		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

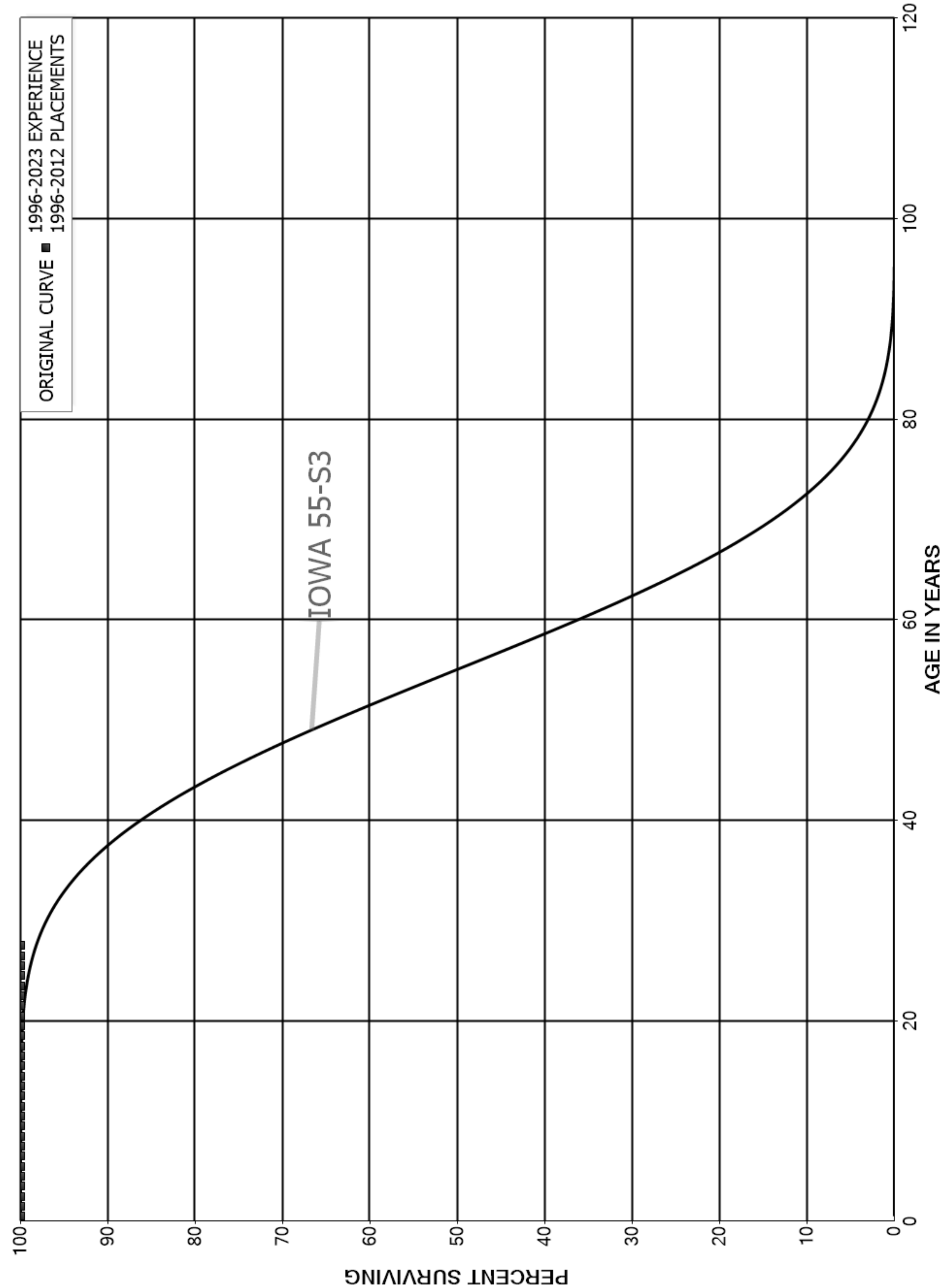
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2014 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,939,513		0.0000	1.0000	100.00
0.5	3,939,512		0.0000	1.0000	100.00
1.5	3,939,512		0.0000	1.0000	100.00
2.5	3,939,512		0.0000	1.0000	100.00
3.5	3,939,512		0.0000	1.0000	100.00
4.5	3,939,512		0.0000	1.0000	100.00
5.5	3,939,512		0.0000	1.0000	100.00
6.5	3,939,512		0.0000	1.0000	100.00
7.5	3,939,512		0.0000	1.0000	100.00
8.5	3,939,512		0.0000	1.0000	100.00
9.5	3,539,512		0.0000	1.0000	100.00
10.5	3,539,512		0.0000	1.0000	100.00
11.5	3,539,512		0.0000	1.0000	100.00
12.5	3,539,512		0.0000	1.0000	100.00
13.5	3,539,512		0.0000	1.0000	100.00
14.5	3,539,512		0.0000	1.0000	100.00
15.5	3,539,512		0.0000	1.0000	100.00
16.5	3,539,512		0.0000	1.0000	100.00
17.5	3,539,512		0.0000	1.0000	100.00
18.5	3,539,512		0.0000	1.0000	100.00
19.5	3,538,491		0.0000	1.0000	100.00
20.5	3,538,491		0.0000	1.0000	100.00
21.5	3,535,500		0.0000	1.0000	100.00
22.5	3,535,500		0.0000	1.0000	100.00
23.5	3,535,500		0.0000	1.0000	100.00
24.5	3,530,407		0.0000	1.0000	100.00
25.5	3,038,080		0.0000	1.0000	100.00
26.5	1,448,101		0.0000	1.0000	100.00
27.5	1,210,801		0.0000	1.0000	100.00
28.5	1,210,801		0.0000	1.0000	100.00
29.5	1,210,801		0.0000	1.0000	100.00
30.5	1,210,800		0.0000	1.0000	100.00
31.5	1,210,800		0.0000	1.0000	100.00
32.5	1,210,800		0.0000	1.0000	100.00
33.5	1,210,800		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.20 RESERVOIRS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

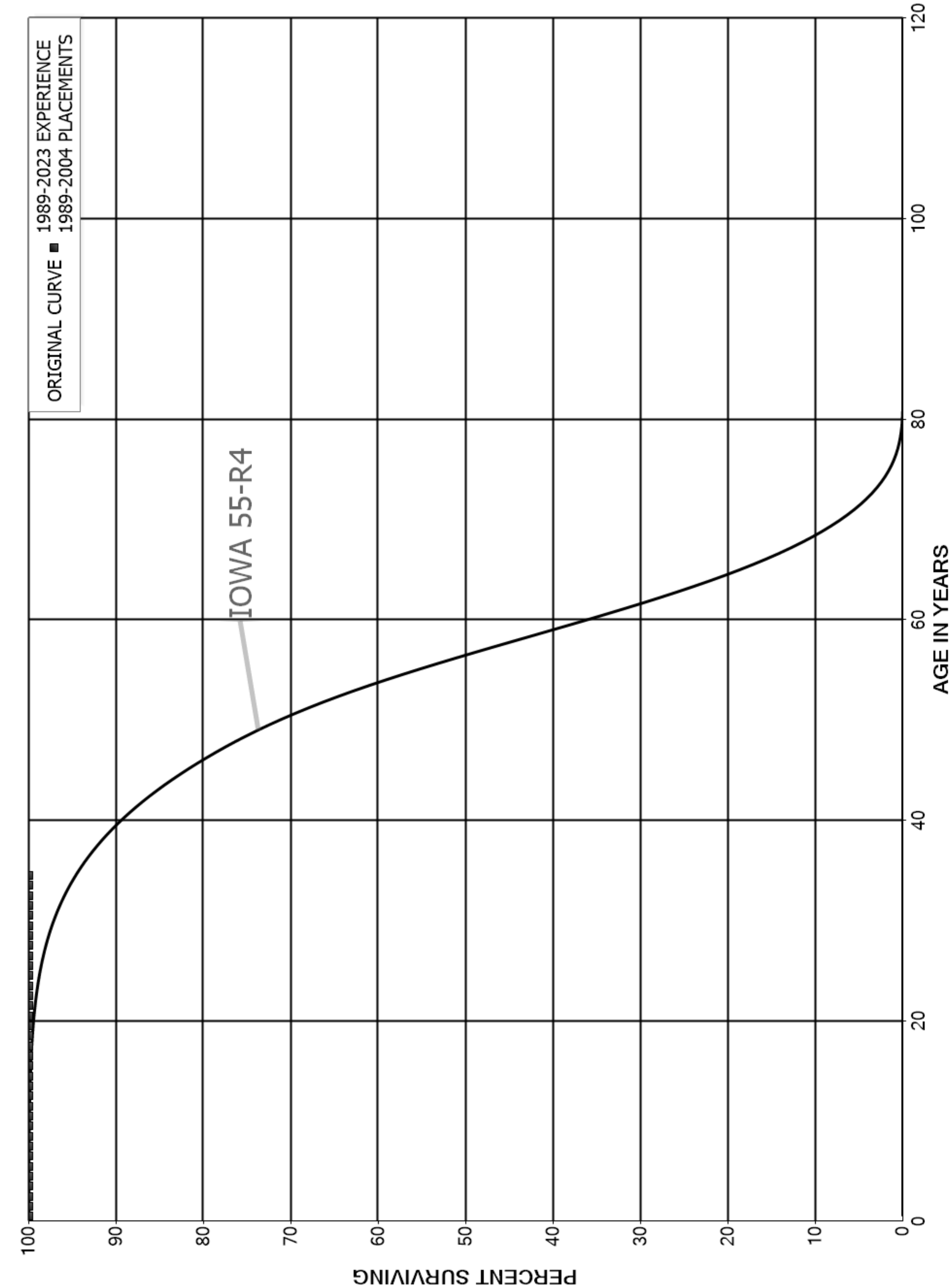
ACCOUNT 352.20 RESERVOIRS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1996-2012 EXPERIENCE BAND 1996-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,303,798		0.0000	1.0000	100.00
0.5	7,303,798		0.0000	1.0000	100.00
1.5	7,303,798		0.0000	1.0000	100.00
2.5	9,211,060		0.0000	1.0000	100.00
3.5	9,211,060		0.0000	1.0000	100.00
4.5	10,834,055		0.0000	1.0000	100.00
5.5	10,834,055		0.0000	1.0000	100.00
6.5	10,834,055		0.0000	1.0000	100.00
7.5	10,834,055		0.0000	1.0000	100.00
8.5	10,834,055		0.0000	1.0000	100.00
9.5	10,834,055		0.0000	1.0000	100.00
10.5	10,834,055		0.0000	1.0000	100.00
11.5	10,816,555		0.0000	1.0000	100.00
12.5	10,816,555		0.0000	1.0000	100.00
13.5	11,963,401		0.0000	1.0000	100.00
14.5	11,963,401		0.0000	1.0000	100.00
15.5	10,816,555		0.0000	1.0000	100.00
16.5	10,816,555		0.0000	1.0000	100.00
17.5	10,816,555		0.0000	1.0000	100.00
18.5	8,371,537		0.0000	1.0000	100.00
19.5	7,159,166		0.0000	1.0000	100.00
20.5	7,159,166		0.0000	1.0000	100.00
21.5	4,161,435		0.0000	1.0000	100.00
22.5	4,161,435		0.0000	1.0000	100.00
23.5	3,685,094		0.0000	1.0000	100.00
24.5	3,679,091		0.0000	1.0000	100.00
25.5	1,679,184		0.0000	1.0000	100.00
26.5	1,679,184		0.0000	1.0000	100.00
27.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.30 NONRECOVERABLE GAS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

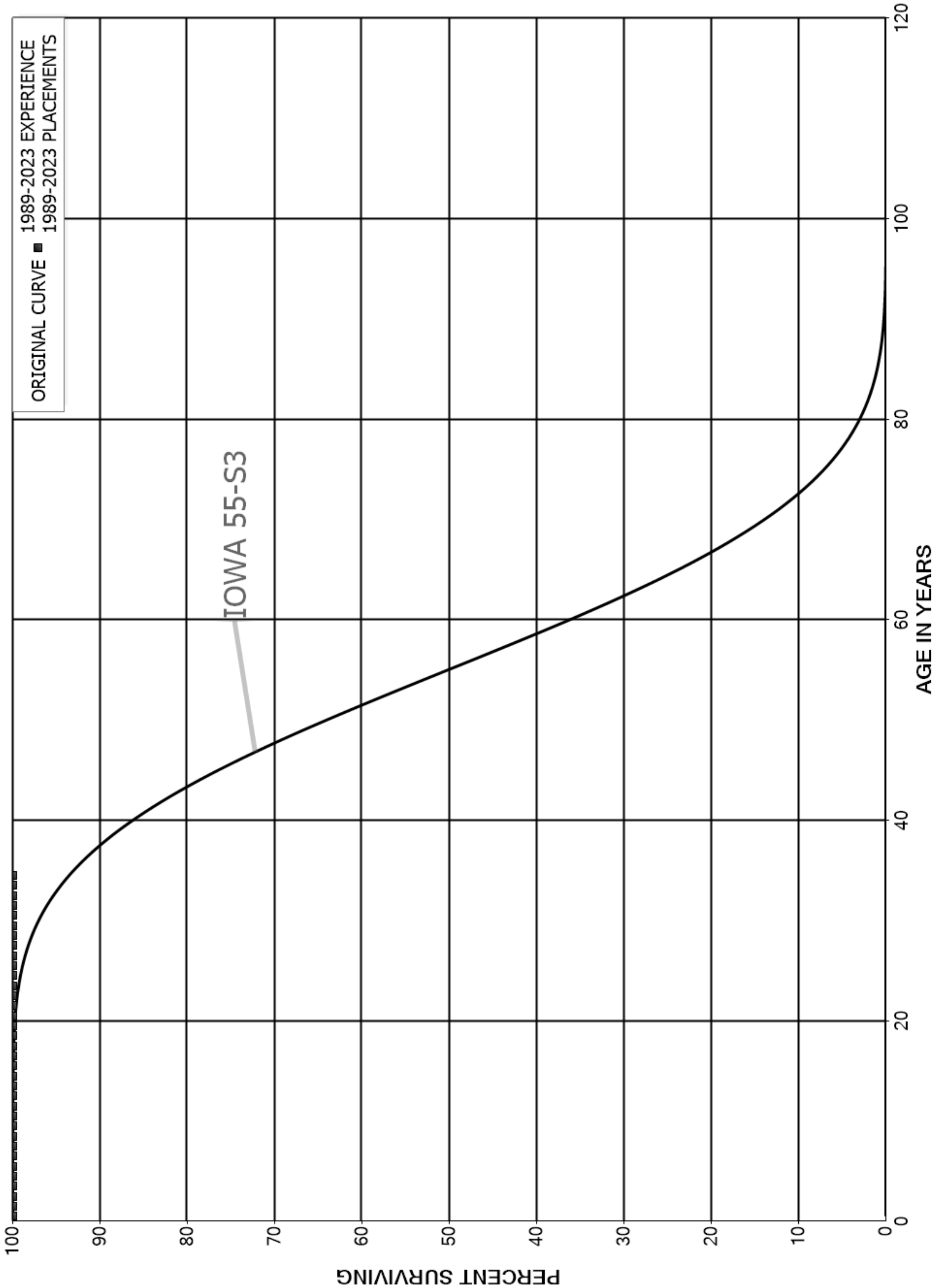
ACCOUNT 352.30 NONRECOVERABLE GAS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2004 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,440,891		0.0000	1.0000	100.00
0.5	6,440,890		0.0000	1.0000	100.00
1.5	6,440,890		0.0000	1.0000	100.00
2.5	6,440,890		0.0000	1.0000	100.00
3.5	6,440,890		0.0000	1.0000	100.00
4.5	6,440,890		0.0000	1.0000	100.00
5.5	6,440,890		0.0000	1.0000	100.00
6.5	6,440,890		0.0000	1.0000	100.00
7.5	6,440,890		0.0000	1.0000	100.00
8.5	6,440,890		0.0000	1.0000	100.00
9.5	6,440,890		0.0000	1.0000	100.00
10.5	6,440,890		0.0000	1.0000	100.00
11.5	6,440,890		0.0000	1.0000	100.00
12.5	6,440,890		0.0000	1.0000	100.00
13.5	6,440,890		0.0000	1.0000	100.00
14.5	6,440,890		0.0000	1.0000	100.00
15.5	6,440,890		0.0000	1.0000	100.00
16.5	6,440,890		0.0000	1.0000	100.00
17.5	6,440,890		0.0000	1.0000	100.00
18.5	6,440,890		0.0000	1.0000	100.00
19.5	6,375,402		0.0000	1.0000	100.00
20.5	6,375,402		0.0000	1.0000	100.00
21.5	6,375,402		0.0000	1.0000	100.00
22.5	6,375,402		0.0000	1.0000	100.00
23.5	6,375,402		0.0000	1.0000	100.00
24.5	6,375,402		0.0000	1.0000	100.00
25.5	6,312,953		0.0000	1.0000	100.00
26.5	6,312,953		0.0000	1.0000	100.00
27.5	4,057,953		0.0000	1.0000	100.00
28.5	4,057,953		0.0000	1.0000	100.00
29.5	4,057,953		0.0000	1.0000	100.00
30.5	4,057,952		0.0000	1.0000	100.00
31.5	4,057,952		0.0000	1.0000	100.00
32.5	4,057,952		0.0000	1.0000	100.00
33.5	4,057,952		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 353.00 LINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

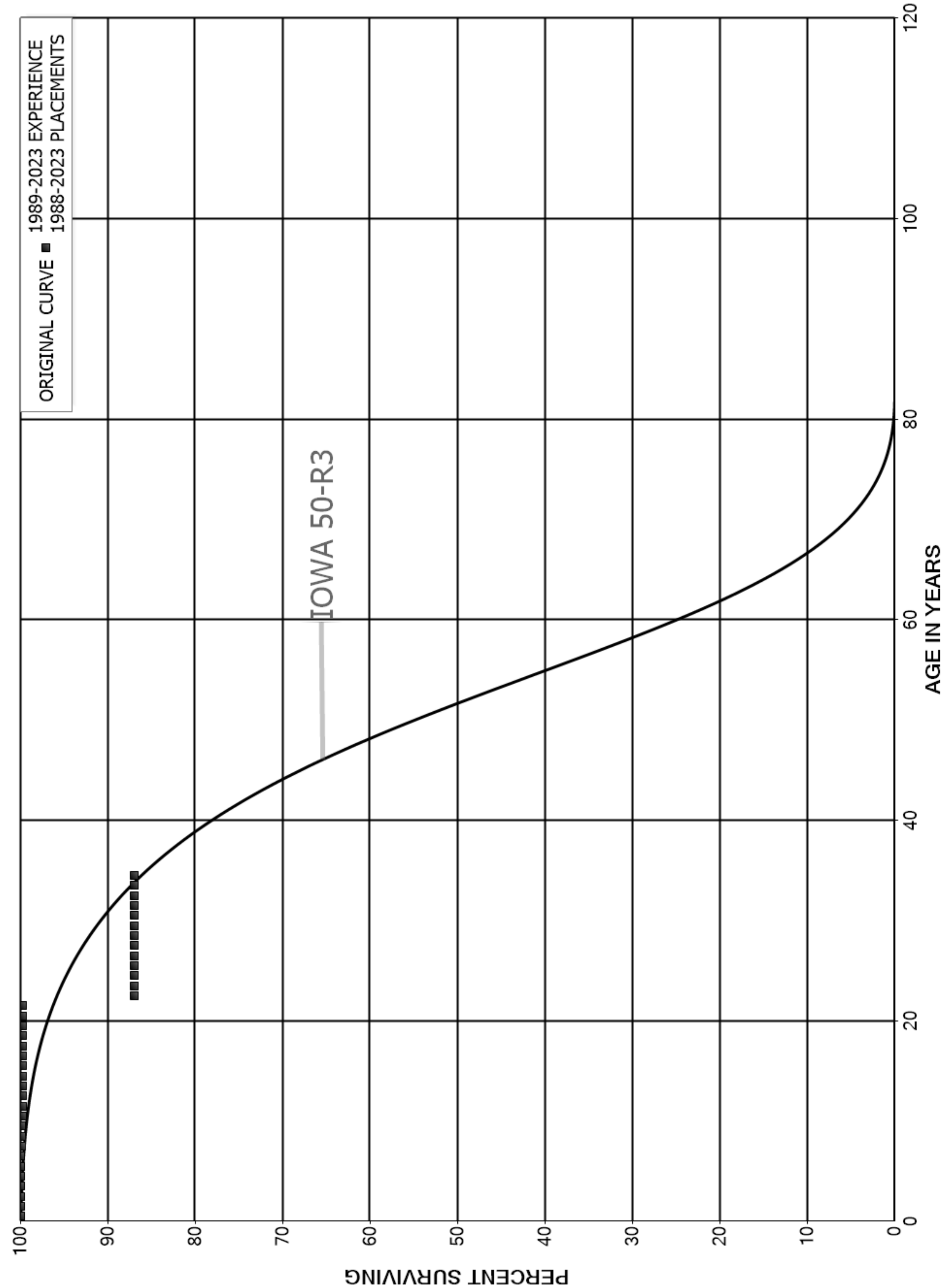
ACCOUNT 353.00 LINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,986,910		0.0000	1.0000	100.00
0.5	12,167,086		0.0000	1.0000	100.00
1.5	10,790,930		0.0000	1.0000	100.00
2.5	10,790,148		0.0000	1.0000	100.00
3.5	10,673,228		0.0000	1.0000	100.00
4.5	9,535,478		0.0000	1.0000	100.00
5.5	8,201,964		0.0000	1.0000	100.00
6.5	8,201,964		0.0000	1.0000	100.00
7.5	8,201,964		0.0000	1.0000	100.00
8.5	8,201,964		0.0000	1.0000	100.00
9.5	8,201,964		0.0000	1.0000	100.00
10.5	8,201,964		0.0000	1.0000	100.00
11.5	8,201,964		0.0000	1.0000	100.00
12.5	8,201,964		0.0000	1.0000	100.00
13.5	8,201,964		0.0000	1.0000	100.00
14.5	8,201,964		0.0000	1.0000	100.00
15.5	8,201,964		0.0000	1.0000	100.00
16.5	7,641,810		0.0000	1.0000	100.00
17.5	7,641,810		0.0000	1.0000	100.00
18.5	7,137,450		0.0000	1.0000	100.00
19.5	6,453,175		0.0000	1.0000	100.00
20.5	6,445,334		0.0000	1.0000	100.00
21.5	6,445,334		0.0000	1.0000	100.00
22.5	6,445,334		0.0000	1.0000	100.00
23.5	6,445,334		0.0000	1.0000	100.00
24.5	6,392,472		0.0000	1.0000	100.00
25.5	2,538,843		0.0000	1.0000	100.00
26.5	2,538,843		0.0000	1.0000	100.00
27.5	2,538,843		0.0000	1.0000	100.00
28.5	2,538,843		0.0000	1.0000	100.00
29.5	2,538,843		0.0000	1.0000	100.00
30.5	2,538,842		0.0000	1.0000	100.00
31.5	2,538,842		0.0000	1.0000	100.00
32.5	2,521,353		0.0000	1.0000	100.00
33.5	2,521,353		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

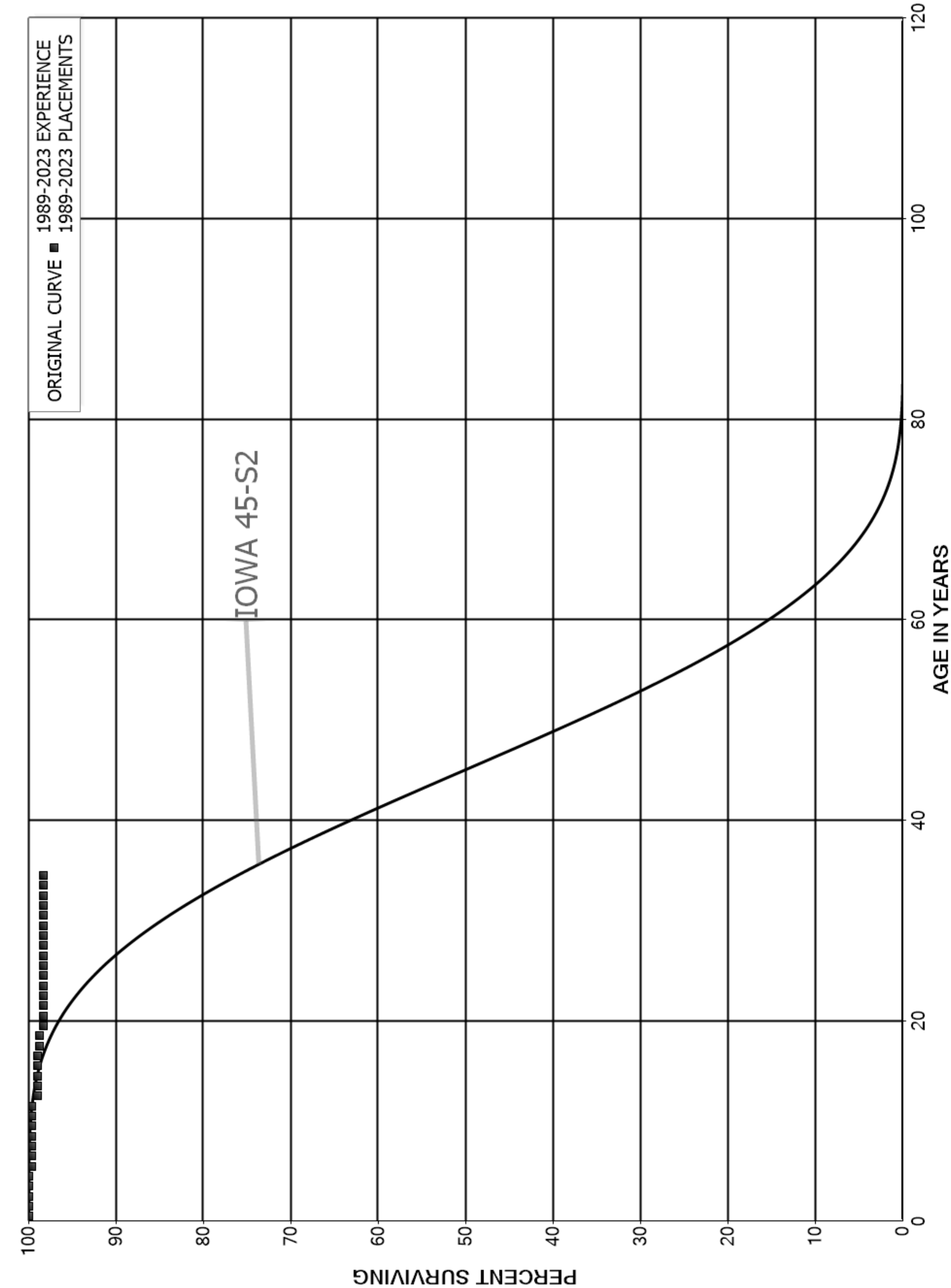
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1988-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,298,004		0.0000	1.0000	100.00
0.5	38,974,814		0.0000	1.0000	100.00
1.5	36,863,881	31,012	0.0008	0.9992	100.00
2.5	35,900,382		0.0000	1.0000	99.92
3.5	43,376,637		0.0000	1.0000	99.92
4.5	45,967,130		0.0000	1.0000	99.92
5.5	45,967,968		0.0000	1.0000	99.92
6.5	45,818,727	51,212	0.0011	0.9989	99.92
7.5	45,725,131		0.0000	1.0000	99.80
8.5	45,465,090		0.0000	1.0000	99.80
9.5	44,683,528	23,443	0.0005	0.9995	99.80
10.5	43,892,758		0.0000	1.0000	99.75
11.5	43,905,008		0.0000	1.0000	99.75
12.5	42,720,488		0.0000	1.0000	99.75
13.5	42,692,516		0.0000	1.0000	99.75
14.5	41,897,297		0.0000	1.0000	99.75
15.5	41,251,651		0.0000	1.0000	99.75
16.5	41,251,651		0.0000	1.0000	99.75
17.5	41,246,901		0.0000	1.0000	99.75
18.5	41,246,901		0.0000	1.0000	99.75
19.5	39,069,867		0.0000	1.0000	99.75
20.5	39,065,888		0.0000	1.0000	99.75
21.5	38,943,483	5,000,000	0.1284	0.8716	99.75
22.5	24,681,689		0.0000	1.0000	86.94
23.5	16,906,902		0.0000	1.0000	86.94
24.5	16,812,180		0.0000	1.0000	86.94
25.5	8,143,343		0.0000	1.0000	86.94
26.5	8,124,254		0.0000	1.0000	86.94
27.5	8,121,118		0.0000	1.0000	86.94
28.5	8,004,748		0.0000	1.0000	86.94
29.5	7,997,100		0.0000	1.0000	86.94
30.5	7,993,959		0.0000	1.0000	86.94
31.5	7,952,213		0.0000	1.0000	86.94
32.5	7,813,027		0.0000	1.0000	86.94
33.5	7,702,081		0.0000	1.0000	86.94
34.5					86.94

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

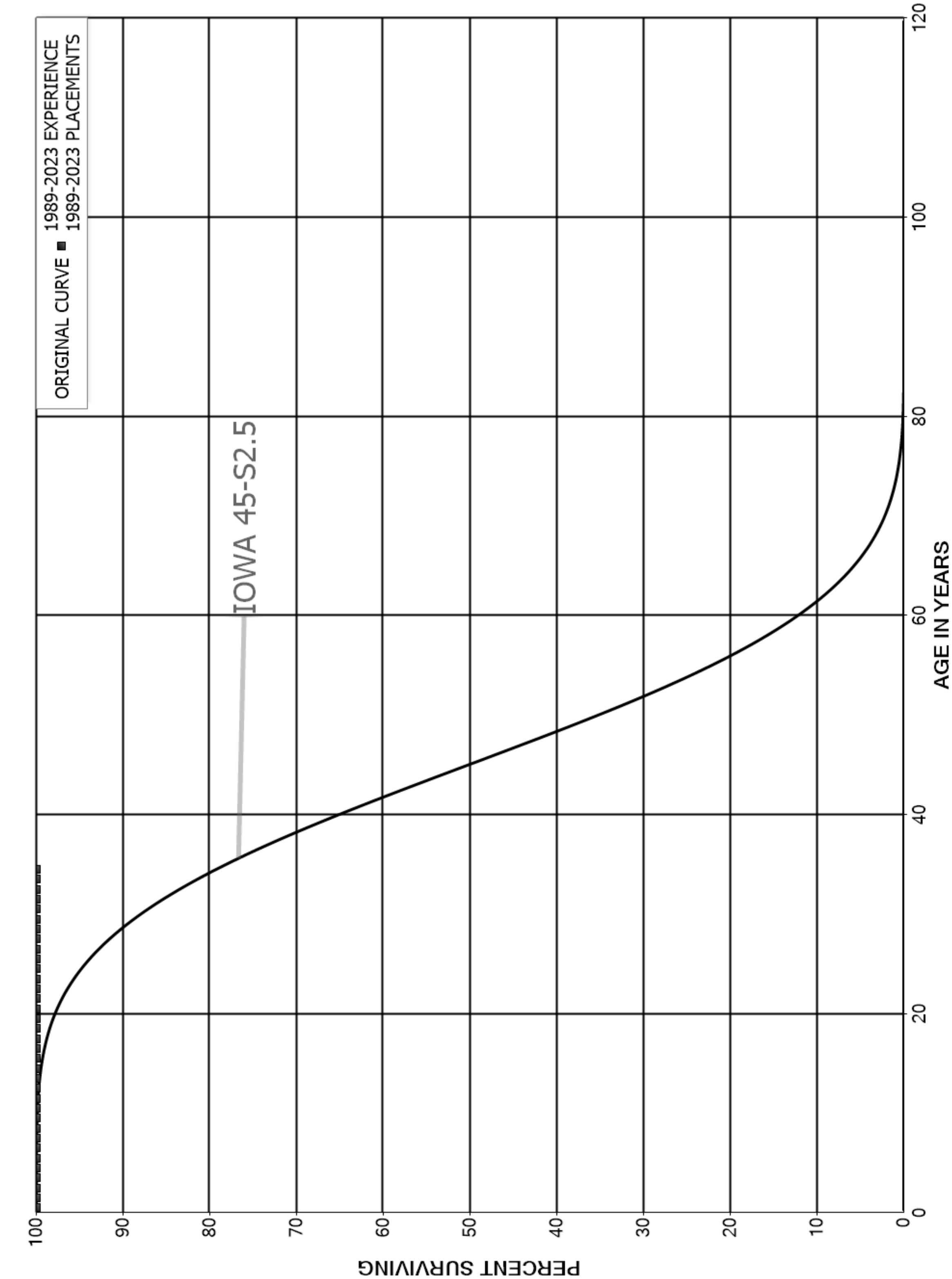
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	39,987,117		0.0000	1.0000	100.00
0.5	36,702,177		0.0000	1.0000	100.00
1.5	27,546,415		0.0000	1.0000	100.00
2.5	18,161,888		0.0000	1.0000	100.00
3.5	16,698,104		0.0000	1.0000	100.00
4.5	17,326,031	58,779	0.0034	0.9966	100.00
5.5	16,417,180		0.0000	1.0000	99.66
6.5	16,292,883		0.0000	1.0000	99.66
7.5	16,168,075		0.0000	1.0000	99.66
8.5	16,158,003		0.0000	1.0000	99.66
9.5	16,158,003		0.0000	1.0000	99.66
10.5	16,086,849		0.0000	1.0000	99.66
11.5	16,069,349	122,683	0.0076	0.9924	99.66
12.5	15,511,149		0.0000	1.0000	98.90
13.5	15,462,884		0.0000	1.0000	98.90
14.5	14,075,689		0.0000	1.0000	98.90
15.5	14,310,699		0.0000	1.0000	98.90
16.5	9,699,149	15,249	0.0016	0.9984	98.90
17.5	9,540,770		0.0000	1.0000	98.74
18.5	7,749,151	32,310	0.0042	0.9958	98.74
19.5	6,886,213		0.0000	1.0000	98.33
20.5	6,886,213		0.0000	1.0000	98.33
21.5	6,688,016		0.0000	1.0000	98.33
22.5	6,639,166		0.0000	1.0000	98.33
23.5	4,935,004		0.0000	1.0000	98.33
24.5	4,696,363		0.0000	1.0000	98.33
25.5	3,606,243		0.0000	1.0000	98.33
26.5	3,606,243		0.0000	1.0000	98.33
27.5	3,590,871		0.0000	1.0000	98.33
28.5	3,581,013		0.0000	1.0000	98.33
29.5	3,580,978		0.0000	1.0000	98.33
30.5	3,579,193		0.0000	1.0000	98.33
31.5	3,561,374		0.0000	1.0000	98.33
32.5	3,539,964		0.0000	1.0000	98.33
33.5	3,473,015		0.0000	1.0000	98.33
34.5					98.33

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 356.00 PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

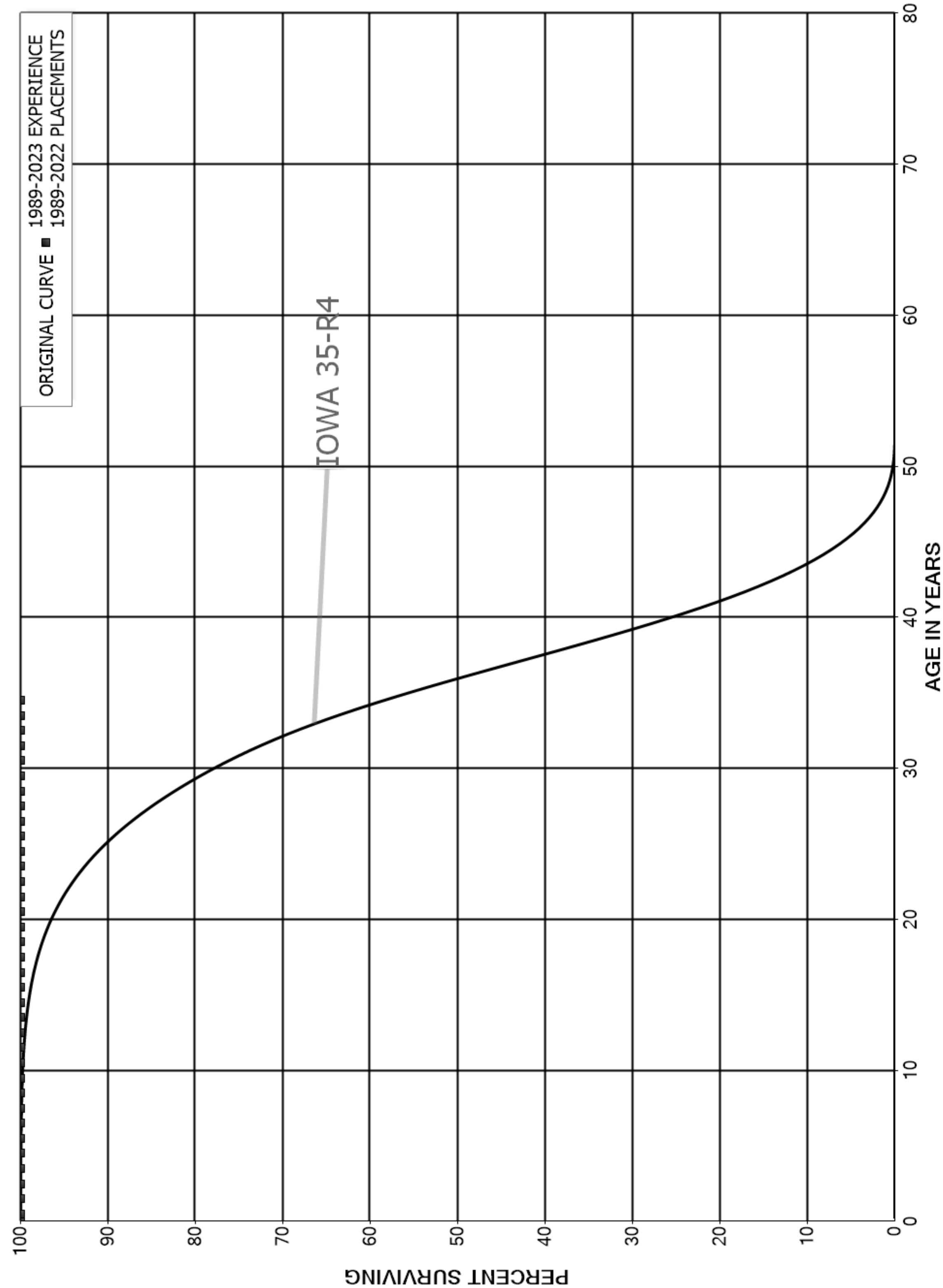
ACCOUNT 356.00 PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,955,345		0.0000	1.0000	100.00
0.5	28,777,466		0.0000	1.0000	100.00
1.5	28,542,130		0.0000	1.0000	100.00
2.5	28,555,651		0.0000	1.0000	100.00
3.5	363,765		0.0000	1.0000	100.00
4.5	363,765		0.0000	1.0000	100.00
5.5	297,363		0.0000	1.0000	100.00
6.5	297,363		0.0000	1.0000	100.00
7.5	297,363		0.0000	1.0000	100.00
8.5	297,363		0.0000	1.0000	100.00
9.5	297,363		0.0000	1.0000	100.00
10.5	297,363		0.0000	1.0000	100.00
11.5	297,363		0.0000	1.0000	100.00
12.5	297,363		0.0000	1.0000	100.00
13.5	297,363		0.0000	1.0000	100.00
14.5	297,363		0.0000	1.0000	100.00
15.5	297,363		0.0000	1.0000	100.00
16.5	297,363		0.0000	1.0000	100.00
17.5	297,363		0.0000	1.0000	100.00
18.5	297,363		0.0000	1.0000	100.00
19.5	297,363		0.0000	1.0000	100.00
20.5	297,363		0.0000	1.0000	100.00
21.5	297,363		0.0000	1.0000	100.00
22.5	297,363		0.0000	1.0000	100.00
23.5	297,363		0.0000	1.0000	100.00
24.5	297,363		0.0000	1.0000	100.00
25.5	294,282		0.0000	1.0000	100.00
26.5	294,282		0.0000	1.0000	100.00
27.5	245,456		0.0000	1.0000	100.00
28.5	171,575		0.0000	1.0000	100.00
29.5	171,575		0.0000	1.0000	100.00
30.5	168,697		0.0000	1.0000	100.00
31.5	152,757		0.0000	1.0000	100.00
32.5	152,757		0.0000	1.0000	100.00
33.5	139,942		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 357.00 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

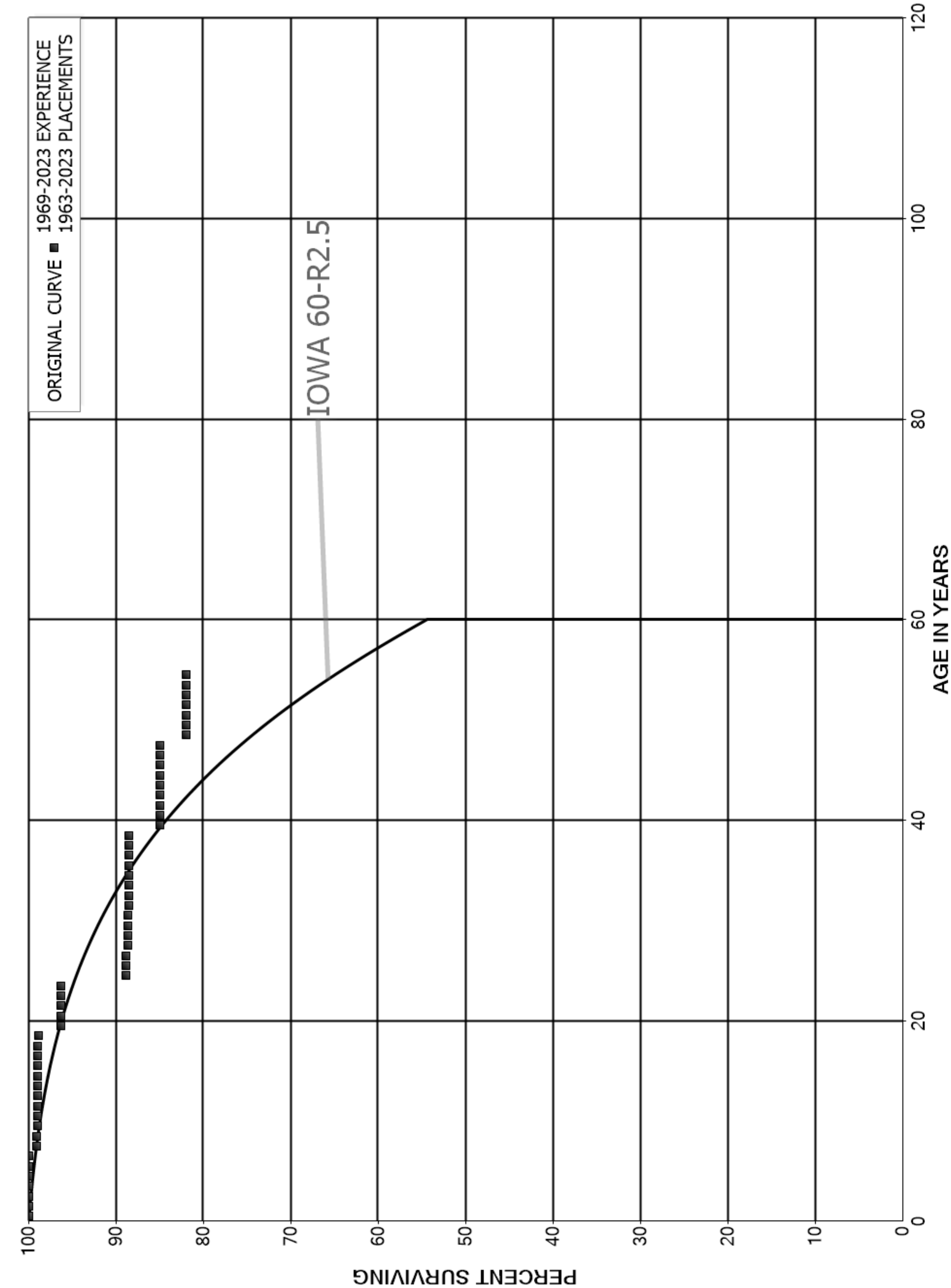
ACCOUNT 357.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,255,463		0.0000	1.0000	100.00
0.5	5,255,463		0.0000	1.0000	100.00
1.5	5,141,896		0.0000	1.0000	100.00
2.5	4,672,992		0.0000	1.0000	100.00
3.5	2,422,822		0.0000	1.0000	100.00
4.5	2,422,822		0.0000	1.0000	100.00
5.5	1,395,285		0.0000	1.0000	100.00
6.5	1,395,285		0.0000	1.0000	100.00
7.5	1,395,285		0.0000	1.0000	100.00
8.5	1,395,285		0.0000	1.0000	100.00
9.5	1,395,285		0.0000	1.0000	100.00
10.5	1,395,285		0.0000	1.0000	100.00
11.5	1,395,285		0.0000	1.0000	100.00
12.5	1,395,285		0.0000	1.0000	100.00
13.5	1,395,285		0.0000	1.0000	100.00
14.5	1,332,029		0.0000	1.0000	100.00
15.5	702,587		0.0000	1.0000	100.00
16.5	702,587		0.0000	1.0000	100.00
17.5	702,587		0.0000	1.0000	100.00
18.5	702,587		0.0000	1.0000	100.00
19.5	702,587		0.0000	1.0000	100.00
20.5	702,587		0.0000	1.0000	100.00
21.5	702,587		0.0000	1.0000	100.00
22.5	702,587		0.0000	1.0000	100.00
23.5	702,587		0.0000	1.0000	100.00
24.5	646,258		0.0000	1.0000	100.00
25.5	82,037		0.0000	1.0000	100.00
26.5	82,037		0.0000	1.0000	100.00
27.5	82,037		0.0000	1.0000	100.00
28.5	82,037		0.0000	1.0000	100.00
29.5	82,037		0.0000	1.0000	100.00
30.5	82,037		0.0000	1.0000	100.00
31.5	76,057		0.0000	1.0000	100.00
32.5	76,057		0.0000	1.0000	100.00
33.5	76,057		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,677,346	44	0.0000	1.0000	100.00
0.5	25,434,110		0.0000	1.0000	100.00
1.5	23,691,351		0.0000	1.0000	100.00
2.5	23,432,096		0.0000	1.0000	100.00
3.5	23,361,127		0.0000	1.0000	100.00
4.5	23,193,204	44	0.0000	1.0000	100.00
5.5	15,702,491		0.0000	1.0000	100.00
6.5	12,828,703	123,196	0.0096	0.9904	100.00
7.5	9,157,629		0.0000	1.0000	99.04
8.5	9,103,804	4,058	0.0004	0.9996	99.04
9.5	9,046,459		0.0000	1.0000	99.00
10.5	9,046,459		0.0000	1.0000	99.00
11.5	8,942,963		0.0000	1.0000	99.00
12.5	8,662,678		0.0000	1.0000	99.00
13.5	7,912,962	6,596	0.0008	0.9992	99.00
14.5	6,555,507		0.0000	1.0000	98.91
15.5	5,296,524		0.0000	1.0000	98.91
16.5	4,864,332		0.0000	1.0000	98.91
17.5	3,854,896	1,150	0.0003	0.9997	98.91
18.5	3,658,107	97,968	0.0268	0.9732	98.88
19.5	3,541,714		0.0000	1.0000	96.23
20.5	3,541,714		0.0000	1.0000	96.23
21.5	3,414,287		0.0000	1.0000	96.23
22.5	3,334,846		0.0000	1.0000	96.23
23.5	3,292,618	253,844	0.0771	0.9229	96.23
24.5	2,853,588		0.0000	1.0000	88.82
25.5	2,786,531		0.0000	1.0000	88.82
26.5	2,594,384	5,060	0.0020	0.9980	88.82
27.5	2,478,519	478	0.0002	0.9998	88.64
28.5	2,394,631		0.0000	1.0000	88.63
29.5	2,143,139		0.0000	1.0000	88.63
30.5	2,074,412	2,147	0.0010	0.9990	88.63
31.5	1,925,445	568	0.0003	0.9997	88.53
32.5	1,837,823		0.0000	1.0000	88.51
33.5	1,813,495		0.0000	1.0000	88.51
34.5	1,729,977		0.0000	1.0000	88.51
35.5	1,682,462		0.0000	1.0000	88.51
36.5	1,673,588		0.0000	1.0000	88.51
37.5	1,664,262		0.0000	1.0000	88.51
38.5	1,644,107	66,938	0.0407	0.9593	88.51

NORTHWEST NATURAL GAS COMPANY

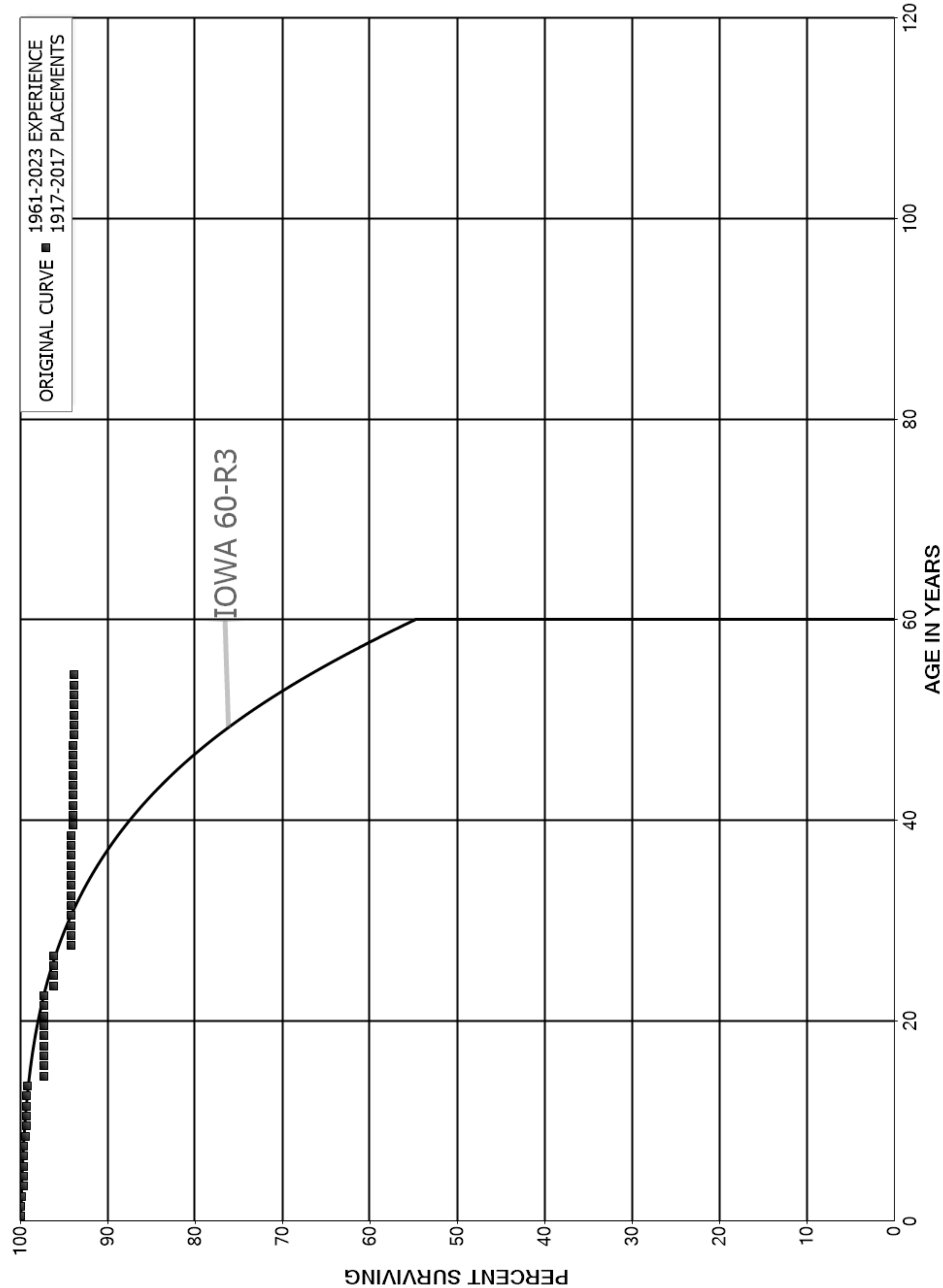
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,576,899		0.0000	1.0000	84.90
40.5	1,576,899		0.0000	1.0000	84.90
41.5	1,516,207		0.0000	1.0000	84.90
42.5	1,515,190		0.0000	1.0000	84.90
43.5	1,515,190		0.0000	1.0000	84.90
44.5	1,499,105		0.0000	1.0000	84.90
45.5	1,457,539		0.0000	1.0000	84.90
46.5	746,366		0.0000	1.0000	84.90
47.5	731,809	25,020	0.0342	0.9658	84.90
48.5	697,146		0.0000	1.0000	82.00
49.5	91,537		0.0000	1.0000	82.00
50.5	91,537		0.0000	1.0000	82.00
51.5	91,537		0.0000	1.0000	82.00
52.5	91,537		0.0000	1.0000	82.00
53.5	65,448		0.0000	1.0000	82.00
54.5	6,036		0.0000	1.0000	82.00
55.5	5,509		0.0000	1.0000	82.00
56.5	5,509		0.0000	1.0000	82.00
57.5	5,509		0.0000	1.0000	82.00
58.5	4,009		0.0000	1.0000	82.00
59.5	4,009		0.0000	1.0000	82.00
60.5					82.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 362.00 GAS HOLDERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1917-2017 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,693,529		0.0000	1.0000	100.00
0.5	10,766,444	954	0.0001	0.9999	100.00
1.5	10,725,963	20,788	0.0019	0.9981	99.99
2.5	10,731,567	24,257	0.0023	0.9977	99.80
3.5	10,732,521		0.0000	1.0000	99.57
4.5	10,732,344		0.0000	1.0000	99.57
5.5	10,735,297		0.0000	1.0000	99.57
6.5	10,360,610		0.0000	1.0000	99.57
7.5	8,673,677	12,049	0.0014	0.9986	99.57
8.5	8,575,271	11,416	0.0013	0.9987	99.43
9.5	8,571,828	472	0.0001	0.9999	99.30
10.5	8,572,007		0.0000	1.0000	99.30
11.5	8,549,518		0.0000	1.0000	99.30
12.5	8,549,518	8,994	0.0011	0.9989	99.30
13.5	9,300,870	174,892	0.0188	0.9812	99.19
14.5	8,812,224		0.0000	1.0000	97.33
15.5	8,812,224	2,066	0.0002	0.9998	97.33
16.5	8,810,257		0.0000	1.0000	97.30
17.5	8,442,780		0.0000	1.0000	97.30
18.5	8,442,780		0.0000	1.0000	97.30
19.5	8,442,780		0.0000	1.0000	97.30
20.5	8,442,780		0.0000	1.0000	97.30
21.5	8,442,709		0.0000	1.0000	97.30
22.5	8,442,031	96,759	0.0115	0.9885	97.30
23.5	8,345,123		0.0000	1.0000	96.19
24.5	8,345,123	1,431	0.0002	0.9998	96.19
25.5	8,345,123		0.0000	1.0000	96.17
26.5	8,345,123	174,892	0.0210	0.9790	96.17
27.5	8,028,102		0.0000	1.0000	94.16
28.5	8,027,148		0.0000	1.0000	94.16
29.5	7,954,233		0.0000	1.0000	94.16
30.5	7,932,289	1,200	0.0002	0.9998	94.16
31.5	7,931,089		0.0000	1.0000	94.14
32.5	7,930,072		0.0000	1.0000	94.14
33.5	7,930,072		0.0000	1.0000	94.14
34.5	7,922,701		0.0000	1.0000	94.14
35.5	7,931,283		0.0000	1.0000	94.14
36.5	7,931,283		0.0000	1.0000	94.14
37.5	7,931,283		0.0000	1.0000	94.14
38.5	7,311,305	18,053	0.0025	0.9975	94.14

NORTHWEST NATURAL GAS COMPANY

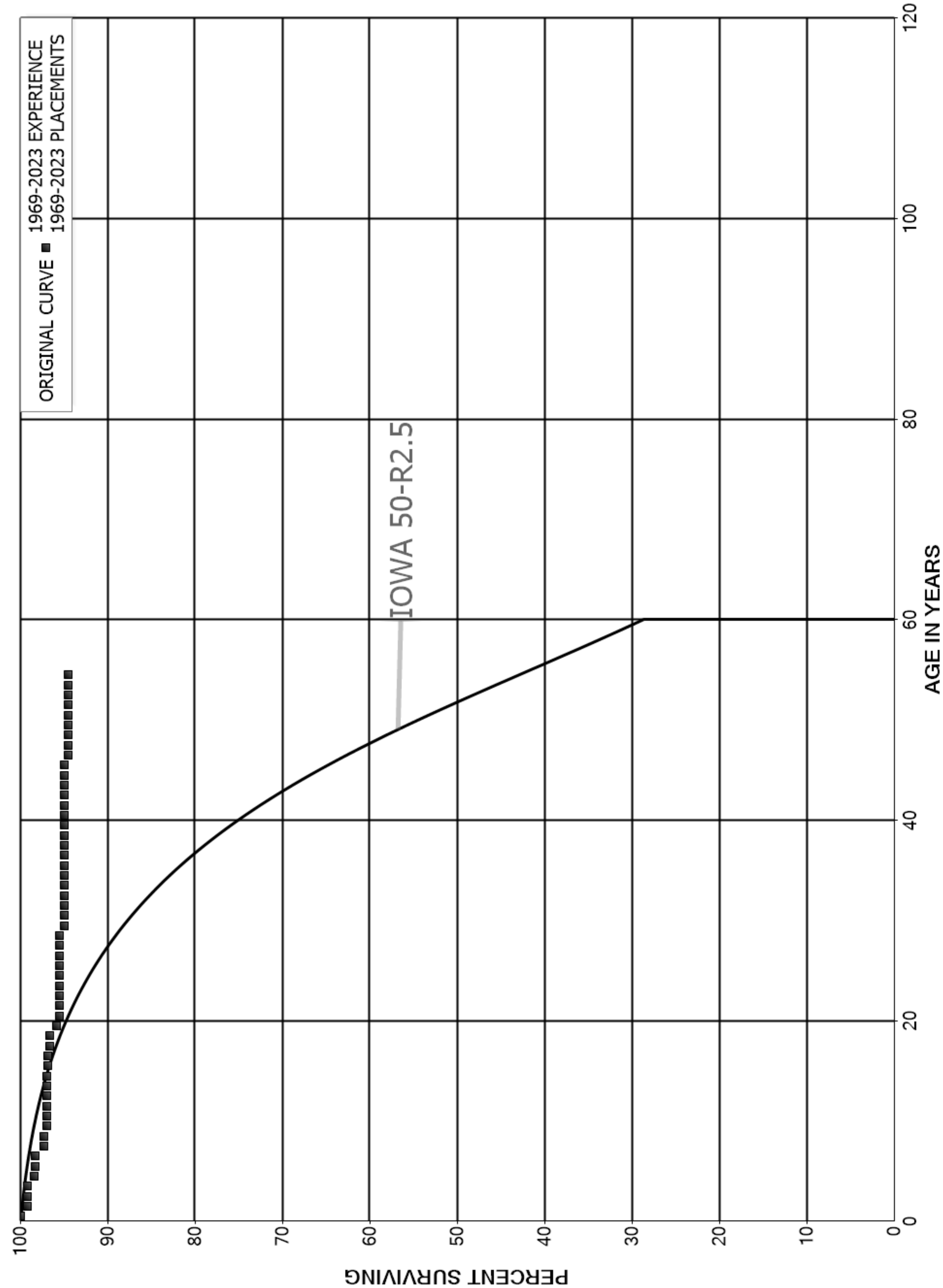
ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2017 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,293,252		0.0000	1.0000	93.91
40.5	7,292,283		0.0000	1.0000	93.91
41.5	7,292,283		0.0000	1.0000	93.91
42.5	7,292,283		0.0000	1.0000	93.91
43.5	7,292,380		0.0000	1.0000	93.91
44.5	7,292,380		0.0000	1.0000	93.91
45.5	7,282,078		0.0000	1.0000	93.91
46.5	1,730,784		0.0000	1.0000	93.91
47.5	1,730,784	602	0.0003	0.9997	93.91
48.5	1,730,182		0.0000	1.0000	93.88
49.5	1,729,367		0.0000	1.0000	93.88
50.5	1,729,367		0.0000	1.0000	93.88
51.5	1,729,367		0.0000	1.0000	93.88
52.5	1,729,367		0.0000	1.0000	93.88
53.5	1,729,367		0.0000	1.0000	93.88
54.5	8,858		0.0000	1.0000	93.88
55.5	8,858		0.0000	1.0000	93.88
56.5	8,858		0.0000	1.0000	93.88
57.5	8,858		0.0000	1.0000	93.88
58.5	8,858		0.0000	1.0000	93.88
59.5	8,858		0.0000	1.0000	93.88
60.5	97		0.0000	1.0000	93.88
61.5	97		0.0000	1.0000	93.88
62.5	97		0.0000	1.0000	93.88
63.5	97		0.0000	1.0000	93.88
64.5	97		0.0000	1.0000	93.88
65.5	97		0.0000	1.0000	93.88
66.5	97		0.0000	1.0000	93.88
67.5	97		0.0000	1.0000	93.88
68.5					93.88

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.10 LIQUEFACTION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	27,179,866	28,598	0.0011	0.9989	100.00
0.5	27,060,071	199,635	0.0074	0.9926	99.89
1.5	20,823,516		0.0000	1.0000	99.16
2.5	19,870,112		0.0000	1.0000	99.16
3.5	19,793,952	146,338	0.0074	0.9926	99.16
4.5	19,417,376	18,698	0.0010	0.9990	98.42
5.5	14,548,542		0.0000	1.0000	98.33
6.5	10,875,424	114,090	0.0105	0.9895	98.33
7.5	10,358,546		0.0000	1.0000	97.30
8.5	10,304,721	34,692	0.0034	0.9966	97.30
9.5	9,758,855		0.0000	1.0000	96.97
10.5	9,758,855		0.0000	1.0000	96.97
11.5	9,685,872		0.0000	1.0000	96.97
12.5	9,685,872	434	0.0000	1.0000	96.97
13.5	9,685,438		0.0000	1.0000	96.97
14.5	9,615,025	13,425	0.0014	0.9986	96.97
15.5	9,539,222		0.0000	1.0000	96.83
16.5	9,495,419	18,523	0.0020	0.9980	96.83
17.5	9,321,042	3,226	0.0003	0.9997	96.64
18.5	9,269,484	74,502	0.0080	0.9920	96.61
19.5	8,899,934	34,032	0.0038	0.9962	95.83
20.5	8,740,379		0.0000	1.0000	95.47
21.5	8,665,232		0.0000	1.0000	95.47
22.5	8,199,959		0.0000	1.0000	95.47
23.5	8,111,837		0.0000	1.0000	95.47
24.5	7,783,304		0.0000	1.0000	95.47
25.5	7,234,849		0.0000	1.0000	95.47
26.5	6,950,150	399	0.0001	0.9999	95.47
27.5	6,756,916		0.0000	1.0000	95.46
28.5	6,754,705	35,128	0.0052	0.9948	95.46
29.5	6,702,869		0.0000	1.0000	94.96
30.5	6,686,673		0.0000	1.0000	94.96
31.5	6,605,144		0.0000	1.0000	94.96
32.5	6,501,938		0.0000	1.0000	94.96
33.5	6,412,166		0.0000	1.0000	94.96
34.5	6,390,407		0.0000	1.0000	94.96
35.5	6,390,407		0.0000	1.0000	94.96
36.5	6,313,086		0.0000	1.0000	94.96
37.5	6,298,223		0.0000	1.0000	94.96
38.5	6,286,698		0.0000	1.0000	94.96

NORTHWEST NATURAL GAS COMPANY

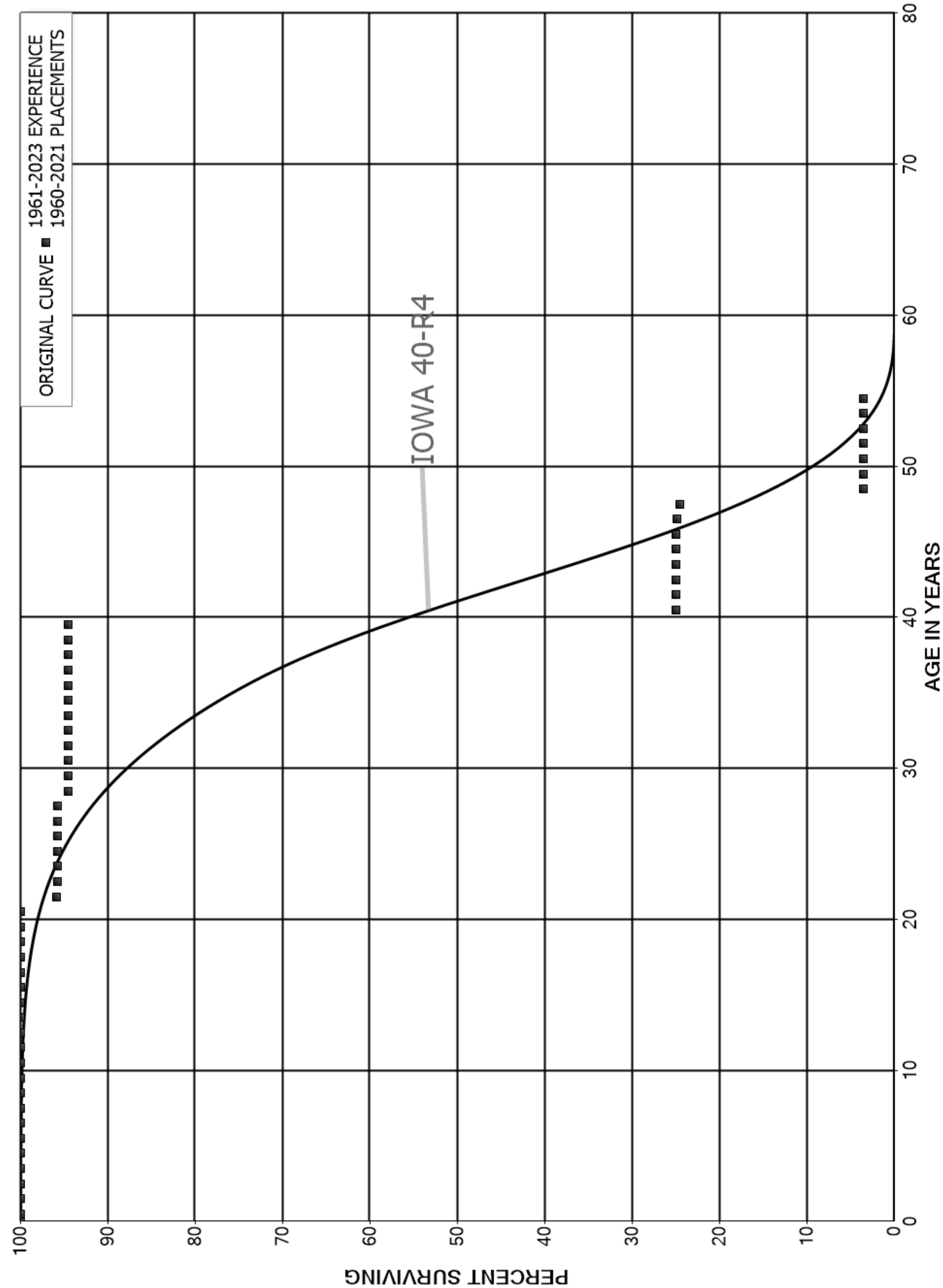
ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,264,779		0.0000	1.0000	94.96
40.5	6,264,779		0.0000	1.0000	94.96
41.5	6,264,779		0.0000	1.0000	94.96
42.5	6,264,779		0.0000	1.0000	94.96
43.5	6,164,100		0.0000	1.0000	94.96
44.5	6,158,562		0.0000	1.0000	94.96
45.5	6,142,214	27,318	0.0044	0.9956	94.96
46.5	878,099		0.0000	1.0000	94.54
47.5	852,144		0.0000	1.0000	94.54
48.5	851,876		0.0000	1.0000	94.54
49.5	849,919		0.0000	1.0000	94.54
50.5	849,919		0.0000	1.0000	94.54
51.5	845,658		0.0000	1.0000	94.54
52.5	844,045		0.0000	1.0000	94.54
53.5	828,857		0.0000	1.0000	94.54
54.5					94.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.20 VAPORIZING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2021 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,831,400		0.0000	1.0000	100.00
0.5	13,831,400	602	0.0000	1.0000	100.00
1.5	14,034,034		0.0000	1.0000	100.00
2.5	14,023,474	1,415	0.0001	0.9999	100.00
3.5	11,055,638		0.0000	1.0000	99.99
4.5	11,055,638		0.0000	1.0000	99.99
5.5	11,055,638		0.0000	1.0000	99.99
6.5	6,584,958	1,983	0.0003	0.9997	99.99
7.5	6,584,958		0.0000	1.0000	99.96
8.5	6,436,057	2,322	0.0004	0.9996	99.96
9.5	6,433,834		0.0000	1.0000	99.92
10.5	6,433,834		0.0000	1.0000	99.92
11.5	6,433,834		0.0000	1.0000	99.92
12.5	5,320,819		0.0000	1.0000	99.92
13.5	5,320,819		0.0000	1.0000	99.92
14.5	5,320,819		0.0000	1.0000	99.92
15.5	5,320,819		0.0000	1.0000	99.92
16.5	5,320,819		0.0000	1.0000	99.92
17.5	4,999,612		0.0000	1.0000	99.92
18.5	4,999,612		0.0000	1.0000	99.92
19.5	4,931,166		0.0000	1.0000	99.92
20.5	4,931,166	200,000	0.0406	0.9594	99.92
21.5	4,730,986	8,350	0.0018	0.9982	95.87
22.5	4,722,636		0.0000	1.0000	95.70
23.5	4,722,636	455	0.0001	0.9999	95.70
24.5	4,722,181	436	0.0001	0.9999	95.69
25.5	4,721,745		0.0000	1.0000	95.68
26.5	4,721,745	303	0.0001	0.9999	95.68
27.5	4,721,442	59,483	0.0126	0.9874	95.67
28.5	4,650,778		0.0000	1.0000	94.47
29.5	4,618,017		0.0000	1.0000	94.47
30.5	4,618,016		0.0000	1.0000	94.47
31.5	4,615,790		0.0000	1.0000	94.47
32.5	4,429,354		0.0000	1.0000	94.47
33.5	3,273,347		0.0000	1.0000	94.47
34.5	3,273,347		0.0000	1.0000	94.47
35.5	3,273,347		0.0000	1.0000	94.47
36.5	3,095,885		0.0000	1.0000	94.47
37.5	3,083,807		0.0000	1.0000	94.47
38.5	3,083,807		0.0000	1.0000	94.47

NORTHWEST NATURAL GAS COMPANY

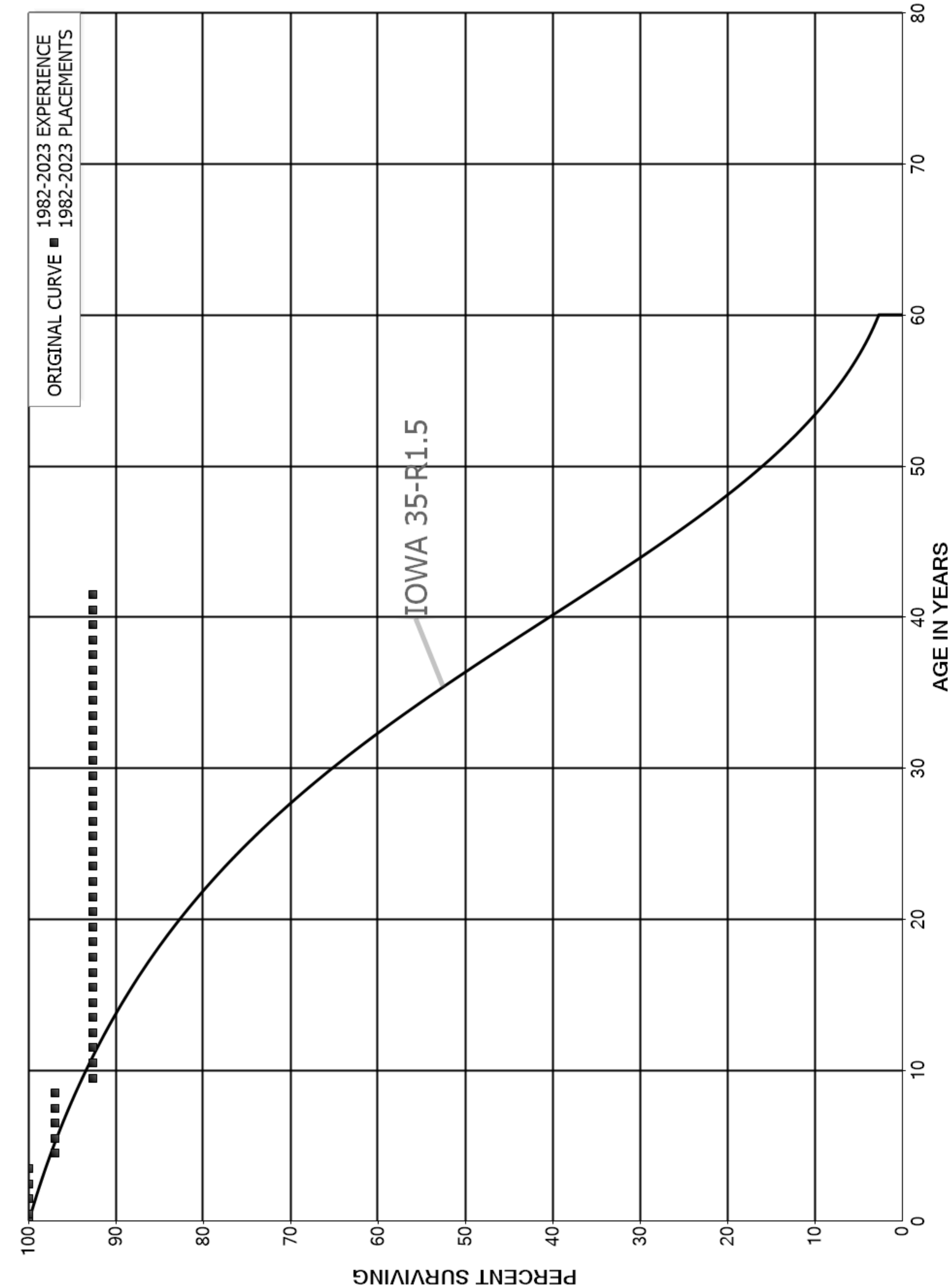
ACCOUNT 363.20 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2021 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,083,807	2,269,514	0.7359	0.2641	94.47
40.5	814,293		0.0000	1.0000	24.94
41.5	814,293		0.0000	1.0000	24.94
42.5	814,293		0.0000	1.0000	24.94
43.5	814,293		0.0000	1.0000	24.94
44.5	814,293		0.0000	1.0000	24.94
45.5	814,293	4,062	0.0050	0.9950	24.94
46.5	749,406	9,122	0.0122	0.9878	24.82
47.5	353,620	303,259	0.8576	0.1424	24.52
48.5	50,092		0.0000	1.0000	3.49
49.5	47,833		0.0000	1.0000	3.49
50.5	34,582		0.0000	1.0000	3.49
51.5	32,214		0.0000	1.0000	3.49
52.5	18,960		0.0000	1.0000	3.49
53.5	18,960		0.0000	1.0000	3.49
54.5					3.49

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.30 COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2023 EXPERIENCE BAND 1982-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,311,101		0.0000	1.0000	100.00
0.5	6,207,702		0.0000	1.0000	100.00
1.5	5,980,975		0.0000	1.0000	100.00
2.5	5,160,185	273	0.0001	0.9999	100.00
3.5	5,038,729	151,425	0.0301	0.9699	99.99
4.5	4,887,304		0.0000	1.0000	96.99
5.5	4,630,707		0.0000	1.0000	96.99
6.5	4,132,901		0.0000	1.0000	96.99
7.5	1,865,931		0.0000	1.0000	96.99
8.5	1,865,931	84,841	0.0455	0.9545	96.99
9.5	395,261		0.0000	1.0000	92.58
10.5	395,261		0.0000	1.0000	92.58
11.5	395,261		0.0000	1.0000	92.58
12.5	395,261		0.0000	1.0000	92.58
13.5	395,261		0.0000	1.0000	92.58
14.5	395,261		0.0000	1.0000	92.58
15.5	343,850		0.0000	1.0000	92.58
16.5	343,850		0.0000	1.0000	92.58
17.5	343,850		0.0000	1.0000	92.58
18.5	327,070		0.0000	1.0000	92.58
19.5	327,070		0.0000	1.0000	92.58
20.5	148,568		0.0000	1.0000	92.58
21.5	148,568		0.0000	1.0000	92.58
22.5	148,568		0.0000	1.0000	92.58
23.5	148,568		0.0000	1.0000	92.58
24.5	148,568		0.0000	1.0000	92.58
25.5	148,568		0.0000	1.0000	92.58
26.5	127,741		0.0000	1.0000	92.58
27.5	108,320		0.0000	1.0000	92.58
28.5	108,320		0.0000	1.0000	92.58
29.5	108,320		0.0000	1.0000	92.58
30.5	108,320		0.0000	1.0000	92.58
31.5	108,320		0.0000	1.0000	92.58
32.5	108,320		0.0000	1.0000	92.58
33.5	108,320		0.0000	1.0000	92.58
34.5	108,320		0.0000	1.0000	92.58
35.5	108,320		0.0000	1.0000	92.58
36.5	108,320		0.0000	1.0000	92.58
37.5	86,804		0.0000	1.0000	92.58
38.5	86,804		0.0000	1.0000	92.58

NORTHWEST NATURAL GAS COMPANY

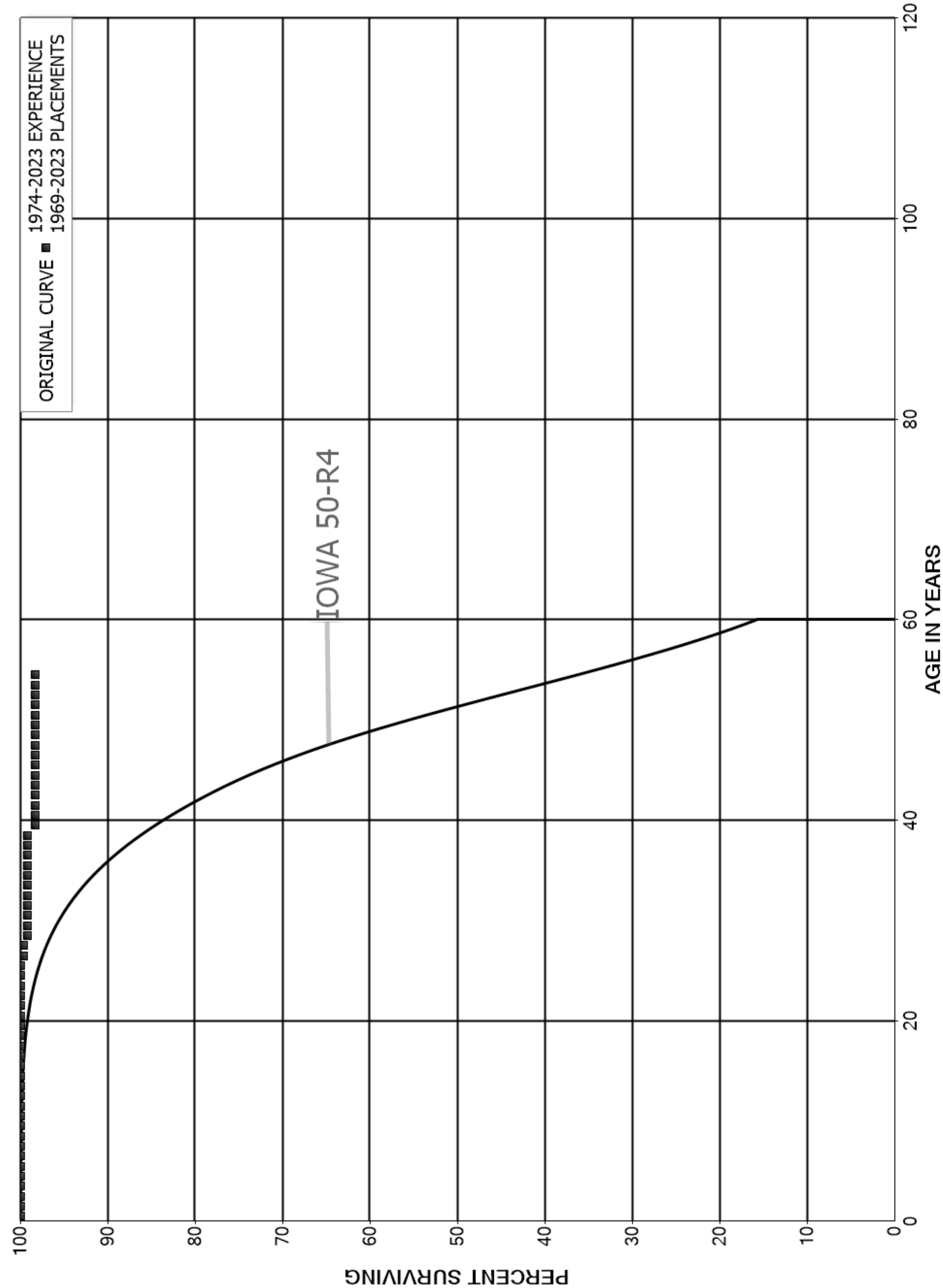
ACCOUNT 363.30 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1982-2023 EXPERIENCE BAND 1982-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	86,804		0.0000	1.0000	92.58
40.5	85,687		0.0000	1.0000	92.58
41.5					92.58

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,645,250		0.0000	1.0000	100.00
0.5	19,061,727		0.0000	1.0000	100.00
1.5	13,805,464		0.0000	1.0000	100.00
2.5	13,447,703		0.0000	1.0000	100.00
3.5	12,989,084		0.0000	1.0000	100.00
4.5	13,333,771		0.0000	1.0000	100.00
5.5	12,752,913		0.0000	1.0000	100.00
6.5	1,362,034		0.0000	1.0000	100.00
7.5	1,362,034		0.0000	1.0000	100.00
8.5	1,362,034		0.0000	1.0000	100.00
9.5	1,002,125		0.0000	1.0000	100.00
10.5	850,563		0.0000	1.0000	100.00
11.5	850,563		0.0000	1.0000	100.00
12.5	850,563		0.0000	1.0000	100.00
13.5	850,563		0.0000	1.0000	100.00
14.5	682,272		0.0000	1.0000	100.00
15.5	682,272		0.0000	1.0000	100.00
16.5	682,272		0.0000	1.0000	100.00
17.5	653,998		0.0000	1.0000	100.00
18.5	653,998		0.0000	1.0000	100.00
19.5	653,998		0.0000	1.0000	100.00
20.5	653,998		0.0000	1.0000	100.00
21.5	636,675		0.0000	1.0000	100.00
22.5	636,675		0.0000	1.0000	100.00
23.5	636,675		0.0000	1.0000	100.00
24.5	636,675		0.0000	1.0000	100.00
25.5	636,675	2,647	0.0042	0.9958	100.00
26.5	634,028		0.0000	1.0000	99.58
27.5	634,028	2,566	0.0040	0.9960	99.58
28.5	631,462		0.0000	1.0000	99.18
29.5	631,462		0.0000	1.0000	99.18
30.5	631,462		0.0000	1.0000	99.18
31.5	628,091		0.0000	1.0000	99.18
32.5	607,580		0.0000	1.0000	99.18
33.5	560,097		0.0000	1.0000	99.18
34.5	555,322		0.0000	1.0000	99.18
35.5	545,620		0.0000	1.0000	99.18
36.5	545,620		0.0000	1.0000	99.18
37.5	545,620		0.0000	1.0000	99.18
38.5	541,958	4,721	0.0087	0.9913	99.18

NORTHWEST NATURAL GAS COMPANY

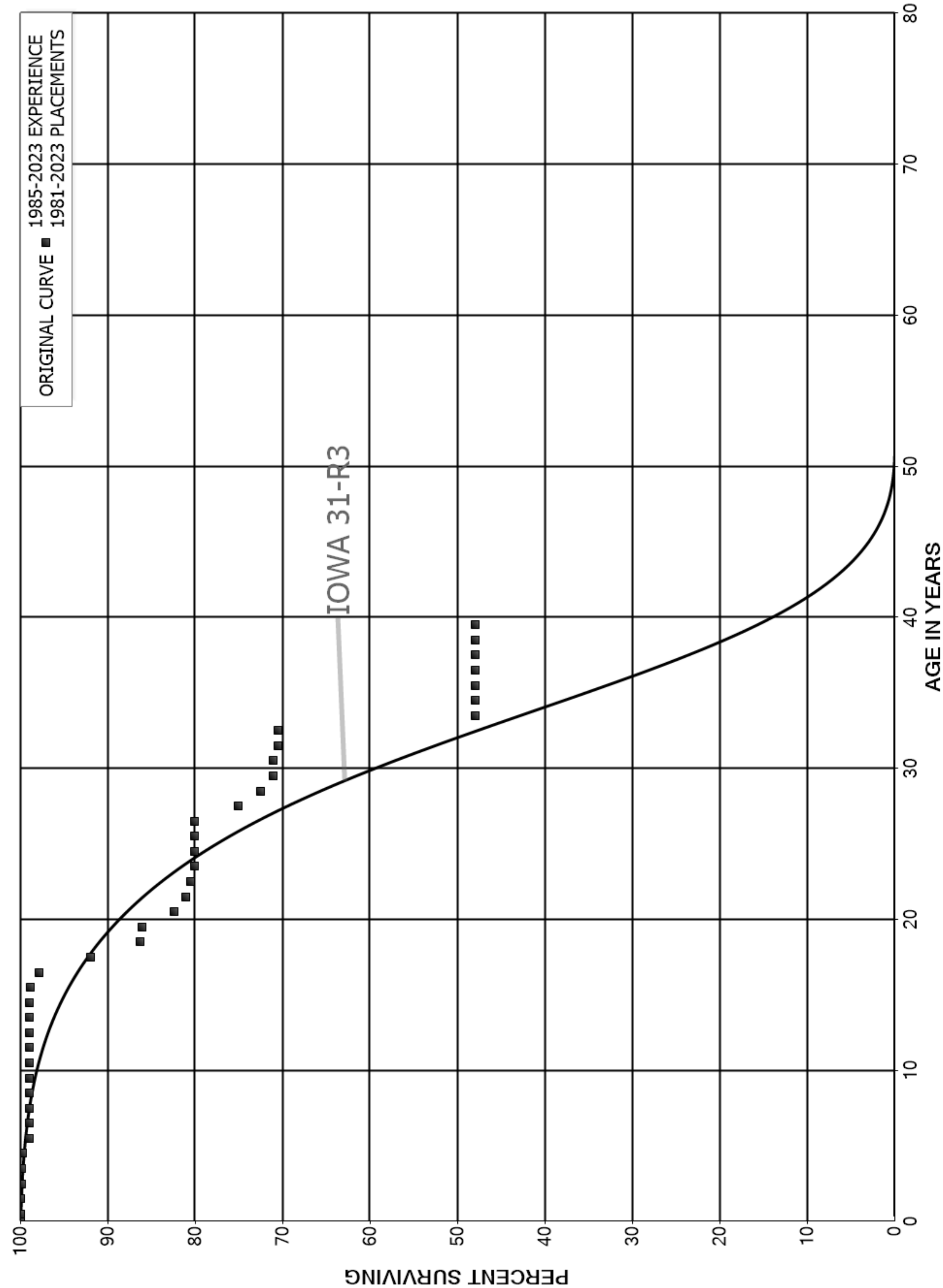
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	537,237		0.0000	1.0000	98.32
40.5	537,237		0.0000	1.0000	98.32
41.5	537,237		0.0000	1.0000	98.32
42.5	537,237		0.0000	1.0000	98.32
43.5	537,237		0.0000	1.0000	98.32
44.5	537,237		0.0000	1.0000	98.32
45.5	537,237		0.0000	1.0000	98.32
46.5	482,034		0.0000	1.0000	98.32
47.5	482,034		0.0000	1.0000	98.32
48.5	481,660		0.0000	1.0000	98.32
49.5	480,333		0.0000	1.0000	98.32
50.5	480,333		0.0000	1.0000	98.32
51.5	474,008		0.0000	1.0000	98.32
52.5	464,177		0.0000	1.0000	98.32
53.5	461,537		0.0000	1.0000	98.32
54.5					98.32

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.50 CNG REFUELING FACILITIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.50 CNG REFUELING FACILITIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2023 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,627,792		0.0000	1.0000	100.00
0.5	3,397,353	3,726	0.0011	0.9989	100.00
1.5	3,504,352	13	0.0000	1.0000	99.89
2.5	3,509,603	1,280	0.0004	0.9996	99.89
3.5	3,517,228	3,071	0.0009	0.9991	99.85
4.5	3,629,180	27,968	0.0077	0.9923	99.77
5.5	3,601,212		0.0000	1.0000	99.00
6.5	3,601,212		0.0000	1.0000	99.00
7.5	3,601,212		0.0000	1.0000	99.00
8.5	3,601,212		0.0000	1.0000	99.00
9.5	2,068,805		0.0000	1.0000	99.00
10.5	1,945,791		0.0000	1.0000	99.00
11.5	1,828,161		0.0000	1.0000	99.00
12.5	1,828,161		0.0000	1.0000	99.00
13.5	1,828,161	1,938	0.0011	0.9989	99.00
14.5	1,826,223	1,632	0.0009	0.9991	98.89
15.5	1,824,591	18,126	0.0099	0.9901	98.80
16.5	1,806,465	108,566	0.0601	0.9399	97.82
17.5	1,697,899	103,851	0.0612	0.9388	91.94
18.5	1,594,048	4,067	0.0026	0.9974	86.32
19.5	1,540,307	66,855	0.0434	0.9566	86.10
20.5	1,473,452	22,396	0.0152	0.9848	82.36
21.5	1,449,756	10,299	0.0071	0.9929	81.11
22.5	1,439,457	8,819	0.0061	0.9939	80.53
23.5	1,430,638		0.0000	1.0000	80.04
24.5	1,426,354		0.0000	1.0000	80.04
25.5	1,397,519		0.0000	1.0000	80.04
26.5	1,349,534	84,323	0.0625	0.9375	80.04
27.5	1,037,060	35,635	0.0344	0.9656	75.04
28.5	708,066	13,528	0.0191	0.9809	72.46
29.5	346,154	25	0.0001	0.9999	71.08
30.5	284,919	2,421	0.0085	0.9915	71.07
31.5	262,791		0.0000	1.0000	70.47
32.5	210,584	67,435	0.3202	0.6798	70.47
33.5	79,670		0.0000	1.0000	47.90
34.5	79,670		0.0000	1.0000	47.90
35.5	79,670		0.0000	1.0000	47.90
36.5	79,670		0.0000	1.0000	47.90
37.5	72,652		0.0000	1.0000	47.90
38.5	71,186		0.0000	1.0000	47.90

NORTHWEST NATURAL GAS COMPANY

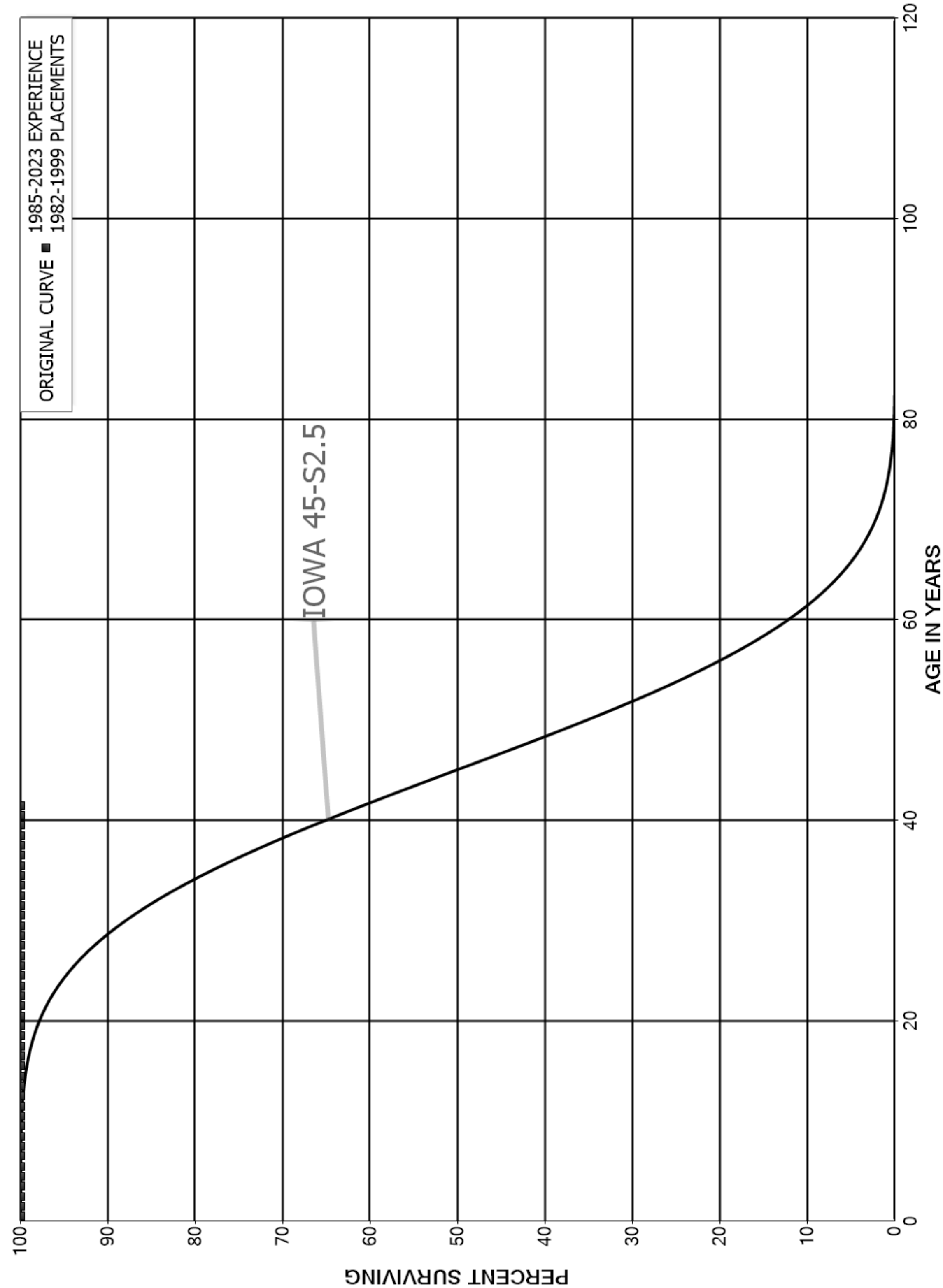
ACCOUNT 363.50 CNG REFUELING FACILITIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1981-2023 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	30,743		0.0000	1.0000	47.90
40.5	29,180		0.0000	1.0000	47.90
41.5	19,620		0.0000	1.0000	47.90
42.5					47.90

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.60 LNG REFUELING FACILITIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.60 LNG REFUELING FACILITIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-1999 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	281,163		0.0000	1.0000	100.00
0.5	281,163		0.0000	1.0000	100.00
1.5	328,416		0.0000	1.0000	100.00
2.5	390,036		0.0000	1.0000	100.00
3.5	739,473		0.0000	1.0000	100.00
4.5	739,473		0.0000	1.0000	100.00
5.5	739,473		0.0000	1.0000	100.00
6.5	739,473		0.0000	1.0000	100.00
7.5	739,473		0.0000	1.0000	100.00
8.5	739,473		0.0000	1.0000	100.00
9.5	739,473		0.0000	1.0000	100.00
10.5	739,473		0.0000	1.0000	100.00
11.5	739,473		0.0000	1.0000	100.00
12.5	739,473		0.0000	1.0000	100.00
13.5	739,473		0.0000	1.0000	100.00
14.5	739,473		0.0000	1.0000	100.00
15.5	739,473		0.0000	1.0000	100.00
16.5	739,473		0.0000	1.0000	100.00
17.5	739,473		0.0000	1.0000	100.00
18.5	739,473		0.0000	1.0000	100.00
19.5	739,473		0.0000	1.0000	100.00
20.5	739,473		0.0000	1.0000	100.00
21.5	739,473		0.0000	1.0000	100.00
22.5	739,473		0.0000	1.0000	100.00
23.5	739,473		0.0000	1.0000	100.00
24.5	730,990		0.0000	1.0000	100.00
25.5	730,990		0.0000	1.0000	100.00
26.5	725,680		0.0000	1.0000	100.00
27.5	712,293		0.0000	1.0000	100.00
28.5	666,615		0.0000	1.0000	100.00
29.5	628,397		0.0000	1.0000	100.00
30.5	573,929		0.0000	1.0000	100.00
31.5	460,040		0.0000	1.0000	100.00
32.5	459,105		0.0000	1.0000	100.00
33.5	459,105		0.0000	1.0000	100.00
34.5	459,105		0.0000	1.0000	100.00
35.5	459,105		0.0000	1.0000	100.00
36.5	459,105		0.0000	1.0000	100.00
37.5	458,997		0.0000	1.0000	100.00
38.5	453,824		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

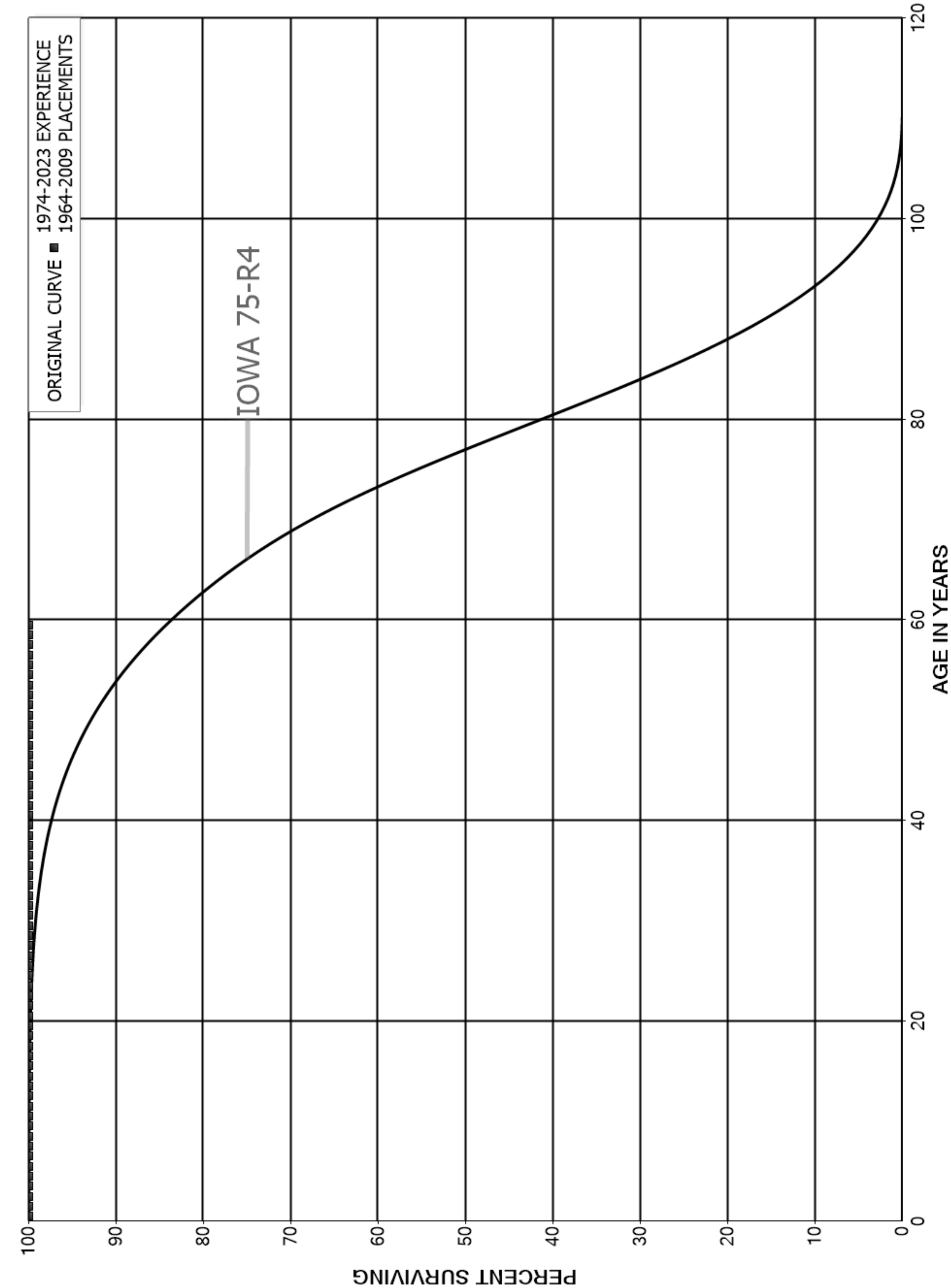
ACCOUNT 363.60 LNG REFUELING FACILITIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1982-1999 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	411,057		0.0000	1.0000	100.00
40.5	349,437		0.0000	1.0000	100.00
41.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 365.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 365.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2009 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,770,969		0.0000	1.0000	100.00
0.5	5,375,541		0.0000	1.0000	100.00
1.5	5,279,074		0.0000	1.0000	100.00
2.5	5,310,109		0.0000	1.0000	100.00
3.5	5,310,109		0.0000	1.0000	100.00
4.5	5,310,109		0.0000	1.0000	100.00
5.5	5,286,730		0.0000	1.0000	100.00
6.5	5,446,043		0.0000	1.0000	100.00
7.5	5,579,754		0.0000	1.0000	100.00
8.5	6,153,400		0.0000	1.0000	100.00
9.5	6,361,083		0.0000	1.0000	100.00
10.5	6,455,177		0.0000	1.0000	100.00
11.5	6,455,177		0.0000	1.0000	100.00
12.5	6,455,177		0.0000	1.0000	100.00
13.5	6,455,177		0.0000	1.0000	100.00
14.5	6,270,968		0.0000	1.0000	100.00
15.5	6,270,968		0.0000	1.0000	100.00
16.5	6,270,968		0.0000	1.0000	100.00
17.5	6,270,968		0.0000	1.0000	100.00
18.5	6,270,968		0.0000	1.0000	100.00
19.5	4,195,148		0.0000	1.0000	100.00
20.5	3,013,374		0.0000	1.0000	100.00
21.5	2,617,946		0.0000	1.0000	100.00
22.5	2,617,946		0.0000	1.0000	100.00
23.5	2,617,946		0.0000	1.0000	100.00
24.5	2,617,946		0.0000	1.0000	100.00
25.5	2,617,946		0.0000	1.0000	100.00
26.5	2,617,946		0.0000	1.0000	100.00
27.5	2,617,946		0.0000	1.0000	100.00
28.5	2,617,946		0.0000	1.0000	100.00
29.5	2,617,946		0.0000	1.0000	100.00
30.5	2,617,946		0.0000	1.0000	100.00
31.5	2,604,197		0.0000	1.0000	100.00
32.5	2,461,137		0.0000	1.0000	100.00
33.5	2,060,125		0.0000	1.0000	100.00
34.5	1,244,309		0.0000	1.0000	100.00
35.5	1,244,309		0.0000	1.0000	100.00
36.5	1,244,309		0.0000	1.0000	100.00
37.5	1,244,309		0.0000	1.0000	100.00
38.5	1,244,309		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

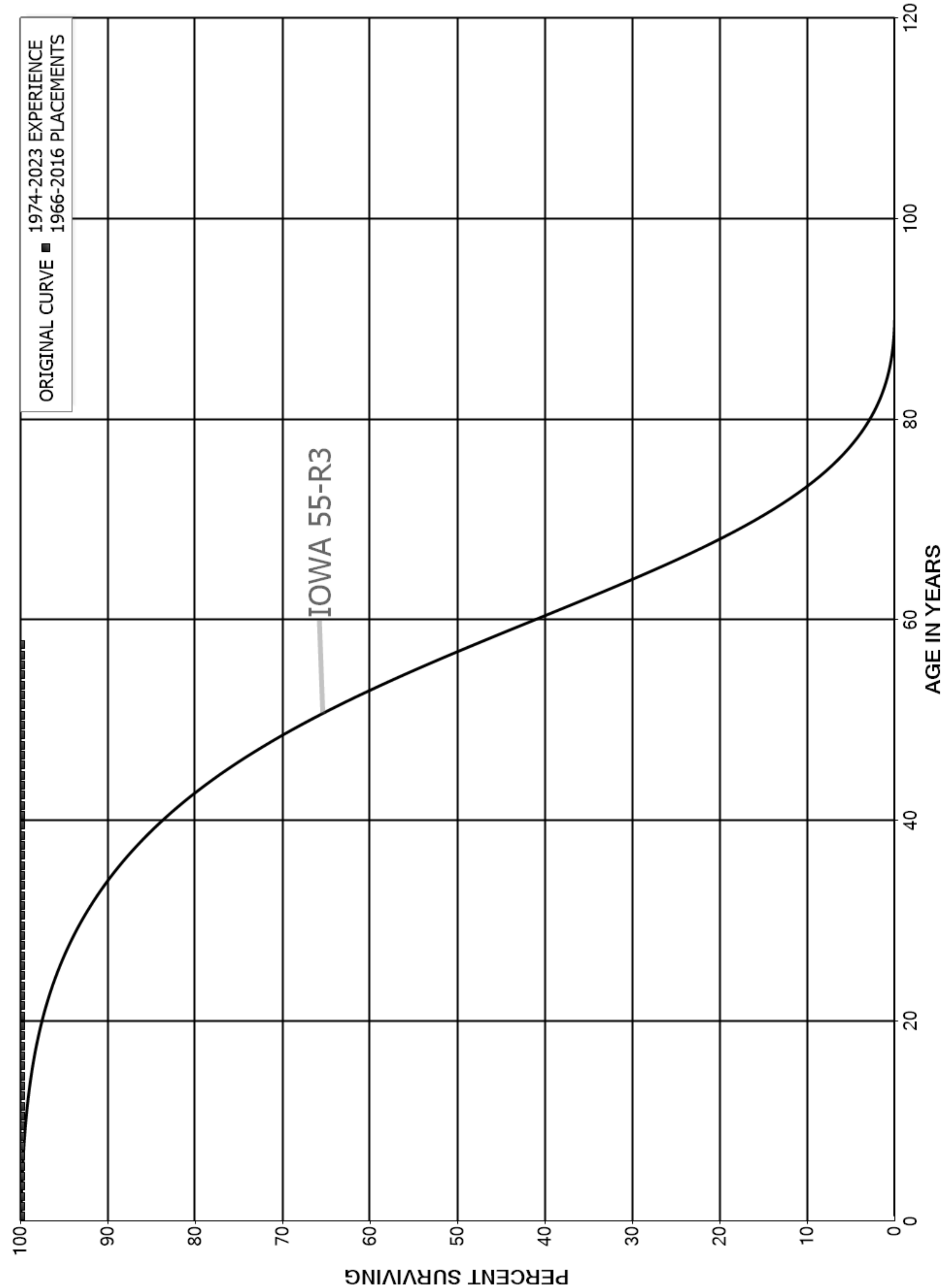
ACCOUNT 365.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1964-2009 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,244,309		0.0000	1.0000	100.00
40.5	1,244,309		0.0000	1.0000	100.00
41.5	1,244,309		0.0000	1.0000	100.00
42.5	1,238,350		0.0000	1.0000	100.00
43.5	1,238,350		0.0000	1.0000	100.00
44.5	1,229,163		0.0000	1.0000	100.00
45.5	1,229,163		0.0000	1.0000	100.00
46.5	1,217,081		0.0000	1.0000	100.00
47.5	1,189,050		0.0000	1.0000	100.00
48.5	1,189,050		0.0000	1.0000	100.00
49.5	1,189,050		0.0000	1.0000	100.00
50.5	1,189,050		0.0000	1.0000	100.00
51.5	1,189,050		0.0000	1.0000	100.00
52.5	1,189,050		0.0000	1.0000	100.00
53.5	1,189,050		0.0000	1.0000	100.00
54.5	1,189,050		0.0000	1.0000	100.00
55.5	1,168,447		0.0000	1.0000	100.00
56.5	1,009,167		0.0000	1.0000	100.00
57.5	539,190		0.0000	1.0000	100.00
58.5	94,094		0.0000	1.0000	100.00
59.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2016 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,460,088		0.0000	1.0000	100.00
0.5	1,460,088		0.0000	1.0000	100.00
1.5	1,460,088		0.0000	1.0000	100.00
2.5	1,460,088		0.0000	1.0000	100.00
3.5	1,460,088		0.0000	1.0000	100.00
4.5	1,460,088		0.0000	1.0000	100.00
5.5	1,460,088		0.0000	1.0000	100.00
6.5	1,460,088		0.0000	1.0000	100.00
7.5	1,041,984		0.0000	1.0000	100.00
8.5	1,041,984		0.0000	1.0000	100.00
9.5	1,041,984		0.0000	1.0000	100.00
10.5	1,041,984		0.0000	1.0000	100.00
11.5	1,041,984		0.0000	1.0000	100.00
12.5	1,041,984		0.0000	1.0000	100.00
13.5	1,041,984		0.0000	1.0000	100.00
14.5	1,041,984		0.0000	1.0000	100.00
15.5	1,041,984		0.0000	1.0000	100.00
16.5	1,041,984		0.0000	1.0000	100.00
17.5	1,041,984		0.0000	1.0000	100.00
18.5	984,166		0.0000	1.0000	100.00
19.5	85,985		0.0000	1.0000	100.00
20.5	85,985		0.0000	1.0000	100.00
21.5	85,985		0.0000	1.0000	100.00
22.5	85,985		0.0000	1.0000	100.00
23.5	85,985		0.0000	1.0000	100.00
24.5	85,985		0.0000	1.0000	100.00
25.5	85,985		0.0000	1.0000	100.00
26.5	85,985		0.0000	1.0000	100.00
27.5	85,985		0.0000	1.0000	100.00
28.5	85,985		0.0000	1.0000	100.00
29.5	85,985		0.0000	1.0000	100.00
30.5	85,985		0.0000	1.0000	100.00
31.5	85,985		0.0000	1.0000	100.00
32.5	85,985		0.0000	1.0000	100.00
33.5	85,985		0.0000	1.0000	100.00
34.5	85,985		0.0000	1.0000	100.00
35.5	85,985		0.0000	1.0000	100.00
36.5	85,985		0.0000	1.0000	100.00
37.5	85,985		0.0000	1.0000	100.00
38.5	85,985		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

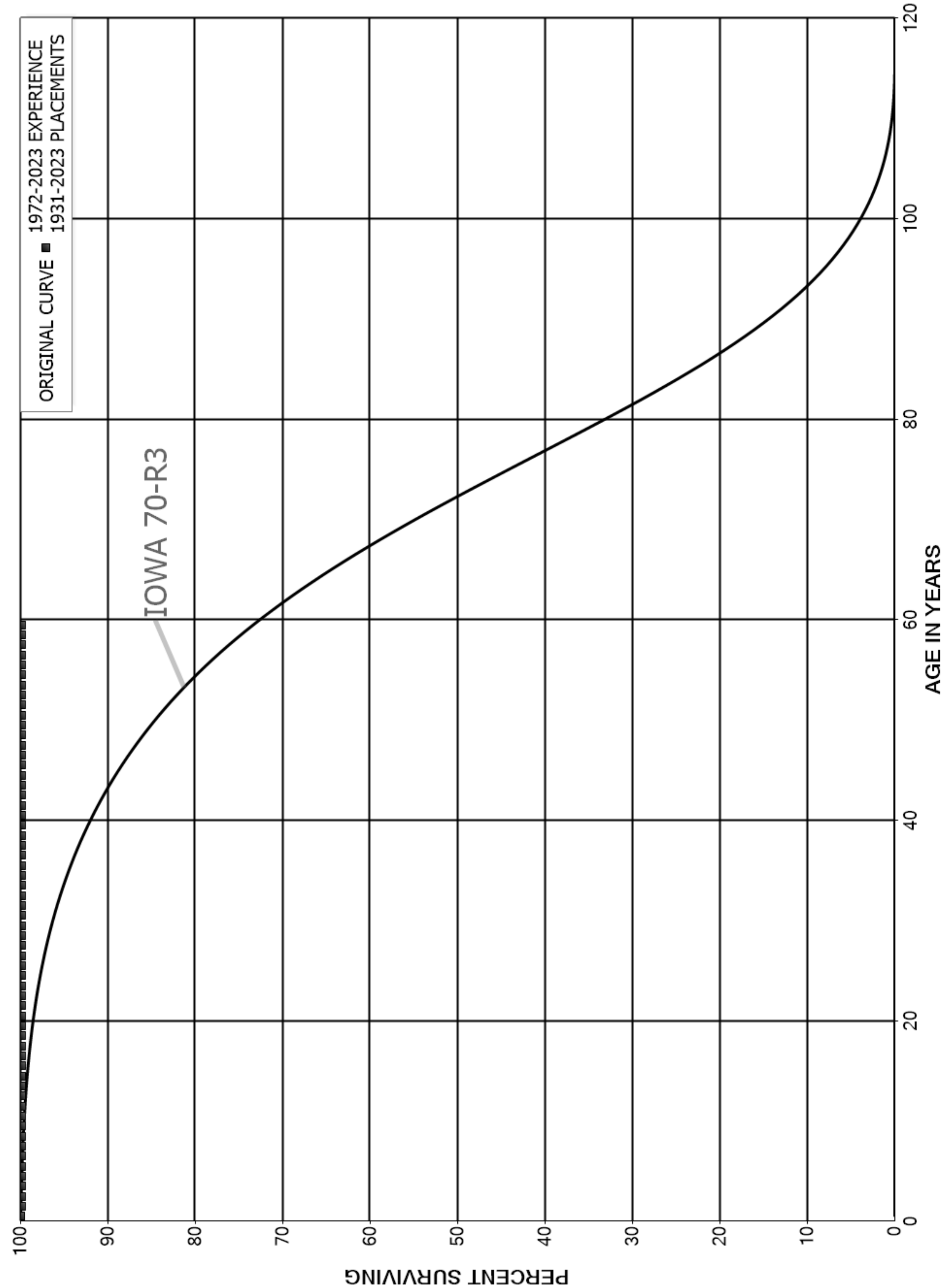
ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2016 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	85,985		0.0000	1.0000	100.00
40.5	85,985		0.0000	1.0000	100.00
41.5	85,985		0.0000	1.0000	100.00
42.5	85,985		0.0000	1.0000	100.00
43.5	85,985		0.0000	1.0000	100.00
44.5	85,985		0.0000	1.0000	100.00
45.5	85,985		0.0000	1.0000	100.00
46.5	85,985		0.0000	1.0000	100.00
47.5	85,985		0.0000	1.0000	100.00
48.5	85,985		0.0000	1.0000	100.00
49.5	85,985		0.0000	1.0000	100.00
50.5	85,985		0.0000	1.0000	100.00
51.5	85,985		0.0000	1.0000	100.00
52.5	85,985		0.0000	1.0000	100.00
53.5	85,985		0.0000	1.0000	100.00
54.5	85,985		0.0000	1.0000	100.00
55.5	85,985		0.0000	1.0000	100.00
56.5	85,985		0.0000	1.0000	100.00
57.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 367.00 THROUGH 367.26 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	311,329,776		0.0000	1.0000	100.00
0.5	316,548,454	532,003	0.0017	0.9983	100.00
1.5	343,813,389		0.0000	1.0000	99.83
2.5	338,009,566		0.0000	1.0000	99.83
3.5	327,984,914	38,942	0.0001	0.9999	99.83
4.5	319,300,797		0.0000	1.0000	99.82
5.5	308,104,740		0.0000	1.0000	99.82
6.5	307,461,718		0.0000	1.0000	99.82
7.5	302,877,415	1,086	0.0000	1.0000	99.82
8.5	297,252,260		0.0000	1.0000	99.82
9.5	279,211,651	1,086	0.0000	1.0000	99.82
10.5	230,288,244	16,355	0.0001	0.9999	99.82
11.5	198,868,205		0.0000	1.0000	99.81
12.5	190,822,564		0.0000	1.0000	99.81
13.5	171,475,182		0.0000	1.0000	99.81
14.5	166,874,669		0.0000	1.0000	99.81
15.5	166,874,669	2,603	0.0000	1.0000	99.81
16.5	166,806,129		0.0000	1.0000	99.81
17.5	166,808,732	541	0.0000	1.0000	99.81
18.5	166,793,797		0.0000	1.0000	99.81
19.5	128,793,642		0.0000	1.0000	99.81
20.5	61,949,897	1,756	0.0000	1.0000	99.81
21.5	61,692,549		0.0000	1.0000	99.81
22.5	61,155,910		0.0000	1.0000	99.81
23.5	61,091,777		0.0000	1.0000	99.81
24.5	27,575,643		0.0000	1.0000	99.81
25.5	27,575,643	481	0.0000	1.0000	99.81
26.5	27,575,162		0.0000	1.0000	99.81
27.5	27,575,162		0.0000	1.0000	99.81
28.5	27,573,648	388	0.0000	1.0000	99.81
29.5	27,440,689		0.0000	1.0000	99.80
30.5	27,295,904		0.0000	1.0000	99.80
31.5	27,295,904		0.0000	1.0000	99.80
32.5	27,292,423		0.0000	1.0000	99.80
33.5	26,995,509		0.0000	1.0000	99.80
34.5	10,178,290		0.0000	1.0000	99.80
35.5	10,178,290		0.0000	1.0000	99.80
36.5	10,178,290		0.0000	1.0000	99.80
37.5	10,160,853		0.0000	1.0000	99.80
38.5	10,131,532		0.0000	1.0000	99.80

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,131,532		0.0000	1.0000	99.80
40.5	10,131,532		0.0000	1.0000	99.80
41.5	9,969,318		0.0000	1.0000	99.80
42.5	9,458,671		0.0000	1.0000	99.80
43.5	9,424,544		0.0000	1.0000	99.80
44.5	9,424,544		0.0000	1.0000	99.80
45.5	9,411,932		0.0000	1.0000	99.80
46.5	9,406,964		0.0000	1.0000	99.80
47.5	8,179,539		0.0000	1.0000	99.80
48.5	8,179,539		0.0000	1.0000	99.80
49.5	8,179,539		0.0000	1.0000	99.80
50.5	8,179,539		0.0000	1.0000	99.80
51.5	8,160,658		0.0000	1.0000	99.80
52.5	8,161,199		0.0000	1.0000	99.80
53.5	8,161,199		0.0000	1.0000	99.80
54.5	8,144,175		0.0000	1.0000	99.80
55.5	8,139,304		0.0000	1.0000	99.80
56.5	8,041,218		0.0000	1.0000	99.80
57.5	4,791,489		0.0000	1.0000	99.80
58.5	632,284		0.0000	1.0000	99.80
59.5	541		0.0000	1.0000	99.80
60.5	541		0.0000	1.0000	99.80
61.5	541		0.0000	1.0000	99.80
62.5	541		0.0000	1.0000	99.80
63.5	541		0.0000	1.0000	99.80
64.5	541		0.0000	1.0000	99.80
65.5	541		0.0000	1.0000	99.80
66.5	541		0.0000	1.0000	99.80
67.5	541		0.0000	1.0000	99.80
68.5	541		0.0000	1.0000	99.80
69.5	541		0.0000	1.0000	99.80
70.5	541		0.0000	1.0000	99.80
71.5	541		0.0000	1.0000	99.80
72.5	541		0.0000	1.0000	99.80
73.5	541		0.0000	1.0000	99.80
74.5	541		0.0000	1.0000	99.80
75.5	541		0.0000	1.0000	99.80
76.5	541		0.0000	1.0000	99.80
77.5	541		0.0000	1.0000	99.80
78.5	541		0.0000	1.0000	99.80

NORTHWEST NATURAL GAS COMPANY

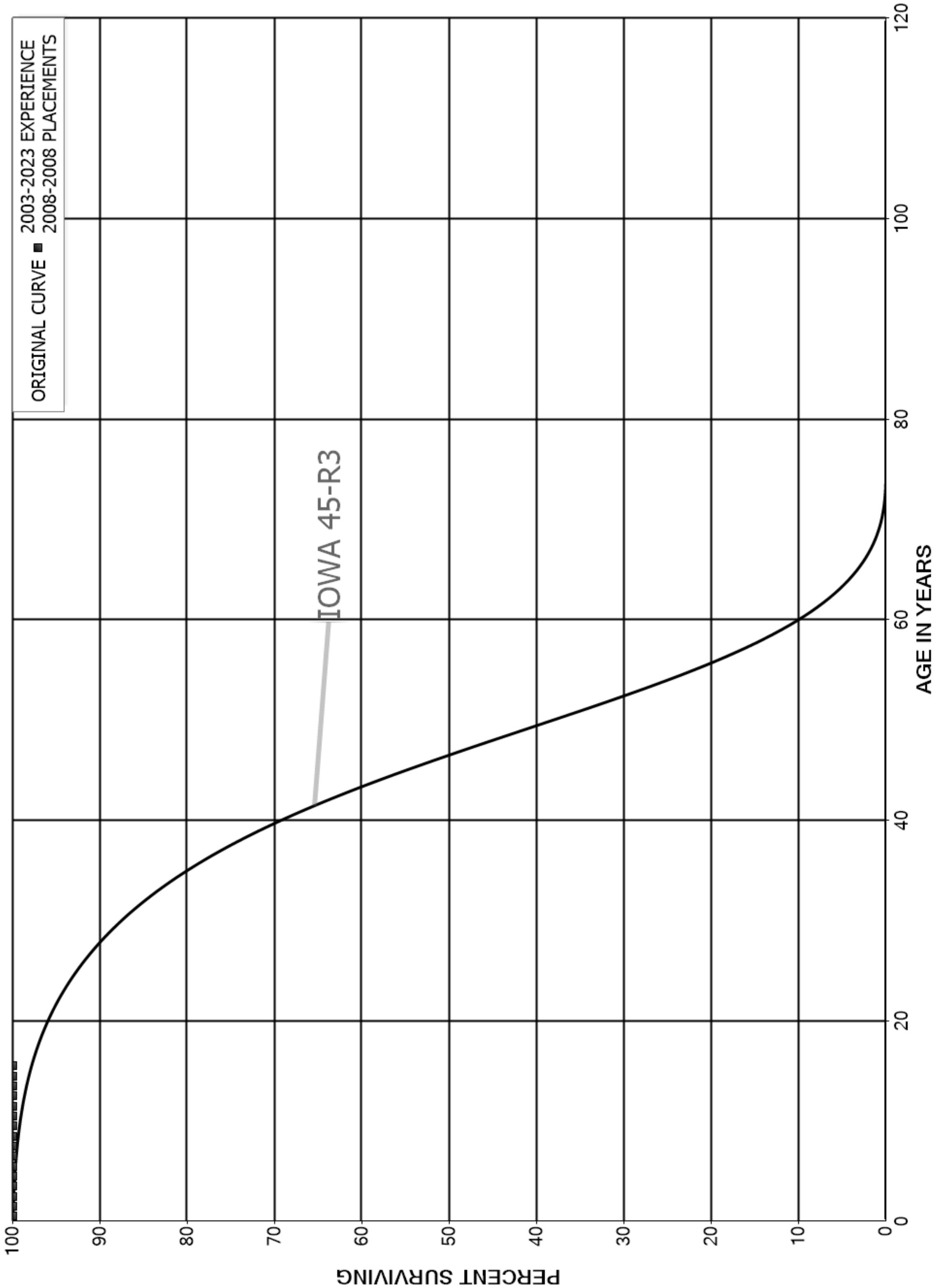
ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	541		0.0000	1.0000	99.80
80.5	541		0.0000	1.0000	99.80
81.5	541		0.0000	1.0000	99.80
82.5	541		0.0000	1.0000	99.80
83.5	541		0.0000	1.0000	99.80
84.5	541		0.0000	1.0000	99.80
85.5	541		0.0000	1.0000	99.80
86.5	541		0.0000	1.0000	99.80
87.5	541		0.0000	1.0000	99.80
88.5	541		0.0000	1.0000	99.80
89.5	541		0.0000	1.0000	99.80
90.5	541		0.0000	1.0000	99.80
91.5	541		0.0000	1.0000	99.80
92.5					99.80

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

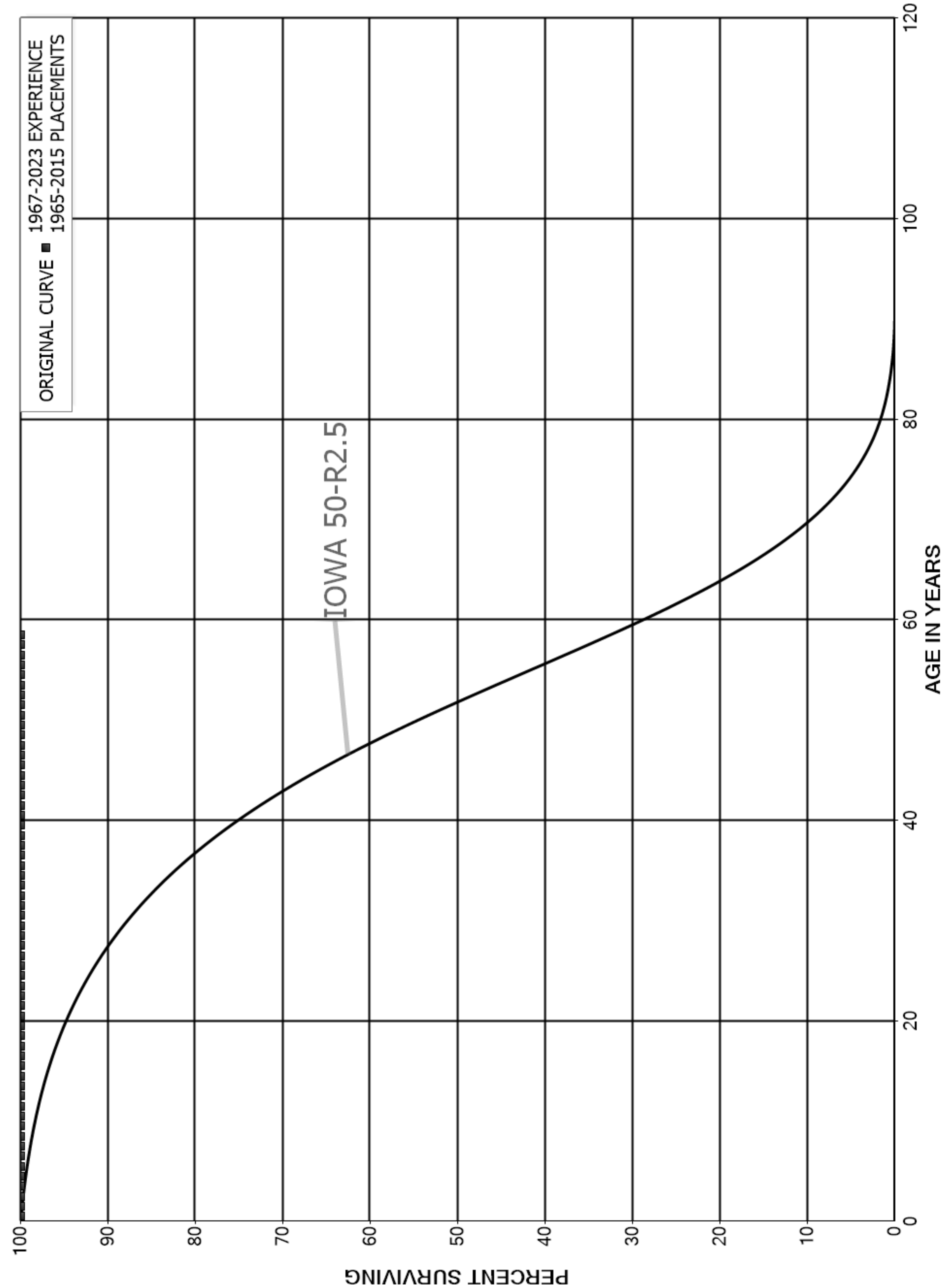
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2008-2008 EXPERIENCE BAND 2003-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,723,454		0.0000	1.0000	100.00
0.5	7,723,454		0.0000	1.0000	100.00
1.5	7,723,454		0.0000	1.0000	100.00
2.5	7,723,454		0.0000	1.0000	100.00
3.5	7,723,454		0.0000	1.0000	100.00
4.5	7,723,454		0.0000	1.0000	100.00
5.5	7,723,454		0.0000	1.0000	100.00
6.5	7,723,454		0.0000	1.0000	100.00
7.5	7,723,454		0.0000	1.0000	100.00
8.5	7,723,454		0.0000	1.0000	100.00
9.5	7,723,454		0.0000	1.0000	100.00
10.5	7,723,454		0.0000	1.0000	100.00
11.5	7,723,454		0.0000	1.0000	100.00
12.5	7,723,454		0.0000	1.0000	100.00
13.5	7,723,454		0.0000	1.0000	100.00
14.5	7,723,454		0.0000	1.0000	100.00
15.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1967-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,811,857		0.0000	1.0000	100.00
0.5	3,838,490	585	0.0002	0.9998	100.00
1.5	4,082,641		0.0000	1.0000	99.98
2.5	3,989,184		0.0000	1.0000	99.98
3.5	3,982,729		0.0000	1.0000	99.98
4.5	3,982,729		0.0000	1.0000	99.98
5.5	3,982,729		0.0000	1.0000	99.98
6.5	3,982,729		0.0000	1.0000	99.98
7.5	3,981,868	638	0.0002	0.9998	99.98
8.5	3,874,781		0.0000	1.0000	99.97
9.5	3,756,815		0.0000	1.0000	99.97
10.5	575,963		0.0000	1.0000	99.97
11.5	542,079		0.0000	1.0000	99.97
12.5	542,079		0.0000	1.0000	99.97
13.5	542,079		0.0000	1.0000	99.97
14.5	542,079		0.0000	1.0000	99.97
15.5	542,079		0.0000	1.0000	99.97
16.5	542,079		0.0000	1.0000	99.97
17.5	408,765		0.0000	1.0000	99.97
18.5	408,765		0.0000	1.0000	99.97
19.5	396,697		0.0000	1.0000	99.97
20.5	207,616		0.0000	1.0000	99.97
21.5	195,625		0.0000	1.0000	99.97
22.5	195,625		0.0000	1.0000	99.97
23.5	195,625		0.0000	1.0000	99.97
24.5	195,625		0.0000	1.0000	99.97
25.5	195,625		0.0000	1.0000	99.97
26.5	195,625		0.0000	1.0000	99.97
27.5	195,625		0.0000	1.0000	99.97
28.5	195,625		0.0000	1.0000	99.97
29.5	195,625		0.0000	1.0000	99.97
30.5	195,625		0.0000	1.0000	99.97
31.5	118,019		0.0000	1.0000	99.97
32.5	118,019		0.0000	1.0000	99.97
33.5	118,019		0.0000	1.0000	99.97
34.5	118,019		0.0000	1.0000	99.97
35.5	118,019		0.0000	1.0000	99.97
36.5	91,081		0.0000	1.0000	99.97
37.5	91,081		0.0000	1.0000	99.97
38.5	91,081		0.0000	1.0000	99.97

NORTHWEST NATURAL GAS COMPANY

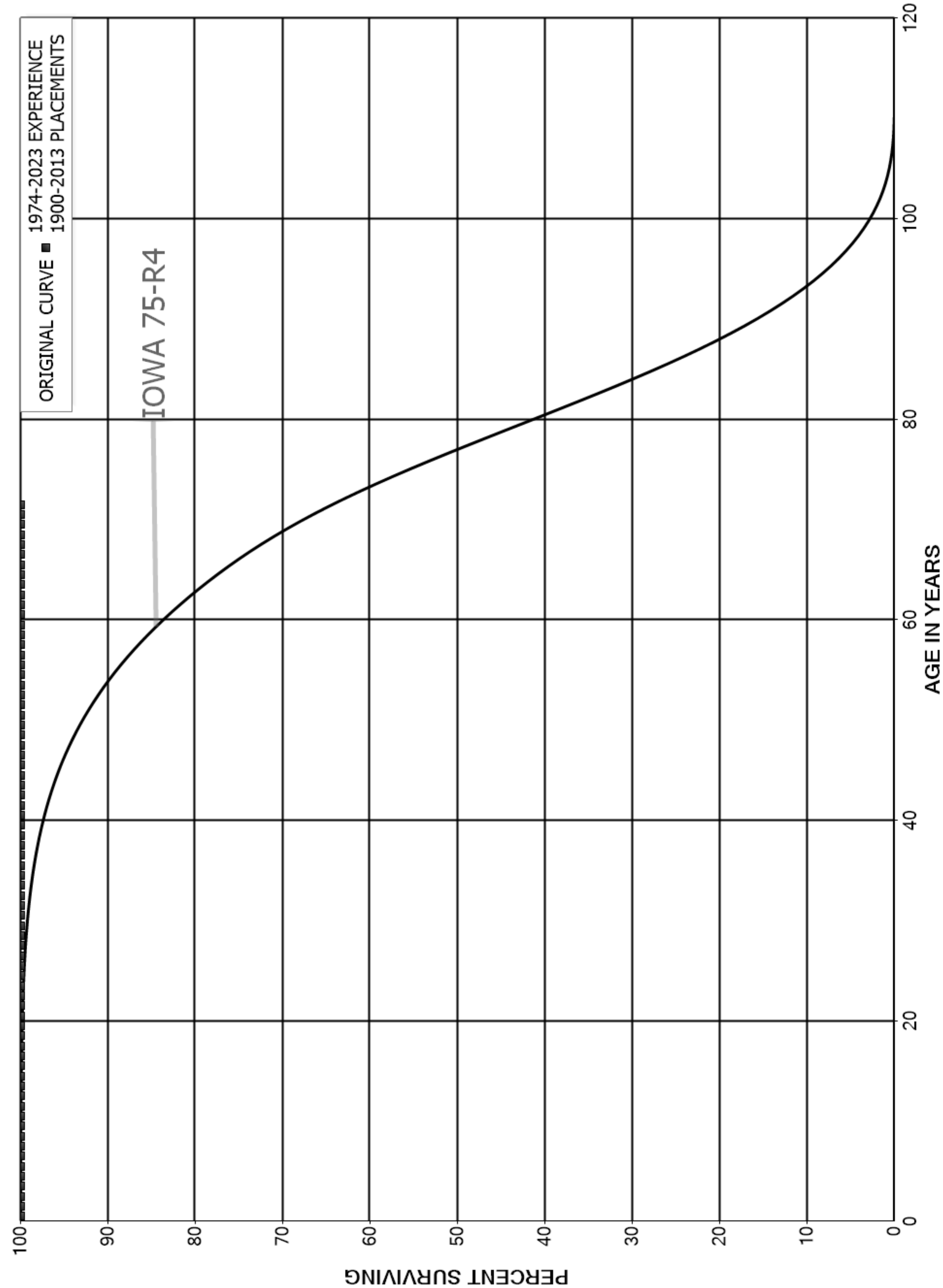
ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1967-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	91,081		0.0000	1.0000	99.97
40.5	91,081		0.0000	1.0000	99.97
41.5	91,081		0.0000	1.0000	99.97
42.5	91,081		0.0000	1.0000	99.97
43.5	91,081		0.0000	1.0000	99.97
44.5	91,081		0.0000	1.0000	99.97
45.5	91,081		0.0000	1.0000	99.97
46.5	45,638		0.0000	1.0000	99.97
47.5	45,638		0.0000	1.0000	99.97
48.5	45,638		0.0000	1.0000	99.97
49.5	45,638		0.0000	1.0000	99.97
50.5	45,638		0.0000	1.0000	99.97
51.5	45,638		0.0000	1.0000	99.97
52.5	45,638		0.0000	1.0000	99.97
53.5	45,638		0.0000	1.0000	99.97
54.5	45,638		0.0000	1.0000	99.97
55.5	45,638		0.0000	1.0000	99.97
56.5	40,610		0.0000	1.0000	99.97
57.5	14,697		0.0000	1.0000	99.97
58.5					99.97

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 374.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,657,830		0.0000	1.0000	100.00
0.5	1,657,830		0.0000	1.0000	100.00
1.5	1,638,506		0.0000	1.0000	100.00
2.5	1,650,827		0.0000	1.0000	100.00
3.5	1,650,827		0.0000	1.0000	100.00
4.5	1,650,827		0.0000	1.0000	100.00
5.5	1,660,496		0.0000	1.0000	100.00
6.5	1,660,496		0.0000	1.0000	100.00
7.5	1,660,496		0.0000	1.0000	100.00
8.5	1,660,496		0.0000	1.0000	100.00
9.5	1,660,496		0.0000	1.0000	100.00
10.5	1,205,455		0.0000	1.0000	100.00
11.5	1,208,880		0.0000	1.0000	100.00
12.5	1,208,980		0.0000	1.0000	100.00
13.5	1,185,830		0.0000	1.0000	100.00
14.5	1,183,628		0.0000	1.0000	100.00
15.5	1,183,828		0.0000	1.0000	100.00
16.5	1,183,828		0.0000	1.0000	100.00
17.5	1,183,828		0.0000	1.0000	100.00
18.5	1,194,968		0.0000	1.0000	100.00
19.5	1,194,968		0.0000	1.0000	100.00
20.5	893,294		0.0000	1.0000	100.00
21.5	770,286		0.0000	1.0000	100.00
22.5	717,371		0.0000	1.0000	100.00
23.5	704,426		0.0000	1.0000	100.00
24.5	680,493		0.0000	1.0000	100.00
25.5	665,368		0.0000	1.0000	100.00
26.5	629,536		0.0000	1.0000	100.00
27.5	611,427		0.0000	1.0000	100.00
28.5	498,713		0.0000	1.0000	100.00
29.5	455,477		0.0000	1.0000	100.00
30.5	425,600		0.0000	1.0000	100.00
31.5	360,634		0.0000	1.0000	100.00
32.5	175,569		0.0000	1.0000	100.00
33.5	165,563		0.0000	1.0000	100.00
34.5	90,569		0.0000	1.0000	100.00
35.5	86,667		0.0000	1.0000	100.00
36.5	76,934		0.0000	1.0000	100.00
37.5	73,182		0.0000	1.0000	100.00
38.5	68,403		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	67,639		0.0000	1.0000	100.00
40.5	67,387		0.0000	1.0000	100.00
41.5	66,348		0.0000	1.0000	100.00
42.5	57,628		0.0000	1.0000	100.00
43.5	56,063		0.0000	1.0000	100.00
44.5	54,474		0.0000	1.0000	100.00
45.5	47,629		0.0000	1.0000	100.00
46.5	37,352		0.0000	1.0000	100.00
47.5	36,548		0.0000	1.0000	100.00
48.5	32,908		0.0000	1.0000	100.00
49.5	29,604		0.0000	1.0000	100.00
50.5	29,604		0.0000	1.0000	100.00
51.5	29,604		0.0000	1.0000	100.00
52.5	27,097		0.0000	1.0000	100.00
53.5	27,097		0.0000	1.0000	100.00
54.5	27,097		0.0000	1.0000	100.00
55.5	17,428		0.0000	1.0000	100.00
56.5	17,428		0.0000	1.0000	100.00
57.5	17,428		0.0000	1.0000	100.00
58.5	17,428		0.0000	1.0000	100.00
59.5	16,678		0.0000	1.0000	100.00
60.5	13,253		0.0000	1.0000	100.00
61.5	13,153		0.0000	1.0000	100.00
62.5	13,153		0.0000	1.0000	100.00
63.5	12,953		0.0000	1.0000	100.00
64.5	12,953		0.0000	1.0000	100.00
65.5	12,953		0.0000	1.0000	100.00
66.5	12,953		0.0000	1.0000	100.00
67.5	1,813		0.0000	1.0000	100.00
68.5	1,813		0.0000	1.0000	100.00
69.5	1,813		0.0000	1.0000	100.00
70.5	1,813		0.0000	1.0000	100.00
71.5					100.00
72.5					
73.5	208,257		0.0000		
74.5	208,257		0.0000		
75.5	208,257		0.0000		
76.5	208,257		0.0000		
77.5	208,257		0.0000		
78.5	208,257		0.0000		

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	208,257		0.0000		
80.5	208,257		0.0000		
81.5	208,257		0.0000		
82.5	208,257		0.0000		
83.5	208,257		0.0000		
84.5	208,257		0.0000		
85.5	208,257		0.0000		
86.5	208,257		0.0000		
87.5	208,257		0.0000		
88.5	208,257		0.0000		
89.5	208,257		0.0000		
90.5	208,257		0.0000		
91.5	208,257		0.0000		
92.5	208,257		0.0000		
93.5	208,257		0.0000		
94.5	208,257		0.0000		
95.5	208,257		0.0000		
96.5	208,257		0.0000		
97.5	208,257		0.0000		
98.5	208,257		0.0000		
99.5	208,257		0.0000		
100.5	208,257		0.0000		
101.5	208,257		0.0000		
102.5	208,257		0.0000		
103.5	208,257		0.0000		
104.5	208,257		0.0000		
105.5	208,257		0.0000		
106.5	208,257		0.0000		
107.5	208,257		0.0000		
108.5	208,257		0.0000		
109.5	208,257		0.0000		
110.5	208,257		0.0000		
111.5	208,257		0.0000		
112.5	208,257		0.0000		
113.5	208,257		0.0000		
114.5	208,257		0.0000		
115.5	208,257		0.0000		
116.5	208,257		0.0000		
117.5	208,257		0.0000		
118.5	208,257		0.0000		

NORTHWEST NATURAL GAS COMPANY

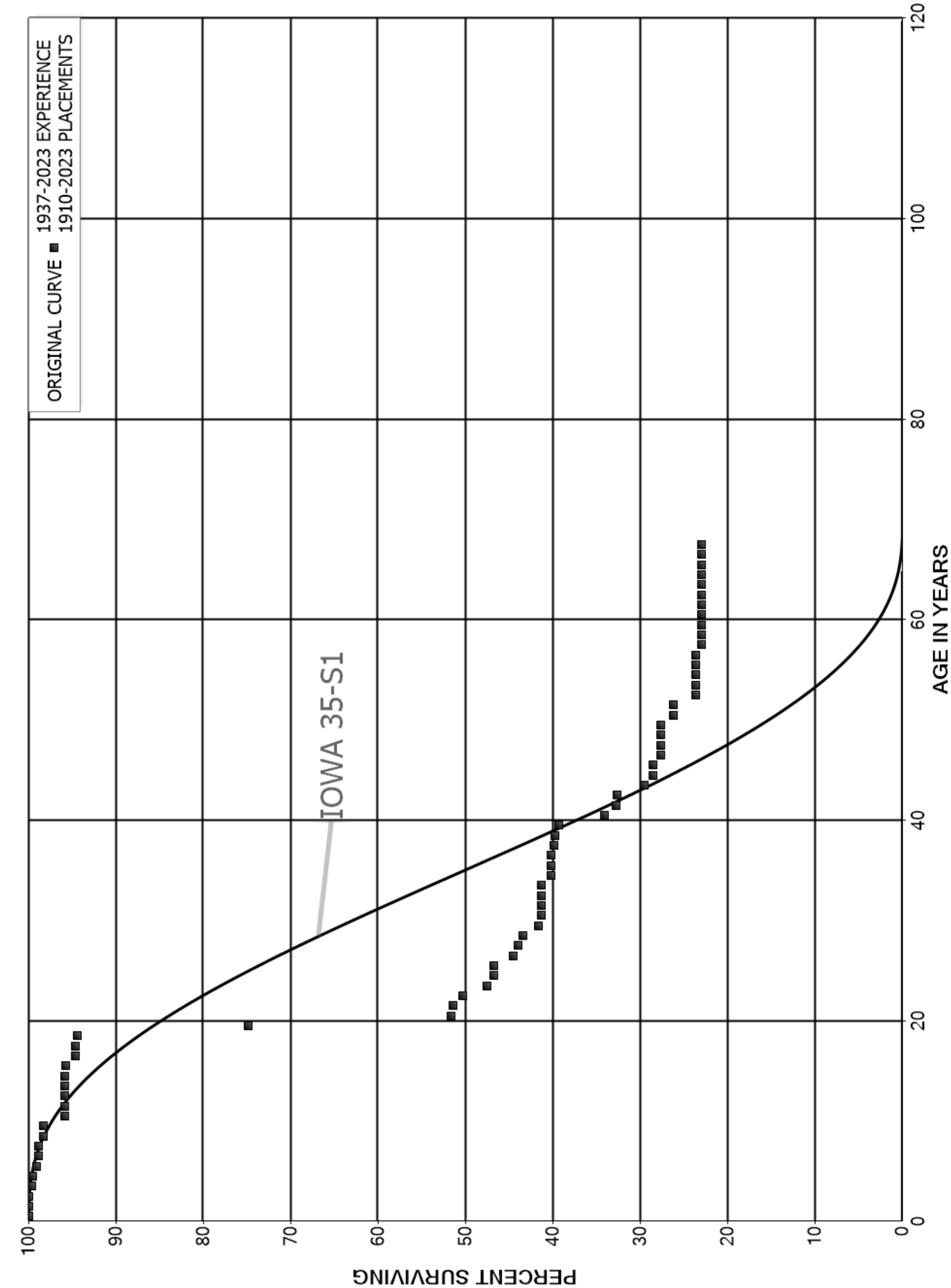
ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	208,257		0.0000		
120.5	208,257		0.0000		
121.5	208,257		0.0000		
122.5	208,257		0.0000		
123.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,616,189		0.0000	1.0000	100.00
0.5	1,574,618	119	0.0001	0.9999	100.00
1.5	1,548,149	582	0.0004	0.9996	99.99
2.5	1,548,149	5,004	0.0032	0.9968	99.95
3.5	1,548,149	2,755	0.0018	0.9982	99.63
4.5	1,548,149	5,302	0.0034	0.9966	99.45
5.5	1,464,971	3,403	0.0023	0.9977	99.11
6.5	1,464,971		0.0000	1.0000	98.88
7.5	108,808	611	0.0056	0.9944	98.88
8.5	108,808		0.0000	1.0000	98.33
9.5	110,952	2,752	0.0248	0.9752	98.33
10.5	110,952		0.0000	1.0000	95.89
11.5	110,952		0.0000	1.0000	95.89
12.5	110,952		0.0000	1.0000	95.89
13.5	110,952		0.0000	1.0000	95.89
14.5	110,952	170	0.0015	0.9985	95.89
15.5	99,983	1,206	0.0121	0.9879	95.74
16.5	99,983		0.0000	1.0000	94.59
17.5	99,983	167	0.0017	0.9983	94.59
18.5	99,983	20,760	0.2076	0.7924	94.43
19.5	99,553	30,809	0.3095	0.6905	74.82
20.5	99,553	506	0.0051	0.9949	51.67
21.5	99,553	2,221	0.0223	0.9777	51.40
22.5	99,553	5,411	0.0544	0.9456	50.26
23.5	99,403	1,664	0.0167	0.9833	47.53
24.5	99,403	118	0.0012	0.9988	46.73
25.5	99,403	4,717	0.0475	0.9525	46.67
26.5	99,403	1,209	0.0122	0.9878	44.46
27.5	99,403	1,250	0.0126	0.9874	43.92
28.5	99,403	4,092	0.0412	0.9588	43.37
29.5	95,587	588	0.0062	0.9938	41.58
30.5	93,092		0.0000	1.0000	41.33
31.5	93,092		0.0000	1.0000	41.33
32.5	93,092	23	0.0002	0.9998	41.33
33.5	67,622	1,870	0.0277	0.9723	41.32
34.5	65,874		0.0000	1.0000	40.17
35.5	65,874		0.0000	1.0000	40.17
36.5	65,874	639	0.0097	0.9903	40.17
37.5	65,874	150	0.0023	0.9977	39.78
38.5	65,874	588	0.0089	0.9911	39.69

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	65,874	8,863	0.1345	0.8655	39.34
40.5	57,179	2,300	0.0402	0.9598	34.05
41.5	54,879	167	0.0030	0.9970	32.68
42.5	54,879	5,090	0.0927	0.9073	32.58
43.5	54,757	1,928	0.0352	0.9648	29.56
44.5	52,840		0.0000	1.0000	28.51
45.5	52,840	1,623	0.0307	0.9693	28.51
46.5	52,840	107	0.0020	0.9980	27.64
47.5	52,840	4	0.0001	0.9999	27.58
48.5	52,840		0.0000	1.0000	27.58
49.5	52,840	2,607	0.0493	0.9507	27.58
50.5	52,840		0.0000	1.0000	26.22
51.5	58,646	5,806	0.0990	0.9010	26.22
52.5	52,840		0.0000	1.0000	23.62
53.5	52,840		0.0000	1.0000	23.62
54.5	52,840		0.0000	1.0000	23.62
55.5	52,840		0.0000	1.0000	23.62
56.5	52,840	1,625	0.0308	0.9692	23.62
57.5	52,840		0.0000	1.0000	22.90
58.5	52,542		0.0000	1.0000	22.90
59.5	52,542		0.0000	1.0000	22.90
60.5	52,542		0.0000	1.0000	22.90
61.5	49,800		0.0000	1.0000	22.90
62.5	49,074		0.0000	1.0000	22.90
63.5	42,091		0.0000	1.0000	22.90
64.5	41,220		0.0000	1.0000	22.90
65.5	37,913		0.0000	1.0000	22.90
66.5	37,913		0.0000	1.0000	22.90
67.5	4,985		0.0000	1.0000	22.90
68.5	4,985		0.0000	1.0000	22.90
69.5	4,985		0.0000	1.0000	22.90
70.5	4,971		0.0000	1.0000	22.90
71.5	4,971		0.0000	1.0000	22.90
72.5	4,971		0.0000	1.0000	22.90
73.5	4,971		0.0000	1.0000	22.90
74.5	4,971		0.0000	1.0000	22.90
75.5	4,971		0.0000	1.0000	22.90
76.5	4,971		0.0000	1.0000	22.90
77.5	4,971		0.0000	1.0000	22.90
78.5	4,971		0.0000	1.0000	22.90

NORTHWEST NATURAL GAS COMPANY

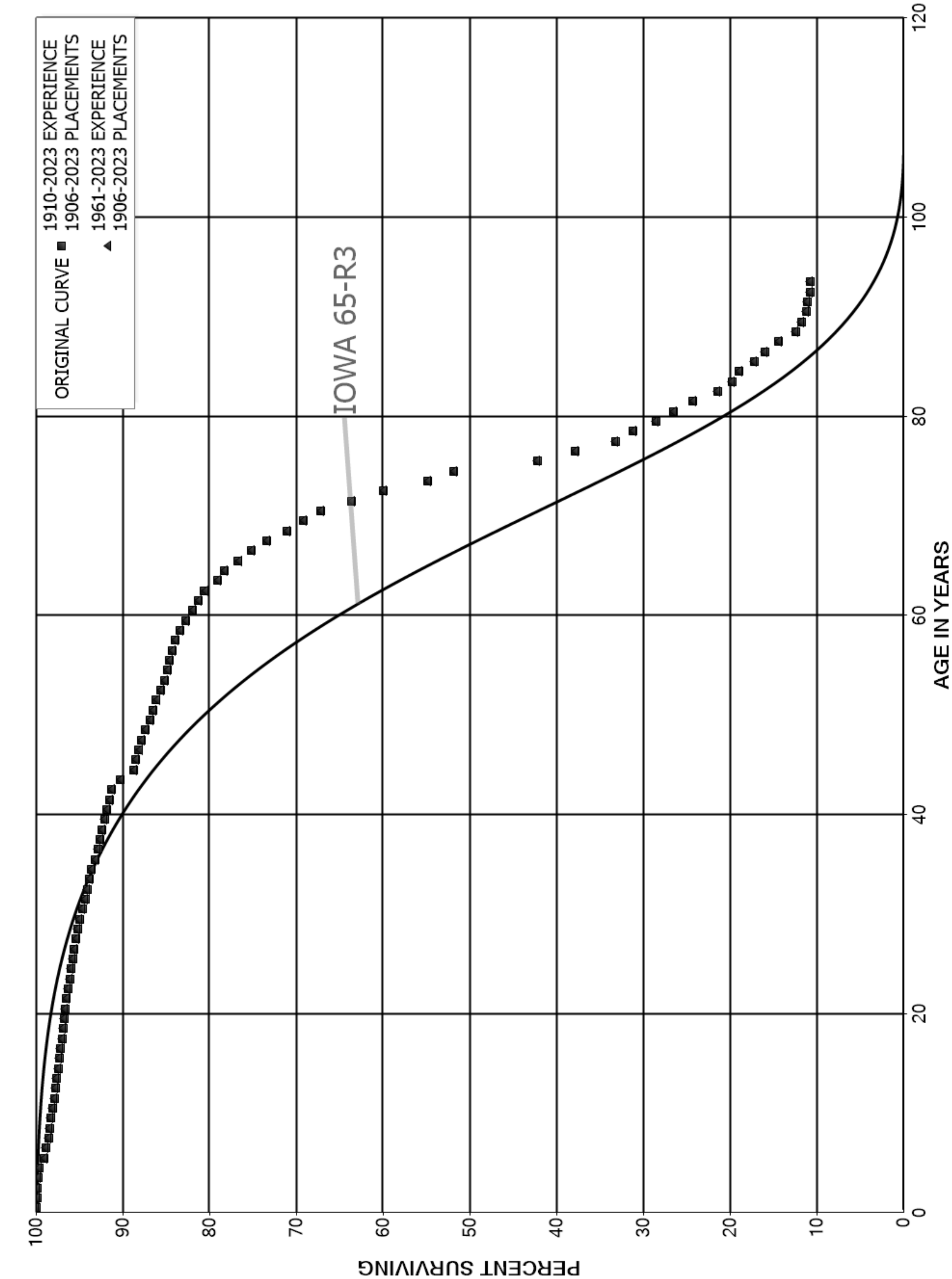
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,971		0.0000	1.0000	22.90
80.5	4,971		0.0000	1.0000	22.90
81.5	4,971		0.0000	1.0000	22.90
82.5	4,971		0.0000	1.0000	22.90
83.5	4,971		0.0000	1.0000	22.90
84.5	4,971		0.0000	1.0000	22.90
85.5	4,971		0.0000	1.0000	22.90
86.5	4,971		0.0000	1.0000	22.90
87.5	4,971		0.0000	1.0000	22.90
88.5	4,971		0.0000	1.0000	22.90
89.5	4,971		0.0000	1.0000	22.90
90.5	4,971		0.0000	1.0000	22.90
91.5	4,971		0.0000	1.0000	22.90
92.5	4,971		0.0000	1.0000	22.90
93.5	4,971		0.0000	1.0000	22.90
94.5	4,971		0.0000	1.0000	22.90
95.5	4,971		0.0000	1.0000	22.90
96.5	2,827		0.0000	1.0000	22.90
97.5	2,827		0.0000	1.0000	22.90
98.5	2,827		0.0000	1.0000	22.90
99.5	2,827		0.0000	1.0000	22.90
100.5	2,827		0.0000	1.0000	22.90
101.5	2,827		0.0000	1.0000	22.90
102.5	2,827		0.0000	1.0000	22.90
103.5	2,827		0.0000	1.0000	22.90
104.5	2,827		0.0000	1.0000	22.90
105.5	2,827		0.0000	1.0000	22.90
106.5	2,827		0.0000	1.0000	22.90
107.5	2,827		0.0000	1.0000	22.90
108.5	2,827		0.0000	1.0000	22.90
109.5	2,827		0.0000	1.0000	22.90
110.5					22.90

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 376.11 AND 376.12 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,566,625,527	488,618	0.0003	0.9997	100.00
0.5	1,507,853,007	1,278,873	0.0008	0.9992	99.97
1.5	1,440,364,002	1,130,173	0.0008	0.9992	99.88
2.5	1,386,456,431	1,277,310	0.0009	0.9991	99.81
3.5	1,315,275,380	1,569,039	0.0012	0.9988	99.71
4.5	1,254,493,788	7,337,073	0.0058	0.9942	99.59
5.5	1,187,492,682	1,580,845	0.0013	0.9987	99.01
6.5	1,147,058,819	4,151,125	0.0036	0.9964	98.88
7.5	1,102,673,752	1,424,368	0.0013	0.9987	98.52
8.5	1,067,034,627	1,463,150	0.0014	0.9986	98.40
9.5	1,029,628,344	1,894,828	0.0018	0.9982	98.26
10.5	988,942,041	1,931,798	0.0020	0.9980	98.08
11.5	952,155,514	1,653,209	0.0017	0.9983	97.89
12.5	928,252,632	1,339,387	0.0014	0.9986	97.72
13.5	905,969,208	1,289,655	0.0014	0.9986	97.58
14.5	885,658,271	1,035,076	0.0012	0.9988	97.44
15.5	855,880,078	1,571,951	0.0018	0.9982	97.32
16.5	818,770,110	1,411,402	0.0017	0.9983	97.15
17.5	781,597,808	1,039,749	0.0013	0.9987	96.98
18.5	743,320,505	881,102	0.0012	0.9988	96.85
19.5	707,755,053	1,049,285	0.0015	0.9985	96.73
20.5	659,621,353	879,463	0.0013	0.9987	96.59
21.5	628,276,315	1,070,975	0.0017	0.9983	96.46
22.5	599,863,209	1,177,665	0.0020	0.9980	96.30
23.5	567,677,064	1,067,108	0.0019	0.9981	96.11
24.5	536,995,951	1,132,411	0.0021	0.9979	95.93
25.5	505,433,689	870,005	0.0017	0.9983	95.73
26.5	468,258,879	924,863	0.0020	0.9980	95.56
27.5	432,115,542	838,801	0.0019	0.9981	95.37
28.5	401,643,833	802,038	0.0020	0.9980	95.19
29.5	370,923,932	1,489,425	0.0040	0.9960	95.00
30.5	340,993,704	1,035,753	0.0030	0.9970	94.62
31.5	313,784,159	882,702	0.0028	0.9972	94.33
32.5	290,767,692	717,613	0.0025	0.9975	94.06
33.5	273,086,240	774,852	0.0028	0.9972	93.83
34.5	255,120,651	1,157,496	0.0045	0.9955	93.56
35.5	239,513,077	709,746	0.0030	0.9970	93.14
36.5	225,568,945	594,710	0.0026	0.9974	92.86
37.5	209,409,397	536,765	0.0026	0.9974	92.62
38.5	192,771,688	592,874	0.0031	0.9969	92.38

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	175,080,552	538,472	0.0031	0.9969	92.10
40.5	163,056,549	539,846	0.0033	0.9967	91.81
41.5	151,365,702	405,775	0.0027	0.9973	91.51
42.5	138,657,496	1,559,462	0.0112	0.9888	91.26
43.5	125,576,948	2,127,218	0.0169	0.9831	90.24
44.5	112,462,063	308,709	0.0027	0.9973	88.71
45.5	103,307,204	387,395	0.0037	0.9963	88.47
46.5	97,522,396	344,330	0.0035	0.9965	88.13
47.5	92,284,943	422,346	0.0046	0.9954	87.82
48.5	87,490,284	537,769	0.0061	0.9939	87.42
49.5	81,364,709	333,321	0.0041	0.9959	86.88
50.5	75,018,624	348,497	0.0046	0.9954	86.53
51.5	69,871,087	377,916	0.0054	0.9946	86.13
52.5	63,924,181	323,188	0.0051	0.9949	85.66
53.5	58,915,102	260,476	0.0044	0.9956	85.23
54.5	53,292,587	143,175	0.0027	0.9973	84.85
55.5	47,750,480	161,169	0.0034	0.9966	84.62
56.5	42,896,920	185,513	0.0043	0.9957	84.34
57.5	36,304,185	244,607	0.0067	0.9933	83.97
58.5	30,633,419	243,043	0.0079	0.9921	83.41
59.5	24,843,846	231,464	0.0093	0.9907	82.74
60.5	20,083,392	156,493	0.0078	0.9922	81.97
61.5	18,649,935	174,667	0.0094	0.9906	81.34
62.5	15,155,821	279,877	0.0185	0.9815	80.57
63.5	11,509,542	116,803	0.0101	0.9899	79.09
64.5	9,323,167	190,887	0.0205	0.9795	78.28
65.5	7,202,377	139,882	0.0194	0.9806	76.68
66.5	5,931,763	142,765	0.0241	0.9759	75.19
67.5	3,568,388	111,159	0.0312	0.9688	73.38
68.5	3,362,695	89,931	0.0267	0.9733	71.10
69.5	3,253,605	95,887	0.0295	0.9705	69.19
70.5	3,124,770	163,508	0.0523	0.9477	67.15
71.5	2,915,090	170,852	0.0586	0.9414	63.64
72.5	2,722,865	232,397	0.0854	0.9146	59.91
73.5	2,475,055	136,254	0.0551	0.9449	54.80
74.5	2,316,312	427,449	0.1845	0.8155	51.78
75.5	1,857,841	194,340	0.1046	0.8954	42.23
76.5	1,515,013	183,626	0.1212	0.8788	37.81
77.5	1,287,572	79,645	0.0619	0.9381	33.23
78.5	1,211,011	101,880	0.0841	0.9159	31.17

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,107,584	80,711	0.0729	0.9271	28.55
80.5	1,025,549	85,060	0.0829	0.9171	26.47
81.5	928,668	108,546	0.1169	0.8831	24.27
82.5	791,423	61,510	0.0777	0.9223	21.44
83.5	724,410	32,179	0.0444	0.9556	19.77
84.5	687,312	62,266	0.0906	0.9094	18.89
85.5	617,718	42,757	0.0692	0.9308	17.18
86.5	560,807	57,255	0.1021	0.8979	15.99
87.5	487,210	66,475	0.1364	0.8636	14.36
88.5	414,791	22,665	0.0546	0.9454	12.40
89.5	381,613	18,140	0.0475	0.9525	11.72
90.5	366,872	3,707	0.0101	0.9899	11.16
91.5	359,953	10,887	0.0302	0.9698	11.05
92.5	325,135	768	0.0024	0.9976	10.72
93.5	279,498	306	0.0011	0.9989	10.69
94.5	277,386	511	0.0018	0.9982	10.68
95.5	260,149	252	0.0010	0.9990	10.66
96.5	257,429	460	0.0018	0.9982	10.65
97.5	218,212	3,122	0.0143	0.9857	10.63
98.5	185,469	4,135	0.0223	0.9777	10.48
99.5	175,679	913	0.0052	0.9948	10.25
100.5	159,335	4,783	0.0300	0.9700	10.19
101.5	115,043	5,719	0.0497	0.9503	9.89
102.5	95,898	4,399	0.0459	0.9541	9.39
103.5	82,103	1,475	0.0180	0.9820	8.96
104.5	80,335	1,580	0.0197	0.9803	8.80
105.5	74,754	1,018	0.0136	0.9864	8.63
106.5	71,085	170	0.0024	0.9976	8.51
107.5	60,734		0.0000	1.0000	8.49
108.5	59,014		0.0000	1.0000	8.49
109.5	58,760	331	0.0056	0.9944	8.49
110.5	36,814	946	0.0257	0.9743	8.44
111.5	35,761		0.0000	1.0000	8.23
112.5	35,621		0.0000	1.0000	8.23
113.5	15,210		0.0000	1.0000	8.23
114.5	38		0.0000	1.0000	8.23
115.5	38		0.0000	1.0000	8.23
116.5	38		0.0000	1.0000	8.23
117.5					8.23

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,542,371,840	488,618	0.0003	0.9997	100.00
0.5	1,487,853,380	1,278,873	0.0009	0.9991	99.97
1.5	1,423,481,430	1,130,173	0.0008	0.9992	99.88
2.5	1,372,839,774	1,277,310	0.0009	0.9991	99.80
3.5	1,304,005,748	1,569,039	0.0012	0.9988	99.71
4.5	1,247,479,914	7,337,073	0.0059	0.9941	99.59
5.5	1,180,750,457	1,580,845	0.0013	0.9987	99.00
6.5	1,140,492,105	4,151,125	0.0036	0.9964	98.87
7.5	1,096,323,094	1,424,368	0.0013	0.9987	98.51
8.5	1,060,925,395	1,463,150	0.0014	0.9986	98.38
9.5	1,023,664,394	1,894,828	0.0019	0.9981	98.25
10.5	983,089,808	1,931,798	0.0020	0.9980	98.07
11.5	946,392,271	1,653,209	0.0017	0.9983	97.87
12.5	922,632,182	1,339,387	0.0015	0.9985	97.70
13.5	900,713,646	1,289,655	0.0014	0.9986	97.56
14.5	880,518,587	1,035,076	0.0012	0.9988	97.42
15.5	850,771,917	1,571,726	0.0018	0.9982	97.31
16.5	813,698,854	1,411,402	0.0017	0.9983	97.13
17.5	776,554,820	1,039,749	0.0013	0.9987	96.96
18.5	738,298,128	881,102	0.0012	0.9988	96.83
19.5	702,766,395	1,049,285	0.0015	0.9985	96.71
20.5	654,661,028	879,463	0.0013	0.9987	96.57
21.5	623,345,517	1,070,975	0.0017	0.9983	96.44
22.5	594,966,736	1,177,665	0.0020	0.9980	96.27
23.5	562,809,299	1,067,108	0.0019	0.9981	96.08
24.5	532,149,506	1,132,411	0.0021	0.9979	95.90
25.5	500,604,960	870,005	0.0017	0.9983	95.70
26.5	463,473,072	924,863	0.0020	0.9980	95.53
27.5	427,338,847	838,801	0.0020	0.9980	95.34
28.5	396,944,671	802,038	0.0020	0.9980	95.15
29.5	366,367,048	1,489,425	0.0041	0.9959	94.96
30.5	336,572,587	1,035,753	0.0031	0.9969	94.57
31.5	309,451,587	882,702	0.0029	0.9971	94.28
32.5	286,578,630	717,613	0.0025	0.9975	94.01
33.5	269,055,733	774,852	0.0029	0.9971	93.78
34.5	251,363,846	1,157,496	0.0046	0.9954	93.51
35.5	236,278,706	709,746	0.0030	0.9970	93.08
36.5	222,564,078	594,710	0.0027	0.9973	92.80
37.5	206,675,537	536,765	0.0026	0.9974	92.55
38.5	190,428,731	592,874	0.0031	0.9969	92.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	172,895,368	538,472	0.0031	0.9969	92.02
40.5	160,969,028	539,846	0.0034	0.9966	91.74
41.5	149,332,444	405,775	0.0027	0.9973	91.43
42.5	136,683,247	1,559,462	0.0114	0.9886	91.18
43.5	123,616,969	2,127,218	0.0172	0.9828	90.14
44.5	110,554,052	308,709	0.0028	0.9972	88.59
45.5	101,534,154	387,395	0.0038	0.9962	88.34
46.5	95,805,024	344,330	0.0036	0.9964	88.00
47.5	90,678,769	422,346	0.0047	0.9953	87.69
48.5	86,144,169	537,769	0.0062	0.9938	87.28
49.5	80,537,765	333,321	0.0041	0.9959	86.73
50.5	75,018,624	348,497	0.0046	0.9954	86.38
51.5	69,871,087	377,916	0.0054	0.9946	85.97
52.5	63,924,181	323,188	0.0051	0.9949	85.51
53.5	58,915,102	260,476	0.0044	0.9956	85.08
54.5	53,292,587	143,175	0.0027	0.9973	84.70
55.5	47,750,480	161,169	0.0034	0.9966	84.47
56.5	42,896,920	185,513	0.0043	0.9957	84.19
57.5	36,304,185	244,607	0.0067	0.9933	83.82
58.5	30,633,419	243,043	0.0079	0.9921	83.26
59.5	24,843,846	231,464	0.0093	0.9907	82.60
60.5	20,083,392	156,493	0.0078	0.9922	81.83
61.5	18,649,935	174,667	0.0094	0.9906	81.19
62.5	15,155,821	279,877	0.0185	0.9815	80.43
63.5	11,509,542	116,803	0.0101	0.9899	78.95
64.5	9,323,167	190,887	0.0205	0.9795	78.14
65.5	7,202,377	139,882	0.0194	0.9806	76.54
66.5	5,931,763	142,765	0.0241	0.9759	75.06
67.5	3,568,388	111,159	0.0312	0.9688	73.25
68.5	3,362,695	89,931	0.0267	0.9733	70.97
69.5	3,253,605	95,887	0.0295	0.9705	69.07
70.5	3,124,770	163,508	0.0523	0.9477	67.04
71.5	2,915,090	170,852	0.0586	0.9414	63.53
72.5	2,722,865	232,397	0.0854	0.9146	59.81
73.5	2,475,055	136,254	0.0551	0.9449	54.70
74.5	2,316,312	427,449	0.1845	0.8155	51.69
75.5	1,857,841	194,340	0.1046	0.8954	42.15
76.5	1,515,013	183,626	0.1212	0.8788	37.74
77.5	1,287,572	79,645	0.0619	0.9381	33.17
78.5	1,211,011	101,880	0.0841	0.9159	31.12

NORTHWEST NATURAL GAS COMPANY

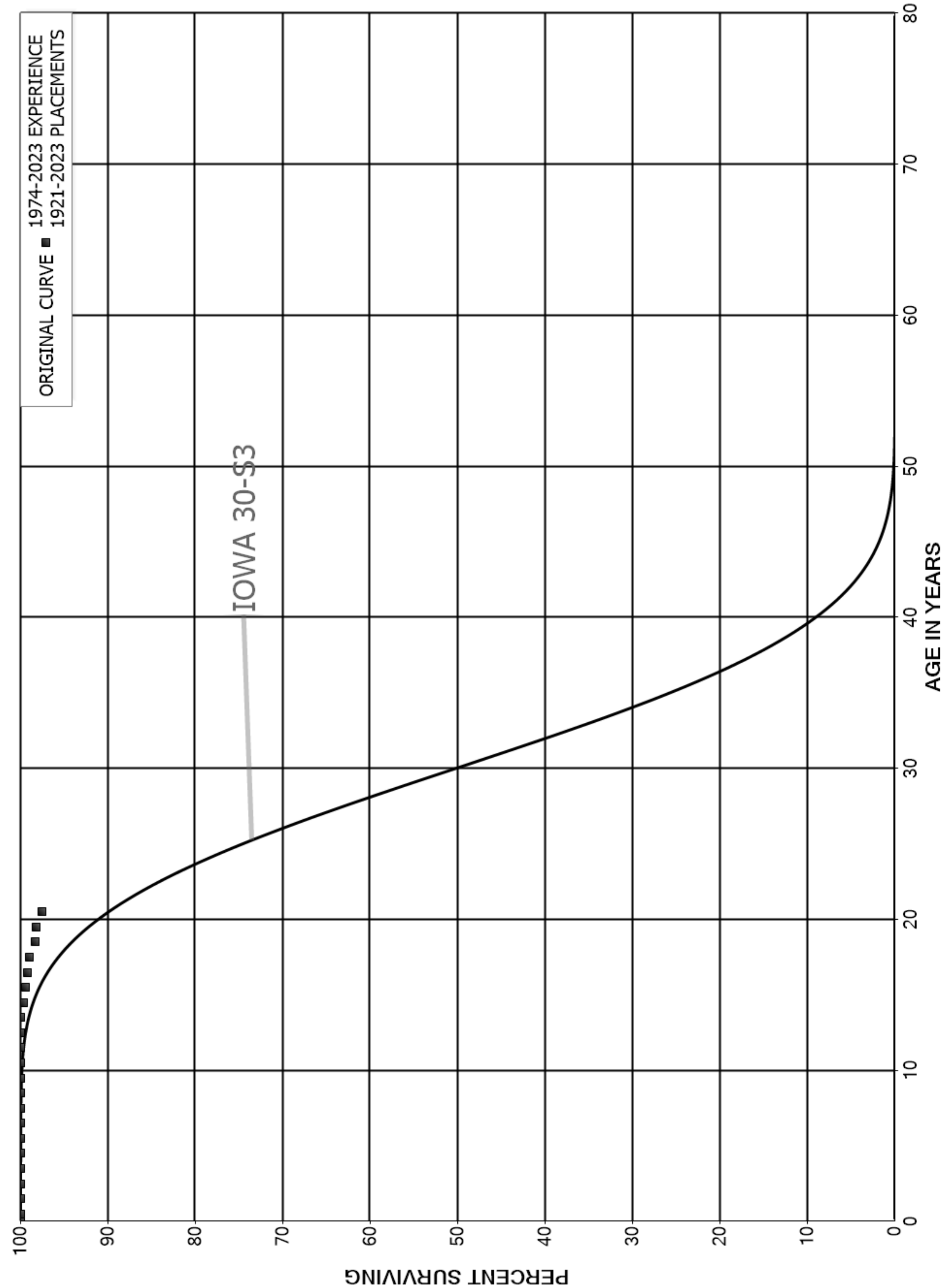
ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,107,584	80,711	0.0729	0.9271	28.50
80.5	1,025,549	85,060	0.0829	0.9171	26.42
81.5	928,668	108,546	0.1169	0.8831	24.23
82.5	791,423	61,510	0.0777	0.9223	21.40
83.5	724,410	32,179	0.0444	0.9556	19.73
84.5	687,312	62,266	0.0906	0.9094	18.86
85.5	617,718	42,757	0.0692	0.9308	17.15
86.5	560,807	57,255	0.1021	0.8979	15.96
87.5	487,210	66,475	0.1364	0.8636	14.33
88.5	414,791	22,665	0.0546	0.9454	12.38
89.5	381,613	18,140	0.0475	0.9525	11.70
90.5	366,872	3,707	0.0101	0.9899	11.14
91.5	359,953	10,887	0.0302	0.9698	11.03
92.5	325,135	768	0.0024	0.9976	10.70
93.5	279,498	306	0.0011	0.9989	10.67
94.5	277,386	511	0.0018	0.9982	10.66
95.5	260,149	252	0.0010	0.9990	10.64
96.5	257,429	460	0.0018	0.9982	10.63
97.5	218,212	3,122	0.0143	0.9857	10.61
98.5	185,469	4,135	0.0223	0.9777	10.46
99.5	175,679	913	0.0052	0.9948	10.23
100.5	159,335	4,783	0.0300	0.9700	10.17
101.5	115,043	5,719	0.0497	0.9503	9.87
102.5	95,898	4,399	0.0459	0.9541	9.38
103.5	82,103	1,475	0.0180	0.9820	8.95
104.5	80,335	1,580	0.0197	0.9803	8.79
105.5	74,754	1,018	0.0136	0.9864	8.61
106.5	71,085	170	0.0024	0.9976	8.50
107.5	60,734		0.0000	1.0000	8.48
108.5	59,014		0.0000	1.0000	8.48
109.5	58,760	331	0.0056	0.9944	8.48
110.5	36,814	946	0.0257	0.9743	8.43
111.5	35,761		0.0000	1.0000	8.21
112.5	35,621		0.0000	1.0000	8.21
113.5	15,210		0.0000	1.0000	8.21
114.5	38		0.0000	1.0000	8.21
115.5	38		0.0000	1.0000	8.21
116.5	38		0.0000	1.0000	8.21
117.5					8.21

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,012,249		0.0000	1.0000	100.00
0.5	969,942		0.0000	1.0000	100.00
1.5	969,942		0.0000	1.0000	100.00
2.5	818,380		0.0000	1.0000	100.00
3.5	818,380		0.0000	1.0000	100.00
4.5	818,380		0.0000	1.0000	100.00
5.5	818,380		0.0000	1.0000	100.00
6.5	818,380		0.0000	1.0000	100.00
7.5	818,380		0.0000	1.0000	100.00
8.5	818,380		0.0000	1.0000	100.00
9.5	818,380		0.0000	1.0000	100.00
10.5	818,723		0.0000	1.0000	100.00
11.5	818,723	343	0.0004	0.9996	100.00
12.5	821,132		0.0000	1.0000	99.96
13.5	823,074	2,752	0.0033	0.9967	99.96
14.5	821,705	1,942	0.0024	0.9976	99.62
15.5	821,730	1,383	0.0017	0.9983	99.39
16.5	825,785	1,967	0.0024	0.9976	99.22
17.5	824,755	5,438	0.0066	0.9934	98.98
18.5	825,560	937	0.0011	0.9989	98.33
19.5	824,623	6,243	0.0076	0.9924	98.22
20.5					97.48
21.5					
22.5					
23.5	6,883		0.0000		
24.5	7,084	6,883	0.9716		
25.5	18,727	201	0.0107		
26.5	30,122	18,526	0.6150		
27.5	19,331	11,596	0.5999		
28.5	7,773	7,735	0.9951		
29.5	124,160	38	0.0003		
30.5	124,122	124,122	1.0000		
31.5					
32.5					
33.5					
34.5					
35.5	4,800		0.0000		
36.5	4,992	4,800	0.9615		
37.5	3,005	192	0.0639		
38.5	2,813	2,813	1.0000		

NORTHWEST NATURAL GAS COMPANY

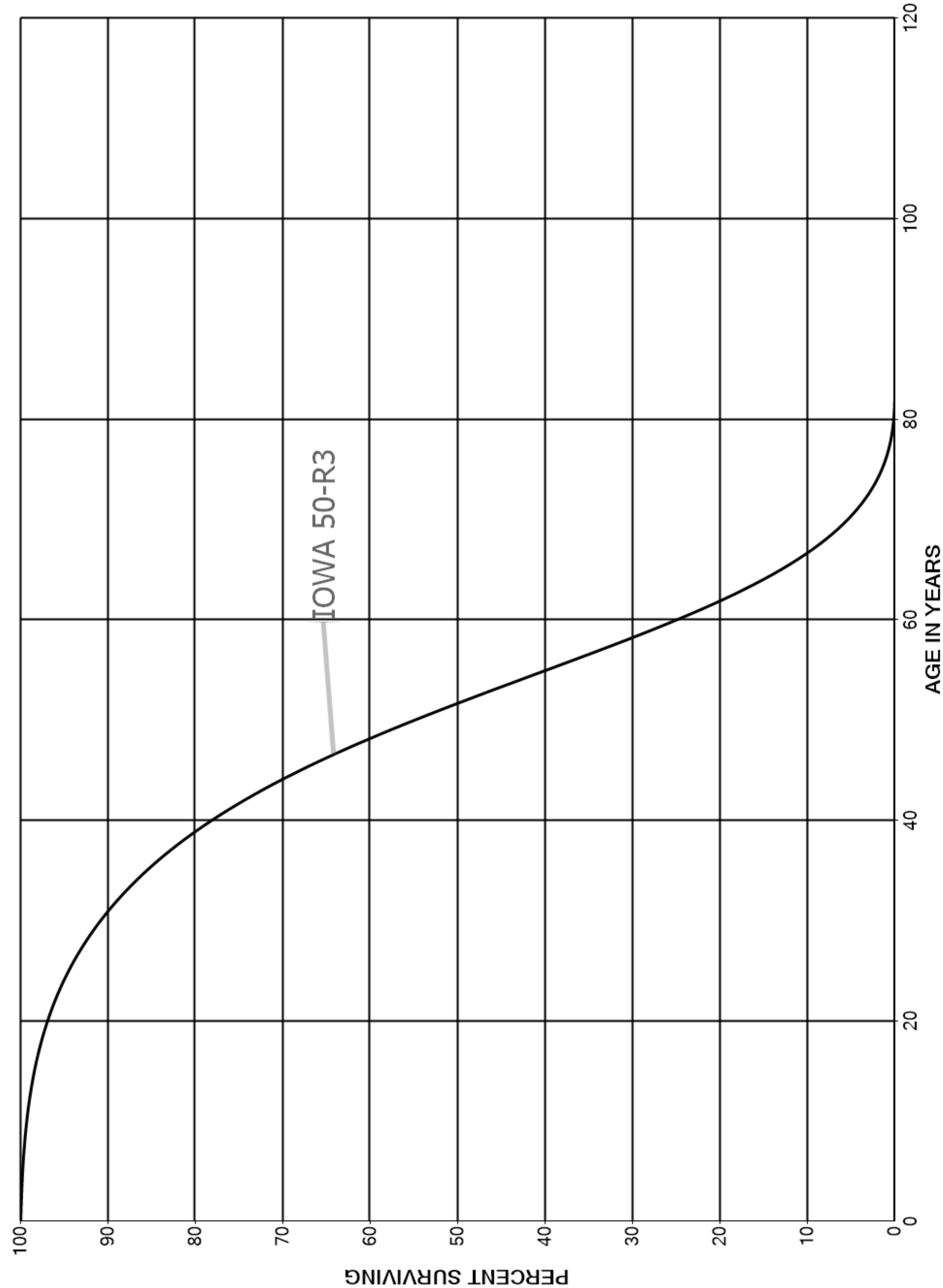
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

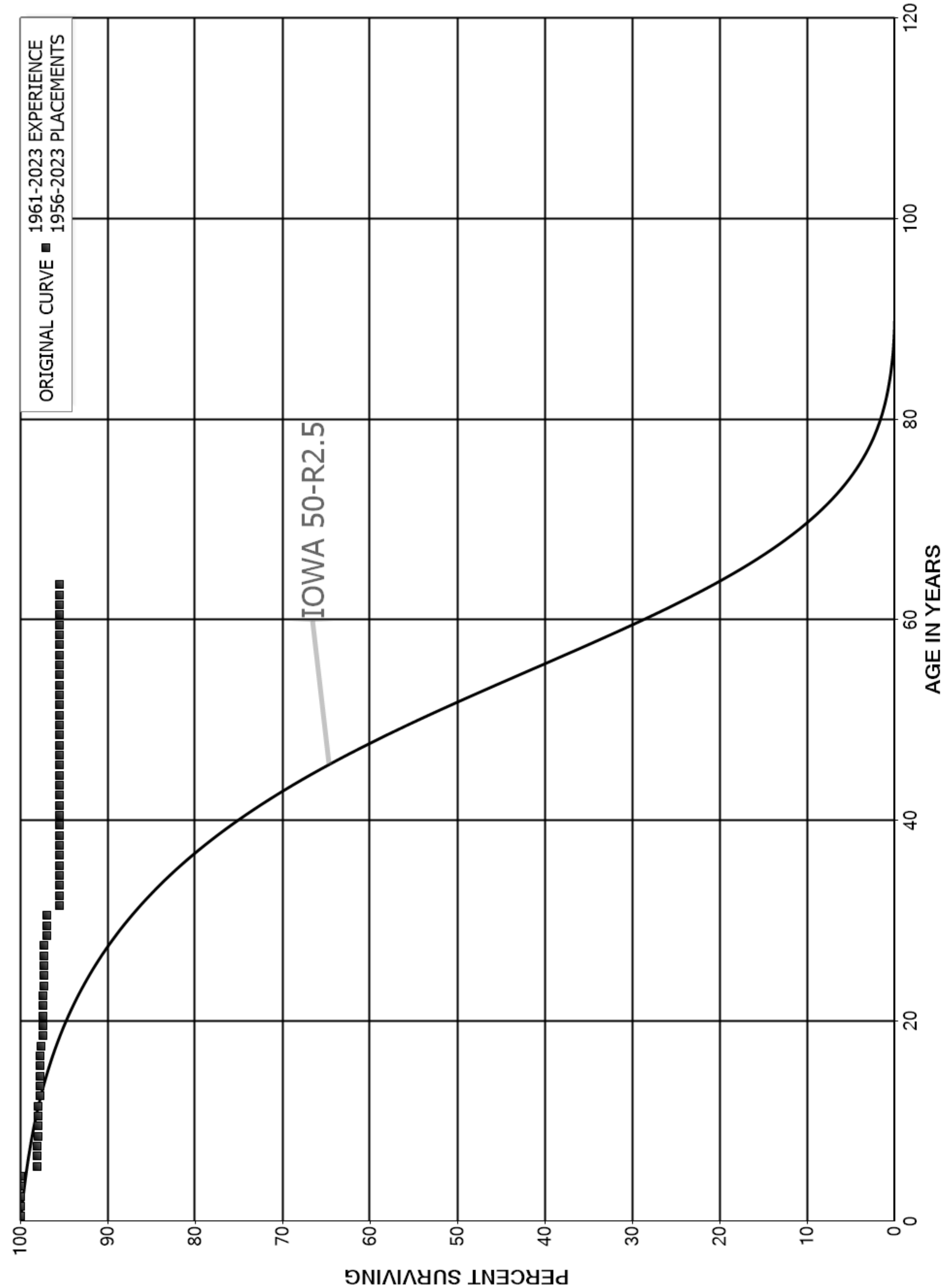
PLACEMENT BAND 1921-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80		0.0000		
40.5	80	80	1.0000		
41.5					
42.5					
43.5					
44.5					
45.5					
46.5	8,347		0.0000		
47.5	8,347	8,347	1.0000		
48.5	1,078		0.0000		
49.5	1,078	1,078	1.0000		
50.5					
51.5					
52.5	496		0.0000		
53.5	496	496	1.0000		
54.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
SMOOTH SURVIVOR CURVE



NORTHWEST NATURAL GAS COMPANY
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,935,097	110	0.0000	1.0000	100.00
0.5	21,501,568	235	0.0000	1.0000	100.00
1.5	20,028,391	1,228	0.0001	0.9999	100.00
2.5	18,593,059	4,769	0.0003	0.9997	99.99
3.5	16,891,692	4,411	0.0003	0.9997	99.97
4.5	14,407,590	273,564	0.0190	0.9810	99.94
5.5	11,415,296	1,235	0.0001	0.9999	98.04
6.5	8,313,909	838	0.0001	0.9999	98.03
7.5	5,748,376	881	0.0002	0.9998	98.02
8.5	4,850,085	1,074	0.0002	0.9998	98.01
9.5	4,017,874	1,551	0.0004	0.9996	97.99
10.5	1,927,322		0.0000	1.0000	97.95
11.5	1,850,955	4,000	0.0022	0.9978	97.95
12.5	1,787,679		0.0000	1.0000	97.74
13.5	1,652,581		0.0000	1.0000	97.74
14.5	1,524,539		0.0000	1.0000	97.74
15.5	1,524,539		0.0000	1.0000	97.74
16.5	1,524,539	1,383	0.0009	0.9991	97.74
17.5	1,523,156	3,498	0.0023	0.9977	97.65
18.5	1,367,849		0.0000	1.0000	97.42
19.5	1,367,547		0.0000	1.0000	97.42
20.5	1,367,547	831	0.0006	0.9994	97.42
21.5	1,366,496	116	0.0001	0.9999	97.36
22.5	1,325,741	520	0.0004	0.9996	97.36
23.5	1,118,413		0.0000	1.0000	97.32
24.5	1,118,413		0.0000	1.0000	97.32
25.5	1,118,413		0.0000	1.0000	97.32
26.5	1,118,413		0.0000	1.0000	97.32
27.5	1,089,712	4,292	0.0039	0.9961	97.32
28.5	1,085,420		0.0000	1.0000	96.93
29.5	1,085,420		0.0000	1.0000	96.93
30.5	1,084,441	15,797	0.0146	0.9854	96.93
31.5	1,066,814		0.0000	1.0000	95.52
32.5	1,031,855		0.0000	1.0000	95.52
33.5	1,029,117		0.0000	1.0000	95.52
34.5	1,024,179		0.0000	1.0000	95.52
35.5	992,184		0.0000	1.0000	95.52
36.5	979,664		0.0000	1.0000	95.52
37.5	895,551		0.0000	1.0000	95.52
38.5	895,551		0.0000	1.0000	95.52

NORTHWEST NATURAL GAS COMPANY

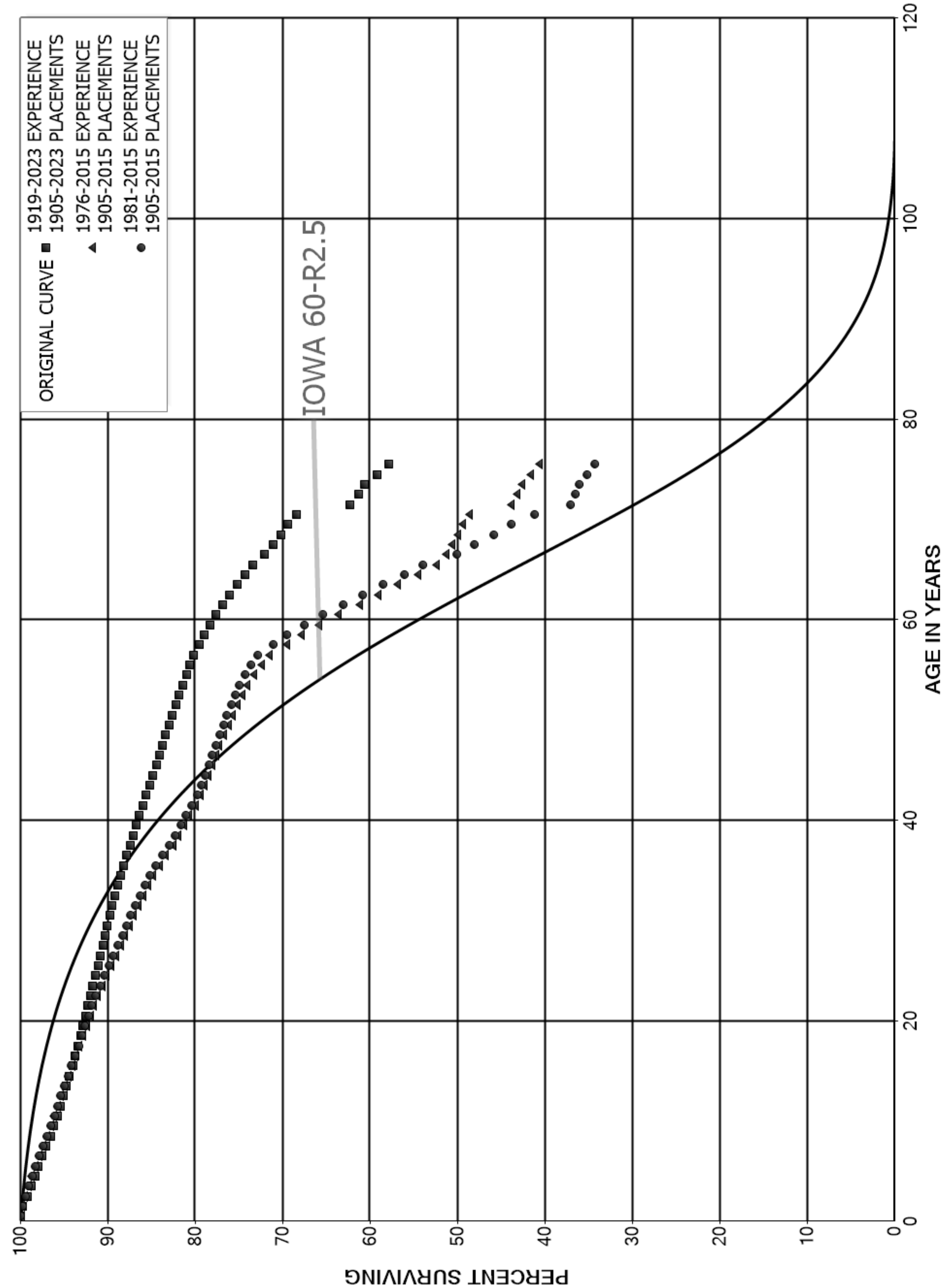
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	866,500		0.0000	1.0000	95.52
40.5	859,527		0.0000	1.0000	95.52
41.5	830,451		0.0000	1.0000	95.52
42.5	793,737		0.0000	1.0000	95.52
43.5	696,182		0.0000	1.0000	95.52
44.5	696,182		0.0000	1.0000	95.52
45.5	696,182		0.0000	1.0000	95.52
46.5	648,984		0.0000	1.0000	95.52
47.5	629,219		0.0000	1.0000	95.52
48.5	617,455		0.0000	1.0000	95.52
49.5	608,726		0.0000	1.0000	95.52
50.5	580,682		0.0000	1.0000	95.52
51.5	495,890		0.0000	1.0000	95.52
52.5	466,037		0.0000	1.0000	95.52
53.5	456,050		0.0000	1.0000	95.52
54.5	420,982		0.0000	1.0000	95.52
55.5	408,617		0.0000	1.0000	95.52
56.5	400,659		0.0000	1.0000	95.52
57.5	380,063		0.0000	1.0000	95.52
58.5	323,399		0.0000	1.0000	95.52
59.5	259,255		0.0000	1.0000	95.52
60.5	241,009		0.0000	1.0000	95.52
61.5	232,890		0.0000	1.0000	95.52
62.5	223,874		0.0000	1.0000	95.52
63.5	97,566		0.0000	1.0000	95.52
64.5	97,426		0.0000	1.0000	95.52
65.5	90,855		0.0000	1.0000	95.52
66.5	90,440		0.0000	1.0000	95.52
67.5					95.52

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 380.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,071,935,044	1,042,465	0.0010	0.9990	100.00
0.5	1,024,432,762	2,348,906	0.0023	0.9977	99.90
1.5	981,212,325	4,568,417	0.0047	0.9953	99.67
2.5	932,992,695	4,342,737	0.0047	0.9953	99.21
3.5	890,168,864	3,689,532	0.0041	0.9959	98.75
4.5	847,557,834	3,365,978	0.0040	0.9960	98.34
5.5	810,714,221	3,634,585	0.0045	0.9955	97.95
6.5	775,307,803	3,867,851	0.0050	0.9950	97.51
7.5	742,295,182	3,610,865	0.0049	0.9951	97.02
8.5	713,806,792	2,973,769	0.0042	0.9958	96.55
9.5	683,891,469	2,644,703	0.0039	0.9961	96.15
10.5	656,782,462	2,412,969	0.0037	0.9963	95.78
11.5	636,163,883	2,276,060	0.0036	0.9964	95.42
12.5	617,840,941	2,261,124	0.0037	0.9963	95.08
13.5	605,102,265	2,522,848	0.0042	0.9958	94.74
14.5	582,901,137	2,094,086	0.0036	0.9964	94.34
15.5	561,300,730	1,927,742	0.0034	0.9966	94.00
16.5	539,591,542	1,802,999	0.0033	0.9967	93.68
17.5	515,211,854	1,577,710	0.0031	0.9969	93.37
18.5	492,079,828	1,557,474	0.0032	0.9968	93.08
19.5	467,010,641	1,407,269	0.0030	0.9970	92.78
20.5	440,456,833	1,240,691	0.0028	0.9972	92.51
21.5	415,073,197	1,147,094	0.0028	0.9972	92.24
22.5	390,910,953	1,344,230	0.0034	0.9966	91.99
23.5	366,779,400	1,069,049	0.0029	0.9971	91.67
24.5	339,590,484	1,145,411	0.0034	0.9966	91.41
25.5	314,521,556	974,845	0.0031	0.9969	91.10
26.5	288,702,622	844,854	0.0029	0.9971	90.82
27.5	264,970,453	806,619	0.0030	0.9970	90.55
28.5	244,034,441	695,856	0.0029	0.9971	90.27
29.5	221,540,066	656,325	0.0030	0.9970	90.02
30.5	199,472,386	608,915	0.0031	0.9969	89.75
31.5	179,602,086	611,957	0.0034	0.9966	89.48
32.5	160,407,653	560,116	0.0035	0.9965	89.17
33.5	142,783,859	517,171	0.0036	0.9964	88.86
34.5	127,301,271	525,792	0.0041	0.9959	88.54
35.5	115,416,970	513,449	0.0044	0.9956	88.17
36.5	104,843,853	497,945	0.0047	0.9953	87.78
37.5	94,680,461	365,423	0.0039	0.9961	87.36
38.5	84,283,555	331,118	0.0039	0.9961	87.03

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	75,672,762	264,550	0.0035	0.9965	86.68
40.5	68,973,892	319,288	0.0046	0.9954	86.38
41.5	62,821,116	265,074	0.0042	0.9958	85.98
42.5	55,286,386	297,340	0.0054	0.9946	85.62
43.5	47,940,334	199,379	0.0042	0.9958	85.16
44.5	42,061,498	182,879	0.0043	0.9957	84.80
45.5	37,288,922	167,822	0.0045	0.9955	84.44
46.5	33,923,653	132,593	0.0039	0.9961	84.06
47.5	31,101,110	133,939	0.0043	0.9957	83.73
48.5	28,817,519	139,440	0.0048	0.9952	83.37
49.5	26,340,722	114,287	0.0043	0.9957	82.96
50.5	23,558,731	112,133	0.0048	0.9952	82.60
51.5	20,922,828	98,874	0.0047	0.9953	82.21
52.5	18,566,445	85,635	0.0046	0.9954	81.82
53.5	16,494,680	88,128	0.0053	0.9947	81.44
54.5	14,449,858	78,961	0.0055	0.9945	81.01
55.5	12,677,145	68,011	0.0054	0.9946	80.57
56.5	11,015,252	89,897	0.0082	0.9918	80.13
57.5	9,346,785	68,019	0.0073	0.9927	79.48
58.5	7,920,229	67,299	0.0085	0.9915	78.90
59.5	6,702,979	51,179	0.0076	0.9924	78.23
60.5	5,707,911	55,641	0.0097	0.9903	77.63
61.5	4,871,433	48,915	0.0100	0.9900	76.88
62.5	4,095,848	47,336	0.0116	0.9884	76.10
63.5	3,419,366	43,691	0.0128	0.9872	75.23
64.5	3,108,567	36,786	0.0118	0.9882	74.26
65.5	3,033,059	55,106	0.0182	0.9818	73.39
66.5	2,774,139	36,273	0.0131	0.9869	72.05
67.5	2,516,291	32,839	0.0131	0.9869	71.11
68.5	2,468,359	29,497	0.0119	0.9881	70.18
69.5	2,425,416	33,744	0.0139	0.9861	69.34
70.5	2,312,532	206,564	0.0893	0.9107	68.38
71.5	2,092,827	33,791	0.0161	0.9839	62.27
72.5	2,007,939	22,736	0.0113	0.9887	61.27
73.5	1,964,340	45,426	0.0231	0.9769	60.57
74.5	1,894,971	41,322	0.0218	0.9782	59.17
75.5	428,582	14,122	0.0330	0.9670	57.88
76.5	378,922	17,652	0.0466	0.9534	55.97
77.5	314,346	11,374	0.0362	0.9638	53.37
78.5	280,533	8,791	0.0313	0.9687	51.43

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	253,766	6,055	0.0239	0.9761	49.82
80.5	242,558	6,563	0.0271	0.9729	48.63
81.5	214,036	6,898	0.0322	0.9678	47.32
82.5	192,310	6,847	0.0356	0.9644	45.79
83.5	172,665	3,716	0.0215	0.9785	44.16
84.5	150,642	3,809	0.0253	0.9747	43.21
85.5	132,410	3,930	0.0297	0.9703	42.12
86.5	119,967	2,471	0.0206	0.9794	40.87
87.5	111,701	1,298	0.0116	0.9884	40.03
88.5	107,133	1,377	0.0129	0.9871	39.56
89.5	102,538	809	0.0079	0.9921	39.05
90.5	99,370	17,363	0.1747	0.8253	38.75
91.5	74,566	3,756	0.0504	0.9496	31.98
92.5	58,925	1,691	0.0287	0.9713	30.36
93.5	52,665	2,161	0.0410	0.9590	29.49
94.5	46,458	4,384	0.0944	0.9056	28.28
95.5	39,313	1,449	0.0369	0.9631	25.61
96.5	37,720	625	0.0166	0.9834	24.67
97.5	32,522	423	0.0130	0.9870	24.26
98.5	24,243	428	0.0176	0.9824	23.95
99.5	18,386	570	0.0310	0.9690	23.52
100.5	16,521	489	0.0296	0.9704	22.79
101.5	15,286	447	0.0292	0.9708	22.12
102.5	14,923	256	0.0172	0.9828	21.47
103.5	12,205	328	0.0269	0.9731	21.11
104.5	9,639	239	0.0248	0.9752	20.54
105.5	7,736	109	0.0141	0.9859	20.03
106.5	7,627	321	0.0421	0.9579	19.75
107.5	7,306	104	0.0143	0.9857	18.92
108.5	7,194	95	0.0132	0.9868	18.65
109.5	6,937	95	0.0137	0.9863	18.40
110.5	6,818	29	0.0043	0.9957	18.15
111.5	5,683	38	0.0066	0.9934	18.07
112.5	5,646	0	0.0000	1.0000	17.95
113.5	2,838	22	0.0077	0.9923	17.95
114.5	2,763		0.0000	1.0000	17.81
115.5	1,588	19	0.0118	0.9882	17.81
116.5	1,569	45	0.0284	0.9716	17.60
117.5	1,392		0.0000	1.0000	17.10
118.5					17.10

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	719,096,775	568,357	0.0008	0.9992	100.00
0.5	693,643,292	1,319,582	0.0019	0.9981	99.92
1.5	667,462,905	2,325,246	0.0035	0.9965	99.73
2.5	643,364,245	2,426,756	0.0038	0.9962	99.38
3.5	625,125,686	2,497,748	0.0040	0.9960	99.01
4.5	609,123,532	2,472,689	0.0041	0.9959	98.61
5.5	598,723,462	2,659,992	0.0044	0.9956	98.21
6.5	578,494,534	2,715,397	0.0047	0.9953	97.78
7.5	557,994,341	2,676,125	0.0048	0.9952	97.32
8.5	537,545,260	2,410,751	0.0045	0.9955	96.85
9.5	514,495,328	2,077,535	0.0040	0.9960	96.42
10.5	492,436,156	1,938,105	0.0039	0.9961	96.03
11.5	468,676,863	1,885,282	0.0040	0.9960	95.65
12.5	442,867,326	1,821,114	0.0041	0.9959	95.26
13.5	418,275,210	2,121,702	0.0051	0.9949	94.87
14.5	394,205,527	1,696,741	0.0043	0.9957	94.39
15.5	370,573,726	1,634,305	0.0044	0.9956	93.99
16.5	343,550,694	1,579,612	0.0046	0.9954	93.57
17.5	318,443,478	1,352,378	0.0042	0.9958	93.14
18.5	292,656,096	1,372,112	0.0047	0.9953	92.74
19.5	268,738,218	1,226,661	0.0046	0.9954	92.31
20.5	247,325,684	1,104,720	0.0045	0.9955	91.89
21.5	224,300,630	1,026,199	0.0046	0.9954	91.48
22.5	201,968,171	1,221,880	0.0060	0.9940	91.06
23.5	181,633,202	924,927	0.0051	0.9949	90.51
24.5	162,206,271	1,038,777	0.0064	0.9936	90.05
25.5	144,233,499	849,065	0.0059	0.9941	89.47
26.5	128,475,042	722,228	0.0056	0.9944	88.94
27.5	116,388,458	688,326	0.0059	0.9941	88.44
28.5	105,767,470	602,401	0.0057	0.9943	87.92
29.5	95,638,161	545,296	0.0057	0.9943	87.42
30.5	85,040,072	514,671	0.0061	0.9939	86.92
31.5	76,220,574	508,309	0.0067	0.9933	86.40
32.5	69,258,973	453,214	0.0065	0.9935	85.82
33.5	62,967,415	423,259	0.0067	0.9933	85.26
34.5	55,241,506	444,813	0.0081	0.9919	84.69
35.5	47,620,517	420,601	0.0088	0.9912	84.00
36.5	41,432,905	414,302	0.0100	0.9900	83.26
37.5	36,357,672	284,751	0.0078	0.9922	82.43
38.5	32,805,062	256,538	0.0078	0.9922	81.78

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,832,670	197,897	0.0066	0.9934	81.14
40.5	27,443,601	250,055	0.0091	0.9909	80.61
41.5	24,781,775	185,983	0.0075	0.9925	79.87
42.5	21,867,977	128,482	0.0059	0.9941	79.27
43.5	19,177,416	103,663	0.0054	0.9946	78.81
44.5	16,786,612	95,564	0.0057	0.9943	78.38
45.5	14,669,601	72,396	0.0049	0.9951	77.93
46.5	12,638,806	69,320	0.0055	0.9945	77.55
47.5	10,847,116	74,557	0.0069	0.9931	77.12
48.5	9,176,584	60,559	0.0066	0.9934	76.59
49.5	7,523,018	41,650	0.0055	0.9945	76.09
50.5	6,134,297	48,594	0.0079	0.9921	75.67
51.5	4,955,088	37,454	0.0076	0.9924	75.07
52.5	3,986,339	29,080	0.0073	0.9927	74.50
53.5	3,188,815	33,901	0.0106	0.9894	73.96
54.5	2,435,730	28,099	0.0115	0.9885	73.17
55.5	1,793,195	23,591	0.0132	0.9868	72.33
56.5	1,508,170	40,874	0.0271	0.9729	71.37
57.5	1,421,983	34,434	0.0242	0.9758	69.44
58.5	1,200,808	36,150	0.0301	0.9699	67.76
59.5	955,749	32,807	0.0343	0.9657	65.72
60.5	927,214	35,142	0.0379	0.9621	63.46
61.5	894,281	31,566	0.0353	0.9647	61.06
62.5	801,115	30,164	0.0377	0.9623	58.90
63.5	781,043	31,842	0.0408	0.9592	56.68
64.5	737,356	27,775	0.0377	0.9623	54.37
65.5	2,392,368	50,900	0.0213	0.9787	52.33
66.5	2,314,924	32,520	0.0140	0.9860	51.21
67.5	2,264,280	29,278	0.0129	0.9871	50.49
68.5	2,197,548	26,661	0.0121	0.9879	49.84
69.5	2,122,871	30,528	0.0144	0.9856	49.24
70.5	2,071,068	203,366	0.0982	0.9018	48.53
71.5	1,848,813	30,648	0.0166	0.9834	43.76
72.5	1,812,315	21,566	0.0119	0.9881	43.04
73.5	1,768,069	44,121	0.0250	0.9750	42.52
74.5	1,708,247	40,134	0.0235	0.9765	41.46
75.5	246,980	13,166	0.0533	0.9467	40.49
76.5	214,880	16,696	0.0777	0.9223	38.33
77.5	183,078	10,462	0.0571	0.9429	35.35
78.5	163,392	7,944	0.0486	0.9514	33.33

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	148,900	5,202	0.0349	0.9651	31.71
80.5	135,883	5,854	0.0431	0.9569	30.60
81.5	126,087	6,306	0.0500	0.9500	29.29
82.5	116,236	6,129	0.0527	0.9473	27.82
83.5	101,396	2,918	0.0288	0.9712	26.35
84.5	85,647	2,997	0.0350	0.9650	25.60
85.5	78,080	3,258	0.0417	0.9583	24.70
86.5	70,775	1,731	0.0245	0.9755	23.67
87.5	66,283	865	0.0130	0.9870	23.09
88.5	68,138	540	0.0079	0.9921	22.79
89.5	63,091	457	0.0072	0.9928	22.61
90.5	54,906	17,083	0.3111	0.6889	22.44
91.5	31,736	3,288	0.1036	0.8964	15.46
92.5	27,236	1,630	0.0599	0.9401	13.86
93.5	24,244	1,781	0.0734	0.9266	13.03
94.5	22,463	4,059	0.1807	0.8193	12.07
95.5	15,942	1,251	0.0785	0.9215	9.89
96.5	12,453	452	0.0363	0.9637	9.11
97.5	10,337	298	0.0288	0.9712	8.78
98.5	9,751	184	0.0188	0.9812	8.53
99.5	9,567	308	0.0321	0.9679	8.37
100.5	9,224	411	0.0445	0.9555	8.10
101.5	7,840	191	0.0244	0.9756	7.74
102.5	7,697	130	0.0169	0.9831	7.55
103.5	5,978	60	0.0100	0.9900	7.42
104.5	5,918	98	0.0165	0.9835	7.35
105.5	3,013		0.0000	1.0000	7.23
106.5	2,960	37	0.0125	0.9875	7.23
107.5	1,748	29	0.0165	0.9835	7.14
108.5	1,719		0.0000	1.0000	7.02
109.5	1,586	42	0.0267	0.9733	7.02
110.5					6.83

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	686,602,942	542,260	0.0008	0.9992	100.00
0.5	668,187,342	1,198,907	0.0018	0.9982	99.92
1.5	647,207,319	2,207,430	0.0034	0.9966	99.74
2.5	625,622,703	2,316,964	0.0037	0.9963	99.40
3.5	608,456,016	2,372,717	0.0039	0.9961	99.03
4.5	592,797,930	2,362,113	0.0040	0.9960	98.65
5.5	582,396,162	2,553,511	0.0044	0.9956	98.25
6.5	562,477,048	2,590,122	0.0046	0.9954	97.82
7.5	543,019,857	2,562,331	0.0047	0.9953	97.37
8.5	523,620,964	2,283,982	0.0044	0.9956	96.91
9.5	501,463,771	1,941,815	0.0039	0.9961	96.49
10.5	480,425,163	1,811,030	0.0038	0.9962	96.12
11.5	457,681,082	1,780,290	0.0039	0.9961	95.75
12.5	432,681,533	1,704,342	0.0039	0.9961	95.38
13.5	408,990,101	2,020,634	0.0049	0.9951	95.01
14.5	386,058,077	1,590,604	0.0041	0.9959	94.54
15.5	363,367,593	1,537,152	0.0042	0.9958	94.15
16.5	337,367,298	1,481,259	0.0044	0.9956	93.75
17.5	313,320,573	1,247,938	0.0040	0.9960	93.34
18.5	288,386,285	1,253,541	0.0043	0.9957	92.97
19.5	265,215,598	1,120,376	0.0042	0.9958	92.56
20.5	244,766,074	998,169	0.0041	0.9959	92.17
21.5	222,582,263	944,564	0.0042	0.9958	91.80
22.5	200,626,816	1,165,841	0.0058	0.9942	91.41
23.5	180,781,649	883,816	0.0049	0.9951	90.87
24.5	161,703,056	1,014,244	0.0063	0.9937	90.43
25.5	143,778,265	831,854	0.0058	0.9942	89.86
26.5	128,004,451	709,855	0.0055	0.9945	89.34
27.5	116,042,901	674,775	0.0058	0.9942	88.85
28.5	105,368,368	590,960	0.0056	0.9944	88.33
29.5	95,219,974	528,938	0.0056	0.9944	87.84
30.5	84,657,724	501,044	0.0059	0.9941	87.35
31.5	75,867,986	493,394	0.0065	0.9935	86.83
32.5	68,947,897	439,817	0.0064	0.9936	86.27
33.5	62,734,300	415,526	0.0066	0.9934	85.72
34.5	55,080,825	439,451	0.0080	0.9920	85.15
35.5	47,479,873	416,417	0.0088	0.9912	84.47
36.5	41,296,661	409,003	0.0099	0.9901	83.73
37.5	36,210,560	280,506	0.0077	0.9923	82.90
38.5	32,667,662	251,837	0.0077	0.9923	82.26

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,709,946	194,129	0.0065	0.9935	81.62
40.5	27,330,959	246,768	0.0090	0.9910	81.09
41.5	24,687,054	183,530	0.0074	0.9926	80.36
42.5	21,791,058	125,974	0.0058	0.9942	79.76
43.5	19,101,966	101,311	0.0053	0.9947	79.30
44.5	16,689,351	93,191	0.0056	0.9944	78.88
45.5	14,564,135	68,550	0.0047	0.9953	78.44
46.5	12,499,424	64,199	0.0051	0.9949	78.07
47.5	10,684,886	69,133	0.0065	0.9935	77.67
48.5	8,992,785	52,655	0.0059	0.9941	77.16
49.5	7,342,051	34,146	0.0047	0.9953	76.71
50.5	5,926,026	40,529	0.0068	0.9932	76.36
51.5	4,739,823	28,844	0.0061	0.9939	75.83
52.5	3,769,650	21,572	0.0057	0.9943	75.37
53.5	2,975,750	25,547	0.0086	0.9914	74.94
54.5	2,234,831	21,145	0.0095	0.9905	74.30
55.5	1,618,723	16,832	0.0104	0.9896	73.59
56.5	1,372,115	34,170	0.0249	0.9751	72.83
57.5	1,321,330	29,062	0.0220	0.9780	71.02
58.5	1,120,211	30,889	0.0276	0.9724	69.45
59.5	895,884	29,028	0.0324	0.9676	67.54
60.5	869,361	31,128	0.0358	0.9642	65.35
61.5	836,293	29,542	0.0353	0.9647	63.01
62.5	725,188	27,505	0.0379	0.9621	60.78
63.5	701,399	28,590	0.0408	0.9592	58.48
64.5	626,729	23,899	0.0381	0.9619	56.10
65.5	598,637	42,722	0.0714	0.9286	53.96
66.5	542,061	22,547	0.0416	0.9584	50.11
67.5	517,559	23,303	0.0450	0.9550	48.02
68.5	473,800	21,434	0.0452	0.9548	45.86
69.5	438,965	26,494	0.0604	0.9396	43.78
70.5	2,067,501	203,366	0.0984	0.9016	41.14
71.5	1,845,299	30,648	0.0166	0.9834	37.10
72.5	1,809,976	21,566	0.0119	0.9881	36.48
73.5	1,765,730	44,121	0.0250	0.9750	36.04
74.5	1,706,098	40,134	0.0235	0.9765	35.14
75.5	246,980	13,166	0.0533	0.9467	34.32
76.5	214,880	16,696	0.0777	0.9223	32.49
77.5	183,078	10,462	0.0571	0.9429	29.96
78.5	163,392	7,944	0.0486	0.9514	28.25

NORTHWEST NATURAL GAS COMPANY

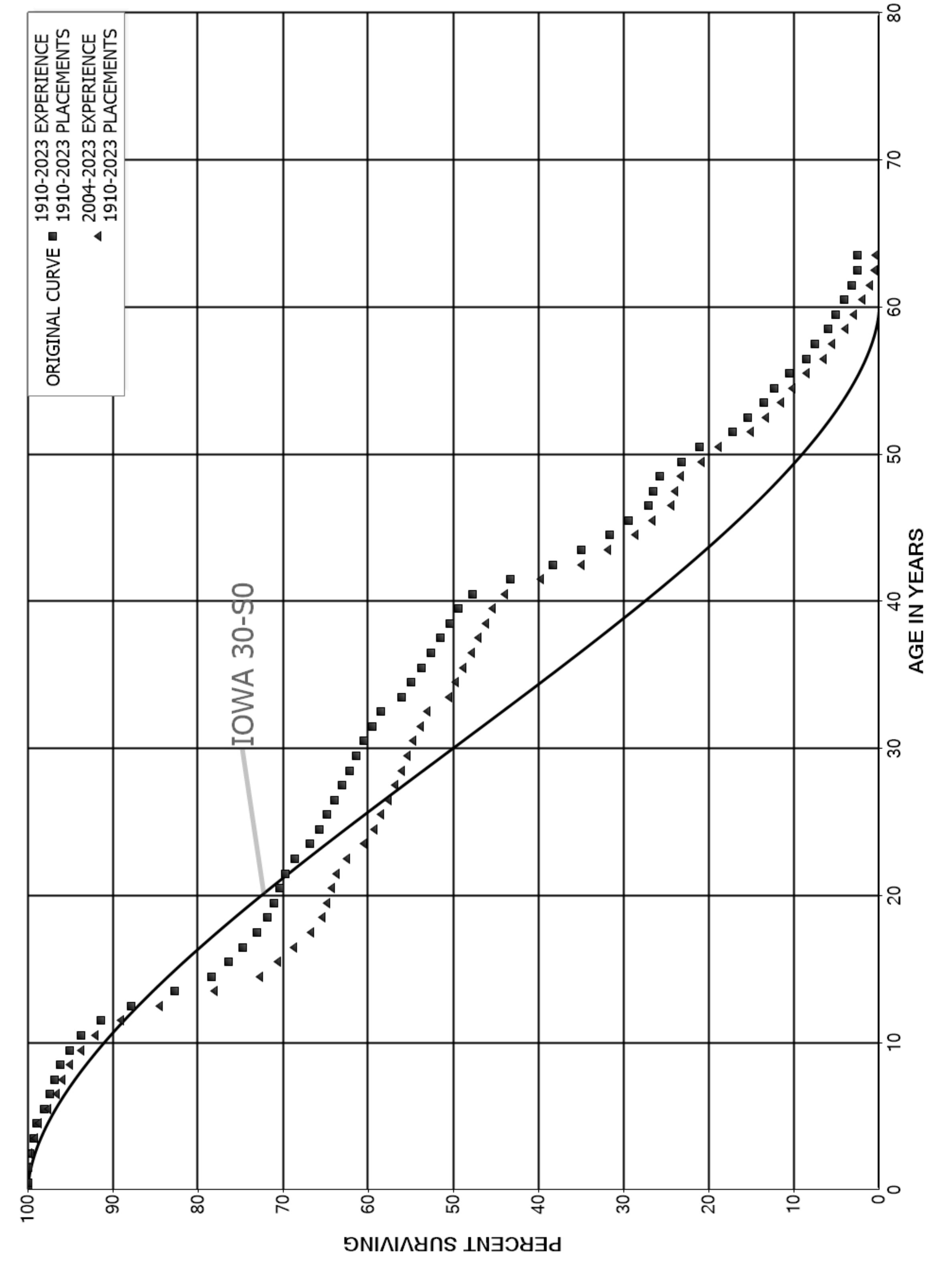
ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	148,900	5,202	0.0349	0.9651	26.88
80.5	135,883	5,854	0.0431	0.9569	25.94
81.5	126,087	6,306	0.0500	0.9500	24.82
82.5	116,236	6,129	0.0527	0.9473	23.58
83.5	101,396	2,918	0.0288	0.9712	22.34
84.5	85,647	2,997	0.0350	0.9650	21.69
85.5	78,080	3,258	0.0417	0.9583	20.93
86.5	70,775	1,731	0.0245	0.9755	20.06
87.5	66,283	865	0.0130	0.9870	19.57
88.5	68,138	540	0.0079	0.9921	19.31
89.5	63,091	457	0.0072	0.9928	19.16
90.5	54,906	17,083	0.3111	0.6889	19.02
91.5	31,736	3,288	0.1036	0.8964	13.10
92.5	27,236	1,630	0.0599	0.9401	11.75
93.5	24,244	1,781	0.0734	0.9266	11.04
94.5	22,463	4,059	0.1807	0.8193	10.23
95.5	15,942	1,251	0.0785	0.9215	8.38
96.5	12,453	452	0.0363	0.9637	7.73
97.5	10,337	298	0.0288	0.9712	7.44
98.5	9,751	184	0.0188	0.9812	7.23
99.5	9,567	308	0.0321	0.9679	7.09
100.5	9,224	411	0.0445	0.9555	6.87
101.5	7,840	191	0.0244	0.9756	6.56
102.5	7,697	130	0.0169	0.9831	6.40
103.5	5,978	60	0.0100	0.9900	6.29
104.5	5,918	98	0.0165	0.9835	6.23
105.5	3,013		0.0000	1.0000	6.13
106.5	2,960	37	0.0125	0.9875	6.13
107.5	1,748	29	0.0165	0.9835	6.05
108.5	1,719		0.0000	1.0000	5.95
109.5	1,586	42	0.0267	0.9733	5.95
110.5					5.79

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	149,428,158	12,947	0.0001	0.9999	100.00
0.5	144,558,717	38,641	0.0003	0.9997	99.99
1.5	140,718,243	286,740	0.0020	0.9980	99.96
2.5	111,169,196	501,548	0.0045	0.9955	99.76
3.5	108,232,797	372,295	0.0034	0.9966	99.31
4.5	103,043,446	929,182	0.0090	0.9910	98.97
5.5	97,538,536	722,128	0.0074	0.9926	98.08
6.5	90,619,372	518,235	0.0057	0.9943	97.35
7.5	90,124,979	614,229	0.0068	0.9932	96.79
8.5	86,424,115	947,386	0.0110	0.9890	96.13
9.5	82,623,284	1,152,351	0.0139	0.9861	95.08
10.5	77,935,757	1,973,473	0.0253	0.9747	93.75
11.5	70,980,811	2,756,415	0.0388	0.9612	91.38
12.5	68,333,755	3,999,415	0.0585	0.9415	87.83
13.5	64,471,958	3,389,223	0.0526	0.9474	82.69
14.5	60,776,723	1,491,303	0.0245	0.9755	78.34
15.5	55,389,889	1,225,363	0.0221	0.9779	76.42
16.5	49,286,137	1,113,923	0.0226	0.9774	74.73
17.5	41,805,028	712,672	0.0170	0.9830	73.04
18.5	40,834,314	408,418	0.0100	0.9900	71.80
19.5	37,558,242	348,691	0.0093	0.9907	71.08
20.5	34,455,337	334,634	0.0097	0.9903	70.42
21.5	32,243,854	503,712	0.0156	0.9844	69.74
22.5	29,953,885	772,505	0.0258	0.9742	68.65
23.5	27,927,421	466,441	0.0167	0.9833	66.88
24.5	26,099,496	368,089	0.0141	0.9859	65.76
25.5	24,406,461	340,210	0.0139	0.9861	64.83
26.5	22,843,947	325,911	0.0143	0.9857	63.93
27.5	21,328,738	276,230	0.0130	0.9870	63.02
28.5	19,890,108	262,123	0.0132	0.9868	62.20
29.5	18,576,734	257,771	0.0139	0.9861	61.38
30.5	17,271,793	296,931	0.0172	0.9828	60.53
31.5	15,846,039	274,336	0.0173	0.9827	59.49
32.5	14,946,340	624,510	0.0418	0.9582	58.46
33.5	13,128,703	251,826	0.0192	0.9808	56.01
34.5	12,141,364	262,755	0.0216	0.9784	54.94
35.5	11,399,424	249,124	0.0219	0.9781	53.75
36.5	11,125,140	227,916	0.0205	0.9795	52.58
37.5	10,150,896	209,028	0.0206	0.9794	51.50
38.5	9,588,490	206,244	0.0215	0.9785	50.44

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,148,552	311,607	0.0341	0.9659	49.35
40.5	8,786,349	802,075	0.0913	0.9087	47.67
41.5	8,021,426	923,765	0.1152	0.8848	43.32
42.5	7,131,457	626,284	0.0878	0.9122	38.33
43.5	6,540,908	631,063	0.0965	0.9035	34.97
44.5	5,932,081	410,645	0.0692	0.9308	31.59
45.5	5,542,802	432,447	0.0780	0.9220	29.41
46.5	5,129,086	116,672	0.0227	0.9773	27.11
47.5	5,031,421	144,653	0.0287	0.9713	26.49
48.5	4,904,365	484,255	0.0987	0.9013	25.73
49.5	4,435,341	411,437	0.0928	0.9072	23.19
50.5	4,035,514	742,192	0.1839	0.8161	21.04
51.5	3,305,065	340,874	0.1031	0.8969	17.17
52.5	2,971,449	359,925	0.1211	0.8789	15.40
53.5	2,614,668	248,151	0.0949	0.9051	13.53
54.5	2,369,222	335,434	0.1416	0.8584	12.25
55.5	2,036,143	384,334	0.1888	0.8112	10.52
56.5	1,657,897	200,168	0.1207	0.8793	8.53
57.5	1,459,377	291,512	0.1998	0.8002	7.50
58.5	1,169,340	193,116	0.1651	0.8349	6.00
59.5	977,179	187,455	0.1918	0.8082	5.01
60.5	790,331	174,158	0.2204	0.7796	4.05
61.5	616,249	119,367	0.1937	0.8063	3.16
62.5	497,009	7,787	0.0157	0.9843	2.55
63.5	489,281	684	0.0014	0.9986	2.51
64.5	488,597	14,217	0.0291	0.9709	2.50
65.5	474,415	21,788	0.0459	0.9541	2.43
66.5	452,627	19,625	0.0434	0.9566	2.32
67.5	433,002	955	0.0022	0.9978	2.22
68.5	432,123	341	0.0008	0.9992	2.21
69.5	431,817	566	0.0013	0.9987	2.21
70.5	431,251	12,934	0.0300	0.9700	2.21
71.5	418,317	138	0.0003	0.9997	2.14
72.5	404,592	168	0.0004	0.9996	2.14
73.5	404,424	2,962	0.0073	0.9927	2.14
74.5	401,462	173	0.0004	0.9996	2.12
75.5	131,182	1,350	0.0103	0.9897	2.12
76.5	129,832	1,838	0.0142	0.9858	2.10
77.5	127,994	649	0.0051	0.9949	2.07
78.5	127,345	8	0.0001	0.9999	2.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	127,337	30	0.0002	0.9998	2.06
80.5	127,307	377	0.0030	0.9970	2.06
81.5	126,930	2,255	0.0178	0.9822	2.05
82.5	124,675		0.0000	1.0000	2.02
83.5	124,675	2,534	0.0203	0.9797	2.02
84.5	122,141		0.0000	1.0000	1.98
85.5	122,141		0.0000	1.0000	1.98
86.5	122,141		0.0000	1.0000	1.98
87.5	122,141		0.0000	1.0000	1.98
88.5	122,141		0.0000	1.0000	1.98
89.5	122,141	87	0.0007	0.9993	1.98
90.5	122,054	148	0.0012	0.9988	1.98
91.5	121,906	320	0.0026	0.9974	1.97
92.5	121,585	1,451	0.0119	0.9881	1.97
93.5	120,134	1,246	0.0104	0.9896	1.94
94.5	118,888	1,739	0.0146	0.9854	1.92
95.5	117,149	3,869	0.0330	0.9670	1.90
96.5	113,280	9,143	0.0807	0.9193	1.83
97.5	104,137	6,898	0.0662	0.9338	1.69
98.5	97,239	2,496	0.0257	0.9743	1.57
99.5	94,743	2,878	0.0304	0.9696	1.53
100.5	91,864	1,720	0.0187	0.9813	1.49
101.5	90,145	1,660	0.0184	0.9816	1.46
102.5	88,485	2,410	0.0272	0.9728	1.43
103.5	86,075	2,640	0.0307	0.9693	1.39
104.5	83,436	1,770	0.0212	0.9788	1.35
105.5	81,666	1,380	0.0169	0.9831	1.32
106.5	80,286	2,030	0.0253	0.9747	1.30
107.5	78,256	1,800	0.0230	0.9770	1.27
108.5	76,456	1,630	0.0213	0.9787	1.24
109.5	74,826	6,630	0.0886	0.9114	1.21
110.5	68,196	2,180	0.0320	0.9680	1.10
111.5	66,016	1,590	0.0241	0.9759	1.07
112.5	64,426	64,426	1.0000		1.04
113.5					

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	107,226,344	76	0.0000	1.0000	100.00
0.5	106,202,970	21,898	0.0002	0.9998	100.00
1.5	104,435,115	268,352	0.0026	0.9974	99.98
2.5	76,931,232	476,124	0.0062	0.9938	99.72
3.5	75,637,222	334,825	0.0044	0.9956	99.11
4.5	72,215,678	862,715	0.0119	0.9881	98.67
5.5	68,324,379	688,269	0.0101	0.9899	97.49
6.5	63,401,496	453,238	0.0071	0.9929	96.51
7.5	64,480,550	551,029	0.0085	0.9915	95.82
8.5	62,298,076	884,427	0.0142	0.9858	95.00
9.5	59,742,491	1,069,422	0.0179	0.9821	93.65
10.5	56,465,285	1,847,270	0.0327	0.9673	91.97
11.5	50,884,506	2,586,072	0.0508	0.9492	88.96
12.5	49,497,743	3,805,234	0.0769	0.9231	84.44
13.5	46,950,305	3,198,204	0.0681	0.9319	77.95
14.5	44,188,877	1,307,134	0.0296	0.9704	72.64
15.5	39,518,396	1,074,609	0.0272	0.9728	70.49
16.5	33,862,944	963,233	0.0284	0.9716	68.57
17.5	27,309,121	535,508	0.0196	0.9804	66.62
18.5	27,126,843	238,226	0.0088	0.9912	65.32
19.5	24,420,312	224,263	0.0092	0.9908	64.74
20.5	21,664,331	182,813	0.0084	0.9916	64.15
21.5	20,343,417	371,575	0.0183	0.9817	63.61
22.5	19,213,560	630,497	0.0328	0.9672	62.45
23.5	17,967,240	356,400	0.0198	0.9802	60.40
24.5	16,892,186	243,933	0.0144	0.9856	59.20
25.5	15,699,043	216,313	0.0138	0.9862	58.34
26.5	14,628,396	216,629	0.0148	0.9852	57.54
27.5	13,510,255	167,645	0.0124	0.9876	56.69
28.5	12,323,498	155,555	0.0126	0.9874	55.98
29.5	11,787,370	145,521	0.0123	0.9877	55.28
30.5	11,084,371	187,496	0.0169	0.9831	54.60
31.5	10,549,200	132,332	0.0125	0.9875	53.67
32.5	10,358,507	513,676	0.0496	0.9504	53.00
33.5	9,068,859	134,452	0.0148	0.9852	50.37
34.5	8,559,817	159,779	0.0187	0.9813	49.62
35.5	8,286,583	160,875	0.0194	0.9806	48.70
36.5	8,499,660	139,438	0.0164	0.9836	47.75
37.5	7,942,258	145,828	0.0184	0.9816	46.97
38.5	7,826,422	139,021	0.0178	0.9822	46.11

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,771,549	252,606	0.0325	0.9675	45.29
40.5	7,748,346	742,484	0.0958	0.9042	43.82
41.5	7,244,445	876,535	0.1210	0.8790	39.62
42.5	6,557,668	585,351	0.0893	0.9107	34.82
43.5	5,989,925	604,398	0.1009	0.8991	31.72
44.5	5,398,634	387,190	0.0717	0.9283	28.51
45.5	5,032,229	412,312	0.0819	0.9181	26.47
46.5	4,641,505	95,508	0.0206	0.9794	24.30
47.5	4,572,995	125,048	0.0273	0.9727	23.80
48.5	4,448,762	465,810	0.1047	0.8953	23.15
49.5	3,983,278	395,033	0.0992	0.9008	20.73
50.5	3,588,811	725,940	0.2023	0.7977	18.67
51.5	2,863,252	329,242	0.1150	0.8850	14.89
52.5	2,534,076	353,381	0.1395	0.8605	13.18
53.5	2,180,854	243,214	0.1115	0.8885	11.34
54.5	1,937,640	331,477	0.1711	0.8289	10.08
55.5	1,606,337	377,811	0.2352	0.7648	8.35
56.5	1,229,260	198,911	0.1618	0.8382	6.39
57.5	1,032,116	290,738	0.2817	0.7183	5.36
58.5	742,058	192,611	0.2596	0.7404	3.85
59.5	550,096	187,074	0.3401	0.6599	2.85
60.5	363,204	174,006	0.4791	0.5209	1.88
61.5	189,304	119,201	0.6297	0.3703	0.98
62.5	70,340	7,645	0.1087	0.8913	0.36
63.5	65,056	609	0.0094	0.9906	0.32
64.5	64,481	14,158	0.2196	0.7804	0.32
65.5	50,323	21,733	0.4319	0.5681	0.25
66.5	28,624	19,548	0.6829	0.3171	0.14
67.5	9,076	869	0.0957	0.9043	0.05
68.5	8,207	326	0.0397	0.9603	0.04
69.5	7,881	566	0.0718	0.9282	0.04
70.5	7,315	381	0.0521	0.9479	0.04
71.5	6,934	66	0.0095	0.9905	0.03
72.5	6,955	160	0.0230	0.9770	0.03
73.5	6,795		0.0000	1.0000	0.03
74.5	7,135	173	0.0242	0.9758	0.03
75.5	6,962	1,344	0.1930	0.8070	0.03
76.5	6,071	1,838	0.3028	0.6972	0.03
77.5	4,943	649	0.1313	0.8687	0.02
78.5	5,073	8	0.0016	0.9984	0.02

NORTHWEST NATURAL GAS COMPANY

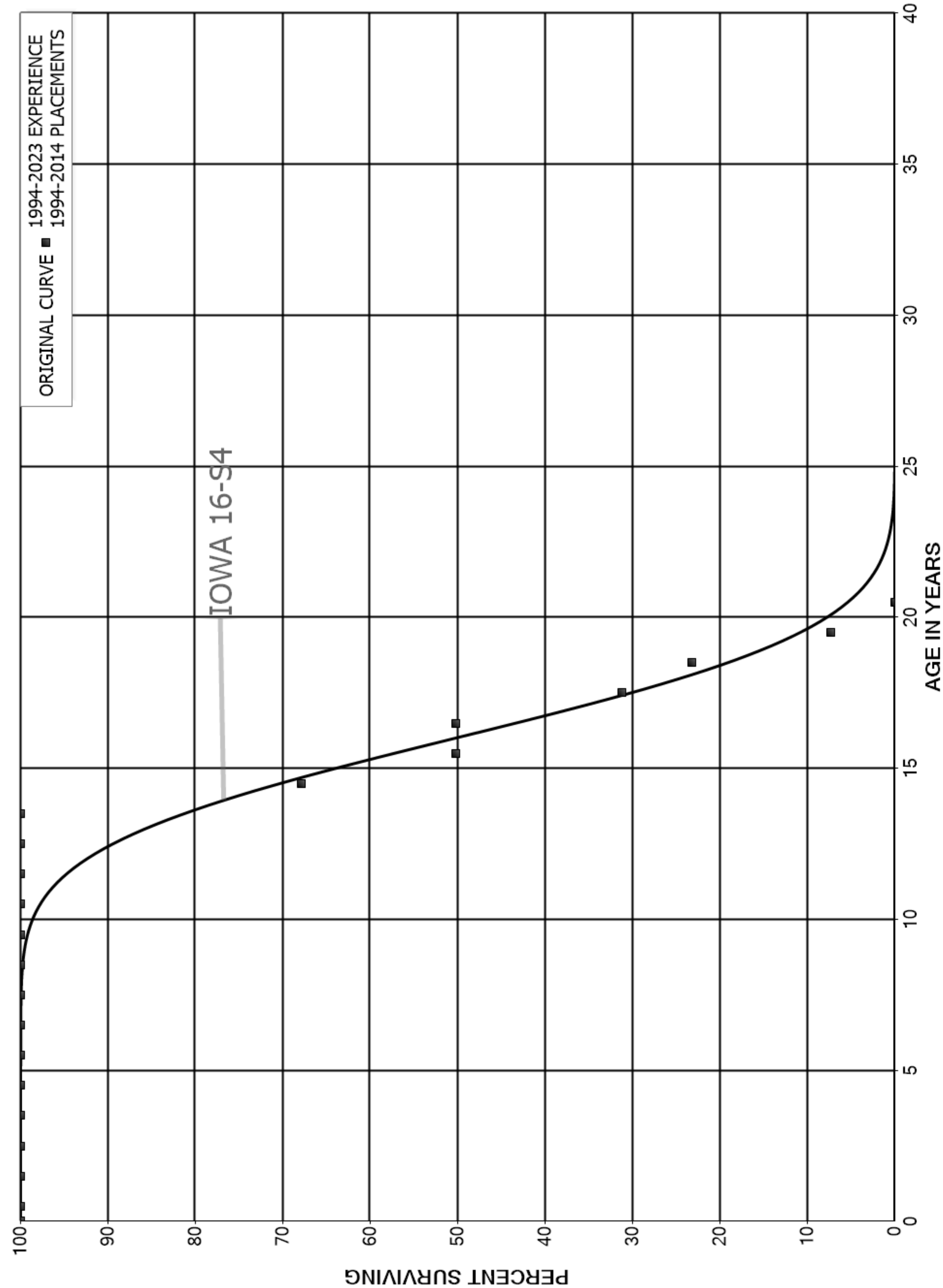
ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	5,533	30	0.0054	0.9946	0.02
80.5	5,919	377	0.0637	0.9363	0.02
81.5	5,542	2,255	0.4069	0.5931	0.01
82.5	3,287		0.0000	1.0000	0.01
83.5	3,326	34	0.0102	0.9898	0.01
84.5	3,292		0.0000	1.0000	0.01
85.5	3,313		0.0000	1.0000	0.01
86.5	3,313		0.0000	1.0000	0.01
87.5	3,313		0.0000	1.0000	0.01
88.5	3,370		0.0000	1.0000	0.01
89.5	3,399	87	0.0256	0.9744	0.01
90.5	3,312	148	0.0448	0.9552	0.01
91.5	3,164	320	0.1013	0.8987	0.01
92.5	2,843	1,451	0.5104	0.4896	0.01
93.5	120,134	1,246	0.0104	0.9896	0.00
94.5	118,888	1,739	0.0146	0.9854	0.00
95.5	117,149	3,869	0.0330	0.9670	0.00
96.5	113,280	9,143	0.0807	0.9193	0.00
97.5	104,137	6,898	0.0662	0.9338	0.00
98.5	97,239	2,496	0.0257	0.9743	0.00
99.5	94,743	2,878	0.0304	0.9696	0.00
100.5	91,864	1,720	0.0187	0.9813	0.00
101.5	90,145	1,660	0.0184	0.9816	0.00
102.5	88,485	2,410	0.0272	0.9728	0.00
103.5	86,075	2,640	0.0307	0.9693	0.00
104.5	83,436	1,770	0.0212	0.9788	0.00
105.5	81,666	1,380	0.0169	0.9831	0.00
106.5	80,286	2,030	0.0253	0.9747	0.00
107.5	78,256	1,800	0.0230	0.9770	0.00
108.5	76,456	1,630	0.0213	0.9787	0.00
109.5	74,826	6,630	0.0886	0.9114	0.00
110.5	68,196	2,180	0.0320	0.9680	0.00
111.5	66,016	1,590	0.0241	0.9759	0.00
112.5	64,426	64,426	1.0000		0.00
113.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.10 METERS - ELECTRIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

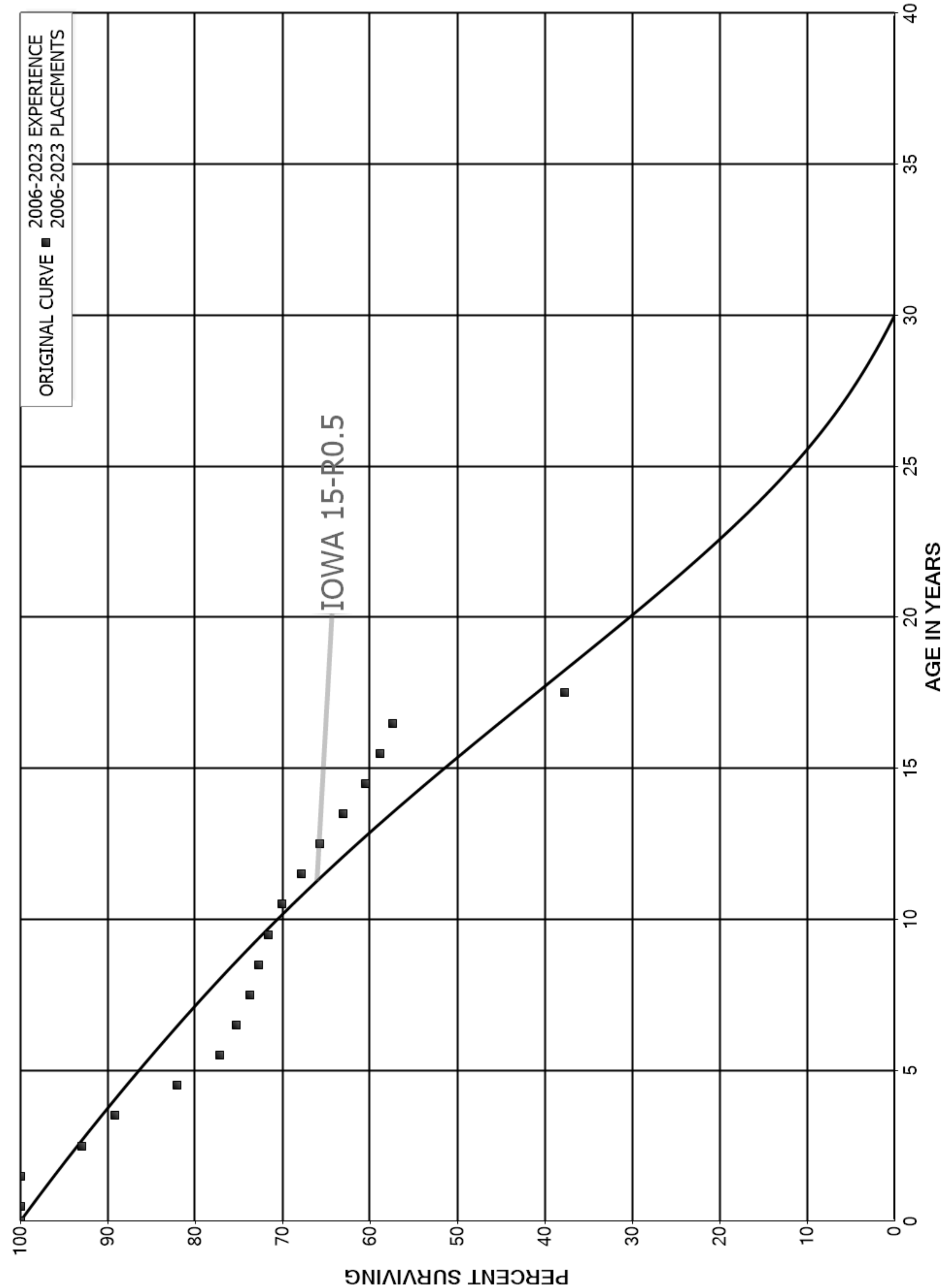
ACCOUNT 381.10 METERS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2014 EXPERIENCE BAND 1994-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,231,438		0.0000	1.0000	100.00
0.5	2,231,438		0.0000	1.0000	100.00
1.5	2,231,438		0.0000	1.0000	100.00
2.5	2,203,945		0.0000	1.0000	100.00
3.5	2,203,945		0.0000	1.0000	100.00
4.5	2,203,945		0.0000	1.0000	100.00
5.5	2,203,945		0.0000	1.0000	100.00
6.5	2,203,945		0.0000	1.0000	100.00
7.5	2,203,945		0.0000	1.0000	100.00
8.5	2,203,945		0.0000	1.0000	100.00
9.5	507,007		0.0000	1.0000	100.00
10.5	507,007		0.0000	1.0000	100.00
11.5	507,007		0.0000	1.0000	100.00
12.5	507,007		0.0000	1.0000	100.00
13.5	507,007	162,981	0.3215	0.6785	100.00
14.5	344,026	89,373	0.2598	0.7402	67.85
15.5	254,653		0.0000	1.0000	50.23
16.5	254,653	96,599	0.3793	0.6207	50.23
17.5	158,054	40,588	0.2568	0.7432	31.17
18.5	117,466	80,578	0.6860	0.3140	23.17
19.5	36,888	36,888	1.0000		7.28
20.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.20 METERS - ERT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

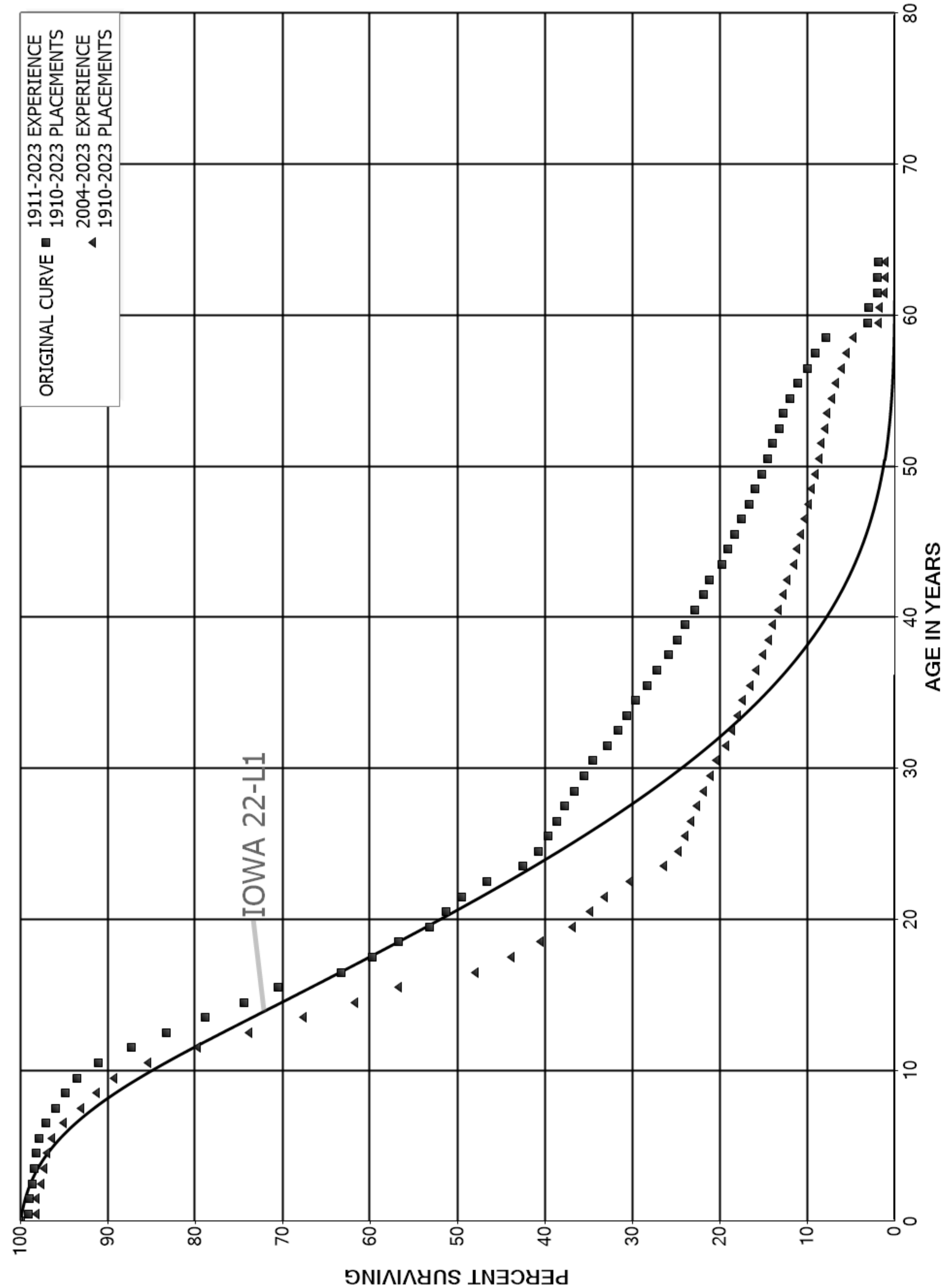
ACCOUNT 381.20 METERS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2023 EXPERIENCE BAND 2006-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	71,509,753		0.0000	1.0000	100.00
0.5	61,289,403	18,697	0.0003	0.9997	100.00
1.5	61,441,154	4,338,344	0.0706	0.9294	99.97
2.5	49,939,945	1,992,852	0.0399	0.9601	92.91
3.5	47,321,419	3,797,990	0.0803	0.9197	89.20
4.5	42,141,954	2,483,292	0.0589	0.9411	82.04
5.5	39,461,679	1,008,737	0.0256	0.9744	77.21
6.5	38,016,829	764,390	0.0201	0.9799	75.24
7.5	37,252,439	489,321	0.0131	0.9869	73.72
8.5	36,763,118	594,698	0.0162	0.9838	72.75
9.5	36,168,420	737,071	0.0204	0.9796	71.58
10.5	32,748,151	1,051,945	0.0321	0.9679	70.12
11.5	31,067,407	997,332	0.0321	0.9679	67.87
12.5	29,573,151	1,191,622	0.0403	0.9597	65.69
13.5	27,807,655	1,126,647	0.0405	0.9595	63.04
14.5	17,740,338	473,590	0.0267	0.9733	60.49
15.5	11,370,908	286,686	0.0252	0.9748	58.87
16.5	8,309,121	2,850,156	0.3430	0.6570	57.39
17.5					37.70

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.00 METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	130,097,586	1,244,242	0.0096	0.9904	100.00
0.5	120,119,915	66,493	0.0006	0.9994	99.04
1.5	114,287,525	374,297	0.0033	0.9967	98.99
2.5	103,051,795	230,434	0.0022	0.9978	98.66
3.5	102,848,987	268,966	0.0026	0.9974	98.44
4.5	98,704,767	407,300	0.0041	0.9959	98.19
5.5	95,320,494	716,510	0.0075	0.9925	97.78
6.5	89,714,474	1,055,779	0.0118	0.9882	97.05
7.5	88,683,539	989,101	0.0112	0.9888	95.90
8.5	85,407,505	1,168,949	0.0137	0.9863	94.83
9.5	82,181,857	2,211,910	0.0269	0.9731	93.54
10.5	77,049,262	3,152,078	0.0409	0.9591	91.02
11.5	70,152,726	3,201,838	0.0456	0.9544	87.30
12.5	67,054,505	3,565,452	0.0532	0.9468	83.31
13.5	63,595,091	3,572,899	0.0562	0.9438	78.88
14.5	60,130,070	3,217,311	0.0535	0.9465	74.45
15.5	56,982,995	5,801,205	0.1018	0.8982	70.47
16.5	51,219,896	2,854,089	0.0557	0.9443	63.29
17.5	48,399,592	2,481,686	0.0513	0.9487	59.77
18.5	45,866,305	2,815,867	0.0614	0.9386	56.70
19.5	39,810,547	1,419,913	0.0357	0.9643	53.22
20.5	38,397,808	1,353,448	0.0352	0.9648	51.32
21.5	36,999,806	2,200,029	0.0595	0.9405	49.51
22.5	32,486,617	2,803,658	0.0863	0.9137	46.57
23.5	27,952,157	1,232,582	0.0441	0.9559	42.55
24.5	26,314,630	692,761	0.0263	0.9737	40.67
25.5	25,635,539	626,318	0.0244	0.9756	39.60
26.5	24,800,481	618,417	0.0249	0.9751	38.64
27.5	24,199,668	691,820	0.0286	0.9714	37.67
28.5	23,004,318	675,609	0.0294	0.9706	36.59
29.5	22,343,927	666,533	0.0298	0.9702	35.52
30.5	21,687,074	1,053,128	0.0486	0.9514	34.46
31.5	19,523,551	675,398	0.0346	0.9654	32.79
32.5	18,295,375	590,778	0.0323	0.9677	31.65
33.5	15,456,799	522,077	0.0338	0.9662	30.63
34.5	13,250,309	578,465	0.0437	0.9563	29.60
35.5	11,725,147	457,764	0.0390	0.9610	28.30
36.5	11,270,647	542,952	0.0482	0.9518	27.20
37.5	9,759,769	411,880	0.0422	0.9578	25.89
38.5	9,352,122	340,295	0.0364	0.9636	24.80

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,018,072	411,969	0.0457	0.9543	23.89
40.5	8,209,803	332,397	0.0405	0.9595	22.80
41.5	7,439,093	255,579	0.0344	0.9656	21.88
42.5	6,360,546	415,268	0.0653	0.9347	21.13
43.5	5,341,268	187,867	0.0352	0.9648	19.75
44.5	5,163,701	214,981	0.0416	0.9584	19.05
45.5	4,464,102	192,565	0.0431	0.9569	18.26
46.5	4,283,800	205,285	0.0479	0.9521	17.47
47.5	3,877,241	156,261	0.0403	0.9597	16.64
48.5	3,727,191	178,630	0.0479	0.9521	15.96
49.5	3,402,782	156,447	0.0460	0.9540	15.20
50.5	2,980,282	119,208	0.0400	0.9600	14.50
51.5	2,225,409	111,775	0.0502	0.9498	13.92
52.5	2,062,785	78,270	0.0379	0.9621	13.22
53.5	1,796,531	110,494	0.0615	0.9385	12.72
54.5	1,687,927	121,785	0.0722	0.9278	11.94
55.5	1,283,244	131,348	0.1024	0.8976	11.08
56.5	842,799	79,013	0.0938	0.9062	9.94
57.5	658,047	86,719	0.1318	0.8682	9.01
58.5	456,831	275,319	0.6027	0.3973	7.82
59.5	168,378	10,272	0.0610	0.9390	3.11
60.5	158,278	52,494	0.3317	0.6683	2.92
61.5	105,952	2,285	0.0216	0.9784	1.95
62.5	103,690	3,218	0.0310	0.9690	1.91
63.5	97,640	4,967	0.0509	0.9491	1.85
64.5	79,765	86	0.0011	0.9989	1.76
65.5	61,565	14	0.0002	0.9998	1.75
66.5	24,110	29	0.0012	0.9988	1.75
67.5	17,941	66	0.0037	0.9963	1.75
68.5	17,889	14	0.0008	0.9992	1.74
69.5	17,882		0.0000	1.0000	1.74
70.5	17,882		0.0000	1.0000	1.74
71.5	17,882		0.0000	1.0000	1.74
72.5	17,882	7	0.0004	0.9996	1.74
73.5	17,875		0.0000	1.0000	1.74
74.5	17,875		0.0000	1.0000	1.74
75.5	17,875		0.0000	1.0000	1.74
76.5	17,875		0.0000	1.0000	1.74
77.5	17,875		0.0000	1.0000	1.74
78.5	17,875		0.0000	1.0000	1.74

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	17,875		0.0000	1.0000	1.74
80.5	17,875		0.0000	1.0000	1.74
81.5	17,875		0.0000	1.0000	1.74
82.5	17,875		0.0000	1.0000	1.74
83.5	17,875		0.0000	1.0000	1.74
84.5	17,875		0.0000	1.0000	1.74
85.5	17,875		0.0000	1.0000	1.74
86.5	17,875		0.0000	1.0000	1.74
87.5	17,875		0.0000	1.0000	1.74
88.5	17,875		0.0000	1.0000	1.74
89.5	17,875	7	0.0004	0.9996	1.74
90.5	17,868		0.0000	1.0000	1.74
91.5	17,868		0.0000	1.0000	1.74
92.5	17,868		0.0000	1.0000	1.74
93.5	17,868	69	0.0039	0.9961	1.74
94.5	17,799	188	0.0105	0.9895	1.74
95.5	17,611	808	0.0459	0.9541	1.72
96.5	16,804	1,136	0.0676	0.9324	1.64
97.5	15,668		0.0000	1.0000	1.53
98.5	15,668	850	0.0542	0.9458	1.53
99.5	14,818	13,591	0.9172	0.0828	1.44
100.5	1,227	830	0.6762	0.3238	0.12
101.5	398	398	1.0000		0.04
102.5					

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	62,899,572	1,232,304	0.0196	0.9804	100.00
0.5	58,766,611	13,012	0.0002	0.9998	98.04
1.5	55,713,012	289,945	0.0052	0.9948	98.02
2.5	47,480,726	179,790	0.0038	0.9962	97.51
3.5	49,945,555	182,860	0.0037	0.9963	97.14
4.5	48,632,884	272,204	0.0056	0.9944	96.78
5.5	48,532,757	654,595	0.0135	0.9865	96.24
6.5	46,383,648	972,881	0.0210	0.9790	94.94
7.5	48,830,635	907,712	0.0186	0.9814	92.95
8.5	48,231,718	1,090,095	0.0226	0.9774	91.23
9.5	47,569,561	2,093,357	0.0440	0.9560	89.16
10.5	44,863,445	2,959,877	0.0660	0.9340	85.24
11.5	40,506,233	3,002,892	0.0741	0.9259	79.62
12.5	39,898,577	3,356,486	0.0841	0.9159	73.71
13.5	39,042,564	3,390,303	0.0868	0.9132	67.51
14.5	37,802,516	3,071,325	0.0812	0.9188	61.65
15.5	36,245,289	5,661,834	0.1562	0.8438	56.64
16.5	31,549,119	2,719,185	0.0862	0.9138	47.79
17.5	30,584,734	2,319,568	0.0758	0.9242	43.67
18.5	29,243,340	2,639,132	0.0902	0.9098	40.36
19.5	24,097,792	1,288,029	0.0535	0.9465	36.72
20.5	23,417,195	1,167,044	0.0498	0.9502	34.76
21.5	23,196,777	2,023,688	0.0872	0.9128	33.02
22.5	20,421,288	2,638,565	0.1292	0.8708	30.14
23.5	17,404,905	1,073,042	0.0617	0.9383	26.25
24.5	16,817,910	550,224	0.0327	0.9673	24.63
25.5	17,195,323	479,320	0.0279	0.9721	23.82
26.5	16,933,673	504,344	0.0298	0.9702	23.16
27.5	16,800,627	567,703	0.0338	0.9662	22.47
28.5	15,841,311	531,480	0.0336	0.9664	21.71
29.5	16,008,772	532,610	0.0333	0.9667	20.98
30.5	16,072,309	886,919	0.0552	0.9448	20.28
31.5	14,948,680	535,078	0.0358	0.9642	19.17
32.5	14,360,838	472,086	0.0329	0.9671	18.48
33.5	12,005,094	399,256	0.0333	0.9667	17.87
34.5	10,168,171	487,761	0.0480	0.9520	17.28
35.5	9,197,363	382,263	0.0416	0.9584	16.45
36.5	9,263,432	473,749	0.0511	0.9489	15.77
37.5	8,198,105	359,611	0.0439	0.9561	14.96
38.5	8,222,345	299,806	0.0365	0.9635	14.30

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,233,119	377,567	0.0459	0.9541	13.78
40.5	7,708,881	301,885	0.0392	0.9608	13.15
41.5	7,166,281	234,999	0.0328	0.9672	12.63
42.5	6,156,542	398,261	0.0647	0.9353	12.22
43.5	5,209,135	175,692	0.0337	0.9663	11.43
44.5	5,051,479	202,116	0.0400	0.9600	11.04
45.5	4,370,744	179,451	0.0411	0.9589	10.60
46.5	4,228,774	190,914	0.0451	0.9549	10.17
47.5	3,836,662	142,674	0.0372	0.9628	9.71
48.5	3,690,243	164,787	0.0447	0.9553	9.35
49.5	3,368,129	145,025	0.0431	0.9569	8.93
50.5	2,948,968	107,931	0.0366	0.9634	8.54
51.5	2,197,678	103,664	0.0472	0.9528	8.23
52.5	2,038,249	73,213	0.0359	0.9641	7.84
53.5	1,774,383	106,955	0.0603	0.9397	7.56
54.5	1,667,343	119,309	0.0716	0.9284	7.11
55.5	1,263,787	129,576	0.1025	0.8975	6.60
56.5	824,008	78,071	0.0947	0.9053	5.92
57.5	639,519	86,134	0.1347	0.8653	5.36
58.5	438,368	274,976	0.6273	0.3727	4.64
59.5	150,034	10,001	0.0667	0.9333	1.73
60.5	140,033	52,366	0.3740	0.6260	1.61
61.5	87,667	2,133	0.0243	0.9757	1.01
62.5	85,467	3,105	0.0363	0.9637	0.99
63.5	79,509	4,899	0.0616	0.9384	0.95
64.5	61,702		0.0000	1.0000	0.89
65.5	43,581		0.0000	1.0000	0.89
66.5	6,140		0.0000	1.0000	0.89
67.5					0.89
68.5					
69.5					
70.5					
71.5					
72.5					
73.5					
74.5					
75.5					
76.5					
77.5					
78.5					

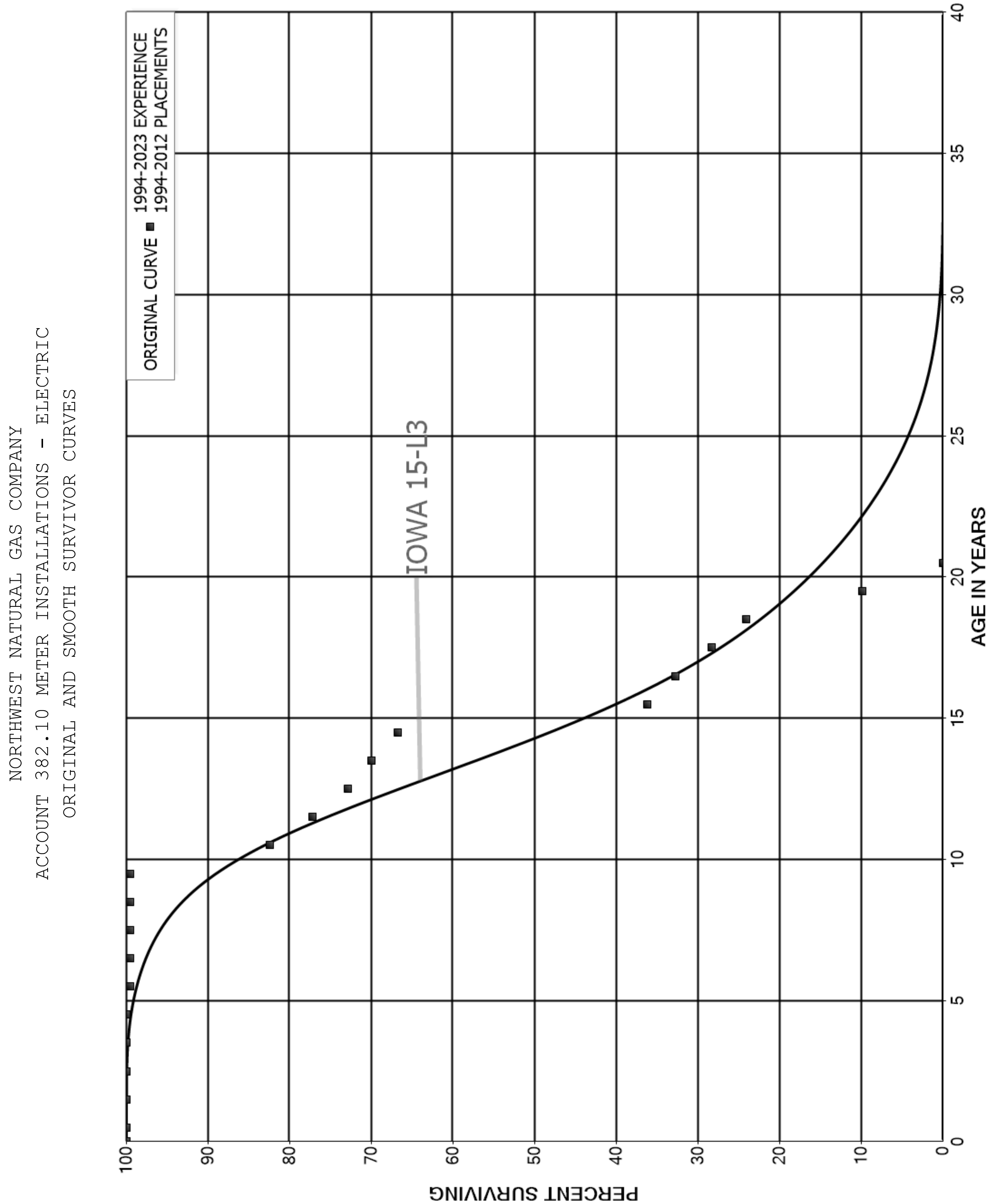
NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5					
80.5	7		0.0000		
81.5	7		0.0000		
82.5	7		0.0000		
83.5	7		0.0000		
84.5	7		0.0000		
85.5	7		0.0000		
86.5	7		0.0000		
87.5	7		0.0000		
88.5	14		0.0000		
89.5	14	7	0.5000		
90.5	7		0.0000		
91.5	7		0.0000		
92.5	7		0.0000		
93.5	17,868	69	0.0039		
94.5	17,799	188	0.0105		
95.5	17,611	808	0.0459		
96.5	16,804	1,136	0.0676		
97.5	15,668		0.0000		
98.5	15,668	850	0.0542		
99.5	14,818	13,591	0.9172		
100.5	1,227	830	0.6762		
101.5	398	398	1.0000		
102.5					


NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1994-2023 EXPERIENCE
1994-2012 PLACEMENTS
IOWA 15-L3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40

NORTHWEST NATURAL GAS COMPANY

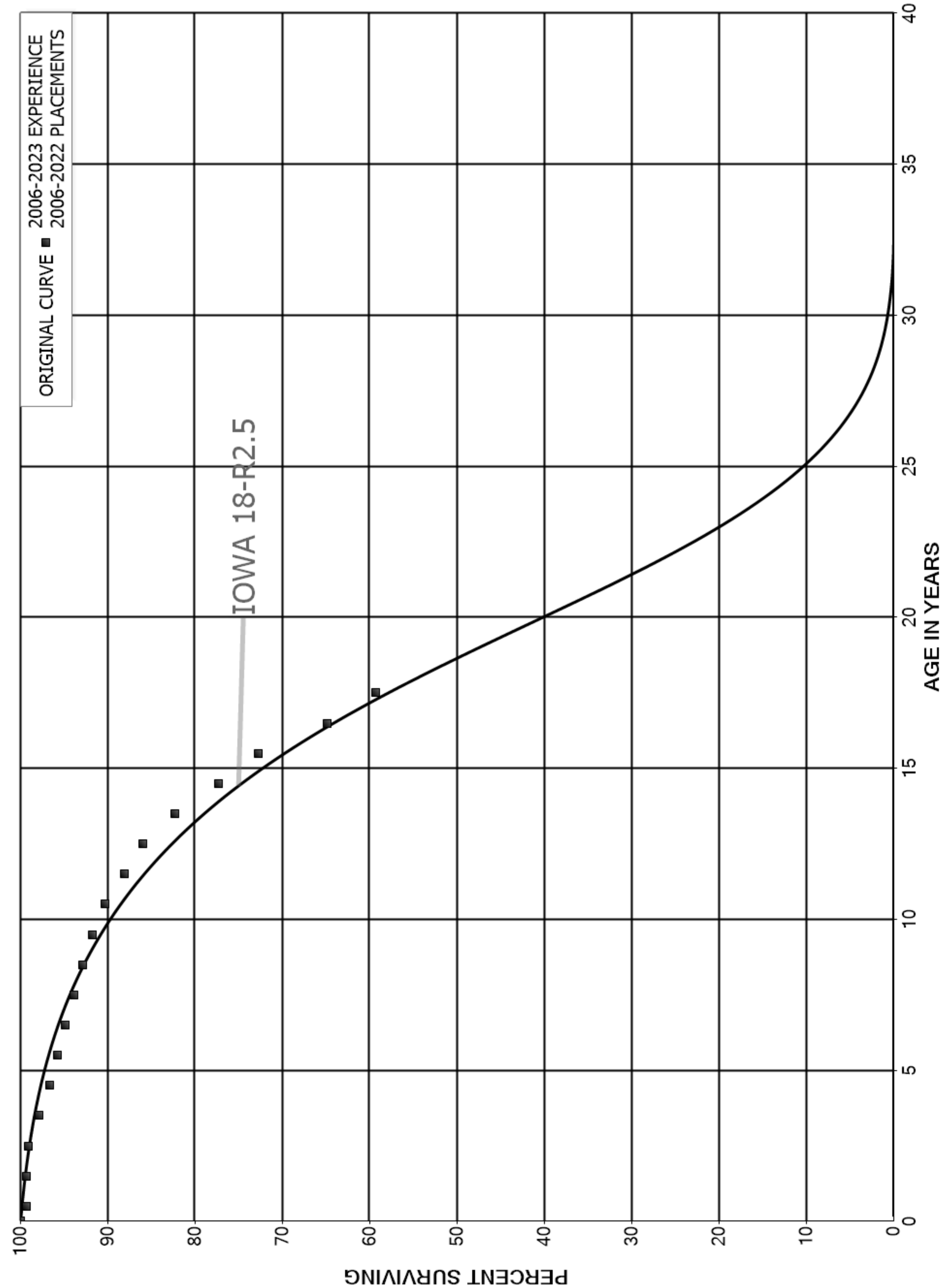
ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2012 EXPERIENCE BAND 1994-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	999,397		0.0000	1.0000	100.00
0.5	999,397		0.0000	1.0000	100.00
1.5	999,397		0.0000	1.0000	100.00
2.5	999,397		0.0000	1.0000	100.00
3.5	999,397		0.0000	1.0000	100.00
4.5	999,397	4,559	0.0046	0.9954	100.00
5.5	994,838		0.0000	1.0000	99.54
6.5	994,838		0.0000	1.0000	99.54
7.5	994,838		0.0000	1.0000	99.54
8.5	994,838		0.0000	1.0000	99.54
9.5	994,838	171,671	0.1726	0.8274	99.54
10.5	823,166	52,429	0.0637	0.9363	82.37
11.5	289,718	16,259	0.0561	0.9439	77.12
12.5	273,459	10,720	0.0392	0.9608	72.79
13.5	262,739	11,880	0.0452	0.9548	69.94
14.5	250,859	114,955	0.4582	0.5418	66.78
15.5	135,904	13,170	0.0969	0.9031	36.18
16.5	122,734	16,477	0.1342	0.8658	32.67
17.5	106,257	15,824	0.1489	0.8511	28.28
18.5	90,433	53,374	0.5902	0.4098	24.07
19.5	37,059	37,059	1.0000		9.86
20.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.20 METER INSTALLATIONS - ERT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

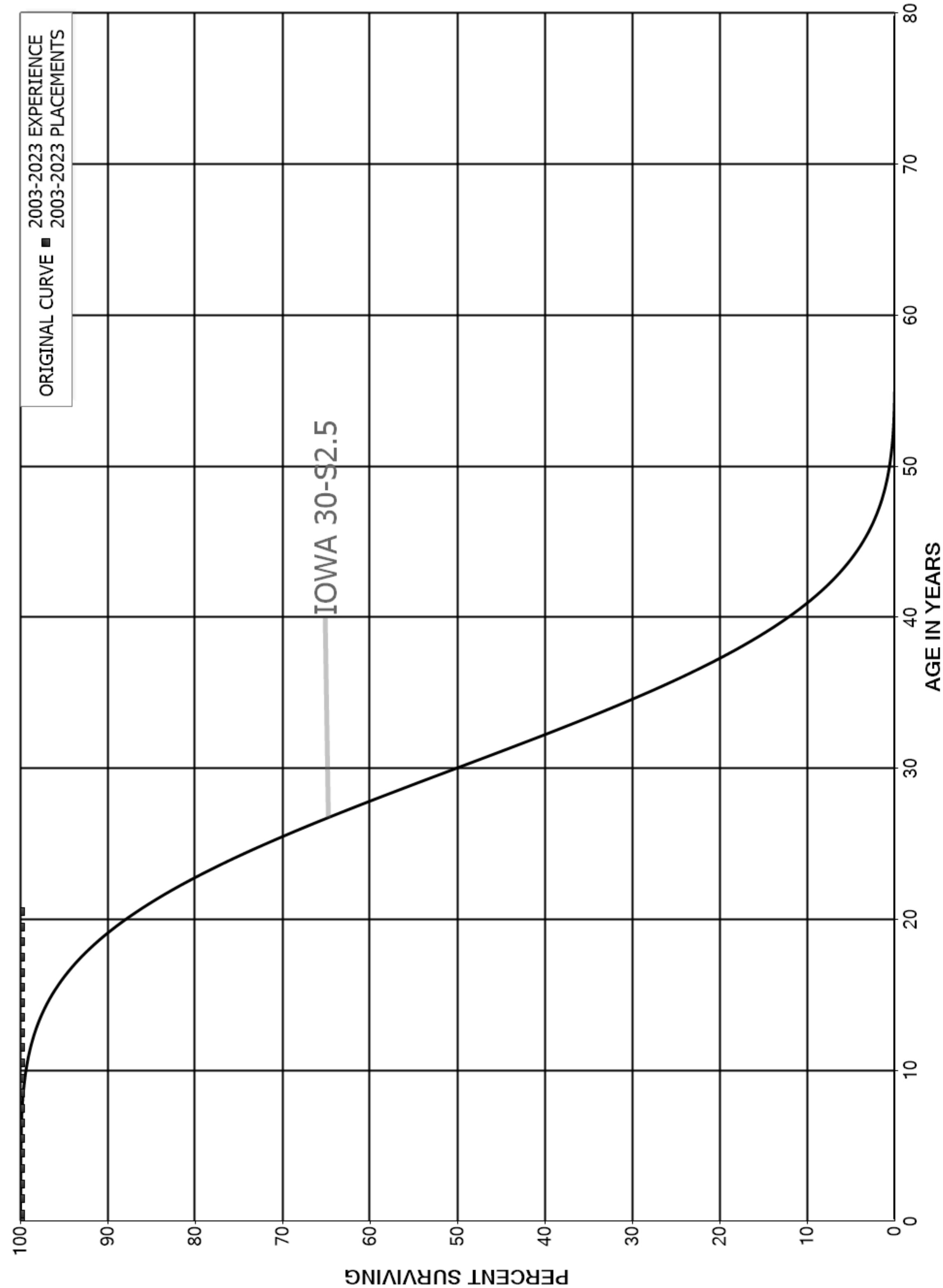
ACCOUNT 382.20 METER INSTALLATIONS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2022 EXPERIENCE BAND 2006-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,039,555	84,095	0.0070	0.9930	100.00
0.5	11,955,461	4,140	0.0003	0.9997	99.30
1.5	11,525,846	22,592	0.0020	0.9980	99.27
2.5	10,521,301	126,165	0.0120	0.9880	99.07
3.5	9,860,496	129,762	0.0132	0.9868	97.88
4.5	9,730,734	87,139	0.0090	0.9910	96.60
5.5	9,643,595	92,939	0.0096	0.9904	95.73
6.5	9,550,657	103,554	0.0108	0.9892	94.81
7.5	9,447,103	96,509	0.0102	0.9898	93.78
8.5	9,350,594	107,272	0.0115	0.9885	92.82
9.5	9,243,321	143,695	0.0155	0.9845	91.76
10.5	9,099,626	231,746	0.0255	0.9745	90.33
11.5	8,867,880	210,110	0.0237	0.9763	88.03
12.5	8,657,770	367,119	0.0424	0.9576	85.95
13.5	3,787,730	229,843	0.0607	0.9393	82.30
14.5	3,557,887	212,155	0.0596	0.9404	77.31
15.5	2,383,715	259,268	0.1088	0.8912	72.70
16.5	888,188	76,089	0.0857	0.9143	64.79
17.5					59.24

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 383.00 HOUSE REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

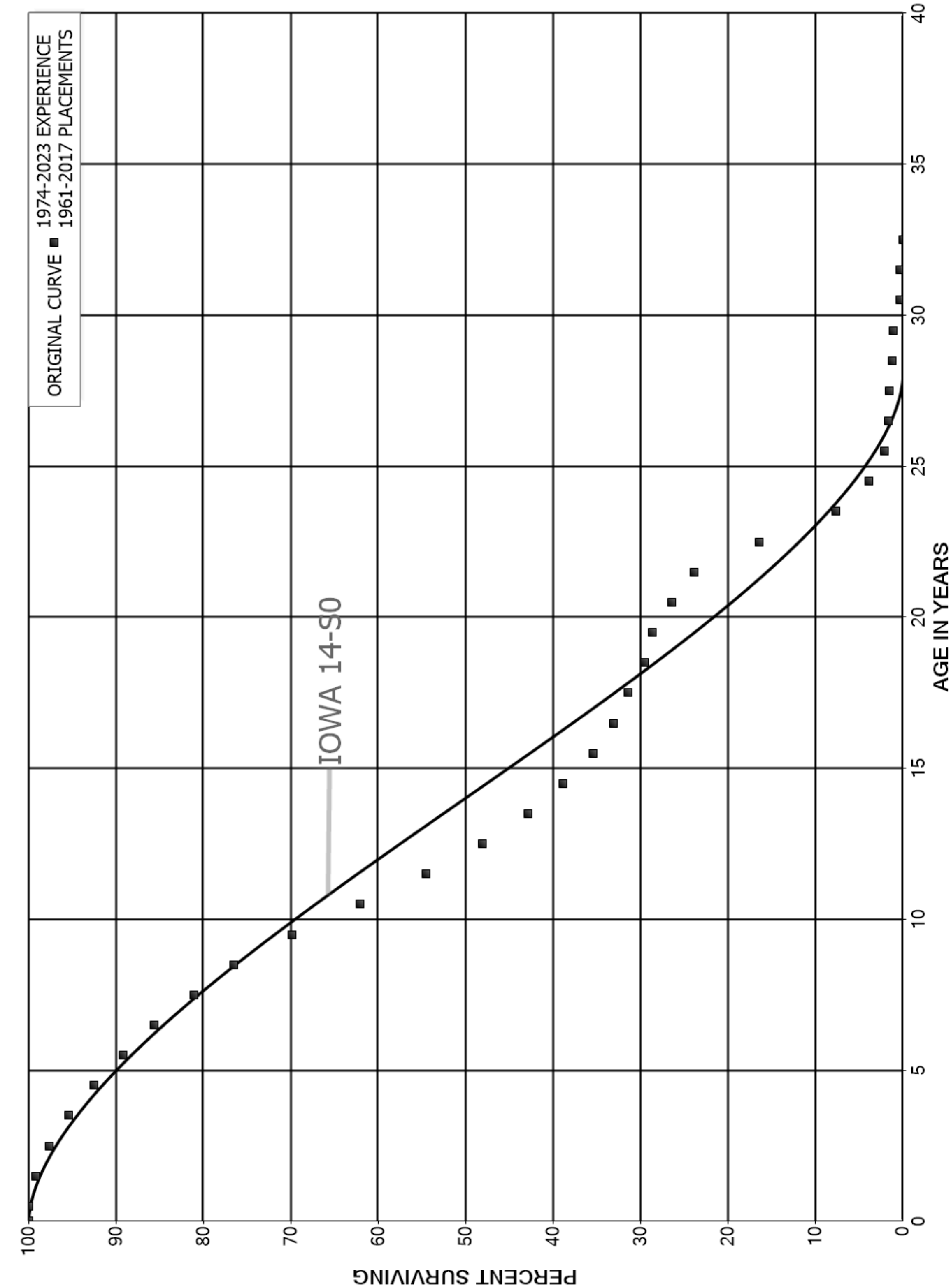
ACCOUNT 383.00 HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 2003-2023 EXPERIENCE BAND 2003-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,244,767		0.0000	1.0000	100.00
0.5	2,822,905		0.0000	1.0000	100.00
1.5	2,679,970		0.0000	1.0000	100.00
2.5	2,553,748		0.0000	1.0000	100.00
3.5	2,419,709		0.0000	1.0000	100.00
4.5	2,199,701		0.0000	1.0000	100.00
5.5	1,877,440		0.0000	1.0000	100.00
6.5	1,678,311		0.0000	1.0000	100.00
7.5	1,495,492		0.0000	1.0000	100.00
8.5	1,280,026		0.0000	1.0000	100.00
9.5	1,115,746		0.0000	1.0000	100.00
10.5	775,208		0.0000	1.0000	100.00
11.5	619,596		0.0000	1.0000	100.00
12.5	569,858		0.0000	1.0000	100.00
13.5	487,625		0.0000	1.0000	100.00
14.5	451,511		0.0000	1.0000	100.00
15.5	369,806		0.0000	1.0000	100.00
16.5	263,639		0.0000	1.0000	100.00
17.5	163,930		0.0000	1.0000	100.00
18.5	52,920		0.0000	1.0000	100.00
19.5	1,945		0.0000	1.0000	100.00
20.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

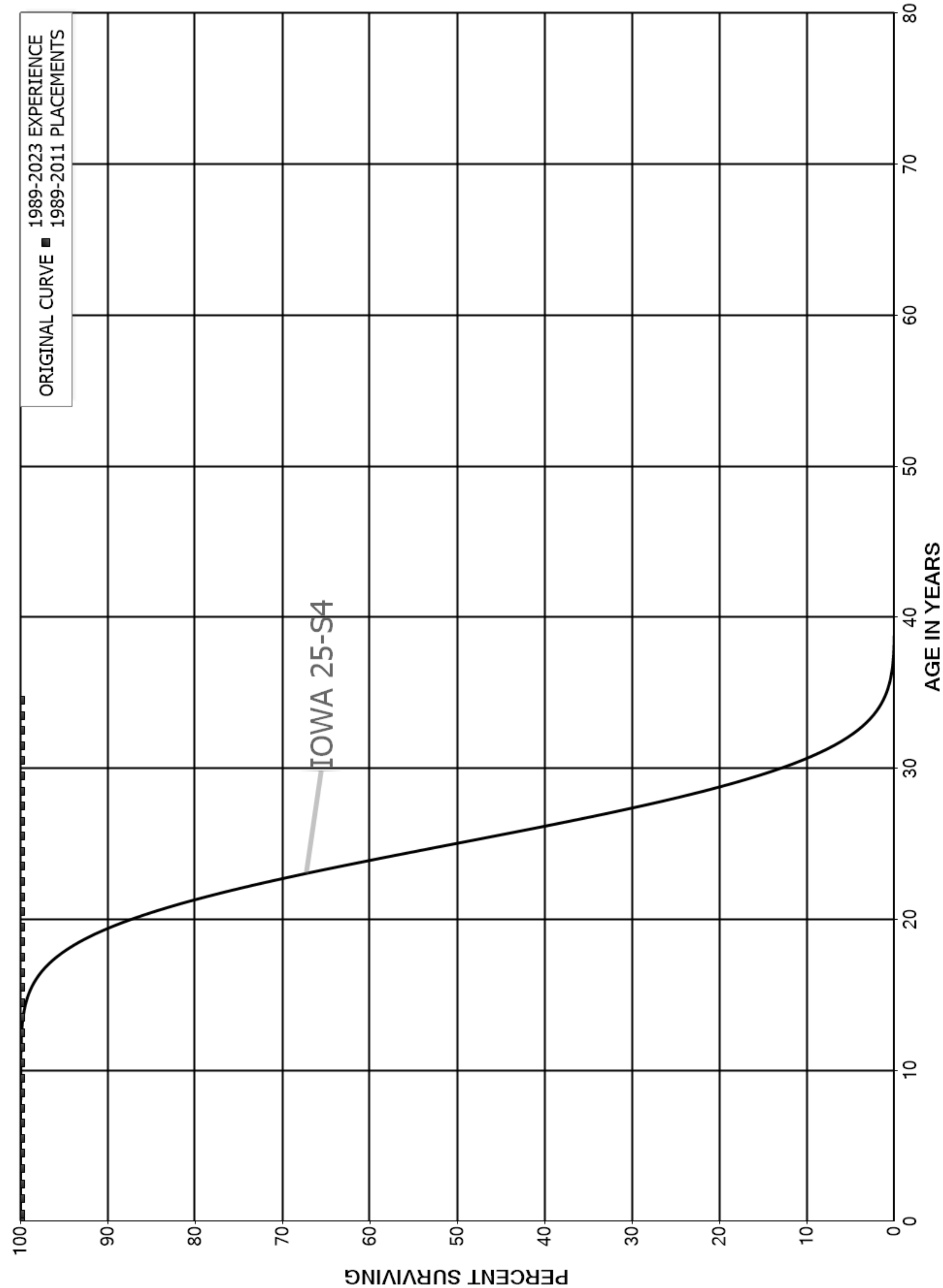
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2017 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,442,554		0.0000	1.0000	100.00
0.5	2,043,820	17,133	0.0084	0.9916	100.00
1.5	2,911,018	45,588	0.0157	0.9843	99.16
2.5	3,930,713	90,018	0.0229	0.9771	97.61
3.5	5,088,205	152,426	0.0300	0.9700	95.37
4.5	6,142,351	224,679	0.0366	0.9634	92.52
5.5	7,031,760	281,453	0.0400	0.9600	89.13
6.5	6,777,605	355,326	0.0524	0.9476	85.56
7.5	7,568,373	425,239	0.0562	0.9438	81.08
8.5	8,085,694	711,200	0.0880	0.9120	76.52
9.5	8,043,360	891,675	0.1109	0.8891	69.79
10.5	7,630,732	922,861	0.1209	0.8791	62.06
11.5	6,973,764	826,393	0.1185	0.8815	54.55
12.5	6,219,017	674,073	0.1084	0.8916	48.09
13.5	5,544,944	528,050	0.0952	0.9048	42.87
14.5	5,016,894	437,695	0.0872	0.9128	38.79
15.5	4,579,199	303,909	0.0664	0.9336	35.41
16.5	4,275,290	217,796	0.0509	0.9491	33.06
17.5	4,057,494	242,066	0.0597	0.9403	31.37
18.5	3,815,428	116,881	0.0306	0.9694	29.50
19.5	3,698,547	285,152	0.0771	0.9229	28.60
20.5	3,413,395	337,691	0.0989	0.9011	26.39
21.5	3,075,704	950,161	0.3089	0.6911	23.78
22.5	2,125,543	1,146,559	0.5394	0.4606	16.43
23.5	978,984	479,837	0.4901	0.5099	7.57
24.5	499,147	226,905	0.4546	0.5454	3.86
25.5	272,242	66,375	0.2438	0.7562	2.11
26.5	205,867	14,758	0.0717	0.9283	1.59
27.5	191,109	38,572	0.2018	0.7982	1.48
28.5	152,537	11,751	0.0770	0.9230	1.18
29.5	140,786	97,214	0.6905	0.3095	1.09
30.5	43,572	11,751	0.2697	0.7303	0.34
31.5	31,821	31,821	1.0000		0.25
32.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

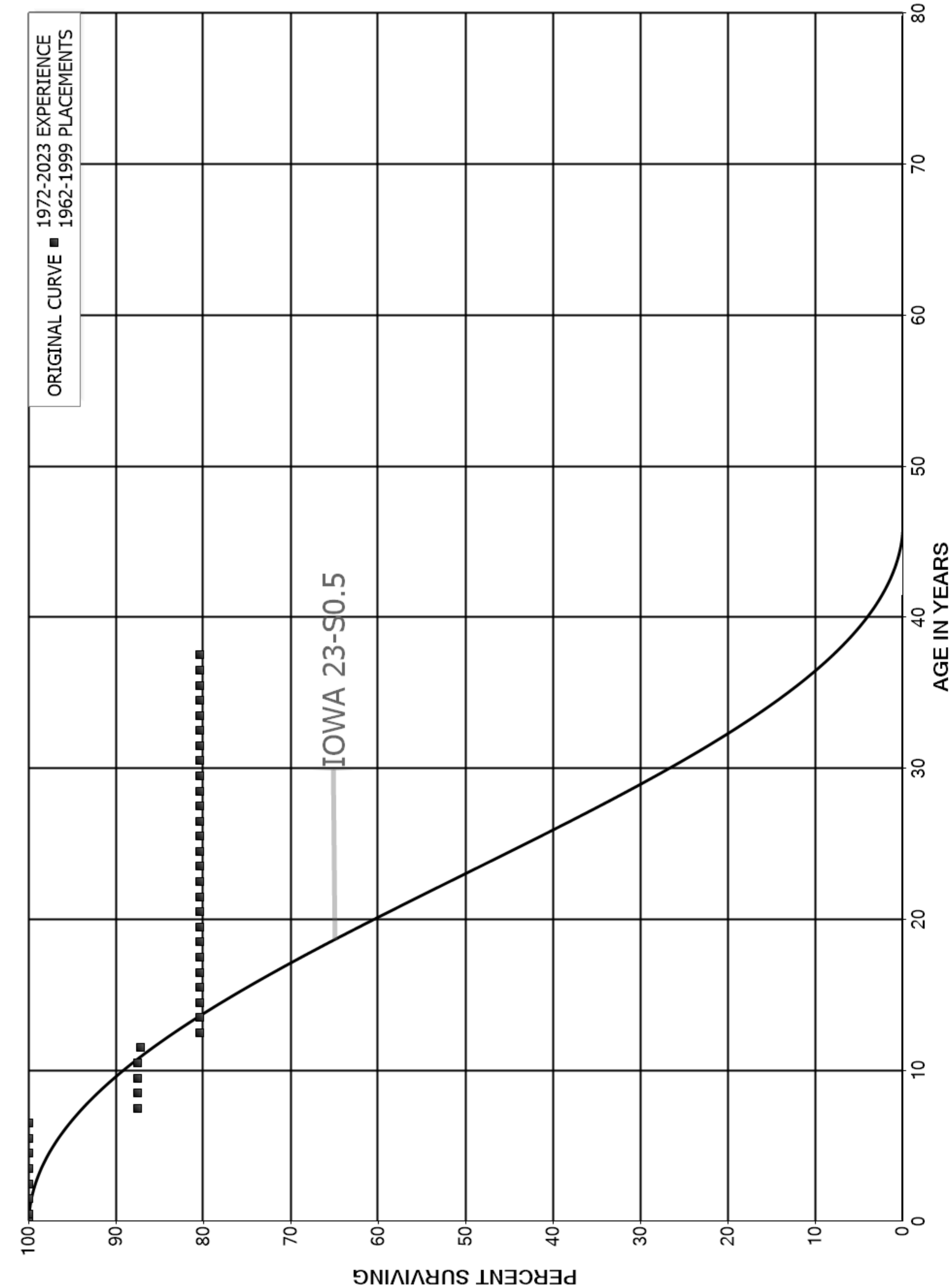
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2011 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	173,859		0.0000	1.0000	100.00
0.5	173,859		0.0000	1.0000	100.00
1.5	173,859		0.0000	1.0000	100.00
2.5	173,859		0.0000	1.0000	100.00
3.5	173,859		0.0000	1.0000	100.00
4.5	173,859		0.0000	1.0000	100.00
5.5	173,859		0.0000	1.0000	100.00
6.5	173,859		0.0000	1.0000	100.00
7.5	173,859		0.0000	1.0000	100.00
8.5	173,859		0.0000	1.0000	100.00
9.5	173,859		0.0000	1.0000	100.00
10.5	173,859		0.0000	1.0000	100.00
11.5	173,859		0.0000	1.0000	100.00
12.5	138,950		0.0000	1.0000	100.00
13.5	138,950		0.0000	1.0000	100.00
14.5	138,950		0.0000	1.0000	100.00
15.5	138,950		0.0000	1.0000	100.00
16.5	138,950		0.0000	1.0000	100.00
17.5	138,950		0.0000	1.0000	100.00
18.5	129,084		0.0000	1.0000	100.00
19.5	129,084		0.0000	1.0000	100.00
20.5	129,084		0.0000	1.0000	100.00
21.5	129,084		0.0000	1.0000	100.00
22.5	129,084		0.0000	1.0000	100.00
23.5	129,084		0.0000	1.0000	100.00
24.5	129,084		0.0000	1.0000	100.00
25.5	129,084		0.0000	1.0000	100.00
26.5	129,084		0.0000	1.0000	100.00
27.5	129,084		0.0000	1.0000	100.00
28.5	129,084		0.0000	1.0000	100.00
29.5	129,084		0.0000	1.0000	100.00
30.5	129,084		0.0000	1.0000	100.00
31.5	46,148		0.0000	1.0000	100.00
32.5	27,929		0.0000	1.0000	100.00
33.5	18,825		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-1999 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	107,454		0.0000	1.0000	100.00
0.5	107,454	25	0.0002	0.9998	100.00
1.5	107,454		0.0000	1.0000	99.98
2.5	107,454		0.0000	1.0000	99.98
3.5	107,454		0.0000	1.0000	99.98
4.5	107,454		0.0000	1.0000	99.98
5.5	107,454		0.0000	1.0000	99.98
6.5	107,454	13,401	0.1247	0.8753	99.98
7.5	107,824		0.0000	1.0000	87.51
8.5	115,988		0.0000	1.0000	87.51
9.5	116,853		0.0000	1.0000	87.51
10.5	104,958	370	0.0035	0.9965	87.51
11.5	104,588	8,164	0.0781	0.9219	87.20
12.5	96,424		0.0000	1.0000	80.39
13.5	96,424		0.0000	1.0000	80.39
14.5	96,424		0.0000	1.0000	80.39
15.5	96,424		0.0000	1.0000	80.39
16.5	96,424		0.0000	1.0000	80.39
17.5	96,424		0.0000	1.0000	80.39
18.5	96,424		0.0000	1.0000	80.39
19.5	96,424		0.0000	1.0000	80.39
20.5	96,424		0.0000	1.0000	80.39
21.5	96,424		0.0000	1.0000	80.39
22.5	96,424		0.0000	1.0000	80.39
23.5	96,424		0.0000	1.0000	80.39
24.5	93,709		0.0000	1.0000	80.39
25.5	89,269		0.0000	1.0000	80.39
26.5	76,317		0.0000	1.0000	80.39
27.5	73,945		0.0000	1.0000	80.39
28.5	71,691		0.0000	1.0000	80.39
29.5	64,033		0.0000	1.0000	80.39
30.5	59,167		0.0000	1.0000	80.39
31.5	59,167		0.0000	1.0000	80.39
32.5	37,876		0.0000	1.0000	80.39
33.5	37,624		0.0000	1.0000	80.39
34.5	37,624		0.0000	1.0000	80.39
35.5	37,624		0.0000	1.0000	80.39
36.5	37,624		0.0000	1.0000	80.39
37.5	11,859		0.0000	1.0000	80.39
38.5	11,859		0.0000	1.0000	80.39

NORTHWEST NATURAL GAS COMPANY

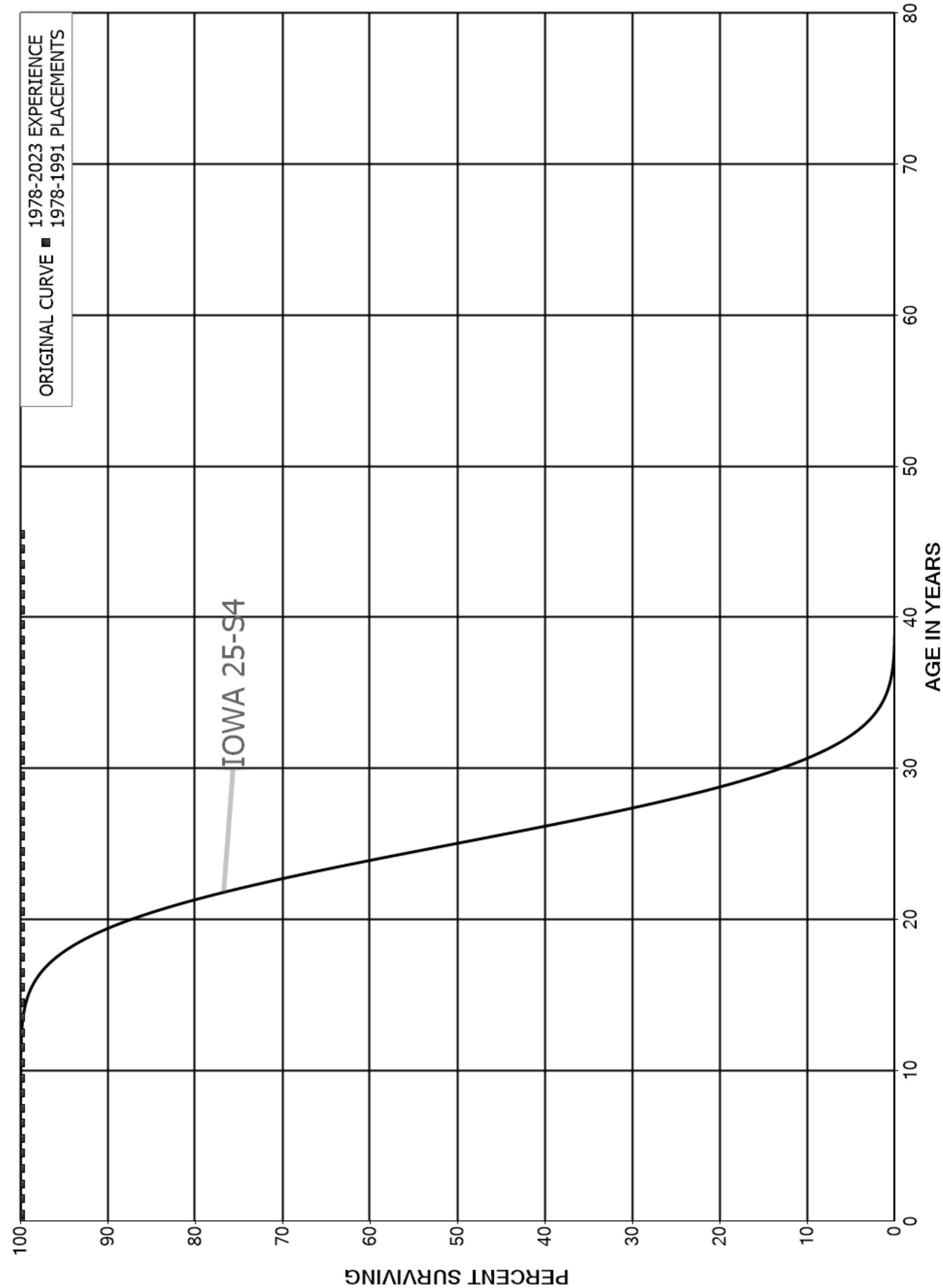
ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-1999 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,859		0.0000	1.0000	80.39
40.5	11,859		0.0000	1.0000	80.39
41.5	11,859		0.0000	1.0000	80.39
42.5	11,859		0.0000	1.0000	80.39
43.5	11,859		0.0000	1.0000	80.39
44.5	11,859		0.0000	1.0000	80.39
45.5	11,859		0.0000	1.0000	80.39
46.5	11,859		0.0000	1.0000	80.39
47.5	11,859		0.0000	1.0000	80.39
48.5	11,859		0.0000	1.0000	80.39
49.5	11,859		0.0000	1.0000	80.39
50.5	11,859		0.0000	1.0000	80.39
51.5	865		0.0000	1.0000	80.39
52.5	865		0.0000	1.0000	80.39
53.5	865		0.0000	1.0000	80.39
54.5	865		0.0000	1.0000	80.39
55.5	865		0.0000	1.0000	80.39
56.5	865		0.0000	1.0000	80.39
57.5	865		0.0000	1.0000	80.39
58.5	865		0.0000	1.0000	80.39
59.5	865		0.0000	1.0000	80.39
60.5	865		0.0000	1.0000	80.39
61.5					80.39

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1978-1991 EXPERIENCE BAND 1978-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	60,776		0.0000	1.0000	100.00
0.5	60,776		0.0000	1.0000	100.00
1.5	60,776		0.0000	1.0000	100.00
2.5	60,776		0.0000	1.0000	100.00
3.5	60,776		0.0000	1.0000	100.00
4.5	60,776		0.0000	1.0000	100.00
5.5	60,776		0.0000	1.0000	100.00
6.5	60,776		0.0000	1.0000	100.00
7.5	60,776		0.0000	1.0000	100.00
8.5	60,776		0.0000	1.0000	100.00
9.5	60,776		0.0000	1.0000	100.00
10.5	72,671		0.0000	1.0000	100.00
11.5	72,671		0.0000	1.0000	100.00
12.5	72,671		0.0000	1.0000	100.00
13.5	72,671		0.0000	1.0000	100.00
14.5	72,671		0.0000	1.0000	100.00
15.5	72,671		0.0000	1.0000	100.00
16.5	72,671		0.0000	1.0000	100.00
17.5	72,671		0.0000	1.0000	100.00
18.5	72,671		0.0000	1.0000	100.00
19.5	72,671		0.0000	1.0000	100.00
20.5	72,671		0.0000	1.0000	100.00
21.5	72,671		0.0000	1.0000	100.00
22.5	72,671		0.0000	1.0000	100.00
23.5	72,671		0.0000	1.0000	100.00
24.5	72,671		0.0000	1.0000	100.00
25.5	72,671		0.0000	1.0000	100.00
26.5	72,671		0.0000	1.0000	100.00
27.5	72,671		0.0000	1.0000	100.00
28.5	72,671		0.0000	1.0000	100.00
29.5	72,671		0.0000	1.0000	100.00
30.5	72,671		0.0000	1.0000	100.00
31.5	72,671		0.0000	1.0000	100.00
32.5	60,776		0.0000	1.0000	100.00
33.5	60,170		0.0000	1.0000	100.00
34.5	60,170		0.0000	1.0000	100.00
35.5	60,170		0.0000	1.0000	100.00
36.5	58,537		0.0000	1.0000	100.00
37.5	57,190		0.0000	1.0000	100.00
38.5	16,792		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

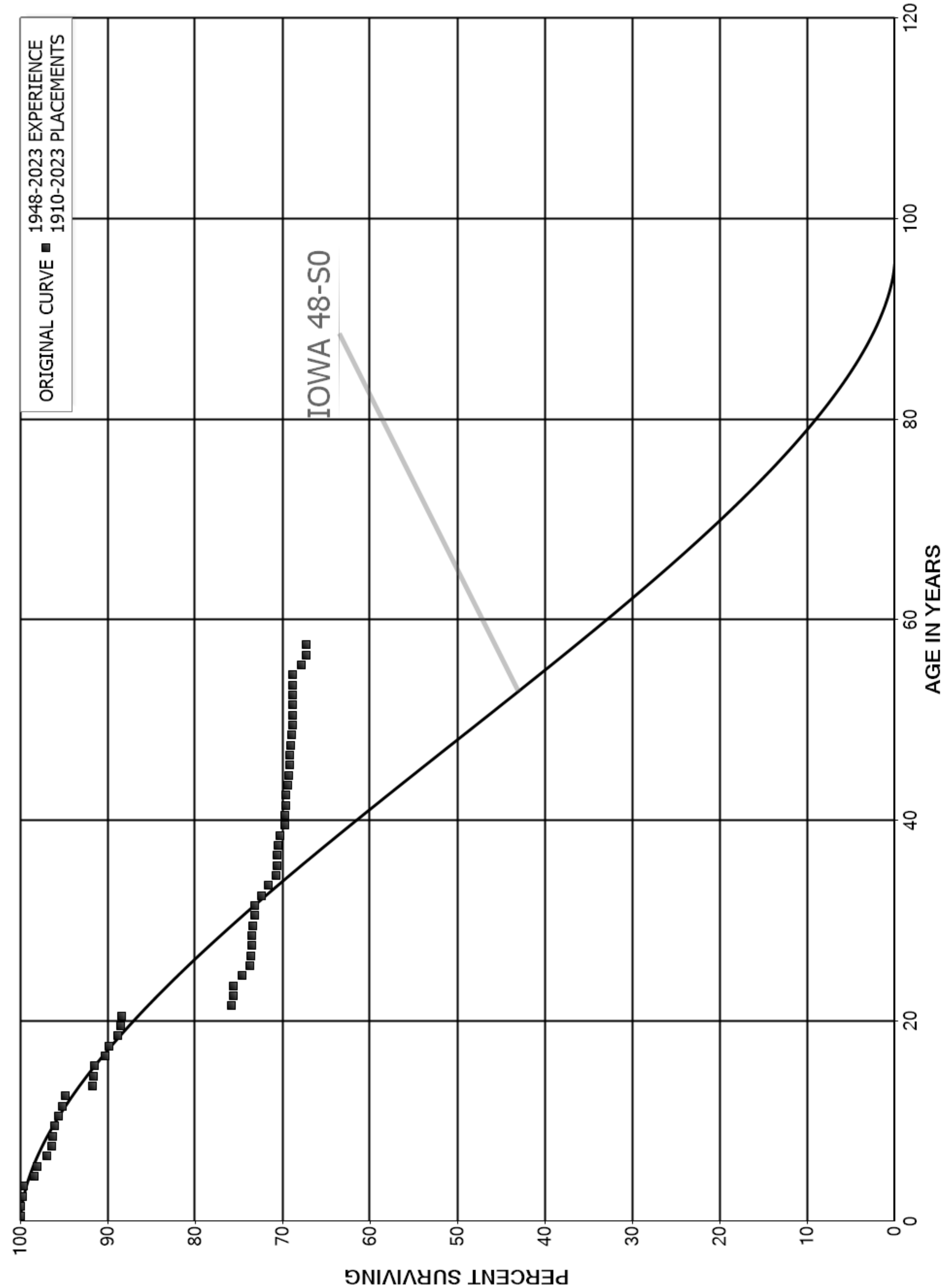
ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1978-1991 EXPERIENCE BAND 1978-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,567		0.0000	1.0000	100.00
40.5	15,567		0.0000	1.0000	100.00
41.5	15,567		0.0000	1.0000	100.00
42.5	15,567		0.0000	1.0000	100.00
43.5	15,567		0.0000	1.0000	100.00
44.5	6,819		0.0000	1.0000	100.00
45.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,507,854	39,299	0.0002	0.9998	100.00
0.5	174,467,479	63,712	0.0004	0.9996	99.98
1.5	147,249,495	278,632	0.0019	0.9981	99.94
2.5	111,216,870	192,359	0.0017	0.9983	99.75
3.5	109,531,844	1,337,593	0.0122	0.9878	99.58
4.5	104,970,230	300,827	0.0029	0.9971	98.36
5.5	92,754,025	1,097,379	0.0118	0.9882	98.08
6.5	90,954,613	475,026	0.0052	0.9948	96.92
7.5	86,655,231	126,822	0.0015	0.9985	96.42
8.5	84,369,484	163,031	0.0019	0.9981	96.27
9.5	73,684,194	393,305	0.0053	0.9947	96.09
10.5	39,359,139	154,142	0.0039	0.9961	95.58
11.5	30,336,991	99,411	0.0033	0.9967	95.20
12.5	26,296,254	873,148	0.0332	0.9668	94.89
13.5	24,644,700	38,768	0.0016	0.9984	91.74
14.5	23,891,392	24,337	0.0010	0.9990	91.59
15.5	23,549,321	317,423	0.0135	0.9865	91.50
16.5	22,787,234	100,550	0.0044	0.9956	90.27
17.5	20,868,782	246,103	0.0118	0.9882	89.87
18.5	19,253,697	69,123	0.0036	0.9964	88.81
19.5	14,642,704	23,841	0.0016	0.9984	88.49
20.5	12,979,613	1,843,884	0.1421	0.8579	88.35
21.5	10,603,372	27,089	0.0026	0.9974	75.80
22.5	9,716,130	4	0.0000	1.0000	75.60
23.5	9,310,212	118,594	0.0127	0.9873	75.60
24.5	8,764,638	110,670	0.0126	0.9874	74.64
25.5	8,165,699	11,605	0.0014	0.9986	73.70
26.5	7,805,416	9,618	0.0012	0.9988	73.59
27.5	7,699,600	3,094	0.0004	0.9996	73.50
28.5	7,666,084	2,415	0.0003	0.9997	73.47
29.5	7,650,338	27,872	0.0036	0.9964	73.45
30.5	7,473,141	6,135	0.0008	0.9992	73.18
31.5	7,212,551	70,812	0.0098	0.9902	73.12
32.5	7,010,712	74,315	0.0106	0.9894	72.40
33.5	6,766,260	84,148	0.0124	0.9876	71.64
34.5	6,520,415	7,153	0.0011	0.9989	70.75
35.5	6,435,276	5,915	0.0009	0.9991	70.67
36.5	6,319,990	6,901	0.0011	0.9989	70.60
37.5	6,133,575	18,930	0.0031	0.9969	70.53
38.5	6,047,497	53,995	0.0089	0.9911	70.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,847,725	710	0.0001	0.9999	69.68
40.5	5,557,270	3,798	0.0007	0.9993	69.67
41.5	5,299,850	3,567	0.0007	0.9993	69.62
42.5	4,935,188	9,794	0.0020	0.9980	69.58
43.5	4,835,673	12,969	0.0027	0.9973	69.44
44.5	4,788,883	8,014	0.0017	0.9983	69.25
45.5	3,982,147	786	0.0002	0.9998	69.14
46.5	2,901,848	4,086	0.0014	0.9986	69.12
47.5	2,226,866	622	0.0003	0.9997	69.03
48.5	2,191,007	3,943	0.0018	0.9982	69.01
49.5	1,777,154	450	0.0003	0.9997	68.88
50.5	1,545,146	28	0.0000	1.0000	68.87
51.5	1,463,047		0.0000	1.0000	68.86
52.5	1,440,548		0.0000	1.0000	68.86
53.5	1,428,160	418	0.0003	0.9997	68.86
54.5	1,403,802	20,908	0.0149	0.9851	68.84
55.5	1,328,620	10,091	0.0076	0.9924	67.82
56.5	1,295,002	558	0.0004	0.9996	67.30
57.5	642,291	3,476	0.0054	0.9946	67.27
58.5	369,608		0.0000	1.0000	66.91
59.5	239,103	435	0.0018	0.9982	66.91
60.5	231,368		0.0000	1.0000	66.79
61.5	226,079		0.0000	1.0000	66.79
62.5	219,077		0.0000	1.0000	66.79
63.5	216,762		0.0000	1.0000	66.79
64.5	264,704	38,544	0.1456	0.8544	66.79
65.5	223,904	9,030	0.0403	0.9597	57.06
66.5	211,055		0.0000	1.0000	54.76
67.5	164,997		0.0000	1.0000	54.76
68.5	147,143	8,917	0.0606	0.9394	54.76
69.5	138,163		0.0000	1.0000	51.44
70.5	126,631		0.0000	1.0000	51.44
71.5	97,411		0.0000	1.0000	51.44
72.5	87,330		0.0000	1.0000	51.44
73.5	87,082		0.0000	1.0000	51.44
74.5	78,739		0.0000	1.0000	51.44
75.5	75,677		0.0000	1.0000	51.44
76.5	68,896		0.0000	1.0000	51.44
77.5	68,703		0.0000	1.0000	51.44
78.5	67,941		0.0000	1.0000	51.44

NORTHWEST NATURAL GAS COMPANY

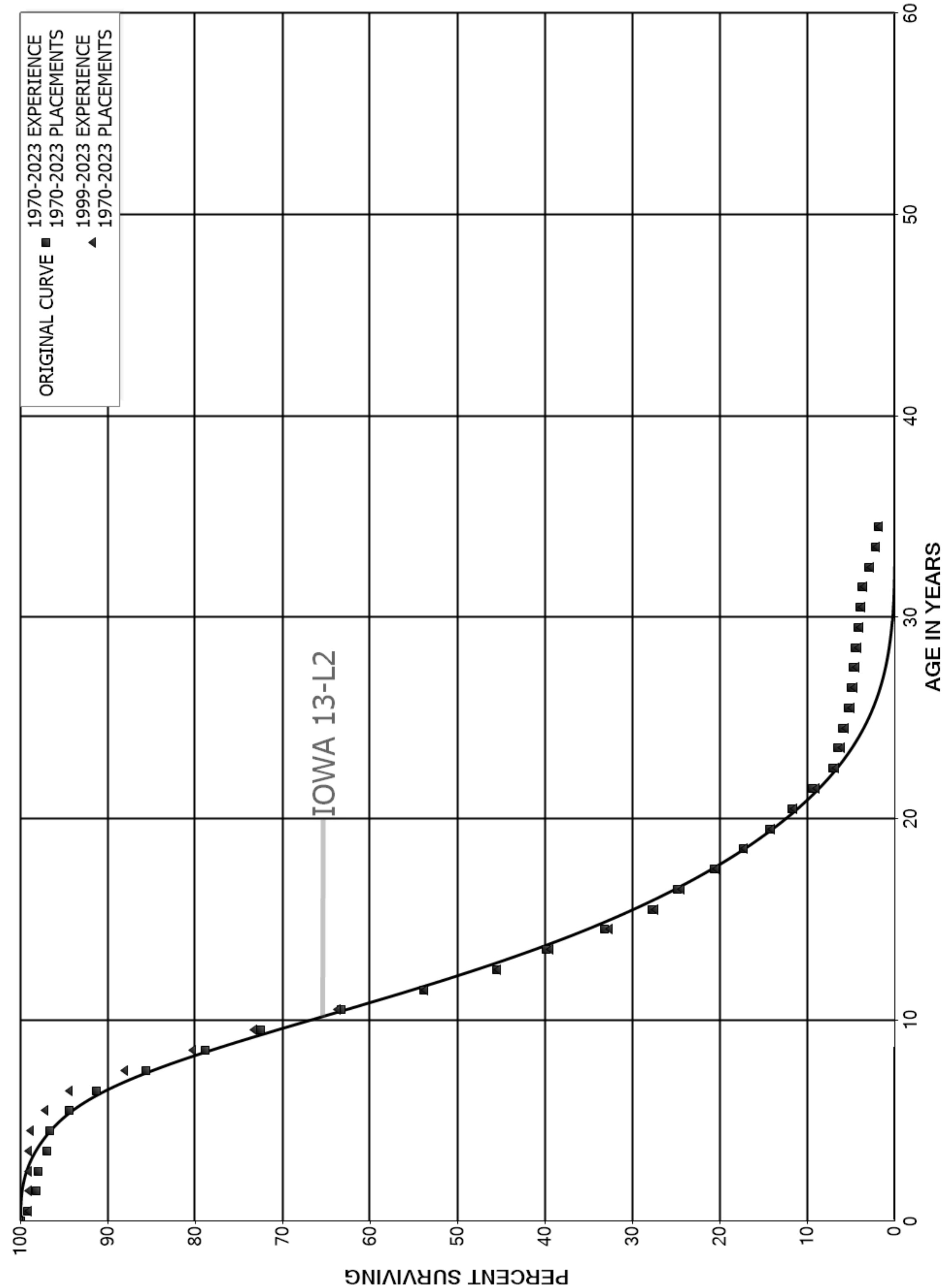
ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	67,910		0.0000	1.0000	51.44
80.5	64,852		0.0000	1.0000	51.44
81.5	64,341		0.0000	1.0000	51.44
82.5	62,997		0.0000	1.0000	51.44
83.5	62,902		0.0000	1.0000	51.44
84.5	62,795		0.0000	1.0000	51.44
85.5	61,850	416	0.0067	0.9933	51.44
86.5	61,198		0.0000	1.0000	51.10
87.5	61,165		0.0000	1.0000	51.10
88.5	61,165		0.0000	1.0000	51.10
89.5	61,165		0.0000	1.0000	51.10
90.5	61,165		0.0000	1.0000	51.10
91.5	61,165	4,535	0.0741	0.9259	51.10
92.5	56,630		0.0000	1.0000	47.31
93.5	56,453		0.0000	1.0000	47.31
94.5	56,453	5,153	0.0913	0.9087	47.31
95.5	51,300		0.0000	1.0000	42.99
96.5	50,755		0.0000	1.0000	42.99
97.5	50,755		0.0000	1.0000	42.99
98.5	50,663		0.0000	1.0000	42.99
99.5	50,652		0.0000	1.0000	42.99
100.5	50,585		0.0000	1.0000	42.99
101.5	50,075		0.0000	1.0000	42.99
102.5	50,075		0.0000	1.0000	42.99
103.5	49,651		0.0000	1.0000	42.99
104.5	49,651		0.0000	1.0000	42.99
105.5	49,651		0.0000	1.0000	42.99
106.5	49,651		0.0000	1.0000	42.99
107.5	49,651		0.0000	1.0000	42.99
108.5	49,479		0.0000	1.0000	42.99
109.5	49,479		0.0000	1.0000	42.99
110.5					42.99

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1970-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	103,000,891	810,292	0.0079	0.9921	100.00
0.5	101,168,447	1,043,743	0.0103	0.9897	99.21
1.5	97,763,703	277,244	0.0028	0.9972	98.19
2.5	93,409,406	913,832	0.0098	0.9902	97.91
3.5	87,539,201	295,923	0.0034	0.9966	96.95
4.5	79,760,292	1,864,246	0.0234	0.9766	96.63
5.5	51,640,698	1,679,914	0.0325	0.9675	94.37
6.5	49,790,256	3,081,630	0.0619	0.9381	91.30
7.5	46,517,221	3,726,898	0.0801	0.9199	85.65
8.5	42,567,044	3,415,602	0.0802	0.9198	78.78
9.5	37,075,615	4,714,481	0.1272	0.8728	72.46
10.5	28,544,623	4,248,575	0.1488	0.8512	63.25
11.5	21,358,720	3,296,502	0.1543	0.8457	53.83
12.5	17,333,847	2,181,678	0.1259	0.8741	45.53
13.5	13,505,141	2,237,165	0.1657	0.8343	39.80
14.5	10,983,785	1,824,552	0.1661	0.8339	33.20
15.5	8,613,411	895,995	0.1040	0.8960	27.69
16.5	7,468,788	1,277,769	0.1711	0.8289	24.81
17.5	6,129,743	972,045	0.1586	0.8414	20.56
18.5	5,092,789	895,469	0.1758	0.8242	17.30
19.5	3,851,531	670,605	0.1741	0.8259	14.26
20.5	2,966,297	613,790	0.2069	0.7931	11.78
21.5	2,270,208	553,251	0.2437	0.7563	9.34
22.5	1,649,730	137,289	0.0832	0.9168	7.06
23.5	1,489,505	113,735	0.0764	0.9236	6.48
24.5	1,235,428	146,339	0.1185	0.8815	5.98
25.5	971,230	70,523	0.0726	0.9274	5.27
26.5	865,547	34,821	0.0402	0.9598	4.89
27.5	741,361	30,978	0.0418	0.9582	4.69
28.5	579,963	42,868	0.0739	0.9261	4.50
29.5	414,518	19,394	0.0468	0.9532	4.17
30.5	399,466	20,433	0.0512	0.9488	3.97
31.5	379,033	86,154	0.2273	0.7727	3.77
32.5	283,033	73,243	0.2588	0.7412	2.91
33.5	209,790	32,157	0.1533	0.8467	2.16
34.5	147,565	6,956	0.0471	0.9529	1.83
35.5	140,028	12,235	0.0874	0.9126	1.74
36.5	127,793		0.0000	1.0000	1.59
37.5	127,793	9,128	0.0714	0.9286	1.59
38.5	118,665	9,517	0.0802	0.9198	1.48

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1970-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,804	3,518	0.0329	0.9671	1.36
40.5	75,940		0.0000	1.0000	1.31
41.5	75,940		0.0000	1.0000	1.31
42.5	75,940		0.0000	1.0000	1.31
43.5	75,940		0.0000	1.0000	1.31
44.5	75,940		0.0000	1.0000	1.31
45.5	75,940		0.0000	1.0000	1.31
46.5	75,940		0.0000	1.0000	1.31
47.5	69,477		0.0000	1.0000	1.31
48.5	69,477		0.0000	1.0000	1.31
49.5	69,477		0.0000	1.0000	1.31
50.5	69,477		0.0000	1.0000	1.31
51.5					1.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1999-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	79,345,235	810,292	0.0102	0.9898	100.00
0.5	79,846,496		0.0000	1.0000	98.98
1.5	80,046,168	21,443	0.0003	0.9997	98.98
2.5	78,316,136	43,927	0.0006	0.9994	98.95
3.5	75,002,739	104,526	0.0014	0.9986	98.90
4.5	69,518,649	1,190,138	0.0171	0.9829	98.76
5.5	43,748,678	1,275,411	0.0292	0.9708	97.07
6.5	42,861,155	2,841,718	0.0663	0.9337	94.24
7.5	40,951,949	3,621,172	0.0884	0.9116	87.99
8.5	38,042,090	3,311,277	0.0870	0.9130	80.21
9.5	33,370,336	4,389,400	0.1315	0.8685	73.23
10.5	25,660,027	4,032,763	0.1572	0.8428	63.60
11.5	19,103,052	2,954,460	0.1547	0.8453	53.60
12.5	15,423,125	2,068,291	0.1341	0.8659	45.31
13.5	12,200,248	2,099,737	0.1721	0.8279	39.23
14.5	10,023,164	1,615,406	0.1612	0.8388	32.48
15.5	7,968,568	855,914	0.1074	0.8926	27.25
16.5	6,964,791	1,162,181	0.1669	0.8331	24.32
17.5	5,791,366	922,320	0.1593	0.8407	20.26
18.5	4,881,498	895,469	0.1834	0.8166	17.04
19.5	3,660,170	670,605	0.1832	0.8168	13.91
20.5	2,802,334	613,790	0.2190	0.7810	11.36
21.5	2,131,096	553,251	0.2596	0.7404	8.87
22.5	1,517,081	137,289	0.0905	0.9095	6.57
23.5	1,356,856	100,018	0.0737	0.9263	5.98
24.5	1,146,564	143,962	0.1256	0.8744	5.53
25.5	884,743	70,523	0.0797	0.9203	4.84
26.5	851,350	34,821	0.0409	0.9591	4.45
27.5	731,844	30,978	0.0423	0.9577	4.27
28.5	579,963	42,868	0.0739	0.9261	4.09
29.5	414,518	19,394	0.0468	0.9532	3.79
30.5	399,466	20,433	0.0512	0.9488	3.61
31.5	379,033	86,154	0.2273	0.7727	3.43
32.5	283,033	73,243	0.2588	0.7412	2.65
33.5	209,790	32,157	0.1533	0.8467	1.96
34.5	147,565	6,956	0.0471	0.9529	1.66
35.5	140,028	12,235	0.0874	0.9126	1.58
36.5	127,793		0.0000	1.0000	1.45
37.5	127,793	9,128	0.0714	0.9286	1.45
38.5	118,665	9,517	0.0802	0.9198	1.34

NORTHWEST NATURAL GAS COMPANY

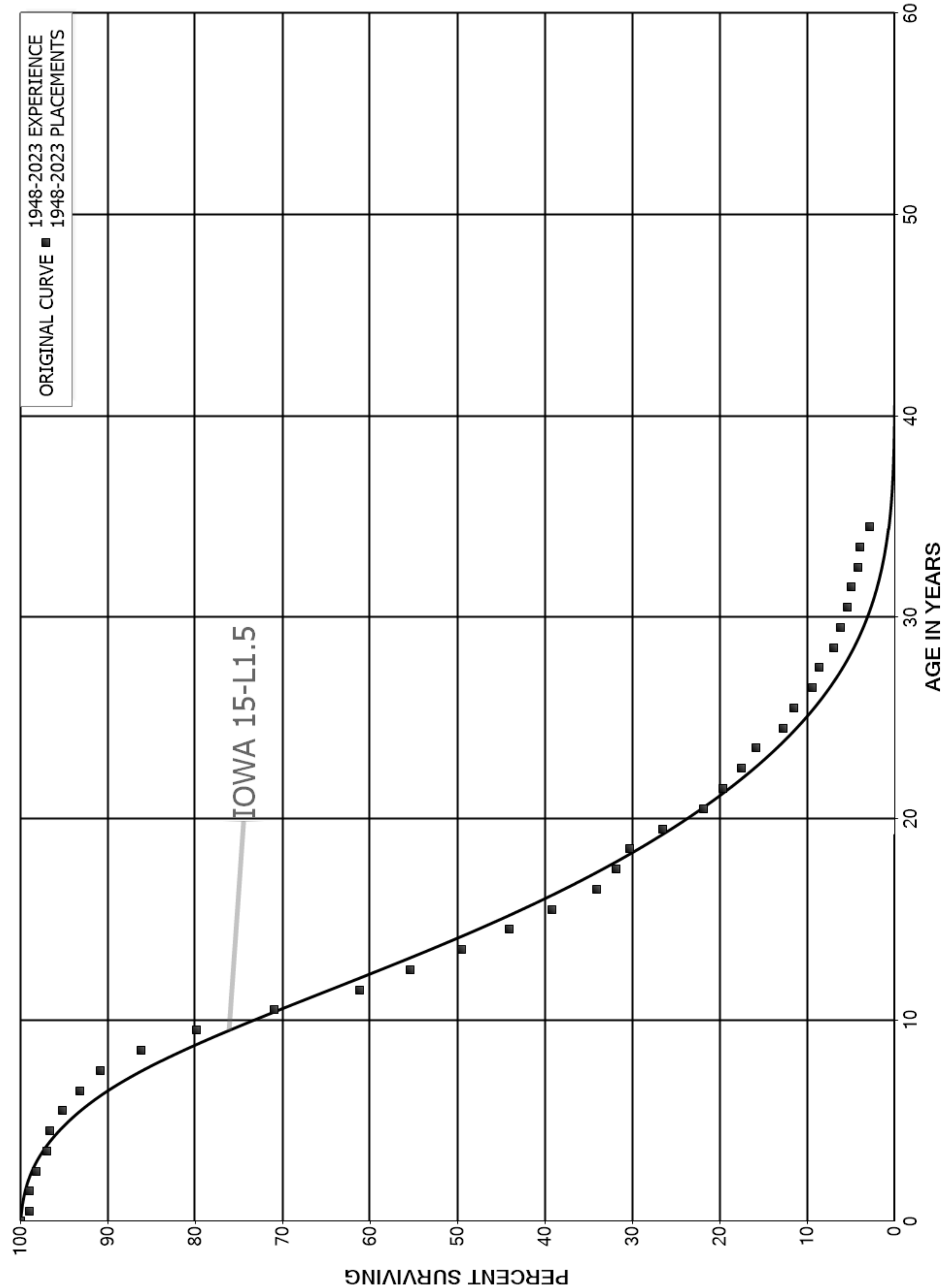
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1999-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,804	3,518	0.0329	0.9671	1.23
40.5	75,940		0.0000	1.0000	1.19
41.5	75,940		0.0000	1.0000	1.19
42.5	75,940		0.0000	1.0000	1.19
43.5	75,940		0.0000	1.0000	1.19
44.5	75,940		0.0000	1.0000	1.19
45.5	75,940		0.0000	1.0000	1.19
46.5	75,940		0.0000	1.0000	1.19
47.5	69,477		0.0000	1.0000	1.19
48.5	69,477		0.0000	1.0000	1.19
49.5	69,477		0.0000	1.0000	1.19
50.5	69,477		0.0000	1.0000	1.19
51.5					1.19

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	26,880,447	288,089	0.0107	0.9893	100.00
0.5	25,281,767		0.0000	1.0000	98.93
1.5	24,324,429	187,123	0.0077	0.9923	98.93
2.5	21,978,096	268,514	0.0122	0.9878	98.17
3.5	19,960,191	66,342	0.0033	0.9967	96.97
4.5	18,122,706	268,368	0.0148	0.9852	96.65
5.5	12,034,695	252,087	0.0209	0.9791	95.21
6.5	11,866,127	297,998	0.0251	0.9749	93.22
7.5	11,594,547	594,677	0.0513	0.9487	90.88
8.5	10,998,956	807,883	0.0735	0.9265	86.22
9.5	9,881,042	1,108,142	0.1121	0.8879	79.89
10.5	8,567,207	1,177,004	0.1374	0.8626	70.93
11.5	7,047,484	666,155	0.0945	0.9055	61.18
12.5	5,690,217	606,769	0.1066	0.8934	55.40
13.5	4,918,015	543,883	0.1106	0.8894	49.49
14.5	4,335,258	481,182	0.1110	0.8890	44.02
15.5	3,783,300	488,233	0.1290	0.8710	39.13
16.5	3,255,980	211,609	0.0650	0.9350	34.08
17.5	2,763,336	139,493	0.0505	0.9495	31.87
18.5	2,124,170	262,192	0.1234	0.8766	30.26
19.5	1,803,679	318,213	0.1764	0.8236	26.52
20.5	1,387,483	143,146	0.1032	0.8968	21.84
21.5	1,144,741	122,544	0.1070	0.8930	19.59
22.5	1,022,197	97,196	0.0951	0.9049	17.49
23.5	925,001	180,554	0.1952	0.8048	15.83
24.5	697,695	68,335	0.0979	0.9021	12.74
25.5	579,885	105,633	0.1822	0.8178	11.49
26.5	456,931	40,160	0.0879	0.9121	9.40
27.5	409,809	77,980	0.1903	0.8097	8.57
28.5	319,621	34,938	0.1093	0.8907	6.94
29.5	306,400	41,139	0.1343	0.8657	6.18
30.5	260,912	19,501	0.0747	0.9253	5.35
31.5	241,411	37,953	0.1572	0.8428	4.95
32.5	193,616	12,255	0.0633	0.9367	4.17
33.5	181,362	49,370	0.2722	0.7278	3.91
34.5	117,331		0.0000	1.0000	2.85
35.5	117,331		0.0000	1.0000	2.85
36.5	117,331		0.0000	1.0000	2.85
37.5	117,331		0.0000	1.0000	2.85
38.5	54,944		0.0000	1.0000	2.85

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	54,944		0.0000	1.0000	2.85
40.5	54,944		0.0000	1.0000	2.85
41.5	30,054		0.0000	1.0000	2.85
42.5	30,054	20,334	0.6766	0.3234	2.85
43.5	1,025		0.0000	1.0000	0.92
44.5	1,025		0.0000	1.0000	0.92
45.5	1,025		0.0000	1.0000	0.92
46.5	1,025		0.0000	1.0000	0.92
47.5	1,025	1,025	1.0000		0.92
48.5					

PART VIII. NET SALVAGE STATISTICS

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 AND 376.12 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	1,431,992	226,683	16		0	226,683-	16-
1994	1,342,378	503,908	38		0	503,908-	38-
1995	344,510	450,493	131		0	450,493-	131-
1996	1,098,128	507,451	46		0	507,451-	46-
1997	1,806,918	503,848	28		0	503,848-	28-
1998	1,534,412	584,938	38		0	584,938-	38-
1999	1,902,441	652,267	34	15-	0	652,282-	34-
2000	1,690,556	86,394	5		0	86,394-	5-
2001	2,229,849	807,009	36		0	807,009-	36-
2002	1,765,905	59,291	3	53,763-	3-	113,054-	6-
2003	978,308	1,219,533	125	3,457	0	1,216,076-	124-
2004	1,104,995	1,369,122	124		0	1,369,122-	124-
2005	1,600,635	1,206,093	75		0	1,206,093-	75-
2006	3,661,277	1,273,053	35		0	1,273,053-	35-
2007	1,377,807	1,317,655	96		0	1,317,655-	96-
2008	794,472	1,177,857	148		0	1,177,857-	148-
2009	985,969	1,375,758	140	31,298	3	1,344,460-	136-
2010	874,891	2,057,941	235	72,780	8	1,985,161-	227-
2011	1,100,014	2,172,997	198	50,054	5	2,122,943-	193-
2012	4,007,215	1,968,930	49	33,775	1	1,935,155-	48-
2013	910,088	1,829,071	201	41,432	5	1,787,639-	196-
2014	3,674,656	2,600,318	71	44,128	1	2,556,190-	70-
2015	839,793	2,844,855	339	20,544	2	2,824,311-	336-
2016	1,258,301	2,367,778	188	18,016	1	2,349,762-	187-
2017	393,185	1,743,030	443	36,627	9	1,706,403-	434-
2018	583,585	2,079,219	356	77,396	13	2,001,823-	343-
2019	495,564	993,867	201	94,181	19	899,686-	182-
2020	89,443	214,670	240	73,714	82	140,956-	158-
2021	391,433	2,570,854	657	130,472	33	2,440,382-	623-
2022	635,695	2,694,366	424	32,232	5	2,662,134-	419-
2023	1,636,252		0	60,650	4	60,650	4
TOTAL	42,540,667	39,459,249	93	766,978	2	38,692,271-	91-

THREE-YEAR MOVING AVERAGES

93-95	1,039,627	393,695	38		0	393,695-	38-
94-96	928,339	487,284	52		0	487,284-	52-
95-97	1,083,185	487,264	45		0	487,264-	45-
96-98	1,479,819	532,079	36		0	532,079-	36-
97-99	1,747,924	580,351	33	5-	0	580,356-	33-
98-00	1,709,136	441,200	26	5-	0	441,205-	26-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 AND 376.12 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	1,940,949	515,223	27	5-	0	515,228-	27-
00-02	1,895,437	317,565	17	17,921-	1-	335,486-	18-
01-03	1,658,021	695,278	42	16,769-	1-	712,046-	43-
02-04	1,283,069	882,649	69	16,769-	1-	899,417-	70-
03-05	1,227,979	1,264,916	103	1,152	0	1,263,764-	103-
04-06	2,122,302	1,282,756	60		0	1,282,756-	60-
05-07	2,213,240	1,265,600	57		0	1,265,600-	57-
06-08	1,944,519	1,256,188	65		0	1,256,188-	65-
07-09	1,052,749	1,290,423	123	10,433	1	1,279,991-	122-
08-10	885,111	1,537,185	174	34,693	4	1,502,493-	170-
09-11	986,958	1,868,899	189	51,377	5	1,817,521-	184-
10-12	1,994,040	2,066,623	104	52,203	3	2,014,420-	101-
11-13	2,005,772	1,990,333	99	41,754	2	1,948,579-	97-
12-14	2,863,986	2,132,773	74	39,778	1	2,092,995-	73-
13-15	1,808,179	2,424,748	134	35,368	2	2,389,380-	132-
14-16	1,924,250	2,604,317	135	27,563	1	2,576,754-	134-
15-17	830,426	2,318,554	279	25,062	3	2,293,492-	276-
16-18	745,024	2,063,342	277	44,013	6	2,019,329-	271-
17-19	490,778	1,605,372	327	69,401	14	1,535,971-	313-
18-20	389,531	1,095,919	281	81,764	21	1,014,155-	260-
19-21	325,480	1,259,797	387	99,456	31	1,160,341-	357-
20-22	372,190	1,826,630	491	78,806	21	1,747,824-	470-
21-23	887,793	1,755,073	198	74,451	8	1,680,622-	189-
FIVE-YEAR AVERAGE							
19-23	649,677	1,294,751	199	78,250	12	1,216,502-	187-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	2,841,387	396,430	14		0	396,430-	14-
1994	2,500,176	663,273	27		0	663,273-	27-
1995	2,342,406	748,847	32		0	748,847-	32-
1996	2,230,345	741,543	33		0	741,543-	33-
1997	1,902,901	771,714	41		0	771,714-	41-
1998	1,960,026	842,083	43		0	842,083-	43-
1999	1,994,257	896,403	45	105-	0	896,508-	45-
2000	1,617,520	35,662	2		0	35,662-	2-
2001	1,390,478	876,280	63		0	876,280-	63-
2002	1,276,053	52,935	4	108,373-	8-	161,308-	13-
2003	1,166,885	923,195	79	133	0	923,062-	79-
2004	1,204,971	1,334,747	111		0	1,334,747-	111-
2005	1,698,676	1,075,509	63		0	1,075,509-	63-
2006	1,337,959	1,267,508	95		0	1,267,508-	95-
2007	1,674,091	2,072,481	124		0	2,072,481-	124-
2008	986,328	2,488,358	252		0	2,488,358-	252-
2009	430,790	465,616	108		0	465,616-	108-
2010	496,643	1,318,460	265		0	1,318,460-	265-
2011	489,210	1,171,358	239		0	1,171,358-	239-
2012	689,693	2,784,271	404		0	2,784,271-	404-
2013	1,699,245	2,306,446	136		0	2,306,446-	136-
2014	1,630,916	2,933,879	180		0	2,933,879-	180-
2015	1,293,428	2,577,664	199		0	2,577,664-	199-
2016	2,214,181	5,577,376	252		0	5,577,376-	252-
2017	1,162,235	1,248,131	107		0	1,248,131-	107-
2018	1,714,774	2,079,495	121		0	2,079,495-	121-
2019	1,477,866	2,552,534	173		0	2,552,534-	173-
2020	135,451	195,198	144		0	195,198-	144-
2021	1,352,193	7,221,715	534		0	7,221,715-	534-
2022	2,709,157	4,137,277	153		0	4,137,277-	153-
2023	2,523,393		0		0		0
TOTAL	48,143,634	51,756,388	108	108,345-	0	51,864,733-	108-

THREE-YEAR MOVING AVERAGES

93-95	2,561,323	602,850	24		0	602,850-	24-
94-96	2,357,642	717,888	30		0	717,888-	30-
95-97	2,158,551	754,035	35		0	754,035-	35-
96-98	2,031,091	785,113	39		0	785,113-	39-
97-99	1,952,395	836,733	43	35-	0	836,768-	43-
98-00	1,857,268	591,383	32	35-	0	591,418-	32-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	1,667,418	602,782	36	35-	0	602,817-	36-
00-02	1,428,017	321,626	23	36,124-	3-	357,750-	25-
01-03	1,277,805	617,470	48	36,080-	3-	653,550-	51-
02-04	1,215,970	770,292	63	36,080-	3-	806,372-	66-
03-05	1,356,844	1,111,150	82	44	0	1,111,106-	82-
04-06	1,413,869	1,225,921	87		0	1,225,921-	87-
05-07	1,570,242	1,471,833	94		0	1,471,833-	94-
06-08	1,332,793	1,942,782	146		0	1,942,782-	146-
07-09	1,030,403	1,675,485	163		0	1,675,485-	163-
08-10	637,920	1,424,145	223		0	1,424,145-	223-
09-11	472,214	985,145	209		0	985,145-	209-
10-12	558,515	1,758,030	315		0	1,758,030-	315-
11-13	959,383	2,087,358	218		0	2,087,358-	218-
12-14	1,339,951	2,674,865	200		0	2,674,865-	200-
13-15	1,541,196	2,605,996	169		0	2,605,996-	169-
14-16	1,712,842	3,696,306	216		0	3,696,306-	216-
15-17	1,556,615	3,134,390	201		0	3,134,390-	201-
16-18	1,697,063	2,968,334	175		0	2,968,334-	175-
17-19	1,451,625	1,960,053	135		0	1,960,053-	135-
18-20	1,109,364	1,609,076	145		0	1,609,076-	145-
19-21	988,503	3,323,149	336		0	3,323,149-	336-
20-22	1,398,934	3,851,397	275		0	3,851,397-	275-
21-23	2,194,914	3,786,331	173		0	3,786,331-	173-
FIVE-YEAR AVERAGE							
19-23	1,639,612	2,821,345	172		0	2,821,345-	172-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	35,525		0		0		0
1994	75,695		0	25	0	25	0
1995	109,668		0	220	0	220	0
1996	169,183		0	158	0	158	0
1997	187,776		0	6,160	3	6,160	3
1998	234,076		0	16,920	7	16,920	7
1999	237,115		0	6,900	3	6,900	3
2000	182,134		0	1,936	1	1,936	1
2001	147,077		0		0		0
2002	205,198		0		0		0
2003	323,750		0		0		0
2004	293,768		0		0		0
2005	316,926		0		0		0
2006	517,442		0		0		0
2007	865,099		0		0		0
2008	679,498		0		0		0
2009	2,445,908		0		0		0
2010	832,853		0		0		0
2011	387,538		0		0		0
2012	442,790		0		0		0
2013	822,151		0		0		0
2014	839,332		0		0		0
2015	1,126,709		0		0		0
2016	1,315,911		0		0		0
2017	696,854		0		0		0
2018	1,576,280		0		0		0
2019	1,729,669		0		0		0
2020	4,769,124		0	43,305	1	43,305	1
2021	5,165,289		0	70,297	1	70,297	1
2022	2,543,509		0	11,177	0	11,177	0
2023	7,065,967		0		0		0
TOTAL	36,339,814		0	157,098	0	157,098	0

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
93-95	73,629		0	82	0	82	0
94-96	118,182		0	134	0	134	0
95-97	155,542		0	2,179	1	2,179	1
96-98	197,012		0	7,746	4	7,746	4
97-99	219,656		0	9,993	5	9,993	5
98-00	217,775		0	8,585	4	8,585	4

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	188,775		0	2,945	2	2,945	2
00-02	178,136		0	645	0	645	0
01-03	225,342		0		0		0
02-04	274,239		0		0		0
03-05	311,481		0		0		0
04-06	376,045		0		0		0
05-07	566,489		0		0		0
06-08	687,346		0		0		0
07-09	1,330,168		0		0		0
08-10	1,319,420		0		0		0
09-11	1,222,100		0		0		0
10-12	554,394		0		0		0
11-13	550,826		0		0		0
12-14	701,424		0		0		0
13-15	929,397		0		0		0
14-16	1,093,984		0		0		0
15-17	1,046,491		0		0		0
16-18	1,196,348		0		0		0
17-19	1,334,268		0		0		0
18-20	2,691,691		0	14,435	1	14,435	1
19-21	3,888,027		0	37,867	1	37,867	1
20-22	4,159,307		0	41,593	1	41,593	1
21-23	4,924,922		0	27,158	1	27,158	1
FIVE-YEAR AVERAGE							
19-23	4,254,712		0	24,956	1	24,956	1

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.10 METERS - ELECTRIC

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2014	507,007		0		0		0
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
TOTAL	507,007		0		0		0
THREE-YEAR MOVING AVERAGES							
14-16	169,002		0		0		0
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
21-23							
FIVE-YEAR AVERAGE							
19-23							

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	631,904		0		0		0
2011	272,574		0		0		0
2012	479,487		0		0		0
2013	500,211		0		0		0
2014	422,728		0		0		0
2015	607,184		0		0		0
2016	552,861		0		0		0
2017	403,962		0		0		0
2018	1,074,843		0		0		0
2019	4,021,547		0		0		0
2020	4,090,445		0		0		0
2021	3,274,304		0		0		0
2022	5,021,163		0		0		0
2023	2,850,156		0		0		0
TOTAL	24,203,369		0		0		0
THREE-YEAR MOVING AVERAGES							
10-12	461,322		0		0		0
11-13	417,424		0		0		0
12-14	467,475		0		0		0
13-15	510,041		0		0		0
14-16	527,591		0		0		0
15-17	521,336		0		0		0
16-18	677,222		0		0		0
17-19	1,833,451		0		0		0
18-20	3,062,278		0		0		0
19-21	3,795,432		0		0		0
20-22	4,128,637		0		0		0
21-23	3,715,208		0		0		0
FIVE-YEAR AVERAGE							
19-23	3,851,523		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	46,518	2,598	6		0	2,598-	6-
1994	96,011	9,377	10	1,694	2	7,683-	8-
1995	131,729	3,165	2		0	3,165-	2-
1996	238,906	303	0		0	303-	0
1997	191,607	1,715	1		0	1,715-	1-
1998	328,975	596	0		0	596-	0
1999	370,161	8,471	2	290	0	8,181-	2-
2000	278,986		0	6,715	2	6,715	2
2001	242,395	6,349	3		0	6,349-	3-
2002	329,497	1,602	0		0	1,602-	0
2003	514,135	19,994	4		0	19,994-	4-
2004	480,981	4,365	1		0	4,365-	1-
2005	516,182		0		0		0
2006	813,246		0		0		0
2007	1,549,221		0		0		0
2008	1,077,855		0		0		0
2009	10,496,732		0		0		0
2010	3,633,211		0		0		0
2011	1,646,617		0		0		0
2012	1,809,044		0		0		0
2013	2,227,911		0		0		0
2014	3,182,624		0		0		0
2015	3,438,321		0		0		0
2016	2,975,570		0		0		0
2017	1,694,704		0		0		0
2018	2,778,764		0		0		0
2019	2,692,778		0		0		0
2020	5,030,201		0		0		0
2021	2,322,890		0		0		0
2022	2,969,507		0		0		0
2023	4,862,972		0		0		0
TOTAL	58,968,251	58,535	0	8,699	0	49,836-	0

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
93-95	91,419	5,047	6	565	1	4,482-	5-
94-96	155,549	4,282	3	565	0	3,717-	2-
95-97	187,414	1,728	1		0	1,728-	1-
96-98	253,163	871	0		0	871-	0
97-99	296,914	3,594	1	97	0	3,497-	1-
98-00	326,041	3,022	1	2,335	1	687-	0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	297,181	4,940	2	2,335	1	2,605-	1-
00-02	283,626	2,650	1	2,238	1	412-	0
01-03	362,009	9,315	3		0	9,315-	3-
02-04	441,538	8,654	2		0	8,654-	2-
03-05	503,766	8,120	2		0	8,120-	2-
04-06	603,470	1,455	0		0	1,455-	0
05-07	959,550		0		0		0
06-08	1,146,774		0		0		0
07-09	4,374,603		0		0		0
08-10	5,069,266		0		0		0
09-11	5,258,853		0		0		0
10-12	2,362,957		0		0		0
11-13	1,894,524		0		0		0
12-14	2,406,526		0		0		0
13-15	2,949,619		0		0		0
14-16	3,198,838		0		0		0
15-17	2,702,865		0		0		0
16-18	2,483,013		0		0		0
17-19	2,388,749		0		0		0
18-20	3,500,581		0		0		0
19-21	3,348,623		0		0		0
20-22	3,440,866		0		0		0
21-23	3,385,123		0		0		0
FIVE-YEAR AVERAGE							
19-23	3,575,670		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	518,377		0		0		0
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
TOTAL	518,377		0		0		0
THREE-YEAR MOVING AVERAGES							
14-16	172,792		0		0		0
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
21-23							
FIVE-YEAR AVERAGE							
19-23							

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2010	116,947		0		0		0
2011	52,987		0		0		0
2012	94,349		0		0		0
2013	101,403		0		0		0
2014	99,995		0		0		0
2015	113,714		0		0		0
2016	103,020		0		0		0
2017	74,826		0		0		0
2018	125,764		0		0		0
2019	197,054		0		0		0
2020	377,910		0		0		0
2021	321,469		0		0		0
2022	257,923		0		0		0
2023	547,368		0		0		0
TOTAL	2,584,729		0		0		0
THREE-YEAR MOVING AVERAGES							
10-12	88,094		0		0		0
11-13	82,913		0		0		0
12-14	98,582		0		0		0
13-15	105,037		0		0		0
14-16	105,576		0		0		0
15-17	97,187		0		0		0
16-18	101,203		0		0		0
17-19	132,548		0		0		0
18-20	233,576		0		0		0
19-21	298,811		0		0		0
20-22	319,101		0		0		0
21-23	375,587		0		0		0
FIVE-YEAR AVERAGE							
19-23	340,345		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993		12,158				12,158-	
1994	723	155,281		50	7	155,231-	
1995		12,056				12,056-	
1996	374,465		0		0		0
1997	43,454	6,063	14		0	6,063-	14-
1998							
1999							
2000	125,000		0		0		0
2001	728,234		0		0		0
2002							
2003	6,013		0		0		0
2004							
2005	8,335		0		0		0
2006							
2007							
2008							
2009	2,852		0		0		0
2010							
2011							
2012	10,603		0		0		0
2013	649,588		0		0		0
2014	57,511		0		0		0
2015							
2016							
2017							
2018							
2019							
2020	231,371		0		0		0
2021	1,132,240		0		0		0
2022							
2023							
TOTAL	3,370,388	185,558	6	50	0	185,508-	6-

THREE-YEAR MOVING AVERAGES

93-95	241	59,832		17	7	59,815-	
94-96	125,063	55,779	45	17	0	55,762-	45-
95-97	139,306	6,040	4		0	6,040-	4-
96-98	139,306	2,021	1		0	2,021-	1-
97-99	14,485	2,021	14		0	2,021-	14-
98-00	41,667		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
99-01	284,411		0		0		0
00-02	284,411		0		0		0
01-03	244,749		0		0		0
02-04	2,004		0		0		0
03-05	4,783		0		0		0
04-06	2,778		0		0		0
05-07	2,778		0		0		0
06-08							
07-09	951		0		0		0
08-10	951		0		0		0
09-11	951		0		0		0
10-12	3,534		0		0		0
11-13	220,064		0		0		0
12-14	239,234		0		0		0
13-15	235,700		0		0		0
14-16	19,170		0		0		0
15-17							
16-18							
17-19							
18-20	77,124		0		0		0
19-21	454,537		0		0		0
20-22	454,537		0		0		0
21-23	377,413		0		0		0
FIVE-YEAR AVERAGE							
19-23	272,722		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1996	3,663,578		0		0		0
1997	1,147,124		0		0		0
1998	643,102		0	194,772	30	194,772	30
1999	1,082,085		0	254,777	24	254,777	24
2000	785,471		0	152,200	19	152,200	19
2001	755,493		0	272,108	36	272,108	36
2002	1,093,048		0	277,660	25	277,660	25
2003	1,374,444		0	282,314	21	282,314	21
2004	1,197,018		0	346,555	29	346,555	29
2005	2,326,071		0	242,308	10	242,308	10
2006	1,212,955		0	218,615	18	218,615	18
2007	1,390,528		0	198,400	14	198,400	14
2008	1,213,420		0	132,689	11	132,689	11
2009	1,806,465		0	116,482	6	116,482	6
2010	2,718,582		0	206,572	8	206,572	8
2011	2,232,500		0	154,173	7	154,173	7
2012	1,908,460		0	240,524	13	240,524	13
2013	1,815,857		0	150,375	8	150,375	8
2014	943,871		0	83,811	9	83,811	9
2015	1,390,921		0	234,987	17	234,987	17
2016	2,350,445		0	328,690	14	328,690	14
2017	1,737,627		0	223,715	13	223,715	13
2018	1,541,208		0	251,821	16	251,821	16
2019	2,256,423		0	342,064	15	342,064	15
2020	1,534,186		0	350,318	23	350,318	23
2021	2,179,673		0	440,019	20	440,019	20
2022	2,112,903		0	481,303	23	481,303	23
2023	1,013,642		0	262,602	26	262,602	26
TOTAL	45,427,101		0	6,439,854	14	6,439,854	14

THREE-YEAR MOVING AVERAGES

96-98	1,817,935		0	64,924	4	64,924	4
97-99	957,437		0	149,850	16	149,850	16
98-00	836,886		0	200,583	24	200,583	24
99-01	874,350		0	226,362	26	226,362	26
00-02	878,004		0	233,989	27	233,989	27
01-03	1,074,329		0	277,361	26	277,361	26
02-04	1,221,503		0	302,176	25	302,176	25
03-05	1,632,511		0	290,392	18	290,392	18
04-06	1,578,681		0	269,159	17	269,159	17

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
05-07	1,643,185		0	219,775	13	219,775	13
06-08	1,272,301		0	183,235	14	183,235	14
07-09	1,470,138		0	149,190	10	149,190	10
08-10	1,912,822		0	151,914	8	151,914	8
09-11	2,252,516		0	159,076	7	159,076	7
10-12	2,286,514		0	200,423	9	200,423	9
11-13	1,985,606		0	181,691	9	181,691	9
12-14	1,556,063		0	158,237	10	158,237	10
13-15	1,383,550		0	156,391	11	156,391	11
14-16	1,561,746		0	215,829	14	215,829	14
15-17	1,826,331		0	262,464	14	262,464	14
16-18	1,876,427		0	268,075	14	268,075	14
17-19	1,845,086		0	272,533	15	272,533	15
18-20	1,777,272		0	314,734	18	314,734	18
19-21	1,990,094		0	377,467	19	377,467	19
20-22	1,942,254		0	423,880	22	423,880	22
21-23	1,768,739		0	394,641	22	394,641	22
FIVE-YEAR AVERAGE							
19-23	1,819,365		0	375,261	21	375,261	21

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	520,485		0		0		0
1996	75,190		0		0		0
1997	30,348		0		0		0
1998	63,975		0	19,797	31	19,797	31
1999	10,223		0	10,646	104	10,646	104
2000	104,702		0	26,730	26	26,730	26
2001	189,458		0	14,283	8	14,283	8
2002	190,349		0	29,311	15	29,311	15
2003	102,476		0	16,777	16	16,777	16
2004	302,574		0	14,825	5	14,825	5
2005	872,364		0	186,761	21	186,761	21
2006	504,138		0	20,352	4	20,352	4
2007	251,001		0	59,528	24	59,528	24
2008	114,341		0	15,286	13	15,286	13
2009	139,361		0	4,647	3	4,647	3
2010	240,789		0	46,089	19	46,089	19
2011	498,971		0	119,294	24	119,294	24
2012	365,158		0	92,512	25	92,512	25
2013	502,213		0	214,520	43	214,520	43
2014	255,426		0	38,520	15	38,520	15
2015	581,404		0	150,376	26	150,376	26
2016	710,358		0	170,180	24	170,180	24
2017	441,739		0	129,938	29	129,938	29
2018	549,609		0	136,469	25	136,469	25
2019	598,755		0	202,211	34	202,211	34
2020	204,308		0	34,185	17	34,185	17
2021	935,455		0	339,759	36	339,759	36
2022	730,921		0	316,493	43	316,493	43
2023	661,295		0	403,147	61	403,147	61
TOTAL	10,747,387		0	2,812,636	26	2,812,636	26

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	208,674		0		0		0
96-98	56,504		0	6,599	12	6,599	12
97-99	34,849		0	10,148	29	10,148	29
98-00	59,633		0	19,058	32	19,058	32
99-01	101,461		0	17,220	17	17,220	17
00-02	161,503		0	23,441	15	23,441	15
01-03	160,761		0	20,124	13	20,124	13
02-04	198,466		0	20,304	10	20,304	10

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
03-05	425,805		0	72,788	17	72,788	17
04-06	559,692		0	73,979	13	73,979	13
05-07	542,501		0	88,880	16	88,880	16
06-08	289,827		0	31,722	11	31,722	11
07-09	168,235		0	26,487	16	26,487	16
08-10	164,830		0	22,007	13	22,007	13
09-11	293,040		0	56,677	19	56,677	19
10-12	368,306		0	85,965	23	85,965	23
11-13	455,447		0	142,109	31	142,109	31
12-14	374,266		0	115,184	31	115,184	31
13-15	446,348		0	134,472	30	134,472	30
14-16	515,729		0	119,692	23	119,692	23
15-17	577,834		0	150,165	26	150,165	26
16-18	567,235		0	145,529	26	145,529	26
17-19	530,034		0	156,206	29	156,206	29
18-20	450,891		0	124,288	28	124,288	28
19-21	579,506		0	192,052	33	192,052	33
20-22	623,561		0	230,146	37	230,146	37
21-23	775,890		0	353,133	46	353,133	46
FIVE-YEAR AVERAGE							
19-23	626,147		0	259,159	41	259,159	41

PART IX. DETAILED DEPRECIATION CALCULATIONS

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.10 MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	502,539.37	502,539	502,539			
2001	558,085.41	558,085	558,085			
2002	459,910.17	459,910	459,910			
2003	2,307,822.96	2,307,823	2,307,823			
2005	885,137.94	885,138	885,138			
2006	379,424.15	379,424	379,424			
2007	905,024.86	905,025	905,025			
2008	195,433.83	195,434	195,434			
2009	691,265.93	668,226	415,957	275,309	0.50	275,309
2013	5,127,530.65	3,589,271	2,234,249	2,893,282	4.50	642,952
2014	2,852,281.63	1,806,436	1,124,470	1,727,812	5.50	314,148
2015	5,990,559.80	3,394,671	2,113,114	3,877,446	6.50	596,530
2016	1,565,025.78	782,513	487,098	1,077,928	7.50	143,724
2017	5,367,950.67	2,326,094	1,447,946	3,920,005	8.50	461,177
2018	11,968,877.76	4,388,628	2,731,832	9,237,046	9.50	972,321
2019	7,863,607.95	2,359,082	1,468,481	6,395,127	10.50	609,060
2020	41,394,131.14	9,658,493	6,012,216	35,381,915	11.50	3,076,688
2021	8,025,999.41	1,337,693	832,687	7,193,312	12.50	575,465
2022	15,225,935.26	1,522,594	947,784	14,278,151	13.50	1,057,641
2023	15,784,388.35	526,094	327,483	15,456,905	14.50	1,065,993
	128,050,933.02	38,553,173	26,336,695	101,714,238		9,791,008

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 7.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	46,726,994.21	7,009,049	4,141,642	42,585,352	8.50	5,010,041
	46,726,994.21	7,009,049	4,141,642	42,585,352		5,010,041

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   10.72

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.12 MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	22,009,118.33	3,301,368	1,783,632	20,225,486	8.50	2,379,469
2023	233,045.18	11,652	6,295	226,750	9.50	23,868
	22,242,163.51	3,313,020	1,789,927	20,452,237		2,403,337

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.81

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.20 MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
1995	639,469.00	639,469	639,469			
1996	369,842.00	369,842	369,842			
1997	27,346,787.00	27,346,787	27,346,787			
1998	450,570.00	450,570	450,570			
1999	150,721.00	150,721	150,721			
2004	415,255.38	415,255	415,255			
2005	468,752.58	468,753	468,753			
2006	448,313.73	448,314	448,314			
2007	415,837.92	415,838	415,838			
2008	190,259.31	190,259	190,259			
2013	1,267,786.82	887,451	1,267,787			
2014	246,002.37	155,801	235,203	10,799	5.50	1,963
	32,409,597.11	31,939,060	32,398,798	10,799		1,963

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 0.01

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.30 MISCELLANEOUS INTANGIBLE PLANT - INDUSTRIAL AND COMMERCIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
1998	1,427,352.00	1,427,352	1,427,352			
1999	2,707,150.00	2,707,150	2,707,150			
2000	12,449.00	12,449	12,449			
	4,146,951.00	4,146,951	4,146,951			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.40 MISCELLANEOUS INTANGIBLE PLANT - CRMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	2,757,525.21	1,930,268	2,500,610	256,915	1.50	171,277
2021	7,406,959.82	3,703,480	4,797,759	2,609,201	2.50	1,043,680
2022	4,001,784.79	1,200,535	1,555,261	2,446,524	3.50	699,007
2023	19,041,697.58	1,904,170	2,466,801	16,574,897	4.50	3,683,310
	33,207,967.40	8,738,453	11,320,431	21,887,536		5,597,274

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.9   16.86

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.71 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	24,096,593.68	3,614,489	3,203,067	20,893,527	8.50	2,458,062
	24,096,593.68	3,614,489	3,203,067	20,893,527		2,458,062

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.20

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	3,134,883.06	940,465		3,134,883	3.50	895,681
2023	23,000.05	2,300		23,000	4.50	5,111
	3,157,883.11	942,765		3,157,883		900,792

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 28.53

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.11 STRUCTURES AND IMPROVEMENTS - GAS PRODUCTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1963	8,320.00	7,528	8,736			
	8,320.00	7,528	8,736			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.17 STRUCTURES AND IMPROVEMENTS - MIXING STATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1956	44,564.00	42,780	46,792			
1958	2,023.00	1,911	4,454	2,330-		
	46,587.00	44,691	51,246	2,330-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.50 STRUCTURES AND IMPROVEMENTS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1984	13,156.00	9,307	13,814			
	13,156.00	9,307	13,814			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 311.70 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-L0.5						
NET SALVAGE PERCENT.. -5						
1963	403.00	370	423			
1964	224.00	204	235			
1973	3,406.00	2,875	7,408	3,832-		
	4,033.00	3,449	8,066	3,831-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-L0.5						
NET SALVAGE PERCENT.. -5						
1975	4,209.00	3,501	6,585	2,166-		
	4,209.00	3,501	6,585	2,166-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 318.30 LIGHT OIL REFINING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1926	6,740.00	7,077	7,077			
1941	65,282.00	66,475	68,546			
1943	3,000.00	3,028	3,150			
1947	11,000.00	10,911	11,550			
1950	14,536.00	14,228	15,263			
1951	28,111.00	27,391	29,517			
1952	15,110.00	14,656	15,866			
1953	1.00	1	1			
1956	163.00	155	171			
1957	953.00	903	1,000			
	144,896.00	144,825	152,141			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 318.50 TAR PROCESSING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1913	4,028.00	4,229	4,229			
1923	8,294.00	8,709	8,709			
1940	23,539.00	24,068	24,716			
1943	48,609.00	49,066	51,039			
1944	8,137.00	8,179	8,544			
1947	46,907.00	46,527	49,252			
1948	6,861.00	6,775	7,204			
1949	591.00	581	621			
1952	264.00	256	277			
1953	89,945.00	86,845	94,442			
1954	4,566.00	4,388	4,794			
1955	1,810.00	1,732	1,902			
	243,551.00	241,355	255,729			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 319.00 GAS MIXING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R0.5						
NET SALVAGE PERCENT.. -5						
1956	145,043.00	152,295	152,295			
1957	15,520.00	16,296	16,296			
1958	5,736.00	6,023	6,023			
1959	217.00	228	228			
1960	277.00	291	291			
1962	1,667.00	1,750	1,750			
1964	921.00	959	967			
1967	89.00	88	93			
1980	12,421.00	9,960	13,042			
1981	3,557.00	2,802	3,735			
	185,448.00	190,692	194,720			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 350.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1989	40,841.00	19,662	20,150	20,691	36.30	570
1993	5,264.00	2,255	2,311	2,953	40.01	74
1994	400.00	166	170	230	40.95	6
1997	185.00	69	71	114	43.81	3
1998	628.00	226	232	396	44.78	9
2001	3,804.00	1,213	1,243	2,561	47.68	54
2007	58,502.94	13,731	14,072	44,431	53.57	829
	109,624.94	37,322	38,249	71,376		1,545

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.2 1.41

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. 0						
1989	2,101,010.00	1,165,703	1,287,980	813,030	26.71	30,439
1990	45,791.00	24,735	27,330	18,461	27.59	669
1991	275,498.00	144,774	159,960	115,538	28.47	4,058
1992	41,905.00	21,400	23,645	18,260	29.36	622
1993	3,226.00	1,598	1,766	1,460	30.27	48
1994	13,262.00	6,370	7,038	6,224	31.18	200
1995	35,648.00	16,576	18,315	17,333	32.10	540
1998	2,475,159.00	1,035,433	1,144,045	1,331,114	34.90	38,141
1999	4,963.00	1,998	2,208	2,755	35.85	77
2000	32,811.00	12,687	14,018	18,793	36.80	511
2001	884,241.00	327,762	362,143	522,098	37.76	13,827
2002	242,899.00	86,149	95,186	147,713	38.72	3,815
2003	16,898.54	5,720	6,320	10,579	39.69	267
2004	74,234.66	23,928	26,438	47,797	40.66	1,176
2005	123.98	38	42	82	41.64	2
2008	290,921.56	74,767	82,610	208,312	44.58	4,673
2009	3,834.31	922	1,019	2,815	45.57	62
2010	12,998.94	2,912	3,217	9,782	46.56	210
2012	159,638.62	30,491	33,689	125,950	48.54	2,595
2014	426,776.29	67,431	74,504	352,272	50.52	6,973
2015	66,404.73	9,385	10,369	56,036	51.52	1,088
2017	173,824.60	18,803	20,775	153,050	53.51	2,860
2018	1,252,081.82	114,565	126,583	1,125,499	54.51	20,648
2021	285,370.88	11,891	13,138	272,233	57.50	4,734
2022	232,028.00	5,801	6,410	225,618	58.50	3,857
2023	5,403,375.84	45,010	49,731	5,353,645	59.50	89,977
	14,554,925.77	3,256,849	3,598,479	10,956,447		232,069

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.2 1.59

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.00 WELLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S4						
NET SALVAGE PERCENT.. 0						
1989	8,933,762.00	6,037,436	6,331,890	2,601,872	16.21	160,510
1990	536,082.00	353,171	370,396	165,686	17.06	9,712
1991	2,005,008.00	1,286,012	1,348,732	656,276	17.93	36,602
1992	150,577.00	93,900	98,480	52,097	18.82	2,768
1993	182,892.00	110,686	116,084	66,808	19.74	3,384
1994	2,358.00	1,383	1,450	908	20.67	44
1998	6,327,524.00	3,221,975	3,379,115	2,948,409	24.54	120,147
2001	200,085.00	89,998	94,387	105,698	27.51	3,842
2003	44,802.88	18,369	19,265	25,538	29.50	866
2004	5,127,030.63	1,999,542	2,097,062	3,029,969	30.50	99,343
2005	3,853,067.17	1,425,635	1,495,165	2,357,902	31.50	74,854
2007	8,775,470.65	2,895,905	3,037,143	5,738,328	33.50	171,293
2009	831,368.14	241,097	252,856	578,512	35.50	16,296
2012	17,500.00	4,025	4,221	13,279	38.50	345
2018	3,328,509.28	366,136	383,993	2,944,516	44.50	66,169
2019	3,488,288.60	313,946	329,258	3,159,031	45.50	69,429
2020	4,552,032.47	318,642	334,182	4,217,850	46.50	90,706
2021	4,166,820.20	208,341	218,502	3,948,318	47.50	83,122
2022	5,132,799.55	153,984	161,494	4,971,306	48.50	102,501
2023	5,371,642.43	53,716	56,336	5,315,306	49.50	107,380
	63,027,620.00	19,193,899	20,130,011	42,897,609		1,219,313

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.2   1.93

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. 0						
1989	1,210,800.00	720,317	784,140	426,660	22.28	19,150
1993	1.00	1	1			
1996	237,300.00	116,192	126,487	110,813	28.07	3,948
1997	1,589,979.00	752,489	819,163	770,816	28.97	26,607
1998	492,327.00	224,861	244,785	247,542	29.88	8,285
1999	5,093.00	2,241	2,440	2,653	30.80	86
2002	2,991.00	1,162	1,265	1,726	33.64	51
2004	1,020.52	360	392	629	35.58	18
2014	400,000.00	69,092	75,213	324,787	45.50	7,138
	3,939,511.52	1,886,715	2,053,886	1,885,626		65,283

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.9 1.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.20 RESERVOIRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. 0						
1996	1,679,184.00	822,196	853,296	825,888	28.07	29,422
1998	1,999,907.00	913,418	947,969	1,051,938	29.88	35,205
1999	6,003.00	2,641	2,741	3,262	30.80	106
2000	476,341.00	201,449	209,069	267,272	31.74	8,421
2002	2,997,731.00	1,164,199	1,208,235	1,789,496	33.64	53,195
2004	1,212,371.25	428,076	444,268	768,103	35.58	21,588
2005	2,445,017.29	819,741	850,749	1,594,268	36.56	43,607
2012	17,500.00	3,659	3,797	13,703	43.50	315
	10,834,054.54	4,355,379	4,520,124	6,313,931		191,859

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.9 1.77

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.30 NONRECOVERABLE GAS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1989	4,057,952.00	2,431,809	2,751,847	1,306,105	22.04	59,261
1993	1.00	1	1			
1996	2,255,000.00	1,100,440	1,245,264	1,009,736	28.16	35,857
1998	62,449.00	28,386	32,122	30,327	30.00	1,011
2004	65,487.82	22,980	26,004	39,484	35.70	1,106
	6,440,889.82	3,583,616	4,055,238	2,385,652		97,235

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.5   1.51

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 353.00 LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. -15						
1989	2,521,353.00	1,724,975	1,762,844	1,136,712	22.28	51,019
1991	17,489.00	11,395	11,645	8,467	23.84	355
1993	1.00	1	1			
1998	3,853,629.00	2,024,078	2,068,513	2,363,160	29.88	79,088
1999	52,862.00	26,748	27,335	33,456	30.80	1,086
2003	7,841.06	3,343	3,416	5,601	34.61	162
2004	684,275.05	277,852	283,952	502,964	35.58	14,136
2005	504,360.29	194,461	198,730	381,284	36.56	10,429
2007	560,153.49	192,899	197,134	447,043	38.53	11,602
2018	1,333,513.81	153,354	156,721	1,376,820	49.50	27,815
2019	1,137,750.13	107,054	109,404	1,199,009	50.50	23,743
2020	116,919.92	8,557	8,745	125,713	51.50	2,441
2021	782.00	41	42	857	52.50	16
2022	1,344,670.40	42,170	43,096	1,503,275	53.50	28,099
2023	819,822.92	8,570	8,758	934,038	54.50	17,138
	12,955,423.07	4,775,498	4,880,336	10,018,401		267,129

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5   2.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.10 COMPRESSOR STATION EQUIPMENT - TURBINE 1

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1989	3,547,382.00	2,381,074	2,779,504	1,122,616	19.49	57,600
1990	110,946.00	72,687	84,850	37,191	20.22	1,839
1991	139,186.00	88,893	103,768	49,337	20.97	2,353
1992	41,746.00	25,973	30,319	15,602	21.72	718
1993	3,141.00	1,901	2,219	1,236	22.49	55
1994	7,648.00	4,499	5,252	3,161	23.26	136
1995	116,370.00	66,436	77,553	50,454	24.05	2,098
1996	3,136.00	1,735	2,025	1,425	24.85	57
1997	19,089.09	10,222	11,932	9,066	25.66	353
1998	166,055.57	85,924	100,302	82,359	26.48	3,110
2023	3,730,531.56	40,215	46,944	4,056,641	49.51	81,936
	7,885,231.22	2,779,559	3,244,668	5,429,086		150,255

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.1 1.91

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.20 COMPRESSOR STATION EQUIPMENT - TURBINE 2

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1989	4,154,699.00	2,788,717	3,255,359	1,314,810	19.49	67,461
	4,154,699.00	2,788,717	3,255,359	1,314,810		67,461

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.5   1.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.30 COMPRESSOR STATION EQUIPMENT - TURBINE 3

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1998	8,502,780.91	4,399,679	5,135,886	4,217,173	26.48	159,259
1999	94,722.00	47,283	55,195	48,999	27.31	1,794
2000	3,218,557.00	1,547,160	1,806,049	1,734,364	28.15	61,612
2001	1,699,551.00	785,193	916,581	952,925	29.00	32,859
2002	122,405.06	54,235	63,310	71,336	29.86	2,389
2008	131,264.60	42,769	49,926	94,465	35.19	2,684
2009	69,541.41	21,250	24,806	51,690	36.11	1,431
2010	20,130.52	5,744	6,705	15,439	37.03	417
2014	781,561.86	158,532	185,059	674,659	40.78	16,544
2023	6,443,741.67	69,464	81,088	7,007,028	49.51	141,528
	21,084,256.03	7,131,309	8,324,605	14,868,077		420,517

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.40 COMPRESSOR STATION EQUIPMENT - TURBINE 4

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2000	4,556,230.32	2,190,180	2,556,667	2,455,186	28.15	87,218
2001	6,176,092.83	2,853,355	3,330,812	3,462,890	29.00	119,410
2004	2,147,487.86	869,303	1,014,765	1,347,472	31.60	42,642
2012	17,500.00	4,277	4,993	14,257	38.89	367
2013	767,326.56	171,513	200,213	643,846	39.84	16,161
2022	2,731,916.61	88,951	103,835	2,901,273	48.52	59,795
	16,396,554.18	6,177,579	7,211,285	10,824,925		325,593

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.2   1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.50 COMPRESSOR STATION EQUIPMENT - TURBINE 5

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2001	1,386,150.00	640,401	747,561	777,204	29.00	26,800
2003	3,978.82	1,687	1,969	2,408	30.73	78
2004	29,546.20	11,960	13,961	18,540	31.60	587
2011	1,167,361.91	309,211	360,952	923,146	37.96	24,319
2016	42,248.74	6,794	7,931	38,543	42.69	903
2017	145,612.11	20,310	23,709	136,464	43.66	3,126
2020	779,535.40	58,824	68,667	788,822	46.57	16,938
2022	185,043.79	6,025	7,033	196,515	48.52	4,050
	3,739,476.97	1,055,212	1,231,783	2,881,642		76,801

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5   2.05

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.60 COMPRESSOR STATION EQUIPMENT - TURBINE 6

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2015	260,041.78	47,255	55,162	230,884	41.74	5,531
	260,041.78	47,255	55,162	230,884		5,531

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.7   2.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2						
NET SALVAGE PERCENT.. -10						
1989	3,473,015.20	2,439,043	2,570,462	1,249,855	16.27	76,820
1990	66,949.00	46,117	48,602	25,042	16.82	1,489
1991	21,410.00	14,455	15,234	8,317	17.38	479
1992	17,819.00	11,778	12,413	7,188	17.96	400
1993	1,785.00	1,154	1,216	748	18.56	40
1994	35.00	22	23	16	19.18	1
1995	9,858.00	6,068	6,395	4,449	19.82	224
1996	15,372.00	9,214	9,710	7,199	20.48	352
1998	1,090,120.00	616,881	650,119	549,013	21.85	25,126
1999	238,641.00	130,843	137,893	124,612	22.57	5,521
2000	1,704,161.55	903,959	952,666	921,912	23.30	39,567
2001	48,850.00	25,005	26,352	27,383	24.06	1,138
2002	198,196.98	97,671	102,934	115,083	24.84	4,633
2003	0.07					
2004	830,627.56	376,641	396,935	516,755	26.45	19,537
2005	1,791,619.55	775,621	817,412	1,153,370	27.29	42,263
2006	143,130.10	58,953	62,129	95,314	28.15	3,386
2007	4,611,549.49	1,801,368	1,898,428	3,174,276	29.02	109,382
2008	207,002.45	76,356	80,470	147,233	29.91	4,923
2009	993,447.65	344,350	362,904	729,888	30.82	23,682
2011	435,517.72	131,160	138,227	340,842	32.68	10,430
2012	17,500.00	4,864	5,126	14,124	33.63	420
2013	71,153.62	18,106	19,082	59,187	34.59	1,711
2015	10,072.05	2,083	2,195	8,884	36.54	243
2016	124,808.02	22,820	24,050	113,239	37.52	3,018
2017	124,297.12	19,719	20,781	115,946	38.51	3,011
2018	369,594.51	49,600	52,273	354,281	39.51	8,967
2019	76,345.99	8,398	8,850	75,131	40.50	1,855
2020	1,857,532.18	158,927	167,490	1,875,795	41.50	45,200
2021	9,662,801.94	590,552	622,372	10,006,710	42.50	235,452
2022	9,155,761.89	335,678	353,765	9,717,573	43.50	223,392
2023	2,105,592.36	25,732	27,119	2,289,033	44.50	51,439
	39,474,567.00	9,103,138	9,593,627	33,828,397		944,101

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.8   2.39

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 356.00 PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1989	139,942.00	97,731	71,371	75,568	15.07	5,014
1990	12,815.00	8,773	6,407	7,049	15.66	450
1992	15,940.00	10,459	7,638	9,099	16.88	539
1993	2,878.00	1,845	1,347	1,675	17.53	96
1995	73,881.00	45,011	32,871	44,704	18.89	2,367
1996	48,826.00	28,926	21,124	30,143	19.61	1,537
1998	3,081.00	1,718	1,255	1,980	21.10	94
2018	66,401.79	8,521	6,223	63,499	39.50	1,608
2020	28,191,885.97	2,302,403	1,681,396	27,920,084	41.50	672,773
2022	235,336.24	8,236	6,015	241,088	43.50	5,542
2023	177,877.51	2,075	1,515	185,256	44.50	4,163
	28,968,864.51	2,515,698	1,837,162	28,580,146		694,183

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.2   2.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 357.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. 0						
1989	76,057.00	64,410	74,516	1,541	5.36	288
1992	5,980.00	4,779	5,529	451	7.03	64
1998	564,221.00	383,670	443,871	120,350	11.20	10,746
1999	56,329.00	37,064	42,880	13,449	11.97	1,124
2008	629,441.85	273,895	316,872	312,570	19.77	15,810
2009	63,256.08	25,827	29,879	33,377	20.71	1,612
2018	1,027,537.43	161,180	186,471	841,066	29.51	28,501
2020	2,250,170.09	224,364	259,568	1,990,602	31.51	63,174
2021	475,212.76	33,944	39,270	435,943	32.50	13,414
2022	113,567.00	4,867	5,631	107,936	33.50	3,222
	5,261,772.21	1,214,000	1,404,487	3,857,285		137,955

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0 2.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

LINNTON
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2036
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1969	59,412.00	50,994	51,870	10,513	10.13	1,038
1970	26,089.00	22,296	22,679	4,715	10.25	460
1974	183.00	154	157	36	10.68	3
1975	8,525.00	7,123	7,245	1,706	10.77	158
1976	14,557.00	12,105	12,313	2,972	10.86	274
1978	9,671.00	7,960	8,097	2,058	11.04	186
1981	1,017.00	824	838	230	11.26	20
1982	46,738.00	37,632	38,278	10,797	11.33	953
1985	20,155.00	15,929	16,203	4,960	11.51	431
1986	6,343.00	4,980	5,066	1,595	11.56	138
1987	6,731.00	5,248	5,338	1,729	11.61	149
1988	30,340.00	23,481	23,884	7,973	11.66	684
1991	27,819.00	21,018	21,379	7,831	11.79	664
1992	4,998.00	3,743	3,807	1,441	11.83	122
1993	42,483.00	31,514	32,055	12,552	11.87	1,057
1994	37,310.00	27,412	27,883	11,293	11.90	949
1995	45,530.00	33,107	33,676	14,131	11.93	1,184
1996	20,875.00	15,007	15,265	6,654	11.97	556
1997	22,876.00	16,259	16,538	7,482	11.99	624
2000	10,951.00	7,475	7,603	3,895	12.08	322
2001	30,731.00	20,661	21,016	11,252	12.10	930
2002	60,440.00	39,976	40,662	22,800	12.12	1,881
2004	6,103.00	3,888	3,955	2,453	12.17	202
2005	185,610.40	115,870	117,860	77,031	12.18	6,324
2006	961,819.17	586,950	597,029	412,881	12.20	33,843
2007	432,192.31	257,224	261,641	192,161	12.22	15,725
2008	892,383.17	516,588	525,459	411,544	12.24	33,623
2009	1,097,712.30	616,755	627,346	525,252	12.25	42,878
2010	113,303.89	61,521	62,577	56,392	12.27	4,596
2011	221,064.76	115,632	117,618	114,500	12.28	9,324
2012	71,983.47	36,073	36,692	38,890	12.30	3,162
2015	53,824.55	22,787	23,178	33,337	12.33	2,704
2016	484,828.69	190,189	193,455	315,615	12.34	25,577
2017	14,238.78	5,098	5,186	9,765	12.35	791
2018	5,604,150.24	1,791,493	1,822,256	4,062,102	12.36	328,649
2020	43,051.42	9,852	10,021	35,183	12.38	2,842

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
2021	86,705.20	15,082	15,341	75,699	12.39	6,110
2022	1,452,034.00	163,670	166,480	1,358,155	12.39	109,617
2023	244,182.54	9,938	10,109	246,283	12.40	19,862
	12,498,961.89	4,923,508	5,008,053	8,115,857		658,612
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1965	1,500.00	1,246	1,357	218	12.21	18
1974	605,426.00	473,334	515,399	120,299	14.27	8,430
1977	711,173.00	543,725	592,045	154,686	14.86	10,410
1978	31,895.00	24,198	26,348	7,141	15.04	475
1979	16,085.00	12,106	13,182	3,707	15.22	244
1982	13,954.00	10,245	11,155	3,496	15.70	223
1984	270.00	195	212	71	15.98	4
1986	2,983.00	2,112	2,300	832	16.24	51
1987	2,143.00	1,503	1,637	614	16.35	38
1988	17,175.00	11,921	12,980	5,053	16.47	307
1989	83,518.00	57,353	62,450	25,244	16.58	1,523
1990	24,328.00	16,525	17,994	7,551	16.68	453
1991	59,235.00	39,785	43,321	18,876	16.77	1,126
1992	141,822.00	94,098	102,460	46,453	16.87	2,754
1993	26,244.00	17,200	18,729	8,828	16.95	521
1994	214,182.00	138,483	150,790	74,101	17.04	4,349
1995	37,880.00	24,165	26,313	13,461	17.11	787
1996	89,930.00	56,528	61,552	32,875	17.19	1,912
1997	169,271.00	104,764	114,074	63,660	17.26	3,688
1998	67,057.09	40,829	44,457	25,953	17.33	1,498
1999	164,083.00	98,200	106,927	65,360	17.39	3,758
2000	31,277.00	18,380	20,013	12,827	17.45	735
2001	48,710.00	28,064	30,558	20,587	17.51	1,176
2002	66,987.31	37,781	41,139	29,198	17.57	1,662
2003	0.04		0			
2004	12,320.82	6,633	7,222	5,714	17.67	323
2005	10,028.06	5,257	5,724	4,805	17.72	271
2006	47,617.22	24,275	26,432	23,566	17.76	1,327
2008	366,599.53	175,247	190,821	194,108	17.84	10,880

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2009	253,147.32	116,587	126,948	138,857	17.88	7,766
2010	636,411.98	281,326	306,327	361,905	17.92	20,196
2011	60,719.61	25,659	27,939	35,816	17.95	1,995
2012	31,512.46	12,654	13,779	19,310	17.99	1,073
2014	53,287.83	18,931	20,613	35,339	18.05	1,958
2016	3,063,049.39	925,237	1,007,462	2,208,740	18.10	122,030
2017	2,859,549.08	777,925	847,058	2,155,468	18.13	118,890
2018	1,907,457.63	457,927	498,622	1,504,208	18.15	82,876
2019	167,922.77	34,437	37,497	138,822	18.17	7,640
2020	27,918.13	4,651	5,064	24,250	18.19	1,333
2021	71,870.99	8,949	9,744	65,720	18.21	3,609
	12,196,541.26	4,728,435	5,148,646	7,657,722		428,309
OTHER						
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -5						
1963	4,009.00	3,220	3,659	550	14.11	39
1968	527.00	401	456	98	16.55	6
1975	1,118.00	772	877	297	20.54	14
1999	21,103.00	8,095	9,199	12,959	38.08	340
	26,757.00	12,488	14,191	13,904		399
	24,722,260.15	9,664,431	10,170,890	15,787,483		1,087,320

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.5 4.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 362.00 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 60-R3						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -20						
1969	1,720,509.00	1,705,967	1,680,444	384,167	9.83	39,081
1974	815.00	789	777	201	10.53	19
1983	969.00	892	879	284	11.40	25
1991	1,017.00	883	870	351	11.85	30
1993	18,991.00	16,194	15,952	6,837	11.93	573
2006	362,872.63	254,245	250,441	185,006	12.28	15,066
2009	488,646.40	315,183	310,468	275,908	12.33	22,377
2015	53,824.55	26,127	25,736	38,853	12.41	3,131
2016	1,686,933.32	758,999	747,644	1,276,676	12.42	102,792
2017	221,486.45	90,941	89,580	176,203	12.42	14,187
	4,556,064.35	3,170,220	3,122,790	2,344,487		197,281
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R3						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -20						
1977	5,551,294.00	4,918,558	6,156,563	504,990	14.60	34,588
1978	10,302.00	9,054	11,333	1,030	14.82	70
1994	72,915.00	54,346	68,025	19,473	17.16	1,135
1996	138,492.00	100,284	125,526	40,665	17.33	2,347
2006	900.36	528	661	420	17.93	23
2017	153,200.46	47,874	59,924	123,917	18.29	6,775
	5,927,103.82	5,130,644	6,422,031	690,494		44,938
OTHER						
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
2003	1,600.14	624	1,312	608	40.51	15
	1,600.14	624	1,312	608		15
	10,484,768.31	8,301,488	9,546,133	3,035,589		242,234

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5   2.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 50-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	828,857.00	728,737	870,300			
1970	15,188.00	13,287	15,947			
1971	1,613.00	1,404	1,694			
1972	4,261.00	3,688	4,474			
1974	1,957.00	1,675	2,055			
1975	268.00	228	281			
1976	25,955.00	21,957	27,104	149	9.26	16
1980	100,679.00	83,068	102,540	3,173	9.92	320
1986	715.00	566	699	52	10.73	5
1987	68,778.00	53,990	66,646	5,571	10.84	514
1990	86,886.00	66,527	82,122	9,109	11.14	818
1991	51,422.00	39,018	48,164	5,829	11.23	519
1992	77,450.00	58,224	71,872	9,450	11.31	836
1994	15,589.00	11,487	14,180	2,189	11.46	191
1995	2,211.00	1,612	1,990	332	11.52	29
1996	6,143.00	4,428	5,466	984	11.59	85
1997	132,937.00	94,701	116,900	22,684	11.64	1,949
1998	157,516.00	110,774	136,741	28,651	11.70	2,449
1999	78,997.00	54,811	67,659	15,288	11.75	1,301
2000	88,122.00	60,264	74,391	18,138	11.80	1,537
2001	284,485.00	191,511	236,403	62,306	11.85	5,258
2002	44,801.00	29,665	36,619	10,422	11.89	877
2003	131,666.14	85,640	105,715	32,534	11.93	2,727
2004	219,028.75	139,722	172,474	57,506	11.97	4,804
2005	46,627.74	29,138	35,968	12,991	12.00	1,083
2006	127,298.03	77,726	95,946	37,717	12.04	3,133
2007	8,445.29	5,029	6,208	2,660	12.07	220
2009	70,412.91	39,560	48,833	25,100	12.13	2,069
2012	72,983.52	36,594	45,172	31,461	12.20	2,579
2015	53,824.55	22,799	28,143	28,372	12.26	2,314
2016	402,787.76	157,951	194,977	227,951	12.28	18,563
2017	111,506.66	39,864	49,209	67,873	12.30	5,518
2019	55,575.58	15,373	18,977	39,378	12.33	3,194
2020	75,214.89	17,217	21,253	57,723	12.34	4,678
2021	461,522.51	80,492	99,360	385,238	12.35	31,193
	3,911,724.33	2,378,727	2,906,482	1,200,829		98,779

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	5,236,797.00	4,175,830	4,395,745	1,102,892	11.74	93,943
1978	16,348.00	12,910	13,590	3,576	12.05	297
1979	5,538.00	4,331	4,559	1,256	12.35	102
1984	21,919.00	16,276	17,133	5,882	13.77	427
1985	11,525.00	8,464	8,910	3,192	14.03	228
1986	14,148.00	10,271	10,812	4,043	14.29	283
1987	8,543.00	6,131	6,454	2,516	14.53	173
1989	21,759.00	15,245	16,048	6,799	14.98	454
1990	2,886.00	1,997	2,102	928	15.19	61
1991	51,784.00	35,368	37,231	17,143	15.39	1,114
1992	4,079.00	2,749	2,894	1,389	15.58	89
1993	16,196.00	10,770	11,337	5,669	15.75	360
1994	1,119.00	733	772	403	15.92	25
1996	186,692.00	118,692	124,943	71,084	16.23	4,380
1997	151,762.28	94,925	99,924	59,426	16.37	3,630
1998	390,938.46	240,397	253,057	157,428	16.50	9,541
1999	249,536.00	150,686	158,622	103,391	16.63	6,217
2001	180,788.00	104,935	110,461	79,366	16.86	4,707
2002	30,345.79	17,242	18,150	13,713	16.96	809
2004	76,018.79	41,160	43,328	36,492	17.16	2,127
2005	1,705.00	899	946	844	17.24	49
2006	28,555.27	14,628	15,398	14,585	17.33	842
2007	35,357.72	17,562	18,487	18,639	17.40	1,071
2008	62,378.35	29,930	31,506	33,991	17.48	1,945
2014	356,850.62	127,163	133,860	240,833	17.83	13,507
2017	3,561,611.76	970,749	1,021,872	2,717,820	17.97	151,242
2018	4,848,560.74	1,164,258	1,225,572	3,865,417	18.01	214,626
2019	174,662.05	35,828	37,715	145,680	18.04	8,075
2021	221,992.66	27,675	29,132	203,960	18.11	11,262
2022	6,620,268.05	517,801	545,070	6,406,211	18.14	353,154
2023	109,895.48	3,031	3,191	112,200	18.16	6,178
	22,700,560.02	7,978,636	8,398,821	15,436,767		890,918
	26,612,284.35	10,357,363	11,305,303	16,637,596		989,697

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.8   3.72

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	18,960.00	19,216	19,438	470	1.39	338
1971	13,254.00	13,263	13,416	500	1.88	266
1972	2,368.00	2,354	2,381	105	2.13	49
1973	13,251.00	13,082	13,233	680	2.39	285
1974	2,259.00	2,214	2,240	132	2.66	50
1975	269.00	262	265	17	2.93	6
1976	386,664.00	373,416	377,731	28,266	3.21	8,806
1986	12,078.00	10,517	10,639	2,043	6.79	301
1987	177,462.00	152,273	154,033	32,302	7.25	4,455
1990	1,140,108.00	934,622	945,423	251,691	8.58	29,335
1991	181,570.00	146,592	148,286	42,362	8.98	4,717
1993	1.00	1	1			
1994	32,761.00	25,280	25,572	8,827	10.01	882
1995	11,181.00	8,500	8,598	3,142	10.29	305
2006	321,206.91	199,163	201,465	135,803	12.01	11,307
2015	53,824.46	22,958	23,223	33,292	12.41	2,683
2017	2,091,400.63	752,471	761,167	1,434,804	12.45	115,245
	4,458,618.00	2,676,184	2,707,111	1,974,438		179,030
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	60,825.00	58,294	42,719	21,147	3.49	6,059
1990	15,899.00	12,698	9,305	7,389	9.55	774
1991	4,866.00	3,805	2,788	2,321	10.17	228
1992	2,226.00	1,703	1,248	1,089	10.79	101
2002	180.00	108	79	110	15.80	7
2004	68,445.68	38,694	28,356	43,512	16.41	2,652
2011	1,113,015.02	481,397	352,780	815,886	17.76	45,940
2015	95,076.50	31,802	23,305	76,525	18.14	4,219

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2017	2,379,279.54	655,089	480,065	2,018,178	18.26	110,525
2020	2,967,835.97	498,721	365,475	2,750,753	18.37	149,742
2021	10,560.25	1,326	972	10,117	18.40	550
	6,718,208.96	1,783,637	1,307,093	5,747,026		320,797
	11,176,826.96	4,459,821	4,014,204	7,721,464		499,827

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.4 4.47

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1982	85,687.00	70,801	79,182	10,789	7.37	1,464
1983	1,117.00	915	1,023	150	7.58	20
1986	21,516.00	17,164	19,196	3,396	8.19	415
1996	19,421.00	13,896	15,541	4,851	9.98	486
2008	51,410.22	29,245	32,707	21,274	11.30	1,883
2022	233,035.00	25,805	28,860	215,827	11.96	18,046
2023	950,567.29	37,648	42,105	955,991	11.99	79,732
	1,362,753.51	195,474	218,613	1,212,278		102,046
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1997	20,827.00	13,239	19,854	2,014	13.03	155
2003	178,502.00	99,048	148,539	38,888	14.58	2,667
2005	16,780.44	8,804	13,203	4,416	15.01	294
2014	1,385,829.26	484,453	726,516	728,604	16.45	44,292
2016	2,266,969.59	672,916	1,009,148	1,371,171	16.67	82,254
2017	497,806.37	133,115	199,628	323,069	16.77	19,265
2018	256,596.34	60,478	90,697	178,730	16.86	10,601
2020	121,183.04	19,799	29,692	97,550	17.04	5,725
2021	820,790.65	100,558	150,803	711,027	17.11	41,556
2022	13,113.00	1,010	1,515	12,254	17.19	713
2023	2,152,831.40	58,682	88,003	2,172,470	17.26	125,867
	7,731,229.09	1,652,102	2,477,597	5,640,194		333,389
	9,093,982.60	1,847,576	2,696,210	6,852,472		435,435

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.7 4.79

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

LINNTON
INTERIM SURVIVOR CURVE.. IOWA 50-R4
PROBABLE RETIREMENT YEAR.. 6-2036
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1969	461,537.00	432,513	345,073	139,541	5.37	25,985
1970	2,640.00	2,457	1,960	812	5.67	143
1971	9,831.00	9,085	7,248	3,074	5.98	514
1972	6,325.00	5,803	4,630	2,011	6.29	320
1974	1,327.00	1,198	956	438	6.96	63
1975	374.00	335	267	125	7.30	17
1985	3,662.00	2,986	2,382	1,463	10.38	141
1988	3,818.00	3,031	2,418	1,591	10.92	146
1990	33,747.00	26,288	20,973	14,461	11.21	1,290
2002	17,323.00	11,578	9,237	8,952	12.18	735
2006	28,273.59	17,383	13,869	15,819	12.33	1,283
2009	168,291.28	95,165	75,926	100,780	12.39	8,134
2013	151,561.74	72,733	58,029	101,111	12.45	8,121
2014	359,909.59	163,387	130,355	247,550	12.46	19,868
2017	1,203,718.97	432,407	344,988	918,917	12.48	73,631
2018	426,268.10	136,915	109,235	338,346	12.48	27,111
2020	366,277.42	84,183	67,164	317,427	12.49	25,414
2021	330,436.66	57,866	46,167	300,791	12.49	24,083
2022	1,919,653.00	216,116	172,424	1,843,211	12.49	147,575
2023	2,387,812.46	96,502	76,992	2,430,211	12.49	194,573
	7,882,786.81	1,867,931	1,490,295	6,786,631		559,147

NEWPORT
INTERIM SURVIVOR CURVE.. IOWA 50-R4
PROBABLE RETIREMENT YEAR.. 6-2042
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1977	55,203.00	47,540	16,142	41,821	8.97	4,662
1988	5,884.00	4,329	1,470	4,708	14.31	329
1989	4,775.00	3,462	1,176	3,838	14.68	261
1990	13,736.00	9,811	3,331	11,091	15.02	738
1991	20,511.00	14,429	4,899	16,637	15.34	1,085
1992	3,371.00	2,336	793	2,746	15.63	176
2017	10,187,159.88	2,787,940	946,648	9,749,870	18.41	529,596
2018	154,590.07	37,322	12,673	149,647	18.42	8,124
2019	116,849.50	24,024	8,157	114,535	18.44	6,211
2020	101,306.78	16,961	5,759	100,613	18.45	5,453

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2021	188,716.81	23,634	8,025	190,128	18.46	10,299
2022	3,336,609.95	263,143	89,351	3,414,090	18.47	184,845
2023	1,195,710.81	33,095	11,237	1,244,259	18.47	67,366
	15,384,423.80	3,268,026	1,109,662	15,043,983		819,145
	23,267,210.61	5,135,957	2,599,957	21,830,614		1,378,292

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.8 5.92

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.50 CNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 31-R3						
NET SALVAGE PERCENT.. -5						
1981	19,620.00	18,973	20,601			
1982	9,560.00	9,160	10,038			
1983	1,563.00	1,484	1,641			
1984	40,443.00	38,041	42,465			
1985	1,466.00	1,365	1,539			
1986	7,018.00	6,466	7,369			
1990	63,479.00	55,537	64,168	2,485	5.17	481
1991	52,207.00	44,950	51,936	2,881	5.58	516
1992	19,707.00	16,674	19,265	1,427	6.02	237
1993	61,210.00	50,815	58,713	5,558	6.49	856
1994	348,384.00	283,322	327,355	38,448	6.99	5,500
1995	293,359.00	233,306	269,566	38,461	7.52	5,114
1996	228,151.00	177,041	204,556	35,003	8.09	4,327
1997	47,984.57	36,276	41,914	8,470	8.68	976
1998	28,835.82	21,204	24,499	5,779	9.29	622
1999	4,283.40	3,057	3,532	966	9.93	97
2002	1,300.00	836	966	399	12.01	33
2004	49,674.00	29,461	34,040	18,118	13.49	1,343
2012	117,630.32	43,349	50,086	73,426	20.12	3,649
2013	123,013.59	41,624	48,093	81,071	21.01	3,859
2014	1,532,406.79	471,284	544,530	1,064,497	21.92	48,563
2023	230,439.48	3,825	4,419	237,542	30.51	7,786
	3,281,734.97	1,588,050	1,831,291	1,614,531		83,959

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.2   2.56

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.60 LNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1982	349,437.00	272,573	366,909			
1983	61,620.00	47,433	64,701			
1984	42,767.00	32,452	44,905			
1985	5,173.00	3,867	5,432			
1986	108.00	79	113			
1991	935.00	627	918	64	16.26	4
1992	113,889.00	74,727	109,363	10,220	16.88	605
1993	54,468.00	34,912	51,094	6,097	17.53	348
1994	38,218.00	23,899	34,976	5,153	18.20	283
1995	45,678.00	27,828	40,727	7,235	18.89	383
1996	13,387.00	7,931	11,607	2,449	19.61	125
1997	5,310.00	3,055	4,471	1,104	20.34	54
1999	8,483.00	4,576	6,697	2,210	21.88	101
	739,473.00	533,959	741,913	34,534		1,903

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.1 0.26

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 365.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1964	94,094.00	68,451	71,319	22,775	20.44	1,114
1965	445,096.00	319,579	332,971	112,125	21.15	5,301
1966	469,977.00	332,871	346,819	123,158	21.88	5,629
1967	159,280.00	111,262	115,924	43,356	22.61	1,918
1968	20,603.00	14,186	14,780	5,823	23.36	249
1976	28,031.00	16,938	17,648	10,383	29.68	350
1977	12,082.00	7,167	7,467	4,615	30.51	151
1979	9,187.00	5,241	5,461	3,726	32.21	116
1981	5,959.00	3,262	3,399	2,560	33.94	75
1989	815,816.00	368,096	383,521	432,295	41.16	10,503
1990	401,012.00	175,912	183,283	217,729	42.10	5,172
1991	143,060.00	60,962	63,517	79,543	43.04	1,848
1992	13,749.00	5,687	5,925	7,824	43.98	178
2002	395,428.00	112,618	117,337	278,091	53.64	5,184
2003	1,181,773.75	321,123	334,579	847,195	54.62	15,511
2004	2,075,820.15	536,952	559,453	1,516,367	55.60	27,273
2009	184,208.96	35,492	36,979	147,230	60.55	2,432
	6,455,176.86	2,495,799	2,600,382	3,854,795		83,004

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.4 1.29

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1966	85,985.00	70,383	75,892	10,093	9.98	1,011
2004	898,180.86	302,283	325,944	572,237	36.49	15,682
2005	57,818.26	18,512	19,961	37,857	37.39	1,012
2016	504,088.49	66,998	72,242	431,846	47.69	9,055
	1,546,072.61	458,176	494,039	1,052,034		26,760

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.3 1.73

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1931	541.00	688	703	54	6.43	8
1964	631,743.00	634,400	647,969	236,471	19.79	11,949
1965	4,159,205.00	4,125,108	4,213,338	1,609,549	20.41	78,861
1966	3,249,729.00	3,182,778	3,250,853	1,298,768	21.03	61,758
1967	98,086.00	94,810	96,838	40,482	21.67	1,868
1968	4,871.00	4,645	4,744	2,075	22.32	93
1969	17,024.00	16,009	16,351	7,483	22.98	326
1972	18,881.00	16,985	17,348	9,085	25.02	363
1976	1,227,425.00	1,034,233	1,056,354	662,041	27.87	23,755
1977	4,968.00	4,113	4,201	2,754	28.61	96
1978	12,612.00	10,253	10,472	7,185	29.35	245
1980	34,127.00	26,708	27,279	20,499	30.87	664
1981	510,647.00	391,768	400,147	314,759	31.64	9,948
1982	162,214.00	121,921	124,529	102,571	32.42	3,164
1985	29,321.00	20,648	21,090	19,959	34.79	574
1986	17,437.00	11,997	12,254	12,158	35.60	342
1989	522,156.00	333,447	340,579	390,439	38.07	10,256
1990	139,805.00	86,930	88,789	106,938	38.91	2,748
1991	940.00	569	581	735	39.75	18
1993	136,072.00	77,669	79,330	111,171	41.46	2,681
1994	132,571.00	73,392	74,962	110,637	42.32	2,614
1995	1,514.00	812	829	1,291	43.19	30
2001	536,035.70	230,065	234,986	515,464	48.54	10,619
2002	255,592.00	105,048	107,295	250,534	49.45	5,066
2003	145,757.63	57,253	58,478	145,583	50.36	2,891
2004	102,958.14	38,528	39,352	104,789	51.29	2,043
2007	65,936.81	20,994	21,443	70,869	54.08	1,310
2009	4,600,512.66	1,291,815	1,319,445	5,121,273	55.96	91,517
2010	19,347,382.59	5,065,145	5,173,481	21,912,855	56.91	385,044
2011	8,045,641.26	1,953,498	1,995,280	9,268,618	57.86	160,190
2012	31,403,683.70	7,028,270	7,178,594	36,786,563	58.81	625,515
2013	48,073,769.43	9,835,701	10,046,072	57,257,205	59.77	957,959
2014	17,931,560.05	3,324,547	3,395,654	21,708,530	60.73	357,460
2015	5,312,454.39	881,857	900,719	6,536,717	61.70	105,944
2016	4,539,331.08	665,439	679,672	5,675,392	62.67	90,560
2017	3,119,026.03	396,753	405,239	3,961,397	63.64	62,247
2018	14,893,908.12	1,605,563	1,639,903	19,211,568	64.61	297,347
2019	9,883,982.95	871,767	890,413	12,947,163	65.59	197,395
2020	9,993,194.34	687,492	702,196	13,288,276	66.56	199,644

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2021	5,441,231.52	267,687	273,412	7,344,312	67.54	108,740
2022	25,260,061.74	747,597	763,587	34,600,499	68.52	504,969
2023	23,827,440.16	233,509	238,504	33,119,912	69.51	476,477
	243,891,349.30	45,578,411	46,553,265	294,894,624		4,855,298

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 60.7 1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.21 MAINS - NORTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1989	1,430,448.00	913,478	1,153,074	849,553	38.07	22,316
1990	81,695.00	50,798	64,122	50,251	38.91	1,291
1991	2,019.00	1,221	1,541	1,286	39.75	32
2004	181.00	68	86	167	51.29	3
2013	480,239.39	98,255	124,026	548,309	59.77	9,174
	1,994,582.39	1,063,820	1,342,849	1,449,566		32,816

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.2 1.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.22 MAINS - SOUTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1989	14,864,615.00	9,492,484	12,088,213	8,722,248	38.07	229,111
1990	75,414.00	46,892	59,715	45,865	38.91	1,179
1991	522.00	316	402	329	39.75	8
1993	8,713.00	4,973	6,333	5,865	41.46	141
	14,949,264.00	9,544,665	12,154,663	8,774,307		230,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.1 1.54

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.23 MAINS - SOUTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1999	33,516,134.00	15,598,476	17,448,553	29,474,035	46.73	630,730
2000	64,133.00	28,693	32,096	57,690	47.63	1,211
2001	603.00	259	290	554	48.54	11
2003	382,180.95	150,120	167,925	367,128	50.36	7,290
2013	918,290.41	187,879	210,163	1,075,444	59.77	17,993
	34,881,341.36	15,965,427	17,859,027	30,974,851		657,235

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.1 1.88

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.24 MAINS - 11.7M S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	17,466,181.89	6,860,681	7,804,954	16,647,701	50.36	330,574
	17,466,181.89	6,860,681	7,804,954	16,647,701		330,574

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.4 1.89

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.25 MAINS - 12M NORTH S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	10,767,917.66	4,229,617	4,746,732	10,328,353	50.36	205,090
2004	7,746,047.21	2,898,617	3,253,003	7,591,463	51.29	148,011
2005	16,294.30	5,797	6,506	16,306	52.21	312
2013	83,391.98	17,062	19,148	97,601	59.77	1,633
	18,613,651.15	7,151,093	8,025,389	18,033,723		355,046

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.8 1.91

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.26 MAINS - 38M NORTH S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	38,081,707.37	14,958,418	16,867,772	36,446,618	50.36	723,722
2004	30,150,968.21	11,282,673	12,722,839	29,488,516	51.29	574,937
	68,232,675.58	26,241,091	29,590,611	65,935,135		1,298,659

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.8 1.90

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -5						
2008	7,723,454.21	2,654,524	3,373,630	4,735,997	30.27	156,458
	7,723,454.21	2,654,524	3,373,630	4,735,997		156,458

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.3 2.03

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -10						
1965	14,697.00	13,367	16,167			
1966	25,913.00	23,379	28,504			
1967	5,028.00	4,499	5,531			
1977	45,443.00	36,331	49,987			
1987	26,938.00	17,998	29,632			
1992	77,606.00	45,910	85,367			
2002	11,991.00	5,054	10,877	2,313	30.84	75
2003	189,080.78	76,290	164,187	43,802	31.66	1,384
2004	12,068.68	4,649	10,005	3,271	32.49	101
2006	133,313.77	46,399	99,857	46,788	34.18	1,369
2012	33,883.82	7,894	16,989	20,283	39.41	515
2013	3,180,851.99	678,794	1,460,865	2,038,072	40.30	50,573
2014	106,367.62	20,593	44,319	72,685	41.20	1,764
2015	106,367.62	18,463	39,735	77,269	42.11	1,835
	3,969,550.28	999,620	2,062,022	2,304,483		57,616

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.0 1.45

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1900	208,257.00	208,257	208,257			
1952	1,813.00	1,505	1,813			
1956	11,140.00	8,902	11,140			
1960	200.00	153	200			
1962	100.00	75	100			
1963	3,425.00	2,524	3,425			
1964	750.00	546	750			
1968	9,669.00	6,657	9,669			
1971	2,507.00	1,650	2,507			
1974	3,304.00	2,069	3,304			
1975	3,640.00	2,240	3,640			
1976	804.00	486	804			
1977	10,277.00	6,096	10,277			
1978	6,845.00	3,984	6,845			
1979	1,589.00	907	1,589			
1980	1,565.00	875	1,565			
1981	8,720.00	4,774	8,720			
1982	1,039.00	557	1,039			
1983	252.00	132	252			
1984	764.00	391	764			
1985	4,779.00	2,390	4,779			
1986	3,752.00	1,831	3,752			
1987	9,733.00	4,630	9,733			
1988	3,902.00	1,808	3,902			
1989	74,994.00	33,837	74,994			
1990	10,006.00	4,389	10,006			
1991	185,065.00	78,862	185,065			
1992	64,966.00	26,870	64,966			
1993	29,877.00	11,979	29,877			
1994	43,236.00	16,787	43,236			
1995	112,714.00	42,321	112,714			
1996	18,109.00	6,568	18,109			
1997	35,832.00	12,532	35,832			
1998	15,125.00	5,096	15,125			
1999	23,933.00	7,751	23,933			
2000	14,758.00	4,589	14,758			
2001	52,915.00	15,762	52,915			
2002	123,008.00	35,033	123,008			
2003	301,674.10	81,974	301,674			

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2009	2,201.96	424	1,988	214	60.55	4
2010	23,150.32	4,155	19,485	3,665	61.54	60
2013	455,790.26	63,688	298,660	157,130	64.52	2,435
	1,886,180.64	716,056	1,725,171	161,010		2,499

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 64.4   0.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S1						
NET SALVAGE PERCENT.. 0						
1913	2,827.00	2,827	2,827			
1927	2,144.00	2,144	2,144			
1953	14.00	14	14			
1956	32,928.00	32,298	21,328	11,600	0.67	11,600
1958	3,307.00	3,194	2,109	1,198	1.20	998
1959	871.00	834	551	320	1.47	218
1960	6,983.00	6,634	4,381	2,602	1.75	1,487
1961	726.00	684	452	274	2.02	136
1962	2,742.00	2,561	1,691	1,051	2.31	455
1965	298.00	271	179	119	3.16	38
1990	25,470.00	16,832	11,115	14,355	11.87	1,209
1993	1,907.00	1,187	784	1,123	13.21	85
2016	1,356,163.12	275,884	182,177	1,173,986	27.88	42,109
2018	83,178.16	12,667	8,365	74,813	29.67	2,522
2022	26,468.45	1,127	744	25,724	33.51	768
2023	41,571.59	594	392	41,180	34.50	1,194
	1,587,598.32	359,752	239,253	1,348,345		62,819

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.5 3.96

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1906	38.00	63	63			
1910	1,486.00	2,452	2,452			
1911	33.00	54	54			
1912	33.00	54	54			
1913	846.84	1,397	1,397			
1914	389.00	640	642			
1915	258.22	423	426			
1916	203.00	332	335			
1917	91.00	148	150			
1918	420.08	682	693			
1919	2,922.01	4,727	4,821			
1920	530.00	854	874			
1921	1,394.00	2,239	2,300			
1922	3,143.77	5,028	5,187			
1923	824.00	1,313	1,360			
1924	92.28	146	152			
1925	10,444.49	16,510	17,233			
1926	3,628.84	5,713	5,988			
1927	3,028.90	4,749	4,982	16	3.23	5
1928	3,793.38	5,923	6,213	46	3.49	13
1929	598.77	931	977	11	3.74	3
1930	2,212.07	3,425	3,593	57	4.00	14
1931	736.11	1,135	1,191	24	4.26	6
1932	1,984.41	3,047	3,196	78	4.52	17
1933	404.00	618	648	19	4.78	4
1934	1,805.82	2,749	2,884	96	5.03	19
1935	105.33	160	168	6	5.29	1
1936	4,979.21	7,514	7,882	334	5.55	60
1937	1,098.10	1,650	1,731	81	5.81	14
1938	6.66	10	10	1	6.07	
1939	832.67	1,240	1,301	73	6.33	12
1940	4,948.84	7,336	7,695	471	6.60	71
1941	2,439.72	3,600	3,776	250	6.87	36
1942	9,590.13	14,085	14,775	1,049	7.14	147
1943	988.17	1,444	1,515	115	7.43	15
1944	2,042.04	2,970	3,115	254	7.71	33
1945	1,205.00	1,743	1,828	160	8.01	20
1946	23,985.29	34,516	36,206	3,370	8.31	406
1947	16,463.98	23,559	24,713	2,453	8.63	284
1948	545.40	776	814	86	8.95	10
1949	16,924.00	23,934	25,106	2,819	9.29	303
1950	17,887.98	25,142	26,373	3,142	9.63	326

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1951	21,257.02	29,684	31,137	3,937	9.99	394
1952	18,288.79	25,367	26,609	3,568	10.36	344
1953	24,932.17	34,335	36,016	5,122	10.75	476
1954	14,568.02	19,914	20,889	3,148	11.15	282
1955	12,004.04	16,284	17,081	2,726	11.56	236
1956	244,057.60	328,414	344,494	58,201	11.99	4,854
1957	593,138.46	791,526	830,282	148,396	12.43	11,939
1958	525,092.37	694,725	728,741	137,661	12.88	10,688
1959	767,318.21	1,006,049	1,055,309	210,766	13.35	15,788
1960	997,185.67	1,295,027	1,358,437	286,919	13.84	20,731
1961	1,278,561.62	1,644,538	1,725,061	384,566	14.33	26,836
1962	4,974.67	6,333	6,643	1,565	14.85	105
1963	1,774,985.03	2,235,730	2,345,200	583,525	15.38	37,941
1964	2,841,770.78	3,540,511	3,713,868	975,054	15.92	61,247
1965	2,924,595.24	3,602,104	3,778,477	1,047,105	16.48	63,538
1966	3,645,285.91	4,437,000	4,654,253	1,360,469	17.05	79,793
1967	2,832,847.54	3,406,416	3,573,207	1,100,991	17.63	62,450
1968	3,032,314.73	3,600,088	3,776,362	1,226,957	18.23	67,304
1969	3,382,225.91	3,963,115	4,157,165	1,423,508	18.84	75,558
1970	3,057,816.01	3,534,906	3,707,989	1,337,407	19.46	68,726
1971	2,881,102.38	3,283,796	3,444,583	1,309,236	20.10	65,136
1972	2,913,836.19	3,273,026	3,433,286	1,374,544	20.75	66,243
1973	3,621,686.77	4,007,480	4,203,702	1,772,081	21.41	82,769
1974	2,977,758.19	3,244,302	3,403,156	1,510,145	22.08	68,394
1975	2,899,842.46	3,109,363	3,261,609	1,523,131	22.76	66,921
1976	3,803,064.00	4,011,204	4,207,608	2,067,448	23.45	88,164
1977	4,317,582.98	4,476,088	4,695,255	2,428,757	24.16	100,528
1978	6,036,665.11	6,149,412	6,450,511	3,509,986	24.87	141,133
1979	8,192,701.66	8,196,073	8,597,385	4,920,573	25.59	192,285
1980	8,529,471.79	8,372,683	8,782,642	5,290,986	26.33	200,949
1981	7,528,900.44	7,249,134	7,604,080	4,818,606	27.07	178,005
1982	7,008,142.49	6,614,285	6,938,146	4,625,289	27.82	166,258
1983	7,262,725.74	6,714,473	7,043,240	4,940,257	28.58	172,857
1984	9,837,418.10	8,902,460	9,338,359	6,893,381	29.35	234,868
1985	10,754,786.17	9,519,696	9,985,817	7,759,580	30.13	257,537
1986	10,465,733.32	9,056,617	9,500,064	7,768,396	30.91	251,323
1987	9,525,867.89	8,049,811	8,443,961	7,273,721	31.71	229,383
1988	9,712,002.05	8,009,998	8,402,199	7,622,604	32.51	234,470
1989	12,191,490.44	9,804,116	10,284,164	9,831,795	33.32	295,072
1990	12,991,704.53	10,177,318	10,675,639	10,760,673	34.14	315,193
1991	14,453,865.99	11,021,759	11,561,427	12,287,452	34.96	351,472
1992	17,006,491.30	12,605,713	13,222,938	14,837,773	35.80	414,463

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1993	18,884,846.19	13,595,418	14,261,102	16,898,894	36.64	461,214
1994	20,593,727.69	14,381,208	15,085,368	18,894,283	37.49	503,982
1995	17,276,820.25	11,692,045	12,264,533	16,242,220	38.34	423,636
1996	16,693,187.22	10,928,537	11,463,641	16,080,118	39.21	410,102
1997	16,885,115.54	10,681,136	11,204,126	16,656,315	40.08	415,577
1998	18,874,654.18	11,522,976	12,087,186	19,055,993	40.95	465,348
1999	17,866,098.27	10,508,106	11,022,624	18,456,438	41.83	441,225
2000	16,422,214.70	9,287,920	9,742,692	17,353,962	42.72	406,226
2001	13,932,933.38	7,561,654	7,931,902	15,057,438	43.62	345,196
2002	12,921,435.37	6,717,622	7,046,543	14,273,825	44.52	320,616
2003	17,175,512.92	8,532,486	8,950,269	19,389,327	45.43	426,796
2004	16,298,243.59	7,720,185	8,098,195	18,793,907	46.34	405,566
2005	12,917,775.85	5,817,107	6,101,935	15,212,395	47.26	321,887
2006	16,079,402.14	6,865,430	7,201,588	19,329,426	48.18	401,192
2007	14,617,482.51	5,896,093	6,184,789	17,934,057	49.11	365,181
2008	8,414,054.06	3,193,134	3,349,482	10,533,707	50.05	210,464
2009	14,503,392.86	5,158,001	5,410,557	18,520,041	50.99	363,209
2010	4,338,858.45	1,439,555	1,510,041	5,649,075	51.93	108,782
2011	11,457,173.05	3,524,902	3,697,495	15,206,841	52.88	287,573
2012	17,083,653.84	4,844,113	5,081,299	23,106,730	53.83	429,254
2013	13,349,582.09	3,463,275	3,632,850	18,393,960	54.78	335,779
2014	14,720,206.95	3,460,117	3,629,538	20,658,803	55.74	370,628
2015	17,344,181.40	3,649,927	3,828,642	24,789,257	56.71	437,123
2016	21,703,509.94	4,038,383	4,236,118	31,574,673	57.67	547,506
2017	18,914,211.66	3,053,747	3,203,270	28,005,179	58.64	477,578
2018	22,768,384.04	3,115,125	3,267,654	34,300,180	59.61	575,410
2019	23,831,785.80	2,668,028	2,798,665	36,523,782	60.59	602,802
2020	19,749,843.71	1,724,517	1,808,956	30,778,286	61.56	499,972
2021	23,896,951.31	1,492,424	1,565,499	37,864,471	62.54	605,444
2022	21,464,946.66	806,449	845,935	34,571,227	63.52	544,257
2023	29,038,170.24	361,264	378,953	47,534,028	64.51	736,847
	733,069,799.15	377,976,788	396,483,311	813,081,858		18,030,844

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 2.46

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1909	15,171.92	25,034	25,034			
1910	18,924.68	31,226	31,226			
1911	107.55	177	177			
1912	73.85	122	122			
1913	20,767.30	34,266	34,266			
1915	4,079.00	6,685	6,252	478	0.44	478
1916	10,173.75	16,632	15,555	1,232	0.60	1,232
1917	2,712.00	4,418	4,132	343	0.82	343
1918	4,687.00	7,610	7,117	617	1.04	593
1919	80.00	129	121	11	1.27	9
1920	9,605.00	15,480	14,478	1,370	1.51	907
1921	15,536.41	24,949	23,334	2,301	1.74	1,322
1922	37,159.00	59,435	55,587	5,725	1.99	2,877
1923	17,836.00	28,420	26,580	2,849	2.23	1,278
1924	5,562.00	8,827	8,256	921	2.48	371
1925	19,177.00	30,313	28,351	3,291	2.73	1,205
1926	36,316.09	57,174	53,473	6,449	2.98	2,164
1927	10,785.00	16,911	15,816	1,979	3.23	613
1928	13,629.16	21,281	19,903	2,585	3.49	741
1929	512.68	797	745	101	3.74	27
1930	56,369.00	87,285	81,635	11,374	4.00	2,844
1931	22,611.66	34,864	32,607	4,702	4.26	1,104
1932	220.60	339	317	47	4.52	10
1934	8,805.18	13,404	12,536	1,993	5.03	396
1935	5,966.83	9,044	8,459	1,386	5.29	262
1937	13,738.29	20,642	19,306	3,362	5.81	579
1939	5,571.02	8,297	7,760	1,432	6.33	226
1940	204.00	302	282	55	6.60	8
1941	2,385.00	3,519	3,291	644	6.87	94
1942	1,951.00	2,866	2,680	539	7.14	75
1945	4,704.00	6,805	6,364	1,398	8.01	175
1946	10,534.00	15,159	14,178	3,203	8.31	385
1947	133,674.27	191,278	178,896	41,667	8.63	4,828
1948	30,663.40	43,628	40,804	9,791	8.95	1,094
1949	5,025.44	7,107	6,647	1,645	9.29	177
1952	27,604.00	38,287	35,808	9,739	10.36	940
1953	8,981.10	12,368	11,567	3,252	10.75	303
1954	14,182.88	19,387	18,132	5,270	11.15	473
1955	83,723.80	113,575	106,223	31,921	11.56	2,761
1956	1,977,027.61	2,660,369	2,488,148	773,948	11.99	64,549
1957	537,549.99	717,345	670,907	216,050	12.43	17,381
1958	1,404,634.80	1,858,406	1,738,101	579,546	12.88	44,996

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. -65

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1959	1,333,005.20	1,747,734	1,634,593	564,866	13.35	42,312
1960	2,410,450.29	3,130,408	2,927,759	1,049,484	13.84	75,830
1961	2,065,022.94	2,656,117	2,484,172	923,116	14.33	64,418
1962	1,298,743.16	1,653,353	1,546,322	596,604	14.85	40,175
1963	2,811,692.92	3,541,544	3,312,280	1,327,013	15.38	86,282
1964	2,776,712.70	3,459,456	3,235,506	1,346,070	15.92	84,552
1965	2,559,514.74	3,152,449	2,948,373	1,274,826	16.48	77,356
1966	2,794,751.75	3,401,740	3,181,526	1,429,814	17.05	83,860
1967	1,920,831.87	2,309,744	2,160,221	1,009,152	17.63	57,241
1968	2,430,351.86	2,885,413	2,698,624	1,311,457	18.23	71,939
1969	2,044,666.70	2,395,833	2,240,737	1,132,963	18.84	60,136
1970	1,760,487.46	2,035,164	1,903,416	1,001,388	19.46	51,459
1971	2,739,194.38	3,122,053	2,919,945	1,599,726	20.10	79,588
1972	1,979,812.94	2,223,865	2,079,902	1,186,789	20.75	57,195
1973	2,348,449.39	2,598,613	2,430,390	1,444,551	21.41	67,471
1974	2,675,203.26	2,914,665	2,725,982	1,688,103	22.08	76,454
1975	1,602,030.21	1,717,781	1,606,579	1,036,771	22.76	45,552
1976	1,156,683.17	1,219,988	1,141,011	767,516	23.45	32,730
1977	1,168,399.94	1,211,294	1,132,880	794,980	24.16	32,905
1978	2,901,294.41	2,955,482	2,764,157	2,022,979	24.87	81,342
1979	2,901,671.84	2,902,866	2,714,947	2,072,812	25.59	81,001
1980	3,064,189.87	3,007,864	2,813,148	2,242,765	26.33	85,179
1981	4,847,160.57	4,667,045	4,364,921	3,632,894	27.07	134,204
1982	4,260,449.08	4,021,012	3,760,709	3,269,032	27.82	117,507
1983	4,289,416.52	3,965,615	3,708,899	3,368,638	28.58	117,867
1984	7,345,237.69	6,647,139	6,216,833	5,902,809	29.35	201,118
1985	5,441,494.56	4,816,588	4,504,783	4,473,683	30.13	148,479
1986	5,289,026.00	4,576,906	4,280,617	4,446,276	30.91	143,846
1987	3,764,429.16	3,181,121	2,975,189	3,236,119	31.71	102,054
1988	5,178,448.93	4,270,939	3,994,457	4,549,984	32.51	139,956
1989	5,078,987.18	4,084,405	3,819,999	4,560,330	33.32	136,865
1990	4,039,562.73	3,164,474	2,959,620	3,705,659	34.14	108,543
1991	7,798,905.92	5,947,036	5,562,051	7,306,144	34.96	208,986
1992	9,217,025.14	6,831,931	6,389,662	8,818,429	35.80	246,325
1993	9,743,044.14	7,014,130	6,560,066	9,515,957	36.64	259,715
1994	9,348,646.75	6,528,436	6,105,814	9,319,453	37.49	248,585
1995	12,319,839.38	8,337,421	7,797,693	12,530,042	38.34	326,814
1996	18,556,097.27	12,148,129	11,361,713	19,255,847	39.21	491,095
1997	19,387,197.32	12,263,895	11,469,984	20,518,892	40.08	511,948
1998	11,658,055.35	7,117,243	6,656,504	12,579,287	40.95	307,186
1999	11,780,404.27	6,928,751	6,480,214	12,957,453	41.83	309,765
2000	14,910,274.76	8,432,812	7,886,909	16,715,044	42.72	391,270

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
2001	13,447,850.32	7,298,390	6,825,924	15,363,029	43.62	352,201
2002	17,591,699.95	9,145,608	8,553,562	20,472,743	44.52	459,855
2003	29,998,069.85	14,902,501	13,937,779	35,559,036	45.43	782,721
2004	18,467,612.49	8,747,776	8,181,484	22,290,077	46.34	481,012
2005	24,461,006.29	11,015,231	10,302,153	30,058,507	47.26	636,024
2006	19,828,057.91	8,465,996	7,917,945	24,798,351	48.18	514,702
2007	21,085,887.60	8,505,183	7,954,595	26,837,120	49.11	546,470
2008	20,547,899.75	7,797,928	7,293,125	26,610,910	50.05	531,687
2009	4,701,878.38	1,672,181	1,563,931	6,194,168	50.99	121,478
2010	16,753,080.67	5,558,371	5,198,547	22,444,036	51.93	432,198
2011	10,916,634.19	3,358,601	3,141,180	14,871,266	52.88	281,227
2012	18,088,541.14	5,129,051	4,797,019	25,049,074	53.83	465,337
2013	25,619,210.27	6,646,379	6,216,122	36,055,575	54.78	658,189
2014	21,483,638.29	5,049,923	4,723,013	30,724,990	55.74	551,220
2015	17,138,799.86	3,606,706	3,373,224	24,905,796	56.71	439,178
2016	18,898,388.94	3,516,433	3,288,794	27,893,548	57.67	483,675
2017	20,107,462.58	3,246,400	3,036,242	30,141,071	58.64	514,002
2018	36,968,771.74	5,057,993	4,730,561	56,267,912	59.61	943,934
2019	34,459,044.69	3,857,776	3,608,041	53,249,383	60.59	878,848
2020	50,453,856.41	4,405,530	4,120,335	79,128,528	61.56	1,285,389
2021	28,864,939.34	1,802,688	1,685,990	45,941,160	62.54	734,588
2022	52,157,427.85	1,959,581	1,832,726	84,227,030	63.52	1,325,992
2023	29,742,883.10	370,031	346,077	48,729,680	64.51	755,382
	779,378,528.59	318,558,873	297,942,649	988,031,923		20,420,234

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.4   2.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S3						
NET SALVAGE PERCENT.. -5						
2003	818,380.00	546,231	718,571	140,728	10.93	12,875
2023	42,306.82	741	975	43,447	29.50	1,473
	860,686.82	546,972	719,546	184,175		14,348

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.8 1.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. IOWA 50-R3
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1949	13,147.00	15,638	14,988	1,446	2.42	598
1950	2,585.00	3,058	2,931	300	2.68	112
1952	3,901.00	4,565	4,375	501	3.19	157
1953	7,573.00	8,813	8,447	1,019	3.45	295
1954	3,935.00	4,554	4,365	554	3.71	149
1955	13,406.00	15,430	14,789	1,968	3.96	497
1956	48,458.00	55,460	53,154	7,418	4.22	1,758
1957	30,840.00	35,096	33,637	4,913	4.48	1,097
1958	42,875.00	48,513	46,496	7,098	4.74	1,497
1959	36,309.00	40,848	39,150	6,236	5.00	1,247
1960	107,203.00	119,880	114,896	19,108	5.27	3,626
1961	66,657.00	74,073	70,994	12,327	5.55	2,221
1962	43,697.00	48,252	46,246	8,375	5.83	1,437
1963	66,875.00	73,345	70,296	13,298	6.13	2,169
1964	82,595.00	89,967	86,227	17,017	6.43	2,647
1965	155,371.00	167,995	161,011	33,203	6.75	4,919
1966	167,417.00	179,638	172,170	37,101	7.08	5,240
1967	95,011.00	101,139	96,934	21,830	7.42	2,942
1968	116,937.00	123,398	118,268	27,903	7.79	3,582
1969	103,704.00	108,474	103,964	25,666	8.16	3,145
1970	44,816.00	46,429	44,499	11,521	8.56	1,346
1971	104,156.00	106,838	102,396	27,799	8.97	3,099
1972	154,237.00	156,551	150,043	42,753	9.40	4,548
1973	127,698.00	128,177	122,848	36,774	9.85	3,733
1974	68,713.00	68,163	65,329	20,562	10.32	1,992
1975	47,726.00	46,760	44,816	14,842	10.81	1,373
1976	46,498.00	44,964	43,095	15,028	11.32	1,328
1977	209,427.00	199,741	191,437	70,347	11.85	5,936
1978	42,548.00	40,006	38,343	14,842	12.39	1,198
1979	159,252.00	147,467	141,336	57,729	12.96	4,454
1980	159,436.00	145,326	139,284	60,011	13.54	4,432
1981	122,295.00	109,637	105,079	47,790	14.14	3,380
1982	246,534.00	217,258	208,226	99,942	14.75	6,776
1983	244,704.00	211,730	202,928	102,952	15.39	6,690
1984	596,419.00	506,509	485,452	260,072	16.03	16,224
1985	270,231.00	224,967	215,615	122,174	16.70	7,316
1986	371,597.00	303,037	290,439	174,057	17.38	10,015
1987	307,786.00	245,690	235,476	149,256	18.07	8,260
1988	269,971.00	210,780	202,017	135,447	18.77	7,216
1989	300,385.00	229,119	219,594	155,887	19.49	7,998
1990	242,524.00	180,559	173,053	130,102	20.22	6,434
1991	539,949.00	391,868	375,577	299,359	20.97	14,276

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. IOWA 50-R3
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1992	464,086.00	328,109	314,469	265,638	21.72	12,230
1993	273,224.00	187,910	180,098	161,432	22.49	7,178
1994	575,924.00	385,005	368,999	350,906	23.26	15,086
1995	674,159.00	437,361	419,179	423,520	24.05	17,610
1996	1,135,006.00	713,635	683,968	734,790	24.85	29,569
1997	864,430.00	526,006	504,139	576,398	25.66	22,463
1998	600,436.00	353,056	338,379	412,166	26.48	15,565
1999	781,675.00	443,405	424,972	552,122	27.31	20,217
2000	942,827.00	515,019	493,608	684,926	28.15	24,331
2001	85,371.00	44,820	42,957	63,757	29.00	2,199
2002	729,133.00	367,118	351,856	559,560	29.86	18,739
2003	572,105.94	275,612	264,154	450,978	30.73	14,675
2004	933,123.87	429,237	411,393	755,012	31.60	23,893
2005	448,837.66	196,479	188,311	372,736	32.49	11,472
2006	341,438.24	141,868	135,970	290,828	33.38	8,713
2007	921,693.36	362,225	347,166	804,951	34.28	23,482
2008	1,038,546.13	384,522	368,536	929,647	35.19	26,418
2009	1,015,593.77	352,665	338,004	931,488	36.11	25,796
2010	1,776,089.88	575,897	551,956	1,668,156	37.03	45,049
2011	1,339,039.11	403,051	386,295	1,287,504	37.96	33,917
2012	1,530,066.81	424,976	407,309	1,505,275	38.89	38,706
2013	4,230,410.08	1,074,524	1,029,853	4,258,160	39.84	106,882
2014	3,336,812.27	769,135	737,160	3,433,855	40.78	84,204
2015	810,260.45	167,319	160,363	852,463	41.74	20,423
2016	1,873,752.16	342,428	328,193	2,013,997	42.69	47,177
2017	845,963.08	134,085	128,511	928,943	43.66	21,277
2018	2,723,320.39	366,287	351,059	3,053,091	44.62	68,424
2019	1,166,726.01	128,632	123,284	1,335,124	45.59	29,285
2020	2,955,890.46	253,468	242,931	3,451,932	46.57	74,124
2021	4,744,766.72	291,803	279,672	5,651,286	47.54	118,874
2022	4,199,464.10	155,380	148,921	5,100,409	48.52	105,120
2023	5,382,235.81	65,932	63,191	6,664,604	49.51	134,611
	55,197,805.30	16,876,681	16,175,076	52,822,181		1,415,068

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3 2.56

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -25						
1956	90,440.00	99,054	111,948	1,102	6.19	178
1957	415.00	452	511	8	6.44	1
1958	6,571.00	7,115	8,041	173	6.69	26
1959	140.00	151	171	4	6.94	1
1960	126,308.00	135,150	152,742	5,143	7.20	714
1961	9,016.00	9,586	10,834	436	7.47	58
1962	8,119.00	8,576	9,692	457	7.75	59
1963	18,246.00	19,140	21,631	1,176	8.04	146
1964	64,144.00	66,806	75,502	4,678	8.34	561
1965	56,664.00	58,562	66,185	4,645	8.66	536
1966	20,596.00	21,116	23,865	1,880	8.99	209
1967	7,958.00	8,091	9,144	804	9.33	86
1968	12,365.00	12,464	14,086	1,370	9.68	142
1969	35,068.00	35,015	39,573	4,262	10.06	424
1970	9,987.00	9,875	11,160	1,324	10.45	127
1971	29,853.00	29,219	33,022	4,294	10.85	396
1972	84,792.00	82,079	92,763	13,227	11.28	1,173
1973	28,044.00	26,838	30,332	4,723	11.72	403
1974	8,729.00	8,253	9,327	1,584	12.18	130
1975	11,764.00	10,982	12,412	2,293	12.66	181
1976	19,765.00	18,209	20,579	4,127	13.15	314
1977	47,198.00	42,879	48,461	10,536	13.66	771
1980	97,555.00	84,653	95,672	26,272	15.29	1,718
1981	36,714.00	31,326	35,404	10,488	15.87	661
1982	29,076.00	24,380	27,554	8,791	16.46	534
1983	6,973.00	5,741	6,488	2,228	17.07	131
1984	29,051.00	23,466	26,521	9,793	17.69	554
1986	84,113.00	65,251	73,745	31,396	18.97	1,655
1987	12,520.00	9,506	10,743	4,907	19.63	250
1988	31,995.00	23,756	26,848	13,146	20.30	648
1989	4,938.00	3,581	4,047	2,126	20.99	101
1990	2,738.00	1,939	2,191	1,232	21.68	57
1991	34,959.00	24,130	27,271	16,428	22.39	734
1992	1,830.00	1,230	1,390	898	23.11	39
1993	979.00	640	723	501	23.84	21
1996	28,701.00	17,156	19,389	16,487	26.09	632
2000	206,808.00	107,437	121,422	137,088	29.22	4,692
2001	40,639.00	20,299	22,941	27,858	30.02	928
2002	220.00	105	119	156	30.84	5
2004	302.39	132	149	229	32.49	7
2005	155,306.30	64,724	73,149	120,984	33.33	3,630
2009	128,042.07	42,382	47,899	112,154	36.76	3,051

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -25						
2010	135,098.10	41,745	47,179	121,694	37.64	3,233
2011	59,276.55	17,012	19,226	54,870	38.52	1,424
2012	76,366.14	20,218	22,850	72,608	39.41	1,842
2013	2,090,302.12	506,898	572,881	2,039,997	40.30	50,620
2014	832,210.86	183,086	206,918	833,346	41.20	20,227
2015	898,196.35	177,169	200,231	922,514	42.11	21,907
2016	2,565,294.90	447,644	505,914	2,700,705	43.02	62,778
2017	3,101,387.30	470,636	531,899	3,344,835	43.93	76,140
2018	2,742,492.22	352,410	398,284	3,029,831	44.86	67,540
2019	2,555,967.51	269,655	304,756	2,890,203	45.78	63,132
2020	1,699,020.09	139,744	157,935	1,965,840	46.71	42,086
2021	1,485,514.96	87,274	98,635	1,758,259	47.65	36,899
2022	1,556,236.99	54,857	61,998	1,883,298	48.59	38,759
2023	575,634.87	6,764	7,644	711,900	49.53	14,373
	22,002,640.72	4,036,558	4,561,996	22,941,305		527,644

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.5 2.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. IOWA 60-R2.5
NET SALVAGE PERCENT.. -100

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1905	1,391.60	2,783	2,783			
1906	133.00	266	266			
1908	1,175.00	2,350	2,350			
1909	53.00	106	106			
1910	2,807.67	5,615	5,615			
1912	1,105.60	2,209	1,965	246	0.05	246
1913	23.55	47	47			
1914	162.68	323	287	38	0.50	38
1915	7.13	14	14			
1918	1,664.41	3,244	2,885	444	1.53	290
1919	2,237.74	4,341	3,861	614	1.80	341
1920	2,462.15	4,755	4,229	695	2.06	337
1922	784.36	1,500	1,334	235	2.61	90
1923	1,329.26	2,530	2,250	409	2.89	142
1924	5,429.79	10,288	9,150	1,710	3.16	541
1925	7,855.78	14,813	13,174	2,538	3.43	740
1926	4,572.61	8,584	7,634	1,511	3.68	411
1927	143.38	268	238	49	3.93	12
1928	2,761.01	5,139	4,571	951	4.16	229
1929	4,046.62	7,501	6,671	1,422	4.39	324
1930	4,569.31	8,436	7,503	1,636	4.61	355
1931	12,003.10	22,074	19,632	4,374	4.83	906
1932	7,584.75	13,893	12,356	2,814	5.05	557
1933	2,493.26	4,549	4,046	941	5.27	179
1934	3,282.62	5,965	5,305	1,260	5.49	230
1935	6,951.46	12,582	11,190	2,713	5.70	476
1936	5,794.24	10,443	9,288	2,300	5.93	388
1937	8,513.81	15,282	13,591	3,437	6.15	559
1938	14,421.81	25,777	22,925	5,919	6.38	928
1939	18,307.17	32,581	28,977	7,637	6.61	1,155
1940	12,799.11	22,680	20,171	5,427	6.84	793
1941	14,827.40	26,161	23,267	6,388	7.07	904
1942	21,958.54	38,567	34,301	9,616	7.31	1,315
1943	5,153.61	9,010	8,013	2,294	7.55	304
1944	17,975.09	31,277	27,817	8,133	7.80	1,043
1945	22,439.61	38,858	34,559	10,320	8.05	1,282
1946	46,923.71	80,866	71,920	21,927	8.30	2,642
1947	35,538.09	60,936	54,195	16,881	8.56	1,972
1948	17,532.31	29,904	26,596	8,469	8.83	959
1949	23,943.43	40,616	36,123	11,764	9.11	1,291
1950	20,894.57	35,249	31,350	10,439	9.39	1,112
1951	51,399.21	86,214	76,677	26,121	9.68	2,698

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -100						
1952	13,269.00	22,124	19,677	6,861	9.98	687
1953	79,139.83	131,135	116,628	41,652	10.29	4,048
1954	13,446.55	22,133	19,685	7,208	10.62	679
1955	15,093.90	24,679	21,949	8,239	10.95	752
1956	221,575.10	359,692	319,901	123,249	11.30	10,907
1957	203,812.98	328,412	292,082	115,544	11.66	9,909
1958	52,344.56	83,699	74,440	30,249	12.03	2,514
1959	272,343.76	431,937	384,154	160,534	12.42	12,925
1960	637,907.60	1,003,212	892,232	383,583	12.82	29,921
1961	736,450.20	1,148,126	1,021,115	451,785	13.23	34,149
1962	790,177.35	1,220,555	1,085,532	494,823	13.66	36,224
1963	965,559.79	1,476,978	1,313,588	617,532	14.11	43,766
1964	1,170,024.72	1,771,815	1,575,809	764,240	14.57	52,453
1965	1,375,130.50	2,060,853	1,832,873	917,388	15.04	60,997
1966	1,600,778.68	2,372,898	2,110,398	1,091,159	15.53	70,261
1967	1,616,651.67	2,369,462	2,107,342	1,125,961	16.03	70,241
1968	1,734,520.55	2,512,175	2,234,268	1,234,773	16.55	74,609
1969	1,983,691.64	2,837,988	2,524,038	1,443,345	17.08	84,505
1970	2,011,627.70	2,841,746	2,527,380	1,495,875	17.62	84,896
1971	2,288,127.76	3,189,650	2,836,797	1,739,459	18.18	95,680
1972	2,548,857.67	3,504,679	3,116,977	1,980,738	18.75	105,639
1973	2,690,625.00	3,646,712	3,243,297	2,137,953	19.34	110,546
1974	2,363,496.47	3,156,828	2,807,606	1,919,387	19.93	96,306
1975	2,175,749.27	2,861,850	2,545,260	1,806,239	20.54	87,938
1976	2,721,892.66	3,523,926	3,134,094	2,309,691	21.16	109,154
1977	3,238,863.82	4,125,211	3,668,863	2,808,865	21.79	128,906
1978	4,629,171.95	5,795,723	5,154,576	4,103,768	22.44	182,877
1979	5,715,434.75	7,031,928	6,254,027	5,176,842	23.09	224,203
1980	7,091,607.53	8,566,662	7,618,982	6,564,233	23.76	276,272
1981	7,308,099.46	8,664,921	7,706,371	6,909,828	24.43	282,842
1982	5,871,755.83	6,828,852	6,073,416	5,670,096	25.11	225,810
1983	6,470,655.60	7,374,347	6,558,566	6,382,745	25.81	247,297
1984	8,325,450.62	9,294,034	8,265,889	8,385,012	26.51	316,296
1985	10,073,836.79	11,004,055	9,786,740	10,360,934	27.23	380,497
1986	9,697,299.86	10,360,013	9,213,945	10,180,655	27.95	364,245
1987	10,092,908.49	10,536,996	9,371,349	10,814,468	28.68	377,074
1988	11,434,661.42	11,655,808	10,366,393	12,502,930	29.42	424,981
1989	14,999,373.70	14,914,477	13,264,575	16,734,172	30.17	554,663
1990	17,100,936.34	16,576,622	14,742,846	19,459,027	30.92	629,335
1991	18,624,738.10	17,575,420	15,631,153	21,618,323	31.69	682,181
1992	19,308,800.39	17,725,479	15,764,612	22,852,989	32.46	704,035
1993	21,437,043.97	19,121,843	17,006,504	25,867,584	33.24	778,206

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -100						
1994	21,915,889.32	18,971,709	16,872,979	26,958,800	34.03	792,207
1995	20,261,057.71	17,005,916	15,124,650	25,397,465	34.82	729,393
1996	23,000,337.75	18,684,094	16,617,181	29,383,494	35.63	824,684
1997	24,980,949.77	19,618,539	17,448,253	32,513,647	36.44	892,252
1998	24,130,332.60	18,298,996	16,274,684	31,985,981	37.25	858,684
1999	26,245,913.14	19,176,839	17,055,416	35,436,410	38.08	930,578
2000	23,039,621.17	16,196,854	14,405,090	31,674,152	38.91	814,036
2001	23,097,804.98	15,598,872	13,873,259	32,322,351	39.74	813,346
2002	24,210,624.47	15,664,274	13,931,426	34,489,823	40.59	849,712
2003	25,248,075.87	15,619,975	13,892,027	36,604,125	41.44	883,304
2004	23,605,715.78	13,927,372	12,386,667	34,824,765	42.30	823,280
2005	21,657,966.12	12,157,483	10,812,571	32,503,361	43.16	753,090
2006	22,726,940.84	12,098,460	10,760,077	34,693,805	44.03	787,958
2007	19,937,470.02	10,035,326	8,925,176	30,949,764	44.90	689,304
2008	19,728,466.64	9,351,293	8,316,814	31,140,119	45.78	680,212
2009	19,837,820.54	8,814,737	7,839,614	31,836,027	46.67	682,152
2010	10,668,894.37	4,423,964	3,934,566	17,403,223	47.56	365,921
2011	16,262,664.87	6,261,126	5,568,494	26,956,836	48.45	556,385
2012	18,402,748.98	6,532,976	5,810,271	30,995,227	49.35	628,069
2013	24,607,791.19	7,989,165	7,105,370	42,110,212	50.26	837,847
2014	27,142,637.04	7,989,164	7,105,369	47,179,905	51.17	922,023
2015	26,835,791.62	7,084,649	6,300,915	47,370,668	52.08	909,575
2016	29,409,238.23	6,862,352	6,103,210	52,715,266	53.00	994,628
2017	32,009,705.80	6,487,087	5,769,458	58,249,954	53.92	1,080,303
2018	33,746,195.09	5,792,872	5,152,040	62,340,350	54.85	1,136,561
2019	39,217,130.97	5,529,615	4,917,906	73,516,356	55.77	1,318,206
2020	38,744,563.58	4,248,729	3,778,716	73,710,411	56.71	1,299,778
2021	43,903,666.35	3,453,462	3,071,425	84,735,908	57.64	1,470,089
2022	40,867,962.24	1,934,689	1,720,666	80,015,258	58.58	1,365,914
2023	46,499,651.41	728,185	647,630	92,351,673	59.53	1,551,347
	1,004,062,014.54	547,323,025	486,777,081	1,521,346,948		35,336,053

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.1 3.52

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S0						
NET SALVAGE PERCENT.. 0						
1983	74,388.86	55,891	32,221	42,168	7.46	5,653
1984	253,176.22	186,761	107,667	145,509	7.87	18,489
1985	362,639.61	262,551	151,360	211,280	8.28	25,517
1986	758,418.15	538,477	310,430	447,988	8.70	51,493
1987	31,272.11	21,776	12,554	18,718	9.11	2,055
1988	483,011.11	329,414	189,906	293,105	9.54	30,724
1989	738,750.11	493,485	284,493	454,257	9.96	45,608
1990	1,194,883.79	781,060	450,279	744,605	10.39	71,666
1991	628,996.42	402,136	231,830	397,166	10.82	36,707
1992	1,134,824.80	708,891	408,674	726,151	11.26	64,489
1993	1,054,102.00	643,002	370,689	683,413	11.70	58,411
1994	1,059,351.95	630,314	363,374	695,978	12.15	57,282
1995	1,179,089.23	683,872	394,250	784,839	12.60	62,289
1996	1,251,072.12	706,443	407,262	843,810	13.06	64,610
1997	1,304,342.29	716,514	413,068	891,274	13.52	65,923
1998	1,403,612.34	749,066	431,834	971,778	13.99	69,462
1999	1,440,722.63	745,819	429,963	1,010,760	14.47	69,852
2000	1,273,954.67	639,105	368,442	905,513	14.95	60,569
2001	1,801,510.85	874,327	504,047	1,297,464	15.44	84,033
2002	1,899,162.31	890,707	513,490	1,385,672	15.93	86,985
2003	2,772,798.89	1,253,305	722,527	2,050,272	16.44	124,712
2004	2,883,270.72	1,254,223	723,056	2,160,215	16.95	127,446
2005	294,931.04	123,184	71,015	223,916	17.47	12,817
2006	6,419,429.38	2,567,772	1,480,313	4,939,116	18.00	274,395
2007	4,956,971.23	1,893,563	1,091,634	3,865,337	18.54	208,486
2008	3,992,437.41	1,451,930	837,033	3,155,404	19.09	165,291
2009	439,742.81	151,711	87,461	352,282	19.65	17,928
2011	1,979.67	606	349	1,631	20.81	78
2012	5,048,717.03	1,445,599	833,384	4,215,333	21.41	196,886
2013	3,580,551.06	951,245	548,390	3,032,161	22.03	137,638
2014	2,878,498.88	704,282	406,017	2,472,482	22.66	109,112
2015	3,100,226.68	690,327	397,971	2,702,256	23.32	115,877
2017	6,206,258.51	1,100,556	634,467	5,571,792	24.68	225,761
2018	4,603,849.83	705,908	406,954	4,196,896	25.40	165,232
2019	4,830,668.54	619,920	357,382	4,473,287	26.15	171,063
2020	2,443,899.74	250,084	144,173	2,299,727	26.93	85,396

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S0						
NET SALVAGE PERCENT.. 0						
2021	29,266,678.83	2,204,659	1,270,979	27,995,700	27.74	1,009,218
2022	3,176,439.41	148,244	85,463	3,090,976	28.60	108,076
2023	5,320,335.97	85,125	49,074	5,271,262	29.52	178,566
	111,544,967.20	28,661,854	16,523,475	95,021,492		4,465,795

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.3   4.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.10 METERS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 16-S4						
NET SALVAGE PERCENT.. 0						
2014	1,696,938.46	1,001,194	1,461,577	235,361	6.56	35,878
	1,696,938.46	1,001,194	1,461,577	235,361		35,878

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.6   2.11

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R0.5						
NET SALVAGE PERCENT.. 0						
2006	5,458,965.42	3,522,834	3,389,719	2,069,246	5.32	388,956
2007	2,775,100.71	1,707,603	1,643,079	1,132,022	5.77	196,191
2008	5,895,840.23	3,443,171	3,313,066	2,582,774	6.24	413,906
2009	8,940,669.43	4,935,250	4,748,765	4,191,904	6.72	623,795
2010	573,874.12	298,030	286,769	287,105	7.21	39,820
2011	496,924.53	241,172	232,059	264,866	7.72	34,309
2012	628,798.68	282,959	272,267	356,532	8.25	43,216
2013	2,683,198.53	1,110,844	1,068,869	1,614,330	8.79	183,655
2016	0.22					
2017	436,112.85	114,262	109,944	326,169	11.07	29,464
2018	196,983.35	43,862	42,205	154,778	11.66	13,274
2019	1,381,474.71	252,354	242,818	1,138,657	12.26	92,876
2020	625,674.35	89,265	85,892	539,782	12.86	41,974
2021	6,206,202.29	637,191	613,114	5,593,088	13.46	415,534
2022	1,575,712.33	97,694	94,003	1,481,709	14.07	105,310
2023	10,220,349.25	211,255	203,272	10,017,077	14.69	681,898
	48,095,881.00	16,987,746	16,345,841	31,750,040		3,304,178

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6   6.87

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-L1						
NET SALVAGE PERCENT.. 0						
1956	6,139.96	5,978	947	5,193	0.58	5,193
1957	37,441.00	36,199	5,733	31,708	0.73	31,708
1958	18,120.95	17,388	2,754	15,367	0.89	15,367
1959	12,907.89	12,292	1,947	10,961	1.05	10,439
1960	2,852.25	2,697	427	2,425	1.20	2,021
1961	67.51	63	10	58	1.37	42
1964	13,358.16	12,229	1,937	11,421	1.86	6,140
1965	115,016.15	104,404	16,535	98,481	2.03	48,513
1966	106,417.43	95,776	15,169	91,248	2.20	41,476
1967	310,202.72	276,785	43,837	266,366	2.37	112,391
1968	284,247.80	251,431	39,821	244,427	2.54	96,231
1969	84.19	74	12	72	2.72	26
1970	190,653.07	165,521	26,215	164,438	2.90	56,703
1971	55,765.60	47,958	7,595	48,171	3.08	15,640
1972	643,358.09	548,025	86,795	556,563	3.26	170,725
1973	274,135.99	231,146	36,608	237,528	3.45	68,849
1974	157,327.24	131,297	20,795	136,532	3.64	37,509
1975	5,896.92	4,870	771	5,126	3.83	1,338
1976	214,833.34	175,577	27,808	187,025	4.02	46,524
1978	497,135.03	397,256	62,917	434,218	4.42	98,239
1979	1,074.42	849	134	940	4.62	203
1980	617,641.05	482,038	76,344	541,297	4.83	112,070
1981	836,033.76	644,507	102,076	733,958	5.04	145,627
1982	451,748.29	343,943	54,473	397,275	5.25	75,671
1983	406,120.94	305,143	48,328	357,793	5.47	65,410
1984	1,174.82	871	138	1,037	5.69	182
1985	918.50	672	106	812	5.91	137
1986	973,603.35	701,880	111,162	862,441	6.14	140,463
1988	951,407.38	665,557	105,410	845,997	6.61	127,987
1989	1,689,773.02	1,163,645	184,296	1,505,477	6.85	219,778
1990	2,254,008.05	1,527,609	241,940	2,012,068	7.09	283,790
1991	560,680.72	373,615	59,172	501,509	7.34	68,325
1992	1,118,793.09	732,306	115,981	1,002,812	7.60	131,949
1995	524,285.28	324,344	51,369	472,916	8.39	56,367
1997	225,924.86	134,014	21,225	204,700	8.95	22,872
1999	418,560.11	237,056	37,544	381,016	9.54	39,939
2000	1,744,045.82	963,986	152,674	1,591,372	9.84	161,725
2001	2,319,307.03	1,249,272	197,857	2,121,450	10.15	209,010
2002	56,913.36	29,854	4,728	52,185	10.46	4,989
2003	1,106.41	564	89	1,017	10.78	94
2004	3,248,185.58	1,607,852	254,649	2,993,537	11.11	269,445
2005	76,055.16	36,472	5,776	70,279	11.45	6,138

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-L1						
NET SALVAGE PERCENT.. 0						
2007	19,007.75	8,510	1,348	17,660	12.15	1,453
2012	3,799,338.70	1,367,762	216,624	3,582,715	14.08	254,454
2013	2,965,328.90	1,008,212	159,679	2,805,650	14.52	193,227
2014	2,081,456.95	662,278	104,890	1,976,567	15.00	131,771
2015	2,307,252.64	679,601	107,634	2,199,619	15.52	141,728
2017	4,914,628.61	1,181,722	187,159	4,727,470	16.71	282,913
2018	3,018,469.43	632,520	100,177	2,918,292	17.39	167,814
2019	3,928,587.83	692,846	109,732	3,818,856	18.12	210,754
2021	10,884,896.25	1,118,205	177,099	10,707,797	19.74	542,442
2022	5,372,545.91	337,020	53,376	5,319,170	20.62	257,962
2023	6,479,431.73	138,401	21,920	6,457,512	21.53	299,931
	67,194,266.99	21,870,092	3,463,742	63,730,525		5,491,694

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6   8.17

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L3						
NET SALVAGE PERCENT.. 0						
2012	481,019.77	308,492	298,351	182,669	5.38	33,953
	481,019.77	308,492	298,351	182,669		33,953

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4   7.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-R2.5						
NET SALVAGE PERCENT.. 0						
2006	812,099.60	607,272	693,187	118,913	4.54	26,192
2007	1,236,258.68	890,106	1,016,036	220,223	5.04	43,695
2008	962,016.51	662,724	756,484	205,533	5.60	36,702
2010	4,502,920.97	2,794,333	3,189,668	1,313,253	6.83	192,277
2020	534,640.00	96,235	109,850	424,790	14.76	28,780
2021	981,953.28	127,104	145,086	836,867	15.67	53,406
2022	425,475.14	33,327	38,042	387,433	16.59	23,353
	9,455,364.18	5,211,101	5,948,353	3,507,011		404,405

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.7 4.28

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S2.5						
NET SALVAGE PERCENT.. 0						
2003	1,944.74	1,194	1,007	938	11.58	81
2004	50,974.78	30,160	25,424	25,551	12.25	2,086
2005	111,010.40	63,091	53,184	57,826	12.95	4,465
2006	99,709.20	54,209	45,697	54,012	13.69	3,945
2007	106,166.87	54,994	46,359	59,808	14.46	4,136
2008	81,705.03	40,144	33,840	47,865	15.26	3,137
2009	36,113.86	16,745	14,116	21,998	16.09	1,367
2010	82,233.28	35,771	30,154	52,079	16.95	3,073
2011	49,737.69	20,177	17,009	32,729	17.83	1,836
2012	155,612.57	58,406	49,235	106,378	18.74	5,677
2013	340,537.54	117,373	98,942	241,596	19.66	12,289
2014	169,400.03	53,022	44,696	124,704	20.61	6,051
2015	215,465.95	60,546	51,039	164,427	21.57	7,623
2016	177,698.56	44,188	37,249	140,450	22.54	6,231
2017	199,129.42	43,012	36,258	162,871	23.52	6,925
2018	322,261.36	58,974	49,714	272,547	24.51	11,120
2019	220,007.55	33,001	27,819	192,189	25.50	7,537
2020	134,038.69	15,638	13,182	120,857	26.50	4,561
2021	126,222.41	10,518	8,866	117,356	27.50	4,267
2022	142,935.10	7,147	6,025	136,910	28.50	4,804
2023	421,861.93	7,032	5,928	415,934	29.50	14,099
	3,244,766.96	825,342	695,743	2,549,024		115,310

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.1   3.55

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S0						
NET SALVAGE PERCENT.. 0						
2017	1,162,110.41	388,482	753,163	408,947	9.32	43,878
	1,162,110.41	388,482	753,163	408,947		43,878

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.3   3.78

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S4						
NET SALVAGE PERCENT.. 0						
1989	18,825.00	17,861	18,574	251	1.28	196
1990	9,104.00	8,583	8,925	179	1.43	125
1991	18,219.00	17,060	17,741	478	1.59	301
1992	82,936.00	77,064	80,138	2,798	1.77	1,581
2005	9,866.13	7,060	7,342	2,524	7.11	355
2011	34,908.85	17,440	18,135	16,774	12.51	1,341
	173,858.98	145,068	150,855	23,004		3,899

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9   2.24

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-S0.5						
NET SALVAGE PERCENT.. 0						
1962	865.00	865	865			
1972	10,994.00	10,994	10,994			
1986	25,765.00	22,505	25,765			
1990	252.00	205	252			
1991	21,291.00	17,014	21,291			
1993	4,866.00	3,736	4,866			
1994	7,658.00	5,760	7,658			
1995	2,254.00	1,659	2,254			
1996	2,372.00	1,707	2,372			
1997	12,952.00	9,100	12,952			
1998	4,440.00	3,042	4,440			
1999	2,715.00	1,813	2,715			
	96,424.00	78,400	96,424			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S4						
NET SALVAGE PERCENT.. 0						
1978	6,819.00	6,819	6,819			
1979	8,748.00	8,748	8,748			
1984	1,225.00	1,192	1,225			
1985	40,398.00	39,121	40,398			
1986	1,347.00	1,299	1,347			
1987	1,633.00	1,566	1,633			
1990	606.00	571	606			
1991	11,895.00	11,138	11,895			
	72,671.00	70,454	72,671			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
1913	49,479.00	51,953	51,953			
1915	172.00	181	181			
1920	424.00	445	445			
1922	510.00	536	536			
1923	67.00	70	70			
1924	11.00	12	12			
1925	92.00	97	97			
1927	545.00	572	572			
1930	177.00	182	186			
1936	33.00	32	35			
1937	236.00	230	248			
1938	945.00	912	992			
1939	107.00	102	112			
1940	95.00	90	100			
1941	1,344.00	1,264	1,411			
1942	511.00	476	537			
1943	3,058.00	2,825	3,211			
1944	31.00	28	32	1	6.15	
1945	762.00	691	789	11	6.53	2
1946	193.00	173	197	6	6.92	1
1947	6,781.00	6,036	6,889	231	7.31	32
1948	3,062.00	2,700	3,082	133	7.69	17
1949	8,343.00	7,286	8,316	444	8.08	55
1950	248.00	214	244	16	8.47	2
1951	10,081.00	8,631	9,851	734	8.86	83
1952	29,220.00	24,762	28,261	2,420	9.26	261
1953	11,532.00	9,674	11,041	1,068	9.65	111
1954	63.00	52	59	7	10.05	1
1955	17,854.00	14,665	16,737	2,010	10.45	192
1956	46,058.00	37,429	42,718	5,643	10.85	520
1957	3,819.00	3,070	3,504	506	11.25	45
1958	2,256.00	1,793	2,046	323	11.66	28
1959	1,537.00	1,208	1,379	235	12.06	19
1960	2,315.00	1,799	2,053	378	12.47	30
1961	7,174.00	5,511	6,290	1,243	12.88	97
1962	5,289.00	4,016	4,584	969	13.29	73
1963	7,300.00	5,476	6,250	1,415	13.71	103
1964	130,505.00	96,720	110,388	26,642	14.12	1,887
1965	269,207.00	197,042	224,886	57,781	14.54	3,974
1966	652,577.00	471,648	538,297	146,909	14.96	9,820
1967	28,680.00	20,465	23,357	6,757	15.38	439
1968	58,260.00	41,024	46,821	14,352	15.81	908

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
1969	24,007.00	16,679	19,036	6,171	16.24	380
1970	16,934.00	11,606	13,246	4,535	16.67	272
1971	22,591.00	15,270	17,428	6,293	17.10	368
1972	82,143.00	54,733	62,467	23,783	17.54	1,356
1973	232,553.00	152,715	174,295	69,886	17.98	3,887
1974	410,099.00	265,360	302,858	127,746	18.42	6,935
1975	35,275.00	22,485	25,662	11,377	18.86	603
1976	674,980.00	423,614	483,476	225,253	19.31	11,665
1977	71,654.00	44,264	50,519	24,718	19.76	1,251
1978	794,352.00	482,893	551,131	282,939	20.21	14,000
1979	34,675.00	20,730	23,659	12,750	20.67	617
1980	90,623.00	53,266	60,793	34,361	21.13	1,626
1981	357,050.00	206,275	235,424	139,478	21.59	6,460
1982	254,992.00	144,693	165,140	102,602	22.06	4,651
1983	29,883.00	16,649	19,002	12,375	22.53	549
1984	23,017.00	12,582	14,360	9,808	23.01	426
1985	50,285.00	26,960	30,770	22,029	23.49	938
1986	104,994.00	55,190	62,989	47,255	23.97	1,971
1987	70,133.00	36,114	41,217	32,423	24.46	1,326
1988	73,630.00	37,126	42,372	34,940	24.95	1,400
1989	92,458.00	45,608	52,053	45,028	25.45	1,769
1990	164,888.00	79,534	90,773	82,359	25.95	3,174
1991	128,634.00	60,639	69,208	65,858	26.45	2,490
1992	247,197.00	113,772	129,849	129,708	26.96	4,811
1993	153,692.00	68,988	78,737	82,640	27.48	3,007
1995	18,867.50	8,036	9,172	10,639	28.53	373
1996	88,757.78	36,755	41,949	51,247	29.07	1,763
1997	208,311.11	83,799	95,641	123,086	29.61	4,157
1998	372,706.61	145,450	166,004	225,338	30.16	7,471
1999	394,922.00	149,368	170,475	244,193	30.71	7,952
2000	181,017.49	66,246	75,607	114,461	31.27	3,660
2001	409,332.12	144,700	165,148	264,651	31.84	8,312
2002	196,636.83	67,016	76,486	129,983	32.42	4,009
2003	902,838.01	296,244	338,107	609,873	33.00	18,481
2004	4,167,289.98	1,312,696	1,498,195	2,877,459	33.60	85,639
2005	1,213,206.76	366,237	417,991	855,876	34.20	25,026
2006	1,174,466.05	338,868	386,754	846,435	34.81	24,316
2007	88,023.67	24,185	27,603	64,822	35.44	1,829
2008	240,284.56	62,706	71,567	180,732	36.07	5,011
2009	661,837.93	163,454	186,552	508,378	36.71	13,848
2010	716,899.25	166,703	190,260	562,484	37.37	15,052
2011	3,586,892.63	781,494	891,928	2,874,309	38.04	75,560

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
2012	8,807,856.10	1,787,964	2,040,624	7,207,625	38.72	186,147
2013	15,918,360.62	2,987,677	3,409,871	13,304,408	39.42	337,504
2014	9,852,047.32	1,696,109	1,935,789	8,408,861	40.13	209,541
2015	2,147,511.53	335,414	382,812	1,872,075	40.86	45,817
2016	895,762.62	125,206	142,899	797,652	41.61	19,170
2017	539,011.32	66,263	75,627	490,335	42.38	11,570
2018	11,924,207.41	1,259,804	1,437,829	11,082,589	43.17	256,720
2019	2,733,856.88	240,409	274,382	2,596,168	43.98	59,031
2020	1,032,966.80	72,084	82,270	1,002,345	44.81	22,369
2021	35,763,860.80	1,814,891	2,071,356	35,480,698	45.68	776,723
2022	26,269,561.86	821,699	937,815	26,645,225	46.57	572,154
2023	10,939,676.00	117,279	133,852	11,352,808	47.51	238,956
	147,048,661.54	19,028,593	21,709,798	132,691,297		3,132,793

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.4   2.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVMENTS - SOURCE CONTROL PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
2013	17,923,230.89	3,363,966	6,238,535	12,580,857	39.42	319,149
2014	667,063.96	114,840	212,973	487,444	40.13	12,147
2016	3,119,876.16	436,084	808,725	2,467,145	41.61	59,292
2017	216,141.91	26,571	49,276	177,673	42.38	4,192
2019	507,450.98	44,624	82,756	450,068	43.98	10,233
2022	599,800.97	18,761	34,793	594,998	46.57	12,776
	23,033,564.87	4,004,846	7,427,058	16,758,185		417,789

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.1 1.81

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2002	150,625.11	150,625	150,625			
	150,625.11	150,625	150,625			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	900,507.14	877,994	864,690	35,817	0.50	35,817
2005	156,461.63	144,727	142,534	13,928	1.50	9,285
2006	86,514.39	75,700	74,553	11,961	2.50	4,784
2007	161,293.83	133,067	131,051	30,243	3.50	8,641
2008	262,606.27	203,520	200,436	62,170	4.50	13,816
2009	16,197.81	11,743	11,565	4,633	5.50	842
2010	610,092.81	411,813	405,573	204,520	6.50	31,465
2012	915,653.06	526,501	518,523	397,130	8.50	46,721
2013	1,290,726.41	677,631	667,363	623,363	9.50	65,617
2014	1,073,795.73	510,053	502,325	571,471	10.50	54,426
2015	526,655.66	223,829	220,437	306,218	11.50	26,628
2016	228,667.97	85,750	84,451	144,217	12.50	11,537
2017	614,673.90	199,769	196,742	417,932	13.50	30,958
2018	357,096.50	98,202	96,714	260,382	14.50	17,957
2019	221,915.36	49,931	49,174	172,741	15.50	11,145
2020	8,934,077.08	1,563,463	1,539,773	7,394,304	16.50	448,140
2021	917,853.23	114,732	112,994	804,860	17.50	45,992
2022	217,497.71	16,312	16,065	201,433	18.50	10,888
2023	597,503.02	14,938	14,712	582,791	19.50	29,887
	18,089,789.51	5,939,675	5,849,675	12,240,115		904,546
	18,240,414.62	6,090,300	6,000,300	12,240,115		904,546

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5   4.96

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.20 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2016	0.14					
	0.14					
AMORTIZED						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	16,124,026.13	14,511,624	13,482,131	2,641,895	0.50	2,641,895
2020	15,425,944.20	10,798,161	10,032,111	5,393,833	1.50	3,595,889
2021	2,202,453.81	1,101,227	1,023,103	1,179,351	2.50	471,740
2022	4,769,443.93	1,430,833	1,329,326	3,440,118	3.50	982,891
2023	6,527,786.84	652,779	606,469	5,921,318	4.50	1,315,848
	45,049,654.91	28,494,624	26,473,140	18,576,515		9,008,263
	45,049,655.05	28,494,624	26,473,140	18,576,515		9,008,263

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.1 20.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.21 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	2,190,419.85	328,563	328,563	1,861,857	8.50	219,042
	2,190,419.85	328,563	328,563	1,861,857		219,042

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	9,135,002.99	1,370,250	1,370,250	7,764,753	8.50	913,500
2023	6,165.45	308	308	5,857	9.50	617
	9,141,168.44	1,370,558	1,370,558	7,770,610		914,117

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 13-L2						
NET SALVAGE PERCENT.. +15						
1972	69,477.00	59,055	59,055			
1976	6,463.00	5,494	5,494			
1983	27,346.00	23,244	23,244			
1984	2,344.00	1,992	1,992			
1991	9,846.00	7,848	8,369			
1994	122,576.04	93,450	104,190			
1995	130,420.96	97,811	110,858			
1996	89,364.25	65,909	75,960			
1997	35,160.27	25,472	29,886			
1998	117,858.83	83,843	100,180			
1999	137,426.00	95,966	115,777	1,035	2.32	446
2000	22,937.00	15,702	18,943	553	2.53	219
2001	52,722.00	35,334	42,628	2,186	2.75	795
2002	27,181.78	17,808	21,484	1,621	2.98	544
2003	196,904.50	126,042	152,062	15,307	3.21	4,769
2004	340,901.61	212,868	256,812	32,954	3.45	9,552
2005	69,026.34	41,973	50,638	8,034	3.70	2,171
2006	50,063.92	29,624	35,739	6,815	3.95	1,725
2007	143,928.24	82,814	99,910	22,429	4.20	5,340
2008	344,618.82	192,654	232,425	60,501	4.45	13,596
2009	16,819.11	9,128	11,012	3,284	4.70	699
2010	1,369,865.78	721,919	870,949	293,437	4.94	59,400
2011	514,464.34	263,050	317,353	119,942	5.18	23,155
2012	2,546,339.20	1,260,345	1,520,526	643,862	5.43	118,575
2013	3,587,968.55	1,712,570	2,066,106	983,667	5.70	172,573
2014	1,422,283.20	650,035	784,226	424,715	6.01	70,668
2016	2,522.59	1,016	1,226	918	6.84	134
2018	26,230,797.15	8,438,211	10,180,162	12,116,016	8.08	1,499,507
2019	7,424,678.82	2,014,653	2,430,550	3,880,427	8.85	438,466
2020	4,979,112.48	1,077,614	1,300,072	2,932,174	9.69	302,598
2021	4,077,052.92	645,102	778,274	2,687,221	10.58	253,991
2022	2,309,617.01	223,507	269,647	1,693,527	11.52	147,008
2023	1,022,542.64	33,428	40,329	828,832	12.50	66,307
	57,500,630.35	18,365,481	22,116,078	26,759,458		3,192,238

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4   5.55

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1931	410.00	410	410			
1949	142.00	142	142			
1950	555.00	555	555			
1951	854.00	854	854			
1953	319.00	319	319			
1956	5,263.00	5,263	5,263			
1957	4,077.00	4,077	4,077			
1959	2,143.00	2,143	2,143			
1960	4,411.00	4,411	4,411			
1961	7,017.00	7,017	7,017			
1962	1,425.00	1,425	1,425			
1963	6,629.00	6,629	6,629			
1964	7,252.00	7,252	7,252			
1965	912.00	912	912			
1966	22,261.00	22,261	22,261			
1967	2,462.00	2,462	2,462			
1968	5,254.00	5,254	5,254			
1969	2,624.00	2,624	2,624			
1970	3,287.00	3,287	3,287			
1971	2,696.00	2,696	2,696			
1972	1,500.00	1,500	1,500			
1974	2,858.00	2,858	2,858			
1975	135.00	135	135			
1976	9,518.00	9,518	9,518			
1977	2,502.00	2,502	2,502			
1978	2,983.00	2,983	2,983			
1979	6,192.00	6,192	6,192			
1980	4,499.00	4,499	4,499			
1982	3,276.00	3,276	3,276			
1984	1,936.00	1,936	1,936			
1985	2,099.00	2,099	2,099			
1986	1,915.00	1,915	1,915			
	119,406.00	119,406	119,406			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	533,048.95	501,066	501,066	31,983	1.50	21,322
2001	494,438.80	444,995	444,995	49,444	2.50	19,778
2002	479,727.82	412,566	412,566	67,162	3.50	19,189
2003	546,830.13	448,401	448,401	98,429	4.50	21,873
2004	857,542.25	668,883	668,883	188,659	5.50	34,302
2005	731,631.02	541,407	541,407	190,224	6.50	29,265
2006	382,098.07	267,469	267,469	114,629	7.50	15,284
2007	212,322.56	140,133	140,133	72,190	8.50	8,493
2008	419,885.67	260,329	260,329	159,557	9.50	16,795
2009	236,537.99	137,192	137,192	99,346	10.50	9,462
2010	79,462.62	42,910	42,910	36,553	11.50	3,179
2011	286,576.95	143,288	143,288	143,289	12.50	11,463
2012	1,673,154.33	769,651	769,651	903,503	13.50	66,926
2013	944,985.54	396,894	396,894	548,092	14.50	37,799
2014	431,652.65	164,028	164,028	267,625	15.50	17,266
2015	360,232.86	122,479	122,479	237,754	16.50	14,409
2016	1,360,659.75	408,198	408,198	952,462	17.50	54,426
2017	1,829,211.61	475,595	475,595	1,353,617	18.50	73,168
2018	1,359,422.40	299,073	299,073	1,060,349	19.50	54,377
2019	1,205,137.21	216,925	216,925	988,212	20.50	48,205
2020	2,501,680.54	350,235	350,235	2,151,446	21.50	100,067
2021	1,157,247.24	115,725	115,725	1,041,522	22.50	46,290
2022	606,696.19	36,402	36,402	570,294	23.50	24,268
2023	5,202,485.46	104,050	104,050	5,098,435	24.50	208,099
	23,892,668.61	7,467,894	7,467,894	16,424,775		955,705

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2   4.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. IOWA 15-L1.5
NET SALVAGE PERCENT.. +20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1985	62,386.85	44,685	42,031	7,878	1.57	5,018
1989	14,660.73	10,040	9,444	2,285	2.16	1,058
1991	9,842.00	6,567	6,177	1,697	2.49	682
1995	12,208.00	7,670	7,214	2,552	3.22	793
1996	6,962.00	4,303	4,047	1,523	3.41	447
1998	55,390.23	32,998	31,038	13,274	3.83	3,466
1999	17,877.00	10,440	9,820	4,482	4.05	1,107
2002	74,959.64	40,938	38,507	21,461	4.76	4,509
2003	62,542.82	33,323	31,344	18,690	5.01	3,731
2004	58,270.22	30,269	28,471	18,145	5.26	3,450
2005	501,185.16	253,399	238,350	162,598	5.52	29,456
2006	279,938.87	137,656	129,481	94,470	5.78	16,344
2007	11,235.18	5,369	5,050	3,938	6.04	652
2008	38,685.54	17,929	16,864	14,084	6.31	2,232
2010	126,667.32	55,058	51,788	49,546	6.85	7,233
2011	702,206.22	294,365	276,883	284,882	7.14	39,899
2012	307,231.72	123,711	116,364	129,421	7.45	17,372
2013	114,245.00	43,931	41,322	50,074	7.79	6,428
2014	63,570.81	23,123	21,750	29,107	8.18	3,558
2018	5,792,891.03	1,439,742	1,354,239	3,280,074	10.34	317,222
2019	1,761,607.76	370,177	348,193	1,061,093	11.06	95,940
2020	1,698,007.01	286,175	269,180	1,089,226	11.84	91,995
2021	2,159,211.03	267,172	251,305	1,476,064	12.68	116,409
2022	1,008,720.99	76,929	72,360	734,617	13.57	54,135
2023	1,309,883.06	33,533	31,542	1,016,364	14.52	69,998
	16,250,386.19	3,649,502	3,432,764	9,567,545		893,134

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.7   5.50

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	49,718.14	34,803	34,803	14,915	4.50	3,314
	49,718.14	34,803	34,803	14,915		3,314

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5   6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.10 COMMUNICATION EQUIPMENT - MOBILE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	55,474.85	30,511	30,511	24,964	4.50	5,548
2019	4,161,405.21	1,872,632	1,872,632	2,288,773	5.50	416,141
2020	40,009.64	14,003	14,003	26,007	6.50	4,001
2021	29,219.34	7,305	7,305	21,914	7.50	2,922
2023	1,054,670.22	52,734	52,734	1,001,936	9.50	105,467
	5,340,779.26	1,977,185	1,977,185	3,363,594		534,079

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.3   10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.20 COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

SURVIVOR CURVE.. 15-SQUARE
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2013	9,957.65	6,970	6,970	2,988	4.50	664
	9,957.65	6,970	6,970	2,988		664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.30 COMMUNICATION EQUIPMENT - TELEMETER OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2007	53,241.79	53,242	53,242			
	53,241.79	53,242	53,242			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	47,988.32	46,389	46,211	1,778	0.50	1,778
2010	188,278.98	169,451	168,800	19,479	1.50	12,986
2011	562,402.09	468,667	466,865	95,537	2.50	38,215
2012	264,234.41	202,581	201,802	62,432	3.50	17,838
2013	135,620.33	94,934	94,569	41,051	4.50	9,122
2014	386,407.83	244,724	243,783	142,625	5.50	25,932
2015	2,309.81	1,309	1,304	1,006	6.50	155
2018	94,316.84	34,583	34,450	59,867	9.50	6,302
2019	436,457.88	130,937	130,434	306,024	10.50	29,145
2020	4,370,817.24	1,019,843	1,015,923	3,354,895	11.50	291,730
2021	2,379,868.92	396,653	395,128	1,984,741	12.50	158,779
2022	2,884,116.73	288,412	287,303	2,596,813	13.50	192,357
2023	2,211,539.37	73,711	73,428	2,138,112	14.50	147,456
	13,964,358.75	3,172,194	3,160,000	10,804,359		931,795
	14,017,600.54	3,225,436	3,213,242	10,804,359		931,795

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6   6.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2007	61,119.78	61,120	61,120			
	61,119.78	61,120	61,120			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	71,274.98	64,147	64,147	7,128	1.50	4,752
2011	44,683.87	37,236	37,236	7,448	2.50	2,979
2013	177,219.97	124,054	124,054	53,166	4.50	11,815
2014	371,736.68	235,432	235,432	136,305	5.50	24,783
2015	76,277.45	43,224	43,224	33,053	6.50	5,085
2017	1,206,002.15	522,597	522,597	683,405	8.50	80,401
2019	2,763,921.53	829,176	829,176	1,934,746	10.50	184,262
2020	861,088.57	200,918	200,918	660,171	11.50	57,406
2022	336,271.84	33,627	33,627	302,645	13.50	22,418
2023	1,100,802.00	36,690	36,690	1,064,112	14.50	73,387
	7,009,279.04	2,127,101	2,127,101	4,882,178		467,288
	7,070,398.82	2,188,221	2,188,221	4,882,178		467,288

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 6.61

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.50 COMMUNICATION EQUIPMENT - TELEPHONE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	246,231.06	233,920	223,836	22,395	0.50	22,395
2015	94,440.13	80,274	76,814	17,626	1.50	11,751
	340,671.19	314,194	300,650	40,021		34,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.2   10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.10 MISCELLANEOUS EQUIPMENT - PRINT SHOP

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	4,359.31	3,923	3,923	436	1.50	291
	4,359.31	3,923	3,923	436		291

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5 6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.20 MISCELLANEOUS EQUIPMENT - KITCHEN

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	12,812.44	11,531	11,531	1,281	1.50	854
2020	16,052.40	3,746	3,746	12,306	11.50	1,070
	28,864.84	15,277	15,277	13,588		1,924

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1   6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.30 MISCELLANEOUS EQUIPMENT - JANITORIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1947	889.00	889	889			
1958	3,088.00	3,088	3,088			
1960	20.00	20	20			
1962	1,248.00	1,248	1,248			
1963	801.00	801	801			
1964	1,355.00	1,355	1,355			
1965	1,157.00	1,157	1,157			
1966	1,108.00	1,108	1,108			
1967	1,659.00	1,659	1,659			
1968	1,108.00	1,108	1,108			
1969	1,653.00	1,653	1,653			
1970	255.00	255	255			
1976	266.00	266	266			
1992	266.00	266	266			
	14,873.00	14,873	14,873			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.40 MISCELLANEOUS EQUIPMENT - LEASED BUILDINGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1969	605.00	605	605			
1985	4,788.00	4,788	4,788			
1986	4,455.00	4,455	4,455			
1987	272.00	272	272			
	10,120.00	10,120	10,120			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.50 MISCELLANEOUS EQUIPMENT - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1958	299.00	299	299			
1961	486.00	486	486			
1962	5,361.00	5,361	5,361			
1964	972.00	972	972			
1965	410.00	410	410			
1966	864.00	864	864			
1971	267.00	267	267			
1976	1,127.00	1,127	1,127			
1977	12,091.00	12,091	12,091			
1978	741.00	741	741			
1985	262.00	262	262			
1986	5,000.00	5,000	5,000			
1987	1,831.00	1,831	1,831			
1988	814.00	814	814			
1989	7,330.00	7,330	7,330			
1990	765.00	765	765			
1991	5,587.00	5,587	5,587			
1992	8,257.00	8,257	8,257			
1993	14,275.00	14,275	14,275			
	66,739.00	66,739	66,739			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	243.22	18	12	231	18.50	12
	243.22	18	12	231		12
	66,982.22	66,757	66,751	231		12

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.2 0.02

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1500

December 30, 2024

EXHIBIT 1500 – DIRECT TESTIMONY – TEST YEAR / REVENUE REQUIREMENTS / TARIFFS

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company").

A. My name is Kyle T. Walker. My current position is Senior Manager of Rates and Regulatory Affairs. My responsibilities for preparation of the revenue requirement for this rate case include development of Company revenues, calculation of gas costs, derivation of depreciation expense, rate base development, coordination of tax issues, and forecasting of miscellaneous revenues and other taxes.

Q. Please describe your education and employment background.

A. I received a Bachelor of Science Degree in Business Administration with an emphasis in Finance from Oregon State University and a Master of Business Administration from Willamette University. In addition, I received an accounting certificate from the University of Washington, and I am a licensed certified public accountant in the State of Oregon. Prior to my employment with NW Natural, I held positions at the Bonneville Power Administration ("BPA"), including Risk Analyst, Derivative Accountant, Internal Auditor and Finance Analyst. Prior to BPA, I was a Credit Manager for Wells Fargo. In February 2015, I started at NW Natural as a Rates/Regulatory Analyst and was later promoted to Manager and Senior Manager of Rates and Regulatory Affairs. In my current role, I am responsible for regulatory reporting, revenue requirement, rate design, rate spread, and other regulatory duties as assigned.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide an overview of how revenue requirement is calculated;
- Explain the historical base year of calendar year 2024 (“Base Year”) and the test year of November 1, 2025 to October 31, 2026 (“Test Year”);
- Present the revenue requirement needed to yield NW Natural’s proposed overall rate of return (“ROR”) of 7.658 percent and return on equity (“ROE”) of 10.4 percent;
- Present the adjusted results of operations and explain the Company’s projected revenues at current rates, projected operations and maintenance expense (“O&M”), and other expenses for the Test Year;
- Explain how rate base was calculated for the Test Year;
- Describe the allocation or assignment of revenues, costs, and rate base elements to the Oregon jurisdiction;
- Provide routine updates to our weather adjustment rate mechanism (“WARM”) and Decoupling mechanism;
- Propose amortization of the meter modernization deferral; and
- Present Company tariffs for the Test Year that are proposed to change due to the filing of this general rate case.

II. REVENUE REQUIREMENT

Q. Please provide a brief overview of the elements of revenue requirement, and how it is pertinent to a general rate case.

A. The Company's revenue requirement, or cost of service, represents the total annual cost to serve its customers. Costs primarily consist of gas costs (i.e., cost of goods sold), operating and maintenance costs, revenue-related costs, and investment-related costs.

Gas costs include commodity and upstream pipeline costs.[1] Operating and maintenance costs include payroll and other non-capital costs of serving customers. Revenue-related costs, or other taxes, are primarily comprised of franchise taxes, but also include Oregon's Corporate Activity Tax, the statutory commission fee, and uncollectible revenues. Investment-related costs include the return of investment, or depreciation, and the return on investment, which includes the costs of long-term debt and equity to finance our investments.[2] Federal and State income taxes are also a cost to serve customers. The elements of the revenue requirement are shown below in Table 1.

[1] Although gas and upstream gas supply costs are a major cost for the Company, and form a part of NW Natural's revenue requirement, these costs are recovered through the Company's Purchased Gas Adjustment ("PGA"), and not as part of the Company's base rates, which we seek to modify through this general rate case proceeding.

[2] Investment-related costs also include income and property taxes associated with earnings and plant balances, respectively.

Table 1 – Elements of Revenue Requirement

	Cost of Capital (Debt and Equity)
+	Income Taxes (Federal and State)
+	Other Taxes
+	Depreciation Expense
+	Operating & Maintenance Expense
+	Cost of Gas
=	**Revenue Requirement**

Investment costs are related to the Company's rate base, which include several components, but are primarily net plant. Net plant represents the assets that have been acquired or constructed by the Company for purposes of serving its customers, and which are being financed by the Company. Rate base also includes certain other items that are financed, such as gas inventory in storage, cash working capital, and supply inventories. There are also amounts that are received by the Company that reduce the amount of financing required. The largest of those amounts is deferred income taxes, primarily due to differences in depreciation expense between book accounting and tax accounting. The higher level of tax depreciation expense has historically created a financing benefit by lowering the current income tax liability for the Company. Therefore, we factor in that benefit as a reduction to the total amount of investments, or rate base. The overall rate base, including all these components, represents the amount that requires financing from shareholders and bondholders. Table 2 below shows the elements of rate base.

Table 2 – Elements of Rate Base

Utility Plant in Service:	
	Gross Plant
+	Accumulated Depreciation
=	Net Plant
Other Rate Base Items:	
	Aid in Advance of Construction
+	Customer Deposits
+	Gas Inventory
+	Leasehold Improvements
+	Materials & Supplies
+	Accumulated Deferred Income Taxes
+	Cash Working Capital
=	Total Other Rate Base Items
Net Plant	
+ Total Other Rate Base Items	
= Total Rate Base	

The aggregation of gas costs, O&M costs, revenue-related costs, and investment-related costs represents the annual amount that is needed to be recovered from the Company's customers. Our incremental revenue requirement is the amount of additional revenue needed over the amount already generated by existing rates, so that the Company can recover its costs and has an opportunity to earn its authorized return on equity.

Q. Please walk through the steps taken to compile the revenue requirement proposed in this case.

A. <u>The first step</u> in the revenue requirement calculation is to determine the amount of revenue that will be generated in the Test Year at current rates.[3] To do this, the

[3] This includes estimated use-per-customer amounts and a forecast of customer counts for the Test Year.

Company forecasts customers and the average use-per-customer for residential and commercial customers as well as a forecast of usage for current industrial customers.[4]

The second step is to forecast the operating costs and depreciation expense the Company will incur during the Test Year.[5]

The third step is to forecast rate base for the Test Year. Rate base includes capitalized costs such as utility plant in service, gas inventory, cash working capital, and leasehold improvements offset by accumulated deferred income taxes, aid in advance of construction and customer deposits. Rate base forecasts account for retirements and capital additions.

After these first three steps, we can determine the estimated rate of return on rate base and return on equity in the Test Year at current rates. Due to the ROE being below recommended levels using forecasted revenue at current rates, the Company proposes to increase revenues in order to generate a reasonable return in the Test Year after paying for the forecasted operating revenues, return of investment (depreciation expense), and return on investment of Test Year rate base.

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[4] See NW Natural/1600, Wyman.

[5] Operating costs include gas costs, operating and maintenance expense, uncollectible expense, state and federal income tax, property tax, other tax, and depreciation expense. Please see NW Natural/1300, Davilla and NW Natural/1400,Spanos.

The fourth step is to propose a recommended capital structure, cost of debt and cost of equity (ROE) to determine the proposed increase to revenues needed to generate a reasonable rate of return.

Table 3 below shows the steps taken for the proposed increase to revenue requirement:

Table 3 – Revenue Requirement Process Steps

Step 1	Step 2	Step 3	Step 4	Proposed Increase
Forecasted Customers and Usage	Forecast Test Year Operating Expenses	Forecast Capital Additions	Proposed Capital Structure	**Incremental Revenue Requirement**
x	+	+	and	+
Current Rates	Forecast Return of Investment (Depreciation Expense)	Current Rate Base	Proposed Cost of Debt and Equity	Steps 1-3
=	=	=	=	=
Test Year Revenue at Current Rates	**Forecasted Expenses for Test Year**	**Forecasted Rate Base for Test Year**	**Proposed Rate of Return (%) on Rate Base**	**Proposed Rate of Return ($) on Rate Base**

Q. What is the Company's proposed increase to revenue requirement highlighting the steps above?

A. The proposed increase to revenue requirement is $59.4 million, as shown in Table 4 below.

Table 4 – Process Steps with Proposed Increase

($000)		STEP 1 STEP 2		STEP 4	
Line No.	Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Proposed Increase (d)	Proposed Total (e)
Revenues	$977,566	$52,634	$1,030,200	**$59,375**	$1,089,575
Operating Expenses					
Gas Purchased	$378,765	$21,310	$400,075	$0	$400,075
Other Operating & Maintenance Expense	$204,349	$32,090	$236,439	$112	$236,551
Depreciation Expense	$128,504	$26,197	$154,700	$0	$154,700
Taxes					
Federal Income Tax	$27,697	($8,171)	$19,526	$11,126	$30,652
State Income Tax	$16,463	($2,902)	$13,561	$4,623	$18,184
Other Taxes	$64,527	$7,574	$72,101	$1,658	$73,759
Total Operating Revenue Deductions	$820,305	$76,098	$896,403	$17,519	$913,922
Net Operating Revenues	$157,261	($23,464)	$133,797	$41,856	$175,653
		STEP 3			
Average Rate Base					
Utility Plant in Service, Net	$2,286,125	$371,039	$2,657,164	$0	$2,657,164
Other Rate Base Items	($335,667)	($27,775)	($363,442)	$0	($363,442)
Total Rate Base	$1,950,458	$343,264	$2,293,722	$0	$2,293,722
Rate of Return	8.063%		5.833%		7.658%
Return on Common Equity	11.53%		6.89%		10.40%

Q. Please describe how the testimony presented in this rate case establishes NW Natural's revenue requirement within the steps you presented above.

A. Step one is presented by me within this testimony, NW Natural/1500, Walker.

Step two involves forecasts of operating expenses in the following pieces of testimony:

- Ms. Rogers' testimony (NW Natural/1000, Rogers) demonstrates NW Natural's costs of labor, including compensation and benefits for our non-bargaining unit employees, bargaining unit employees and executives.

- Mr. Beck's testimony (NW Natural/1100, Beck) describes the costs associated with our customer communications.
- Mr. Kizer and Mr. Johnson's testimony (NW Natural/500, Kizer-Johnson) describe the operating expenses associated with the Company's safety and other regulatory compliance projects and programs.
- Mr. Pipes' testimony (NW Natural/600, Pipes) describes the operating expenses associated with the Company's facilities.
- Mr. Fellon's two pieces of testimony (NW Natural/700, Fellon and NW Natural/800, Fellon) describe the Company's operating expenses related to Information Technology & Services ("IT&S") and the United States Department of Homeland Security's Transportation Security Administration's ("TSA's") security directives, respectively.
- Mr. Karney's testimony (NW Natural/900, Karney) describes the operating expenses associated with the Company's Meter Modernization Program.
- Mr. Davilla's testimony (NW Natural/1300, Davilla) describes all other operations and maintenance expense, and the total level of expense the Company will incur in the Test Year.
- Mr. Spanos' testimony (NW Natural/1400, Spanos) describes the Company's recently completed depreciation study and presents the proposed depreciation rates in this case.

Finally, I describe the Company's income tax expense and the proposed Excess Deferred Income Taxes ("EDIT") amortization resulting from federal income tax reform in 2017.

Step three, related to forecasted rate base, is comprised of the following testimony:

- Mr. Kizer's and Johnson's testimony (NW Natural/500, Kizer-Johnson) describes the capital additions associated with the Company's distribution and storage projects.
- Mr. Pipes' testimony (NW Natural/600, Pipes) describes capital additions associated with the Company's facilities.
- Mr. Fellon's two pieces of testimony (NW Natural/700, Fellon and NW Natural/800, Fellon) describe the Company's capital additions related to IT&S and TSA's security directives, respectively.
- Mr. Karney's testimony (NW Natural/900, Karney) describes the capital additions associated with the Company's Meter Modernization Program.

In conjunction with these pieces of testimony, my calculations demonstrate NW Natural's rate base that is used in serving our Oregon customers.

Step four, NW Natural's required return on rate base, is established in the following testimonies:

- Mr. Wilson's testimony (NW Natural/300, Wilson) provides evidence of NW Natural's cost of debt, and the amount of debt and equity the Company uses to finance its investments and operations.

- Ms. Nelson's testimony (NW Natural/400, Nelson) provides evidence of the return that NW Natural should pay shareholders to continue to attract their investment in the Company through purchasing common stock.

The proposed increase is the culmination of operating costs, depreciation expense, taxes and the return on rate base less revenue forecasted at current rates for the Test Year, displayed in NW Natural/1501, Walker.

III. BASE YEAR AND TEST YEAR

Q. Why did NW Natural use calendar year 2024 as the Base Year?

A. The Company chose calendar year 2024 as the Base Year because it is the most recent calendar year ahead of the Company's filing. While the last three months of 2024 shown in this filing are forecast data, the actual information will be available within a few months of our filing.[6] NW Natural's use of a forecast for the last three months of its Base Year is consistent with the Company's practice in prior general rate cases.

Q. Why did NW Natural choose the period of November 1, 2025 to October 31, 2026 as the Test Year?

A. The Company chose the 12-month period from November 1, 2025 to October 31, 2026 as the Test Year because it best reflects the conditions expected when new rates from this rate case will be in effect. Given a filing date of December 2024, the maximum suspension period for the rate case process would set rates effective

[6] Utility plant in service is forecasted for the last two months of the Base Year to ensure the disallowance from Commission Order No. 24-359 was included within this rate case filing.

by November 1, 2025. This matches the Test Year revenue requirement in this case, and coincides with the effective date of the annual PGA rate change, which minimizes the frequency of rate changes for customers.

IV. TEST YEAR REVENUE REQUIREMENT

Q. What is the Test Year revenue requirement needed to achieve the rate of return proposed in this case?

A. To achieve the proposed rate of return of 7.658 percent in the Test Year, a revenue requirement increase of $59.4 million, or a 5.8 percent increase, is needed over the revenues expected for the Test Year at present rates.

Q. What would NW Natural's rate of return on equity be in the Test Year absent the proposed revenue increase?

A. At current rate levels, the Company's ROE would be 6.89 percent. This is significantly below the 10.4 percent ROE proposed in this case.

Q. Please describe the changes to revenue requirement elements since the last rate case that combine to cause NW Natural to under-earn at current rate levels in the Test Year.

A. NW Natural/1502, Walker shows a side-by-side comparison of the results of operations from UG 490, the Company's last case in 2024[7] and the Test Year results from this rate case. Of particular note in this detailed comparison are four specific areas:

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[7] UG 490 was completed, and rates became effective November 1, 2024. Due to the black box nature of the settlement and approved Commission Order, the presentation of Exhibit NW Natural/1502, Walker does not tie back to any document from UG 490.

1) Line 6 shows a growth in margins (revenues net of cost of gas) of $6.3 million during the period;

2) Line 9 shows total operating and maintenance expenses increasing by $11.1 million;

3) Line 14 shows an increase in depreciation expense of $12.3 million; and

4) Line 19 shows an increase in net plant of $222.1 million.

In summary, NW Natural has generated revenue growth over the period, but that growth has been insufficient to offset costs for O&M and investments in rate base.

Q. Please describe the cost-of-service schedule treatment in the revenue requirement.

A. All revenues, expenses and rate base associated with Schedule 90 (North Mist) have been removed from the revenue requirement calculation. In addition, all Schedule 4 (multi-family), Schedule H (Compressed Natural Gas), Schedule 198 (renewable natural gas investments), and gas reserves revenues, expenses and rate base have been removed from the revenue requirement calculation. The ratemaking related to these schedules are self-contained and administered either through a cost-of-service schedule, including automatic adjustment clauses, or the PGA filing.[8] See testimony NW Natural/1600, Wyman on cost-of-service schedule changes.

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[8] Gas reserves are included in the weighted average cost of gas, but it has no effect on incremental revenue requirement.

V. RESULTS OF OPERATIONS

Q. Please explain how NW Natural calculated the Test Year revenue requirement.

A. The Company began with actual and forecasted results from the Base Year. We made normalizing and known and measurable changes to Base Year revenues, expenses, and capital (rate base) to reflect conditions anticipated to be in effect during the Test Year. This testimony and the related exhibits explain how these adjustments are reflected in the Test Year revenue requirement.

Q. Have you prepared NW Natural's Oregon-allocated results of operations for the Test Year?

A. Yes. See NW Natural/1501, Walker for a summary of NW Natural's Oregon-allocated Results of Operations for the Test Year.

Q. Please describe Exhibit NW Natural/1501, Walker.

A. Column "a" of NW Natural/1501, Walker shows the Oregon-allocated results for the Base Year, including operating revenues, operating revenue deductions, taxes, and rate base. Column "b" shows the adjustments to Base Year results for each of these categories. Column "c" shows the Test Year results at present rates based on the adjustments to Base Year results. Column "d" indicates the proposed revenue increase necessary to reach the requested ROE. Finally, column "e" shows the Test Year results that reflect the requested ROE.

Q. Please explain the adjustments set forth in Column "b."

A. The amounts in Column "b" show the adjustments from the Base Year to the Test Year. These adjustments impact operating revenues, operating revenue deductions, including taxes, and changes in rate base.

A. Sales of Gas Revenues and Transportation Revenues

Q. Please explain the adjustments to Base Year operating revenues.

A. The first two adjustments to operating revenues are for Sale of Gas and Transportation revenues, shown on lines 1 and 2 of NW Natural/1501, Walker. These adjustments are calculated as the difference between Base Year and Test Year volumes and customers multiplied by current rates.[9]

Q. How did you calculate Base Year Sale of Gas and Transportation revenues?

A. Base Year revenues were projected using the latest available actual volumes and customers for the year-to-date through September 30, 2024, as well as a forecast for the remaining three months of 2024, multiplied by rates that were effective during the applicable months. This calculation is shown in NW Natural/1503, Walker.

Q. How did you forecast the Test Year Sale of Gas and Transportation revenues?

A. Test Year revenues reflect forecast volumes and customers multiplied by current rates. The volume forecast methodology is explained in NW Natural/1600, Wyman.

[9] Current rates became effective November 1, 2024, which include the most recent PGA and base rates from UG 490 and UG 517 (Mist Recall).

Q. What is the third adjustment to operating revenues?

A. The third adjustment is to remove the decoupling amount produced by the mechanism in the Base Year. This adjustment effectively creates no decoupling revenues in the Test Year, since test period revenues have been developed with newly created use per customer ("UPCs"), effectively normalizing usage that will become the baseline for the decoupling mechanism at the rate effective date of this proceeding. The revenue requirement UPCs for residential premises connected to the system prior to January 1, 2018 at the 664.89 therms per year level while residential premises that connected on or after January 1, 2018 UPCs at 450.95 therms per year.

Q. What is the fourth adjustment to operating revenues?

A. The fourth adjustment is to remove the WARM revenue that was related to the Base Year. The Test Year is based on normal weather; therefore, no WARM amount is applicable.

B. Miscellaneous Revenues

Q. What is the fifth and last adjustment to operating revenues?

A. The last adjustment is to Miscellaneous Revenues, identified on line 5 of NW Natural/1501, Walker, and in detail on NW Natural/1504, Walker. The Company has proposed an adjustment that represents the difference between the Base Year and a three-year average ending September 30, 2024. This adjustment is used to forecast, or normalize to a three-year average, for the Test Year. The adjustment was calculated by adjusting specific categories of Miscellaneous Revenues to reflect levels of operating activity, based on three years of historical data. If the amounts for a particular category were trending upward or downward, the most recent year was taken as representative for the forecast. If there was no apparent trend to the historical amounts, a simple three-year average was used. The adjustments to specific categories of Miscellaneous Revenues are set forth in NW Natural/1504, Walker. Cost of service related to Schedule H, curtailment and entitlement revenues,[10] and all non-utility miscellaneous revenues have been removed.

C. Cost of Gas

Q. Please explain the adjustments to Operating Revenue Deductions.

A. The first adjustment to Operating Revenue Deductions is for Gas Purchased, shown on line 7 of NW Natural/1501, Walker. This adjustment reflects the difference between Base Year and Test Year sales volumes multiplied by current commodity and demand rates.

Q. Is the cost of gas included in base rates?

A. No. The annual PGA filing revises billing rates to include the cost of gas for the upcoming year through a mechanism outside of base rates. As a result, the gas cost pricing issue is addressed in the PGA rather than in a general rate case. Although gas costs are not included in base rates, gas costs are included in the total revenue calculation to provide an appropriate expense level relative to the

[10] Curtailment and entitlement revenues are now given back to customers on Schedule 168 and do not impact miscellaneous revenues (see Order No. 20-364).

revenues that are forecasted for the rate case. This ensures that base rates in the rate case are calculated based on an accurate matching of costs and revenues.

Q. Please explain the Uncollectible Accrual for Gas Sales adjustment.

A. The expense amount for uncollectible accounts is shown on line 8 of NW Natural/1501, Walker in summary, and in detail in NW Natural/1505, Walker. The amount is derived by taking a three-year average of net write-offs over revenue, the uncollectible rate.

D. Operations and Maintenance Expense

Q. Please explain the Other O&M Expenses adjustment.

A. The Oregon and System O&M expense excluding Uncollectible Accrual for Gas Sales is set forth in detail for the Base Year in NW Natural/1506, Walker/1-2*,* for the Test Year in NW Natural/1506, Walker, and in summary at line 9 of NW Natural/1501, Walker. The Direct Testimony of Tobin F. Davilla (NW Natural/1300, Davilla) explains in more detail how NW Natural calculated its Test Year O&M.

E. Income Taxes

Q. Please explain the adjustments to income taxes.

A. The first two adjustments to income taxes, included on lines 11 and 12 of NW Natural/1501, Walker*,* reflect changes to Federal and State Income Taxes between the Base Year and Test Year. The adjustments are a function of the impact of statutory income tax rates on the changes to revenues and expenses from the Base Year to Test Year. The calculations of income tax expense are included in NW Natural/1507, Walker. The applicable statutory income tax rates are 21 percent for federal and 7.6 percent for Oregon. The combined statutory rate for both federal and Oregon State income taxes is 27 percent, derived by adding the federal rate to the state rate net of the federal tax benefit of the state income tax deduction. A summary of the tax rates used in the case is included in NW Natural/1508, Walker.

Q. What are the primary differences between income tax expense calculated using only the combined statutory rate and the income tax expense included in the Base Year and Test Year?

A. NW Natural has included historical regulatory income tax flow-through items related primarily to tax benefits that were originally flowed through to customers prior to 1981. NW Natural has also included the regulatory benefits of plant EDIT that were established as a result of federal tax reform in 2017.

Q. What are the historical regulatory income tax flow-through items?

A. The historical regulatory flow-through items relate to accelerated income tax depreciation benefits that occurred prior to 1981 and plant removal costs for income tax. The amortization schedule for the accelerated income tax depreciation benefits previously flowed through to customers was set in Accounting Order UM 1335 on December 8, 2008. The amortization schedule for the income tax cost of the plant removal costs was set in General Rate Case UG 221. The amortization of both items is anticipated to conclude in calendar year 2027.

Q. What are the regulatory benefits of EDIT, associated with 2017 federal income tax reform, that are included in income tax expense?

A. In Order No. 19-105, which concluded NW Natural's General Rate Case UG 344 in March 2019, the Commission approved the agreement of all parties that NW Natural would provide three different categories of regulatory EDIT benefits to customers: Plant, Non-Plant, and Gas Reserves. The full benefit of Non-Plant EDIT was provided to customers in March 2019 consistent with Order No. 19-105. The Plant benefits continue to be provided to customers subject to the timing limitations of the average rate assumption method (ARAM) from Order No. 20-364. The Gas Reserves benefits concluded on October 31, 2023, consistent with Order No. 20-364.

Q. Are the continuing regulatory benefits of Plant EDIT included in income tax expense for the Test Year the same annual dollar amounts documented in Order No. 22-388?

A. No. The annual Plant EDIT amortization dollar amounts included in the income tax expense for the Test Year are proposed to increase $100 thousand to $3.2 million, prior to full revenue gross up. This proposed amount is consistent with Staff's recommendation in the Company's last general rate case, UG 490.[11]

[11] See *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Staff's Opening Testimony of Luz Mondragon, Staff/200 at 19 (Apr. 18, 2024).

F. Taxes Other Than Income Taxes

Q. Please explain the adjustment to Property Taxes.

A. The adjustment to property taxes is included on line 13 of NW Natural/1501, Walker. The supporting calculation is disclosed in NW Natural/1509, Walker. The Base Year property tax expense equals the Oregon property taxes paid (cash basis) in November 2024, less estimated amounts capitalized or otherwise excluded. The determination of the Test Year property tax expense is performed in two steps. First, a weighted average percentage rate of Oregon property tax expense (cash basis) relative to Oregon net plant is determined using the actual results for 2022, 2023 and 2024. This average rate (1.365 percent) is then applied to net plant for year-end 2025 and 2026 to provide forecasted property tax assessments for 2025 and 2026, respectively. The forecasted assessments for two calendar years were then combined at a ratio of eight months and four months to arrive at an appropriate tax expense to include for the Test Year. This is because the ratio is based on property tax assessments occurring on a July to June cycle.

Q. Please explain the adjustment to Other Taxes.

A. The adjustment to Other Taxes is shown on line 14 of NW Natural/1501, Walker. This adjustment was calculated as follows for the different categories within Other Taxes, the detail of which is shown in NW Natural/1509, Walker:

- Franchise fees were derived by applying the effective rate of 2.313 percent to gross revenue by using a three-year weighted average to provide a forecast for total franchise fees for both the Base Year and Test Year.

- Payroll taxes were tied to the payroll tax credit that is calculated within the O&M methodology. The credit within O&M is made to extract the payroll taxes associated with payroll for O&M, with the commensurate charge to the payroll tax expense line item under the Other Tax category.
- The regulatory fee was calculated using the current rate of 0.450 percent multiplied by total revenues for the Base Year and Test Year.
- The Oregon Department of Energy fee is calculated as a function of gross revenues. This fee was calculated using a three-year weighted average effective rate between gross revenue and actual fees paid. Total gross revenue for the Base Year and Test Year was multiplied by 0.116 percent to derive the fee.
- Corporate Activity Tax ("CAT") is directly impacted by revenues the Company receives. Test Year amounts were calculated based on the total revenue requirement proposed in this proceeding. The incremental temporary CAT rate, based on the annual PGA and included on Schedule 177, is proposed to be retained, consistent with our 2022 rate case, UG 435.
- Other taxes, such as permit and licensing fees, were forecasted for the Test Year based on an average of 12-months ended September 2024, 2023, and 2022 amounts. The amounts for the 12-months ended September 30, 2024 were used as a proxy for the Base Year. The system-related other taxes

were allocated to Oregon based on a three-factor allocation of 88.250 percent.

G. Depreciation and Amortization

Q. Please explain the adjustment to Depreciation and Amortization.

A. The Depreciation and Amortization adjustment is shown on line 15 of NW Natural/1501, Walker and in detail in NW Natural/1510, Walker. This adjustment reflects the difference in depreciation expense for the Base Year and Test Year. Depreciation expense was developed by using utility plant as of September 30, 2024, as a base and increasing plant accounts for capital expenditures from October 2024 through October 2026 for the Test Year. Applicable account balances were then decreased for expected retirements. Gross asset balances multiplied by the proposed depreciation rates at the rate effective date annualize the proposed depreciation expense for the Test Year.

Q. Please describe how depreciation rates for each asset category were determined.

A. The Company's current depreciation rates were implemented at the same time as rates from our last rate case in UG 490. In this rate case, the Company is requesting to update depreciation rates. The Company is filing an updated depreciation study (NW Natural/1402, Spanos), performed by Gannett Fleming Valuation and Rate Consultants, LLC, and presented by its President, John J. Spanos (NW Natural/1400, Spanos). The updated depreciation study recommends an increase to depreciation expense of approximately $10.0 million for the Test Year from current depreciation rates.

Q. Does the Company have any unique items related to depreciation?

A. Yes. The Company has acquired cloud-based software assets that are depreciated differently than other utility assets. The Company classifies these assets in FERC 303.7.

Q. How are cloud-based software assets depreciated?

A. Generally accepted accounting principles and FERC align on the guidance for cloud-based software assets.[12] The depreciation follows the contract length of the service provided. Therefore, each asset will depreciate consistent with the underlying service contract. Please see Confidential NW Natural/1511, Walker for the cloud-based assets that are projected to be in FERC 303.7 during the Test Year.

VI. RATE BASE

Q. Please describe the calculation of rate base.

A. The components of rate base are shown in NW Natural/1501, Walker at lines 18-28 and at NW Natural/1510, Walker. Rate base is made up of Utility Plant in Service, net of Accumulated Depreciation, with additions and subtractions for Aid in Advance of Construction, Customer Deposits, Gas Inventory, Leasehold Improvements, Materials and Supplies, Cash Working Capital, and Accumulated Deferred Income Taxes. These components are described in detail below.

[12] FERC order in docket No. AI20-1-000, dated December 20, 2019.

Q. How were amounts for Utility Plant in Service calculated?

A. The Company starts with actual plant account balances as of October 31, 2024. We then forecast additions, retirements, transfers, and removal work in progress ("RWIP") for all FERC accounts. Additions to plant reflect customer additions (mains, services, and meters) as well as recurring replacement of capital assets, and larger planned projects through the Test Year. As future plant balances are then developed, depreciation expense associated with each asset class can be calculated, which also provides for a projection of the accumulated depreciation reserve, net of RWIP. Consistent with mass-asset accounting, both the gross plant and accumulated depreciation amounts are lowered to reflect forecasted asset retirements. Utility plant in service is calculated using a 13-month average of monthly averages ("AMA") of the Test Year. Detail on the various capital projects that are included in the plant projection are described in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (NW Natural/500, Kizer-Johnson), Wayne K. Pipes (NW Natural/600, Pipes), Brian E. Fellon (NW Natural/700, Fellon and NW Natural/800, Fellon), and Joe S. Karney (NW Natural/900, Karney).

Q. Did the Alliance of Western Energy Consumers ("AWEC") discover any errors related to RWIP in the Company's last general rate case, UG 490?

A. Yes. During AWEC's review of the Company's filing, it discovered that RWIP was not included within the deferred income tax forecast of the Test Year.[13] The

[13] See *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, AWEC's Opening Testimony of Bradley G. Mullins, AWEC/100 at 27-28 (Apr. 18, 2024).

Company has ensured alignment between the deferred income tax forecast and the underlying net plant, inclusive of RWIP, in this general rate case filing.

Q. Please describe the remaining components of rate base.

A. The following components complete the calculation of total rate base:

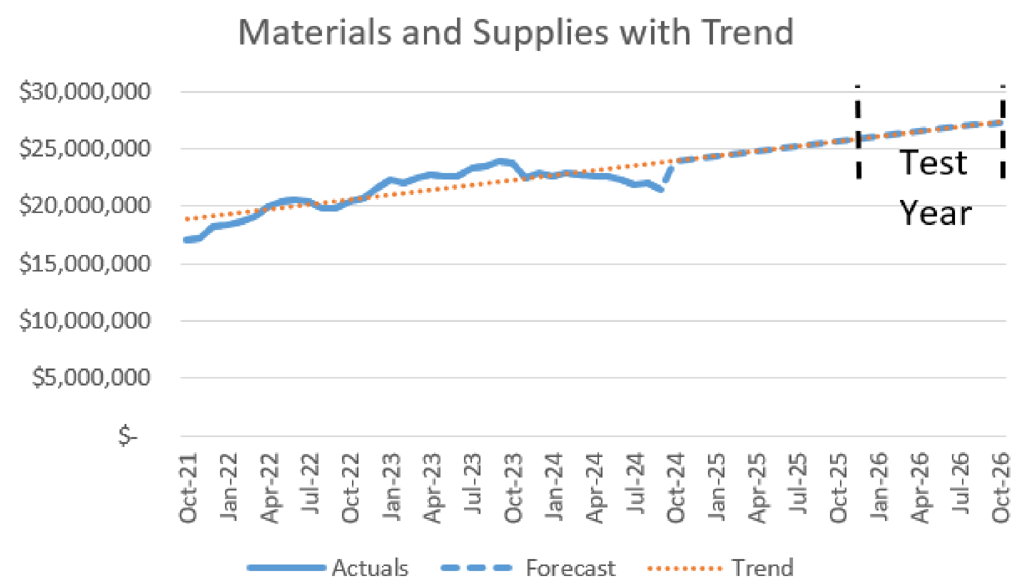
- **Aid in Advance of Construction –** This reduction to rate base represents the amounts of customer-provided contributions toward construction costs. The Test Year balance is forecasted by using the September 30, 2024 balance as a proxy.
- **Customer Deposits –** This reduction to rate base represents amounts that customers are required to provide to comply with credit requirements under our tariff. The Test Year balance is forecasted by using the September 30, 2024 balance as a proxy.
- **Gas Inventory –** This component of rate base includes a 13-month average of monthly averages ("AMA")[14] of stored gas supplies and is composed of two elements. The first element, cushion gas, assumes a continuation of the September 30, 2024 balance. The second element, working gas inventory, was derived by starting with October 2024 storage volume and price balances and then by modeling injections and withdrawals monthly through the end of the Test Year. Withdrawals reflect the PGA pattern of

[14] Average rate base balances were calculated by utilizing monthly forecast amounts to construct a 13-month AMA for all rate base components.

cycling the gas facilities. Injections of gas volumes were priced at a mix of forward prices and IHS Markit Ltd. forecasts in September 2024.

- **Leasehold Improvements –** Leasehold improvements, primarily from the Company's headquarters building at 250 Taylor, have been included in rate base based on a 13-month AMA of the Test Year
- **Materials and Supplies –** The Test Year is derived using trended amounts based on three years of historic balances of actual Material and Supplies inventory. A 13-month AMA of balances is used for the Test Year, as shown in Chart 1 below.

Chart 1 – Materials and Supplies with Trend



- **Cash Working Capital –** The Test Year amount for cash working capital, $29.1 million, was derived using a lead-lag study for days of cash led or lagged in calendar year 2023 combined with the Test Year forecast of revenues and expenses. The lead-lag study is included as NW

Natural/1512, Walker. I discuss the Cash Working Capital component of rate base in greater detail in my testimony below.

- **Deferred Income Taxes –** The Test Year amount of deferred income tax is produced by taking the balances for plant and other utility deferred taxes on December 31, 2023, and forecasted forward for incremental amounts. For plant, new capital expenditures were considered as well as previous basis amounts in generating book-tax differences and consequent tax effects. These deferred income taxes are inclusive of EDIT, taking into account the amount of amortization from October 1, 2024 through October 31, 2026. The deferred income taxes also are inclusive of RWIP forecasted through October 31, 2026. For the other utility federal and state deferred taxes, projections were made for various sub-categories of utility operations.
- **Order No. 22-388 Rate Base Adjustment** – Consistent with Order No. 22-388 in UG 435 and the first multi-party stipulation, NW Natural is reducing rate base by $4.5 million amortized over 15 years starting November 1, 2022. This adjustment offsets utility plant in service.
- **Order No. 24-359 Undepreciated Expense Adjustment** – Consistent with Order No. 24-359 in UG 490, the Company has written off $13.7 million of undepreciated expense in October 2024. For this reason, the Company has included actual utility plant in service balances through October 2024 to ensure the revenue requirement of this case includes this adjustment.

Q. Please define cash working capital.

A. Cash working capital is the amount of investor-supplied capital required to fund the day-to-day operations of a company after accounting for the timing differences between accrued and cash revenue and expenses. It represents amounts funded by investors to provide service prior to payment for such service by customers and, therefore, cash working capital typically is a component of a company's rate base.

Q. Did NW Natural perform a study to determine its cash working capital requirements for the Test Year?

A. Yes. The Company performed a lead-lag study, NW Natural/1512, Walker. The results of the study show that NW Natural's average daily cash working capital requirements in Oregon for the Test Year is $29.4 million, with a cash working capital factor of 3.8 percent.

Q. What is a lead-lag study?

A. A lead-lag study is an analysis designed to determine the funding required to operate a company on a day-to-day basis. The study compares 1) the timing difference between the receipt of service by customers and their subsequent payment for these services, and 2) the timing difference between incurred costs and the subsequent payments of these costs. Therefore, a lead-lag study must compute both a revenue lag (or lead) and an expense lag (or lead). NW Natural/1512, Walker/1 summarizes the lead-lag study results for NW Natural. The net lag days, 13.8 days, represents the average number of days the Company must fund operating expenses before it receives the revenues to cover those expenses.

Q. How did the Company determine the lag days for operating revenues?

A. The number of lag days for operating revenues is the timing difference between the receipt of service by customers and their subsequent payment for these services for calendar year 2023. The measurement of revenue lag days consists of three components: 1) service lag, 2) billing lag, and 3) collection lag. Each of these different components is a separate step in the collections process and, therefore, revenue lag is computed by adding together the total numbers of days associated with each component to determine revenue lag.

Q. Please describe how the Company calculated service lag.

A. The service lag represents 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 given month or about 15.2 days.

Q. Please describe how the Company calculated billing lag.

A. The billing lag represents the time from the meter read date to the billing date. The Company reads and bills for service on the same day, so the Company's average billing lag was determined to be 0 days.

Q. Please describe how the Company calculated collection lag.

A. The collection lag represents the time from the billing date to the date payment is received. This lag was calculated by taking the average monthly accounts receivable balances in 2023 divided by the average daily sales to calculate the number of days, on average, it takes to turn over the accounts receivable balance. The Company's average collection lag was determined to be 25.7 days.

Q. What is the Company's total operating revenue lag?

A. The total operating revenue lag is the sum of the service lag, billing lag and collection lag. As shown on NW Natural/1512, Walker/2, the Company has an average operating revenue lag of 40.9 days.

Q. How did the Company determine the lag days for miscellaneous revenues?

A. For miscellaneous revenues, the lag was calculated using a 30-day service period, no billing lag and payment terms of net 30 days. Therefore, the average lag for miscellaneous revenues was determined to be 45 days (i.e., 30 days/2 + 30 days = 45 days). This is consistent with Company policy and experience for other operating revenues.

Q. What is the Company's total revenue lag?

A. Using a weighted average between revenue from customers and miscellaneous revenues, it is determined that the average revenue lag is 40.9 days.

Q. How did the Company determine the lag days for operating expenses?

A. For the purpose of this study, we first grouped operating expenses into two types: expenses for materials received and expenses for services rendered. The expense lag for materials received is calculated by comparing the invoice date with the payment date. The expense lag for services rendered is calculated by comparing the midpoint of the service period with the payment date. We then analyzed the following categories of operating expenses: Purchased Gas, Labor – Payroll, Employee Benefits, Prepaid Insurance, Prepaid Information Technology ("IT"), Regulatory Fees, Municipal Franchise Fees, Other O&M, Payroll Taxes and Other Taxes (Federal/State, Corporate Activities Tax and Property Taxes).

Q. Please describe how the Company calculated the expense lag for Purchased Gas.

A. The Purchased Gas lag represents the time period from when the Company rendered service to its customers (i.e., supplied gas) to the time the Company makes payments for the gas costs to deliver those services. There are two components to the Purchased Gas lag: the service lag and the payment lag. The service lag is calculated using the same methodology as that used for revenue collected from customers -- the time from the midpoint of service to the meter read date -- which is 15.2 days. The payment lag represents the time from the last day of the service period to the actual payment date for those gas costs. The industry standard is to pay these expenses on the 25th of the month, meaning that the payment lag is 25 days. The total lag for purchased gas, therefore, is 40.2 days (i.e., 15.2 days + 25 days = 40.2 days).

Q. Please describe how the Company calculated the expense lag for Labor – Payroll.

A. Labor – Payroll represents bi-weekly payroll paid to employees, as well as annual incentive pay. For bi-weekly payroll, the lag is the time from the midpoint of the service period to the time the Company pays its employees. Employees are paid every two weeks with a week lag for processing. On average, the bi-weekly payroll lag is 11.5 days. Annual incentive pay is paid once a year, after the end of the year. For this analysis we used 2023 as the service period and July 2nd, 2023, as the midpoint date. The payment was made to employees on March 5, 2024, and therefore there is a 247.0-day lag. On a weighted average basis, the average payroll lag is 27.1 days.

Q. Please describe how the Company calculated the expense lag for Employee Benefits.

A. Employee Benefits costs represent the expenses the Company pays for health benefits, health savings account (HSA), 401K, union dues and other employee benefits costs. These costs were analyzed in two groups to determine the average lag days for benefits expenses: the costs paid on the same day as payroll and those expenses treated like other accounts payable costs. To determine the costs paid on the same day as payroll, we used the bi-weekly payroll lag of 11.5 days. The second group was calculated by summarizing the invoice date and payment days for each of the vendors we pay for benefits costs. The Company's average employee benefits lag was determined to be 1.4 days. Therefore, the total lag for employee benefits is 12.9 days.

Q. Please describe how the Company calculated the expense lag for Prepaid Insurance.

A. Insurance premiums are generally prepaid which means the Company outlays funds prior to the service period. This sequencing causes a negative lag (or lead) in calculated days. The insurance policies were analyzed based on service period and payment date which results in a lead (or negative lag) of 214.3 days. The Company does not forecast prepaid insurance expenses because it is not a usual revenue requirement item. Therefore, the Test Year amounts used for prepaid insurance is the Company's annual policy contracts and adjusted to the Test Year using the most current U.S. Urban Consumer Price Index ("CPI") as reported in the December 2024 Economic and Revenue Forecast published by the Oregon Office of Economic Analysis (OEA).[15]

Q. Please describe how the Company calculated the expense lag for Prepaid IT.

A. Similar to prepaid insurance, prepaid IT contracts require the Company to outlay funds prior to the service period. The prepaid IT contracts were analyzed based on service period and payment date, which results in a lead (or negative lag) of 231.4 days. The Company also does not forecast prepaid IT because it is not a usual revenue requirement item; therefore, the Test Year amount used for prepaid IT is the balance as of December 31, 2023, and adjusted to the Test Year using the most current U.S CPI as reported in December 2024.

Q. Please describe how the Company calculated the expense lag for Regulatory Fees.

A. NW Natural pays two entities for regulatory fees: the Public Utility Commission of Oregon and Washington Utilities and Transportation Commission. Payments are made in the spring of the current year, which creates a lead because the Company is making a payment for a service period (calendar year) that is not yet complete. On a weighted average basis, the average regulatory lead (or negative lag) is 91.3 days.

[15] NW Natural/1303, Davilla.

Q. Please describe how the Company calculated the expense lag for Municipal Franchise Fees.

A. Municipal franchise fees are paid monthly, quarterly, semi-annually and annually to 111 different entities. The fees were analyzed based on service period and payment dates, which results in an average lag of 90.9 days.

Q. Please describe how the Company calculated the expense lag for Other O&M.

A. Other O&M represents the remaining operating expenses the Company pays on a day to-day basis. This analysis compares invoice dates and payment dates for nearly 30,000 items, which results in a lag of 33.2 days.

Q. Please describe how the Company calculated the expense lag for Payroll Taxes.

A. Payroll taxes are paid both quarterly, following the end of the quarterly payroll period, and through employee pay days. Service dates and midpoint dates were analyzed to determine quarterly payments and the bi-weekly payroll lag, 11.5 days, was used for pay day payments. The total lag for payroll taxes is 79.4 days.

Q. Please describe how the Company calculated the expense lag for Other Taxes.

A. Federal and state taxes are paid on a quarterly basis on dates prescribed by the Internal Revenue Service. The total lag for federal and state income taxes is 36.5 days. CAT taxes are paid on a quarterly basis; the total lag for CAT taxes is 75.0 days. The property tax year runs from July 1st through June 30th with payments being made November 15th of that same year. For example, for the July 1, 2023 through June 30, 2024 tax year, taxes were paid on November 15, 2023. The total lead (or negative lag) for property taxes is 45.5 days.

Q. Did NW Natural consider Staff's comments from UG 490 into this updated study?

A. Yes. In UG 490, Staff suggested that "the Company's method of calculating the service lag did not properly account for months that have 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."[16] This updated study reflects Staff's suggestion in calculating the service lag by identifying the number of days in a month (for example, July has 31 days) and dividing that into two in order to find the mid-point of the month (31 days/2= 15.5 days). Previously, the service lag was calculated by using the mid-point date of the month (July 16th or 16 days). This adjustment changed the lead lag from 15.5 days to 15.2 days.

Q. What are the results of the study?

A. The results of the study show that NW Natural's daily cash working capital in Oregon for the Test Year is $29.4 million with a cash working capital factor of 3.8 percent. The Test Year revenue requirement amounts are derived from the Test Year expenses being multiplied by the net lag days and dividing it by 365 to get a daily amount of cash working capital. The net lag days (13.8 days) represents the

[16] See *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Staff's Opening Testimony of Itayi Chipanera, Staff/800 at 8 (Apr. 18, 2024).

average number of days the Company must fund operation expenses before they receive the appropriate revenues for those expenses. Please see Exhibit NW Natural/1512 for a summary of the lead/lag study.

VII. STATE ALLOCATION

Q. Please describe NW Natural's state allocation methodology.

A. NW Natural has used the same state allocation methodology since 2000, approved in the Company's filing under Tariff Advice 00-18. Revenues, costs, and rate base are directly assigned, if applicable, and if elements are allocated, several different allocation factors are available to apply as needed. These factors are typically based on customers, volumes, plant, or labor. The allocation factors used in this case are presented in NW Natural/1513, Walker.

Q. How did you allocate revenues to Oregon?

A. Gas Sales and Transportation Revenues and Miscellaneous Revenues attributed to Oregon customers are directly assigned to Oregon.

Q. How did you allocate the various categories of expense to Oregon?

A. Gas costs correspond precisely with gas costs collected in billing rates over the Test Year, based on forecasted therms sold. The gas costs are the same as the rates currently in effect at the time of filing this rate case. Gas costs, including demand and commodity components, are changed every year in the PGA filing. Because those costs have been fully approved in the PGA filing process, gas costs have not been an issue in general rate cases.

The allocation of O&M expense is accomplished by allocating common costs, along with a direct assignment of non-common costs, to the appropriate jurisdiction. The common costs are considered with respect to specific drivers, such as volumes or customers, that have a causative effect on costs. The O&M costs in this rate case were allocated to the appropriate jurisdiction by applying this methodology to the trailing 12-months ended September 30, 2024. The resulting jurisdictional allocation by FERC account was then applied to the forecasted O&M expenses developed for this case. For more information on O&M development, please see Mr. Davilla's testimony *(*NW Natural/1300, Davilla*)*.

Q. Please describe the jurisdictional allocation of Utility Plant in Service, Depreciation Expense, and Accumulated Depreciation.

A. Intangible software is allocated between Oregon and Washington on the basis of the "all customers" allocation factor; other intangible, production, non-storage related transmission, and distribution plant are directly assigned; storage plant including related transmission plant has been allocated to both Oregon and Washington on the basis of firm volume deliveries; compressed natural gas and liquefied natural gas refueling facilities and most general plant are allocated using the three-factor allocation factor; and land and structures are allocated on a mix of direct and other allocation factors.

Q. Please explain the method for allocating other rate base items.

A. The allocation of rate base items differs by category. For aid in advance of construction, the rate base amount was derived specifically for Oregon. Gas inventory, including both cushion and working gas, was forecasted on a system basis and allocated using the firm volumes allocation factor. The Materials and Supplies amount was allocated using the gross distribution plant factor. Finally, deferred income taxes were allocated using an accumulated book depreciation factor since much of the deferred income tax balance is related to depreciation book-tax timing differences.

VIII. AMORTIZATION OF THE METER MODERNIZATION PROGRAM DEFERRAL

Q. Has the Company filed a deferral application for the Meter Modernization Program?

A. Yes. The Company filed a deferral application on January 2, 2024, which was docketed as UM 2311. As of the filing of this case, the Commission has not yet ruled on the application.

Q. What is the Company's specific proposal regarding the Meter Modernization Program deferral amortization?

A. The Company proposes that the Commission authorize amortization of the June 30, 2025 deferral balance to be amortized to all rate schedules impacted by this rate case over one year starting November 1, 2025, on an equal percent of margin basis, coincident with the Company's PGA filings and the proposed rate effective date of this case. Furthermore, due to the program lasting several years, the Company proposes that amortization of the Meter Modernization Program deferral continue the cadence of taking the June 30 balance and amortize that balance over one year starting November 1 until the balance is zero. For an update on the Meter Modernization Program, please see Mr. Karney's testimony (NW Natural/900, Karney).

Q. What is the estimated deferral balance as of June 30, 2025?

A. The estimated deferral balance as of June 30, 2025, is $2,605,524.

Q. Has the Company proposed a tariff to amortize these costs?

A. Yes. The Company has proposed a tariff (Schedule 151) to incorporate an estimate of the deferred amounts as of June 30, 2025.[17] The Company will update the tariff with known costs as of June 30, 2025 in the compliance filing of this case.

IX. ROUTINE UPDATES FOR DECOUPLING AND WARM

Q. Please provide a brief description of Decoupling and WARM and why routine updates are being proposed.

A. Decoupling and WARM are rate mechanisms that decouple the Company's revenue from usage caused by weather and any other impact that would cause customers to use more or less volume of gas from the normalized level proposed in in this case under NW Natural/1600, Wyman. The routine updates are outputs of Mr. Wyman's models that align the underlying normalized usage that builds revenue requirement and the two rate mechanisms.

Q. What outputs from Mr. Wyman's models referenced above are used in the mechanisms?

A. Both the decoupling mechanism and WARM use the heating statistical coefficient and normalized heating degree days (HDD) that are established in Mr. Wyman's models. It is important that both rate mechanisms are aligned with the UPC model output that builds revenue requirement for the Test Year. This alignment will

[17] See NW Natural/1515, Walker.

ensure that the mechanisms will normalize customer usage back to the rate case UPCs derived in Mr. Wyman's model. The UPCs and statistical coefficients are shown in NW Natural/1514, Walker.

X. COMPANY TARIFFS

Q. Please describe the proposed Tariff changes that relate to the proposals in this case.

A. The Company is proposing Tariff changes in this case that affect the following sections of its Tariff: General Schedules, Adjustment Schedules, and Rate Schedules. NW Natural/1515, Walker includes the proposed Tariff changes.

Q. Which General Schedules are affected by the proposals in this case?

A. General Schedule H, related to compressed natural gas service, is being updated for the cost of capital inputs and is discussed in NW Natural/1600, Wyman.

Q. Which Adjustment Schedules are affected by the proposals in this case?

A. Schedule 167 shows the base rate changes proposed in this case. Schedules 175, 182, 196 and 197 are changing due solely to the billing determinants in this case. Schedules 190 and 195 update the routine inputs needed for the Decoupling and WARM mechanisms, respectively. Schedule 151 is being proposed to amortize the Meter Modernization Program deferral.

Q. Which Rate Schedules are affected by the proposals in this case?

A. The following Rate Schedules are affected by the proposals in the case:

Schedule 2	Schedule 27
Schedule 3	Schedule 31
Schedule 4	Schedule 32
Schedule 15	

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBITS 1501-1515

December 30, 2024

EXHIBITS 1501-1515 – TEST YEAR / REVENUE REQUIREMENTS / TARIFFS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1501

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Increase in Revenue Requirement
($000)

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Proposed Increase (d)	Proposed Total (e)
	Operating Revenues					
1	**Sale of Gas**	$949,959	$59,185	$1,009,144	$59,375	$1,068,519
2	**Transportation**	18,107	(963)	17,144	0	17,144
3	**Decoupling**	(5,612)	5,612	0	0	0
4	**WARM**	10,750	(10,750)	0	0	0
5	**Miscellaneous Revenues**	4,362	(449)	3,913	0	3,913
6	**Total Operating Revenues**	977,566	52,634	1,030,200	59,375	1,089,575
	Operating Revenue Deductions					
7	**Gas Purchased**	378,765	21,310	400,075	0	400,075
8	**Uncollectible Accrual for Gas Sales**	1,887	21	1,908	112	2,020
9	**Other Operating & Maintenance Expenses**	202,462	32,069	234,532	0	234,532
10	**Total Operating & Maintenance Expense**	583,114	53,401	636,515	112	636,627
11	**Federal Income Tax**	27,697	(8,171)	19,526	11,126	30,652
12	**State Excise**	16,463	(2,902)	13,561	4,623	18,184
13	**Property Taxes**	28,786	5,264	34,050	0	34,050
14	**Other Taxes**	35,741	2,310	38,051	1,658	39,709
15	**Depreciation & Amortization**	128,504	26,197	154,700	0	154,700
16	**Total Operating Revenue Deductions**	820,305	76,098	896,403	17,519	913,922
17	**Net Operating Revenues**	$157,261	($23,464)	$133,797	$41,856	$175,653
	Average Rate Base					
18	**Utility Plant in Service**	3,822,216	536,072	4,358,287	0	4,358,287
19	**Accumulated Depreciation**	(1,536,090)	(165,033)	(1,701,123)	0	(1,701,123)
20	**Net Utility Plant**	2,286,125	371,039	2,657,164	0	2,657,164
21	**Aid in Advance of Construction**	(7,715)	(699)	(8,414)	0	(8,414)
22	**Customer Deposits**	(719)	(20)	(739)	0	(739)
23	**Gas Inventory**	58,378	(9,570)	48,809	0	48,809
24	**Leasehold Improvements**	19,713	(2,396)	17,317	0	17,317
25	**Materials & Supplies**	19,478	3,219	22,697	0	22,697
26	**Accumulated Deferred Income Taxes**	(449,967)	(22,529)	(472,496)	0	(472,496)
27	**Cash Working Capital**	25,164	4,220	29,384	0	29,384
28	**Total Rate Base**	$1,950,458	$343,264	$2,293,722	$0	$2,293,722
29	**Rate of Return**	8.063%		5.833%		7.658%
30	**Return on Common Equity**	11.53%		6.89%		10.40%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1502

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Comparison of Test Year to Prior Rate Case
($000)

Line No.		UG 490 Order 24-359 [1]	Current Test Year at Present Rates	Change from Last GRC
		(a)	(b)	(c)
	Operating Revenues (net of Cost of Gas)			
1	**Sale of Gas (net of Cost of Gas)**	$603,212	$609,068	$5,856
2	**Transportation**	16,609	17,144	535
3	**Decoupling**	0	0	0
4	**WARM**	0	0	0
5	**Miscellaneous Revenues**	4,005	3,913	(92)
6	**Total Operating Revenues**	623,826	630,125	6,299
	Operating Revenue Deductions			
7	**Uncollectible Accrual for Gas Sales**	1,135	1,908	773
8	**Other Operating & Maintenance Expenses**	224,215	234,532	10,317
9	**Total Operating & Maintenance Expense**	225,350	236,439	11,089
10	**Federal Income Tax**	23,959	19,526	(4,433)
11	**State Excise**	15,594	13,561	(2,033)
12	**Property Taxes**	31,795	34,050	2,255
13	**Other Taxes**	37,256	38,051	795
14	**Depreciation & Amortization**	142,437	154,700	12,263
15	**Total Operating Revenue Deductions**	476,391	496,328	19,937
16	**Net Operating Revenues**	$147,435	$133,797	($13,638)
	Average Rate Base			
17	**Utility Plant in Service**	4,017,697	4,358,287	340,590
18	**Accumulated Depreciation**	(1,582,615)	(1,701,123)	(118,508)
19	**Net Utility Plant**	2,435,082	2,657,164	222,082
20	**Aid in Advance of Construction**	(6,499)	(8,414)	(1,915)
21	**Customer Deposits**	(755)	(739)	16
22	**Gas Inventory**	43,889	48,809	4,920
23	**Leasehold Improvements**	18,596	17,317	(1,279)
24	**Materials & Supplies**	21,810	22,697	887
25	**EDIT Adjustments to Rate Base**	3,100	0	(3,100)
26	**Accumulated Deferred Income Taxes**	(447,889)	(472,496)	(24,607)
27	**Cash Working Capital**	22,159	29,384	7,225
28	**Total Rate Base**	$2,089,493	$2,293,722	$204,229

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1503

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024 (Actual and Estimate)
Derivation of Forecasted Test Period Revenue

		BASE YEAR			TEST YEAR		
		Actual Therms Sales	Average Class Price Per Therm	Revenues and Margin at present rates	Normalized Therms Sales	Average Class Price Per Therm	Normalized Revenues and Margin
		(a)	(b)	(c)	(d)	(e)	(f)
	Revenues						
	Sales Volumes and Revenues						
1	**Residential**	396,632,294	1.50343	$596,308,782	416,418,766	1.51820	$632,208,142
2	**Commercial**	250,272,351	1.18151	$295,698,118	270,883,937	1.17714	$318,869,311
3	**Industrial Firm**	37,915,696	0.78526	$29,773,749	38,577,551	0.78236	$30,181,558
4	**Interruptible**	52,217,779	0.53963	$28,178,026	52,111,838	0.53509	$27,884,757
5	**Total Sales of Gas Revenues**	737,038,120		$949,958,675	777,992,092		$1,009,143,768
	Transportation Volumes and Revenues						
6	**Firm**	95,095,020	0.10219	$9,717,869	98,908,207	0.09558	$9,454,059
7	**Interruptible**	179,107,200	0.03590	$6,429,998	170,587,251	0.03532	$6,025,041
8	**Special Contracts - Firm**	57,089,323	0.02758	$1,574,681	59,347,305	0.02300	$1,364,754
9	**Special Contracts - Interruptible**	14,848,770	0.02591	$384,692	14,444,831	0.02078	$300,179
10	**Total Transportation**	346,140,313		$18,107,240	343,287,595		$17,144,034
11	**Total Deliveries and Revenues**	1,083,178,433		$968,065,915	1,121,279,687		$1,026,287,802
12	**Decoupling Base Period**			($5,611,986)			
13	**WARM Base Period**			$10,750,139			
14	**Total Revenue**			$973,204,068			$1,026,287,802
	Gas Costs						
15	**Demand Charges**			$68,840,587			$72,929,722
16	**Commodity Charges**			309,924,532			327,145,678
17	**Total Cost of Gas**			$378,765,119			$400,075,400
18	**Total Margin**			$594,438,949			$626,212,402

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1504

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Miscellaneous Revenues Detail
Twelve Months Ended September 2022, 2023 & 2024

Line No.		12 Months Ended September 2022 (a)	12 Months Ended September 2023 (b)	12 Months Ended September 2024 (c)	Test Year (d)	Test Year Method	Reference
1	FORFEITED DISCOUNTS-LATE PAYMENT CHARGE	2,009,100	2,987,712	2,716,594	2,571,135	no trend - 3 year average	Exhibit 1504 - WP1
2	MISC SERV REV- Scheduled CNG Main Rev	12,412	14,390	21,558	-	Exclude Schedule H Activity	Exhibit 1504 - WP1
3	MISC SERV REV- Unscheduled CNG Main Rev	2,235	1,654	11,589	-	Exclude Schedule H Activity	Exhibit 1504 - WP1
4	MISC SERVICE REVENUES-AUTOMATED PAYMENT	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
5	MISC SERVICE REVENUES-FIELD COLLECTION C	(2,740)	116,440	170,320	170,320	trend up - take last year	Exhibit 1504 - WP1
6	MISC SERVICE REVENUES-GAS DIVERSIONS	40,238	47,272	55,532	55,532	trend up - take last year	Exhibit 1504 - WP1
7	MISC SERVICE REVENUES-RECONN CHG-CR-AFTE	80	-	-	27	no trend - 3 year average	Exhibit 1504 - WP1
8	MISC SERVICE REVENUES-RECONN CHG-CR-DURI	11,250	40,690	70,339	70,339	trend up - take last year	Exhibit 1504 - WP1
9	MISC SERVICE REVENUES-RECONN CHG-SEAS-AF	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
10	MISC SERVICE REVENUES-RECONN CHG-SEAS-DU	900	1,410	4,440	4,440	trend up - take last year	Exhibit 1504 - WP1
11	MISC SERVICE REVENUES-DELINQ RECONN FEE	4,100	82,320	177,100	177,100	trend up - take last year	Exhibit 1504 - WP1
12	MISC SERVICE REVENUES-SEAS RECONN FEE	800	6,100	3,900	3,600	no trend - 3 year average	Exhibit 1504 - WP1
13	MISC SERVICE REVENUES-RETURNED CHECK CHA	345,270	446,010	461,652	461,652	trend up - take last year	Exhibit 1504 - WP1
14	MISC SERVICE REVENUES-SUMMARY BILL SVCS	11,751	12,125	11,477	11,784	no trend - 3 year average	Exhibit 1504 - WP1
15	RENT FROM GAS PROPERTY-RENT - UTILITY PR	73,834	75,827	83,827	83,827	trend up - take last year	Exhibit 1504 - WP1
16	RENT FROM GAS PROP - Schedule H CNG Reve	184,924	214,071	257,017	-	Exclude Schedule H Activity	Exhibit 1504 - WP1
17	OTHER GAS REV-LNG SALES & OTHER MISC REV	121,341	92,603	126,521	113,488	no trend - 3 year average	Exhibit 1504 - WP1
18	OTHER GAS REVENUES-METER RENTALS	168,922	165,605	157,930	157,930	trend down - take last year	Exhibit 1504 - WP1
20	OTHER GAS REVENUES-CNG METER RENTALS	838	835	834	-	Exclude Schedule H Activity	Exhibit 1504 - WP1
21	Non-AMR Install/Remove Charge	344	516	688	688	trend up - take last year	Exhibit 1504 - WP1
22	Non-AMR Read Charge	7,301	7,885	8,337	8,337	trend up - take last year	Exhibit 1504 - WP1
23	OTHER GAS REVENUES-MULTIPLE CALL OUT FEE	51,723	26,556	22,351	22,351	trend down - take last year	Exhibit 1504 - WP1
							Exhibit 1504 - WP1
	Total Miscellaneous Revenues	**3,044,623**	**4,340,021**	**4,362,007**	**3,912,550**		

Note: Excludes Billing Amortization Offsets, WARM deferrals, Washington Misc Revenues

Line 15 Detail		12 Months Ended September 2022	12 Months Ended September 2023	12 Months Ended September 2024	Test Year		
RENT FROM GAS PROPERTY-RENT - UTILITY PR	PORTLAND	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
RENT FROM GAS PROPERTY-RENT - UTILITY PR	LINCOLN CI	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
RENT FROM GAS PROPERTY-RENT - UTILITY PR	SALEM	65,374	66,875	74,488	74,488	trend up - take last year	Exhibit 1504 - WP1
RENT FROM GAS PROPERTY-RENT - UTILITY PR	ASTORIA	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
RENT FROM GAS PROPERTY-RENT - UTILITY PR	COOS BAY	8,460	8,951	9,340	9,340	trend up - take last year	
RENT FROM GAS PROPERTY-RENT - UTILITY PR	INCOME ST/	-	-	-	-	no trend - 3 year average	Exhibit 1504 - WP1
Subtotal System		73,834	75,827	83,827	83,827		

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1505

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
Twelve Months Ended September 2022, 2023 & 2024
($000)

Line No.		2022 - 2024 Total (a)	2022 Actual (b)	2023 Actual (c)	2024 Actual (d)
		12 Months Ended September Amounts			
	Gas Revenues				
1	Residential	1,864,384	540,135	679,699	644,550
2	Commercial	872,601	252,739	331,581	288,281
3	Industrial	93,750	24,534	35,659	33,557
4	Interruptible	104,135	32,128	41,147	30,860
5	Total	2,934,869	849,536	1,088,086	997,247
	Net Write-Offs				
6	Residential	4,515	241	2,659	1,616
7	Commercial	890	103	424	363
8	Industrial	162	155	4	2
9	Interruptible	(3)	(3)	-	-
10	Total	5,565	496	3,088	1,981
	Write-Off % - 3-Year Average				
11	Residential	0.242%	0.045%	0.391%	0.251%
12	Commercial	0.102%	0.041%	0.128%	0.126%
13	Industrial	0.172%	0.634%	0.013%	0.005%
14	Interruptible	-0.003%	-0.008%	0.000%	0.000%
15	Weighted Total	0.190%	0.058%	0.284%	0.199%
	Oregon Normalized Revenues (Test Year)				
16	Residential	632,208			
17	Commercial	318,869			
18	Industrial	30,182			
19	Interruptible	27,885			
20	Total	1,009,144			
	Normalized Uncollectible				
21	Residential	$1,531			
22	Commercial	325			
23	Industrial	52			
24	Interruptible	(1)			
25	Total Normalized Uncollectible	$1,908			
26	In Base O&M	$0			
27	Adjustment (Test Year)	$1,908			
28	Uncollectible rate for normalizaing adjustments	0.190%			
29	Uncollectible expense in Base Year (estimated)	$1,887			

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1506

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System (a)	BASE YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$598,825	$537,324
5	818	Compressor Station Expense	96,262	85,635
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	3,381,823	3,009,151
8	821	Purification Expense	-	-
9		Maintenance		
10	832	Wells Expense	279,233	248,406
11	834	Compressor Expense	1,599,543	1,422,954
		Total Underground Storage Expense	5,955,687	5,303,469
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	9,875	8,785
15		Total Other Storage Expense	9,875	8,785
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	1,774,735	1,578,805
19	845	LNG Fuel	(37,631)	(33,477)
20		Maintenance		
21	847	Supervision and Engineering	1,342,850	1,194,600
22		Total Liquified Natural Gas Expense	3,079,954	2,739,927
23		Total Natural Gas Storage	9,045,517	8,052,182
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	1,133,265	1,119,124
27		Maintenance		
28	863	Maintenance of Mains	-	-
29		Total Transmission Expense	1,133,265	1,119,124
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	3,847,465	3,542,243
33	874	Mains and Services Expense	22,373,434	19,807,512
34	875	Measuring and Regulator Station Expense - General	427,570	389,417
35	877	Measuring and Regulator Station Expense - City Gate	708,358	640,667
36	878	Meter and House Regulator Expense	5,719,922	5,024,379
37	879	Customer Installation Expense	14,649,764	12,868,765
38	880	Other Expense	2,241,098	1,973,927
39	881	Rents	369,494	320,366

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System (a)	BASE YEAR Oregon (b)
40		Maintenance		
41	885	Supervision and Engineering	6,102,365	5,526,939
42	887	Mains	5,287,297	4,865,401
43	889	Measuring and Regulator Station Expense - General	2,484,121	2,250,597
44	891	Measuring and Regulator Station Expense - City Gate	218,419	199,420
45	892	Services	422,043	370,722
46	893	Meters and House Regulators	3,561,244	3,132,494
47	894	Other Equipment	16,247	14,271
48		Total Distribution Expense	68,428,840	60,927,121
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,218,235	1,948,498
52	902	Meter Reading Expenses	1,030,007	904,758
53	903	Customer Records and Collection Expense	21,886,182	19,251,186
54	904	Uncollectible Accounts (per adjustment calculation)	-	-
55		Total Customer Accounts Expense	25,134,424	22,104,441
56		Customer Service and Informational		
57		Operation		
58	906	Customer Service and Informational Expense	930,195	817,083
59	907	Supervision	-	-
60	908	Customer Assistance Expense	2,074,215	1,822,198
61	909	Customer Information Expense	2,821,374	2,478,295
62	910	Miscellaneous Customer Service Expense	191,862	168,187
63		Total Customer Service and Informational	6,017,647	5,285,763
64		Sales Expense		
65		Operation		
66	911	Supervision	211,930	186,159
67	912	Demonstration and Selling Expense	1,340,804	1,177,638
68	913	Advertising	869,495	763,764
69	916	Miscellaneous Sales Expense	-	-
70		Total Sales Expense	2,422,229	2,127,561
71		Administrative and General Expense		
72		Operation		
73	921	Office Salaries and Expense	97,543,783	85,401,996
74	922	Administrative Expenses Transferred - Credit	(34,188,416)	(30,064,400)
75	924	Property Insurance Premium	5,903,957	5,210,242
76	925	Injuries and Damages	185,909	164,065
77	926	Employee Pensions and Benefits	17,266,573	16,808,724
78	928	Regulatory Commission Expense	-	-
79	930	Miscellaneous General Expense	5,097,964	4,680,902
80	931	Rents	10,921,021	9,638,244
81		Maintenance		
82	932	Maintenance of General Plant	6,692,635	6,006,208
83		Total Administrative and General Expense	109,423,426	97,845,980
84		Total O&M Expense	221,605,346	197,462,173
85	407	Environmental Rider	5,000,000	5,000,000
86		Total O&M Expense including Environmental Rider	226,605,346	202,462,173

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$622,163	$558,264
5	818	Compressor Station Expense	100,504	89,409
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	3,870,409	3,443,895
8	821	Purification Expense	-	-
9		Maintenance		
10	832	Wells Expense	1,029,874	916,176
11	834	Compressor Expense	1,673,494	1,488,740
		Total Underground Storage Expense	7,296,444	6,496,485
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	10,835	9,639
15		Total Other Storage Expense	10,835	9,639
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	2,025,261	1,801,672
19	845	LNG Fuel	(39,264)	(34,929)
20		Maintenance		
21	847	Supervision and Engineering	1,549,360	1,378,311
22		Total Liquified Natural Gas Expense	3,535,358	3,145,055
23		Total Natural Gas Storage	10,842,638	9,651,179
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	4,651,581	4,593,538
27		Maintenance		
28	863	Maintenance of Mains	-	-
29		Total Transmission Expense	4,651,581	4,593,538
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	4,544,102	4,183,616
33	874	Mains and Services Expense	24,871,704	22,019,266
34	875	Measuring and Regulator Station Expense - General	487,314	443,831
35	877	Measuring and Regulator Station Expense - City Gate	805,569	728,588
36	878	Meter and House Regulator Expense	6,742,973	5,923,027
37	879	Customer Installation Expense	17,193,875	15,103,584
38	880	Other Expense	2,652,843	2,336,587
39	881	Rents	386,801	335,372

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
40		Maintenance		
41	885	Supervision and Engineering	7,262,866	6,578,010
42	887	Mains	6,100,054	5,613,305
43	889	Measuring and Regulator Station Expense - General	2,885,611	2,614,345
44	891	Measuring and Regulator Station Expense - City Gate	253,040	231,029
45	892	Services	490,668	431,003
46	893	Meters and House Regulators	4,207,503	3,700,948
47	894	Other Equipment	19,436	17,073
48		Total Distribution Expense	78,904,361	70,259,583
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,649,734	2,327,526
52	902	Meter Reading Expenses	1,219,248	1,070,987
53	903	Customer Records and Collection Expense	26,636,920	23,429,956
54	904	Uncollectible Accounts (calculated separately)	-	-
55		Total Customer Accounts Expense	30,505,902	26,828,470
56		Customer Service and Informational		
57		Operation		
58	906	Customer Service and Informational Expense	1,106,867	972,272
59	907	Supervision	-	-
60	908	Customer Assistance Expense	2,482,182	2,180,597
61	909	Customer Information Expense	3,540,335	3,109,830
62	910	Miscellaneous Customer Service Expense	229,254	200,964
63		Total Customer Service and Informational	7,358,637	6,463,662
64		Sales Expense		
65		Operation		
66	911	Supervision	253,571	222,737
67	912	Demonstration and Selling Expense	1,572,786	1,381,389
68	913	Advertising	0	0
69	916	Miscellaneous Sales Expense	-	-
70		Total Sales Expense	1,826,358	1,604,126
71		Administrative and General Expense		
72		Operation		
73	921	Office Salaries and Expense	108,433,000	94,935,775
74	922	Administrative Expenses Transferred - Credit	(39,272,217)	(34,534,962)
75	924	Property Insurance Premium	9,490,282	8,375,174
76	925	Injuries and Damages	187,173	165,180
77	926	Employee Pensions and Benefits	20,034,915	19,452,013
78	928	Regulatory Commission Expense	-	-
79	930	Miscellaneous General Expense	5,520,588	5,074,330
80	931	Rents	11,358,034	10,023,925
81		Maintenance		
82	932	Maintenance of General Plant	7,398,475	6,639,655
83		Total Administrative and General Expense	123,150,251	110,131,090
84		Total O&M Expense	257,239,728	229,531,649
85	407	Environmental Rider	5,000,000	5,000,000
86		Total O&M Expense including Environmental Rider	262,239,728	234,531,649

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1507

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Tax Provision
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024
($000)

Line No.		BASE YEAR State Taxes (a)	BASE YEAR Federal Taxes (b)	TEST YEAR State Taxes (c)	TEST YEAR Federal Taxes (d)
1	Operating Revenues	$977,566	$977,566	$1,030,200	$1,030,200
2	Operating Revenue Deductions	583,114	583,114	636,515	636,515
3	Property & Other Taxes	64,527	64,527	72,101	72,101
4	Book Depreciation	128,504	128,504	154,700	154,700
5	Interest (Rate Base * Cost of Debt)	44,783	44,783	51,609	51,609
6	Remove Equity Flotation				
7	State Tax Deduction	4,368	16,463	4,627	13,561
8	Subtotal	152,270	140,176	110,648	101,714
9	Permanent Differences 1/	6,872	6,872	6,900	6,900
10	Taxable Income	159,142	147,048	117,549	108,615
11	Tax Rate	7.60%	21.00%	7.600%	21.000%
12	Tax Before Credits	12,095	30,880	8,934	22,809
13	Tax Credits & EDIT Amortization 2/	4,368	(3,183)	4,627	(3,283)
14	Total Tax	$16,463	$27,697	$13,561	$19,526

1/ Primarily amortization of regulatory flow-through items allocated using accumulated depreciation factor
2/ Oregon excess deferred income taxes (EDIT) amortization and Oregon allocated research credit

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1508

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Base Year and Test Year Cost of Capital and Revenue Sensitive Costs

		BASE YEAR			TEST YEAR		
	Weighted Average Cost of Capital	% of Total Capital	Average Cost	Weighted Cost	% of Total Capital	Average Cost	Weighted Cost
1	**Long Term Debt**	50.0%	4.591%	2.296%	48.0%	4.687%	2.250%
2	**Common Stock**	50.0%	9.400%	4.700%	52.0%	10.400%	5.408%
3	**Total**	100.0%		6.996%	100.0%		7.658%

	Revenue Sensitive Costs	Base Year	Test Year
4	**Gas Sales**	97.18%	97.96%
5	**Transportation**	1.85%	1.66%
6	**Other**	0.97%	0.38%
7	**Subtotal**	100.00%	100.00%
8	**O & M - Uncollectible**	0.20%	0.19%
9	**Franchise Taxes**	2.34%	2.34%
10	**OPUC Fee**	0.450%	0.450%
11	**State Taxable Income**	97.01%	97.02%
12	**State Income Tax**	7.37%	7.37%
13	**Federal Taxable Income**	89.64%	89.65%
14	**Federal Income Tax**	18.82%	18.83%
15	**Utility Operating Income**	70.81%	70.82%
16	**Total Revenue Sensitive Costs**	29.19%	29.18%
17	**Net-to-gross factor**	141.22%	141.20%
18	**Rate of Return on Equity**	9.40%	10.40%
19	**Federal Tax Rate**	21.00%	21.00%
20	**State Tax Rate**	7.60%	7.60%
21	**Combined Tax Rate (Test Year)**	27.00%	27.00%
22	**Franchise Fees**	2.342%	2.342%
23	**Uncollectible Accounts**	0.199%	0.190%
24	**Regulatory Fees**	0.450%	0.450%
25	**Interest Coordination Factor**	2.296%	2.250%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1509

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024 (Actual and Estimate)
Forecast of Other Taxes

Line No.		Actual 2022	Actual 2023	Actual/Forecast 2024	Weighted Average	Test Year Normalized	Base Year Normalized
		(b)	(c)	(d)	(e)	(f)	(g)
	Property Taxes						
1	Taxes Paid	27,195,294	28,587,077	28,984,875			28,785,976
2	Net Plant December 31 of prior year	1,877,906,672	2,106,413,853	2,226,181,159			
3	Effective Rate on Prior Year-End Net Plant	1.448%	1.357%	1.302%	1.365%		
4	Net Plant 12/31/24					2,431,146,526	
5	2024 Payment Forecast (line 4 * line 3e)					33,182,761	
6	Net Plant 12/31/25					2,621,702,904	
7	2025 Payment Forecast (line 6 * line 3e)					35,783,668	
8	Test Period Expense [1]					34,049,730	
9	Other Taxes						
10	Franchise					23,831,407	22,494,970
11	Payroll					7,970,029	6,919,756
12	Regulatory Fee					4,635,902	4,375,926
13	Department of Energy					1,191,403	1,124,591
14	Other					422,591	826,143
15	Other Taxes Excluding Property Taxes					38,051,331	35,741,384
16	[1] eight twelfths is taken from year 2024 and four twelfths from 2025						

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1510

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2026
Base Year Twelve Months Ended December 31, 2024 (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	4,358,287	4,970,698	3,822,216	4,351,134
2	Accumulated Depreciation	(1,701,123)	(1,910,074)	(1,536,090)	(1,724,858)
3	Net Utility Plant	2,657,164	3,060,624	2,286,125	2,626,276
4	Aid in Advance of Construction	(8,414)	(14,020)	(7,715)	(12,886)
5	Customer Deposits	(739)	(842)	(719)	(818)
6	Gas Inventory (Working and Cushion)	48,809	54,866	58,378	65,623
7	Leasehold Improvemets	17,317	19,622	19,713	22,338
8	Materials & Supplies	22,697	26,463	19,478	22,710
9	Accumulated Deferred Income Taxes - Depreciation	(466,668)	(512,865)	(442,904)	(486,991)
10	Accumulated Deferred Income Taxes - Other	(5,827)	(6,387)	(7,062)	(7,789)
12	Cash Working Capital	29,384	32,837	25,164	28,121
13	Total Rate Base	2,293,722	2,660,299	1,950,458	2,256,584
		89.06%		89.06%	

Line No.	Depreciation Expense	Test Year Oregon	Test Year System	Base Year Oregon	Base Year System
14	Intangible - Software	29,627	33,263	23,940	26,898
15	Transmission	6,230	6,463	5,021	5,163
16	Distribution	90,840	101,824	72,666	82,041
17	General	13,684	15,696	15,742	18,072
18	Storage and Storage Transmission	14,320	15,030	11,136	11,542
19	Subtotal	154,700	172,276	128,504	143,715
20					
21					
22	Total	154,700	172,276	128,504	143,715

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1511

REDACTED

December 30, 2024

CLOUD BASED SOFTWARE
Gross Plant Balance on 10/31/2026
FERC Account 303.7

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
1029519	Tech Refr LgSvrs-2019-MicrosoftLic	60	20.00%	Jan-20	$ 104,109
1029520	Success Factors Recruiting Mgmt Impl	60	20.00%	Jan-20	$ 794,670
1029596	SAP Concur	60	20.00%	Jun-20	$ 756,130
1029679	SAP LMS - Cloud Based SW	60	20.00%	Nov-20	$ 1,184,315
1029756	SAP LMS - Phase 2 - Cloud Based SW	60	20.00%	Apr-21	$ 830,935
1029757	Planview - Cloud Based SW	60	20.00%	Apr-21	$ 1,526,203
1029762	Slalom Execution Phase - Cloud Based SW	42	28.57%	Apr-21	$ 789,864
1029837	Cloud Based SAP SF EC&OnBoarding	60	20.00%	Aug-21	$ 3,162,495
1029839	Slalom Execution Phase - Cloud Based SW	38	31.58%	Aug-21	$ 311,239
1029849	Slalom Execution Phase - Cloud Based SW	37	32.43%	Sep-21	$ 199,324
1030482	Execution Leak & Inspection - Cloud Based SW Azure	36	33.33%	Dec-21	$ 423,954
1030487	Slalom Execution Phase - Cloud Based SW	36	33.33%	Dec-21	$ 192,037
1030538	Slalom Execution Phase - Cloud Based SW	36	33.33%	Mar-22	$ 303,550
1030596	Azure DevOpps 2019 - Cloud Based SW	36	33.33%	Jul-22	$ 18,601
1030597	QA Inspection Tool - Cloud Based SW	60	20.00%	Jul-22	$ 624,501
1030598	Slalom Execution Phase - Cloud Based SW	36	33.33%	Jul-22	$ 152,413
9656970	Execution Labor Internal (Capital)	36	33.33%	Oct-22	$ 33,981
9656973	Execution Labor External (Capital)	36	33.33%	Oct-22	$ 307,607
9656978	Planning Labor Internal (Capital)	36	33.33%	Oct-22	$ 133,475
9656981	Planning Labor External (Capital)	36	33.33%	Oct-22	$ 886,527
9656984	Planning Software (Capital)	36	33.33%	Oct-22	$ 698
9656987	Planning Hardware (Capital)	36	33.33%	Oct-22	$ 13,745
9656990	Execution Labor Internal (Capital)	36	33.33%	Oct-22	$ 187,666
9656993	Execution Labor External (Capital)	36	33.33%	Oct-22	$ 1,399,231
9656996	Execution Software (Capital)	36	33.33%	Oct-22	$ 63,766
9656999	Execution Hardware (Capital)	36	33.33%	Oct-22	$ 134
9657002	Planning Labor External (Capital)	36	33.33%	Oct-22	$ 83,146
9657005	Execution Labor External (Capital)	36	33.33%	Oct-22	$ 125,327
9657113	Planning Labor External (Capital)	36	33.33%	Oct-22	$ 5,940
9657116	Planning Software (Capital)	36	33.33%	Oct-22	$ 241,599
9657119	Execution Labor External (Capital)	36	33.33%	Oct-22	$ 1,748
9657152	Cloud Software (Capital)	36	33.33%	Oct-22	$ 145,007
9657164	Cloud Software (Capital)	36	33.33%	Oct-22	$ 542,214
10192713	Internal Labor Azure	33	36.36%	Dec-22	$ 229
10427072	Q3 & Q4 2022 Sprints (Capital)	36	33.33%	Jan-23	$ 536,024
10709735	Plan Cloud Roll Out 1 Labor Inter(Cap)	36	33.33%	Feb-23	$ 91,666
10709738	Labor External (Capital)	36	33.33%	Feb-23	$ 1,291,714
10709741	Execute Cloud MVC (Capital)	36	33.33%	Feb-23	$ 18,369
10709744	Labor External (Capital)	36	33.33%	Feb-23	$ 21,255
12930343	Execution External Labor (Capital)	36	33.33%	Oct-23	$ 37,057
12930346	Reporting Gaps Phase 3 (Capital)	36	33.33%	Oct-23	$ 316,369
12930380	Initiate Cloud Platform Enhance (Cap)	36	33.33%	Oct-23	$ 565
12930383	Planning Cloud Platform Enhance (Cap)	36	33.33%	Oct-23	$ 506
12930386	Execute Cloud Platform Enhance (Cap)	36	33.33%	Oct-23	$ 277,466
13188469	Planning SCM Training Doc (Cap)	36	33.33%	Nov-23	$ 40,634
13188472	Execute SCM Training Doc (Cap)	36	33.33%	Nov-23	$ 339,487
13322836	Assess SecurityBridge 3 YR Cloud (Cap)	36	33.33%	Dec-23	$ 49,702
13322839	Planning SecurityBridge 3 YR Cloud (Cap)	36	33.33%	Dec-23	$ 145,700
13322842	Execute SecurityBridge 3 YR Cloud (Cap)	36	33.33%	Dec-23	$ 824,310
13322856	Execute SAP Treasury Azure Cloud (Cap)	36	33.33%	Dec-23	$ 108,108
13493778	Initiate Labor Internal (Capital)	36	33.33%	Feb-24	$ 1,757
13493781	Initiate Labor External (Capital)	36	33.33%	Feb-24	$ 95,736
13493784	Assess Labor Internal (Capital)	36	33.33%	Feb-24	$ 563
13493787	Assess Labor External (Capital)	36	33.33%	Feb-24	$ 2,513
13493790	Assess Software (Capital)	36	33.33%	Feb-24	$ 38,445
13493793	Planning Labor Internal (Capital)	36	33.33%	Feb-24	$ 1,075
13493796	Planning Other (Capital)	36	33.33%	Feb-24	$ 51
13493799	Execution Labor Internal (Capital)	36	33.33%	Feb-24	$ 7,974
13493802	Execution Labor External (Capital)	36	33.33%	Feb-24	$ 97,967
13493805	Execution Software (Capital)	36	33.33%	Feb-24	$ 456
14125327	Intune Cloud 2023	36	33.33%	Apr-24	$ 2,922
14125330	Cloud Sharepoint 2023	36	33.33%	Apr-24	$ 435,686
14125333	Microsoft EA 2023 True-Up	36	33.33%	Apr-24	$ 124,486
14705231	Q3 2022 DRA Assets	99	12.12%	Jun-24	$ 13,894

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
14705234	Q4 2022 DRA Assets	102	11.76%	Jun-24	$ 1,782,623
14705237	Q1 2023 DRA Assets	105	11.43%	Jun-24	$ 1,295,046
14705240	Q2 2023 DRA Assets	108	11.11%	Jun-24	$ 1,698,405
14705243	Q3 2023 DRA Assets	111	10.81%	Jun-24	$ 2,805,232
14705246	Q4 2023 DRA Assets	114	10.53%	Jun-24	$ 1,757,094
14705249	Q1 2024 DRA Assets	117	10.26%	Jun-24	$ 2,361,146
14705358	Q4 2022 DRA Assets	102	11.76%	Jun-24	$ 28,628
14705361	Q1 2023 DRA Assets	102	11.76%	Jun-24	$ 155,347
14705364	Q2 2023 DRA Assets	108	11.11%	Jun-24	$ 4,164
14705367	Q3 2023 DRA Assets	111	10.81%	Jun-24	$ (197,955)
14705370	Q4 2023 DRA Assets	114	10.53%	Jun-24	$ 348,203
14705373	Q1 2024 DRA Assets	117	10.26%	Jun-24	$ (98,611)
14725687	Program Mgmt Labor Internal (Capital)	102	11.76%	Jun-24	$ 46,399
14725690	Labor External (Capital)	102	11.76%	Jun-24	$ 718,962
14725693	Software (Capital)	102	11.76%	Jun-24	$ 200,430
14725696	Other (Capital)	102	11.76%	Jun-24	$ 19
14725699	Plan Cloud Phase 3 Labor Inter(Cap)	102	11.76%	Jun-24	$ 1,393
14725702	Labor External (Capital)	102	11.76%	Jun-24	$ 1,184,472
14725705	Execute Cloud MVC Phase 3(Capital)	102	11.76%	Jun-24	$ 588
14725708	Labor External (Capital)	102	11.76%	Jun-24	$ 132,426
14725711	Software (Capital)	102	11.76%	Jun-24	$ 56,912
14725714	Labor External (Capital)	108	11.11%	Jun-24	$ 1,045
14725717	Execute Cloud MVC Phase 4(Capital)	108	11.11%	Jun-24	$ 1,219
14725720	Exe Cloud Phase 4 Labor Inter(Cap)	108	11.11%	Jun-24	$ 7,900
14725723	Labor External (Capital)	108	11.11%	Jun-24	$ 683,671
14725726	Other (Capital)	108	11.11%	Jun-24	$ 366
14725729	Cloud Software (Capital)	108	11.11%	Jun-24	$ 363
14725732	Plan DevSecOps Labor Inter(Cap)	4	100.00%	Jun-24	$ 241
14725735	Labor External (Capital)	4	100.00%	Jun-24	$ 8,859
15208843	Exe Clevest Opt Azure Cloud (Cap)	36	33.33%	Jul-24	$ 8,407
15568051	Planning Labor Internal (Capital)	2	100.00%	Aug-24	$ 200
15568054	Planning Labor External (Capital)	2	100.00%	Aug-24	$ (1,896)
15568057	Execution Labor Internal (Capital)	2	100.00%	Aug-24	$ 70,440
15568060	Execution Labor External (Capital)	85	14.12%	Aug-24	$ 1,793,675
15568063	Execution Software (Capital)	2	100.00%	Aug-24	$ (4,764)
15933166	Initiate Website Portals (Cap)	60	20.00%	Sep-24	$ 155,482
15933169	Assess Website Portals (Cap)	60	20.00%	Sep-24	$ 939,727
15933172	Planning Website Portals (Cap)	60	20.00%	Sep-24	$ 547,920
15933175	Execute Website Portals (Cap)	60	20.00%	Sep-24	$ 1,077,894
15933184	Genesys Phase 1 9/30/2024	60	20.00%	Sep-24	$ 1,791,515
15933225	Execution Allocation of Study (Capital)	1	100.00%	Sep-24	$ 5,100
15942546	Q2 2024 DRA Assets	117	10.26%	Sep-24	$ 1,893,790
15942549	Q3 2024 DRA Assets	120	10.00%	Sep-24	$ 1,302,567
16303368	Initiate Identity Gov & Admin Auto (Cap)	36	33.33%	Oct-24	$ 236,066
16303371	Assess Identity Gov & Admin Auto (Cap)	36	33.33%	Oct-24	$ 565,334
16303374	Planning Identity Gov & Admin Auto (Cap)	36	33.33%	Oct-24	$ 571,469
16303377	Execute Identity Gov & Admin Auto (Cap)	36	33.33%	Oct-24	$ 1,984,593
16303429	Hyperproof - GRC Cloud	36	33.33%	Oct-24	$ 219,653
9498306	IT&S Execution Labor External (Cap)	120	10.00%	Sep-22	$ 28,847
9498345	Labor External (Capital)	120	10.00%	Sep-22	$ 185,012
9498357	Labor External (Capital)	120	10.00%	Sep-22	$ 23
9498366	Labor External (Capital)	120	10.00%	Sep-22	$ 18
9498369	Labor External (Capital)	120	10.00%	Sep-22	$ 19
9498378	Labor External (Capital)	120	10.00%	Sep-22	$ 15,937
9498387	DecSecOps Labor Inter (Cap)	120	10.00%	Sep-22	$ 9,293
9498396	Labor External (Capital)	120	10.00%	Sep-22	$ 260,646
9498408	Labor External (Capital)	120	10.00%	Sep-22	$ 20
9498414	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498423	Labor External (Capital)	120	10.00%	Sep-22	$ 71,625
9498435	Labor External (Capital)	120	10.00%	Sep-22	$ 39
9498444	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498456	Labor External (Capital)	120	10.00%	Sep-22	$ 28
9498465	Labor External (Capital)	120	10.00%	Sep-22	$ 13
9498474	Labor External (Capital)	120	10.00%	Sep-22	$ 32,577
9498483	Labor External (Capital)	120	10.00%	Sep-22	$ 78,474
9498492	Labor External (Capital)	120	10.00%	Sep-22	$ 6
9498495	DATA Labor Internal (C)	120	10.00%	Sep-22	$ 14,159
9498504	Labor External (Capital)	120	10.00%	Sep-22	$ 381,179

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
9498519	Labor External (Capital)	120	10.00%	Sep-22	$ 12
9498522	Labor External (Capital)	120	10.00%	Sep-22	$ 8
9498537	Mobility Test & QA Proc Labor Inter (C)	120	10.00%	Sep-22	$ 3,492
9498543	Labor External (Capital)	120	10.00%	Sep-22	$ 117,593
9498549	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498558	Project Management (Allocate)	120	10.00%	Sep-22	$ 73,691
9498567	Execution Labor Internal (Capital)	120	10.00%	Sep-22	$ 8,668
9498576	Execution Labor External (Capital)	120	10.00%	Sep-22	$ 939,113
9498636	EAM Labor Internal (Capital)	120	10.00%	Sep-22	$ 560,354
9498639	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 1,519,700
9498651	External Labor Other (Capital)	120	10.00%	Sep-22	$ 195,195
9498663	Supply Chain Labor Internal (Capital)	120	10.00%	Sep-22	$ 326,662
9498666	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 653,579
9498675	External Labor Other (Capital)	120	10.00%	Sep-22	$ 81,962
9498690	Finance Labor Internal (Capital)	120	10.00%	Sep-22	$ 349,957
9498699	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 2,051,134
9498705	External Labor Other (Capital)	120	10.00%	Sep-22	$ 32,055
9498714	IT&S Horizon 1 Labor Internal (Capital)	120	10.00%	Sep-22	$ 878,328
9498726	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 360,186
9498729	External Labor Other (Capital)	120	10.00%	Sep-22	$ 553,077
9498744	HCM Rel 1 Labor Internal (Capital)	120	10.00%	Sep-22	$ 16,074
9498747	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 279,106
9498762	HCM Rel 2 Labor Internal (Capital)	120	10.00%	Sep-22	$ 76,115
9498768	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 914,309
9498774	External Labor Other (Capital)	120	10.00%	Sep-22	$ 90,362
9498783	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 165,313
9498792	External Labor Other (Capital)	120	10.00%	Sep-22	$ 36,934
9498801	Data Migration Labor Internal (Capital)	120	10.00%	Sep-22	$ 33,351
9498813	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 178,674
9498819	External Labor Other (Capital)	120	10.00%	Sep-22	$ 86,544
9498834	Mobility Labor Internal (Capital)	120	10.00%	Sep-22	$ 50,367
9498837	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 29,443
9498852	Reporting & Analytics Labor Inter (Cap)	120	10.00%	Sep-22	$ 19,480
9498861	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 160,448
9498870	External Labor Other (Capital)	120	10.00%	Sep-22	$ 843,659
9498876	Security Labor Inter (Cap)	120	10.00%	Sep-22	$ 13,502
9498888	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 230,218
9498897	External Labor Other (Capital)	120	10.00%	Sep-22	$ 103,650
9498903	Dev Training Materials Labor Internal	120	10.00%	Sep-22	$ 10,002
9498912	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 265,550
9498918	External Labor Other (Capital)	120	10.00%	Sep-22	$ 294,367
9498927	Program Mgmt Labor Inter (Cap)	120	10.00%	Sep-22	$ 114,547
9498939	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 988,267
9498951	External Labor Other (Capital)	120	10.00%	Sep-22	$ 966,550
9498960	Development Labor Inter (Cap)	120	10.00%	Sep-22	$ 84,790
9498963	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 306,499
9498972	Testing Labor Internal (Cap)	120	10.00%	Sep-22	$ 66,041
9498981	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 231,042
9498996	External Labor Other (Capital)	120	10.00%	Sep-22	$ 319,972
9499002	Tech Arch Labor Internal (Cap)	120	10.00%	Sep-22	$ 129,576
9499008	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 276,595
9499020	External Labor Other (Capital)	120	10.00%	Sep-22	$ 7,248
9499029	Travel (Capital)	120	10.00%	Sep-22	$ 106,793
9499041	PWC (Capital)	120	10.00%	Sep-22	$ 205,774
9499044	On Prem SW SAP (Capital)	120	10.00%	Sep-22	$ 1,087,978
9499053	On Prem Clevest (Capital)	120	10.00%	Sep-22	$ 331,926
9499065	On Prem PowerPlan (Capital)	120	10.00%	Sep-22	$ 619,527
9499074	On Prem Other (Capital)	120	10.00%	Sep-22	$ 73,175
9499080	Cloud Based SAP (Capital)	120	10.00%	Sep-22	$ 1,016,295
9499095	Cloud Based Clevest (Capital)	120	10.00%	Sep-22	$ 138
9499101	Cloud Based PowerPlan (Capital)	120	10.00%	Sep-22	$ 61,534
9499107	Cloud Based SW Accenture (Capital)	120	10.00%	Sep-22	$ 15,392
9499116	Cloud Based SW Azure (Capital)	120	10.00%	Sep-22	$ 430,353
9499125	Cloud Other (Capital)	120	10.00%	Sep-22	$ 2,874
9499140	On Prem SW Maint SAP (Capital)	120	10.00%	Sep-22	$ 350,757
9499149	On Prem SW Maint Clevest (Capital)	120	10.00%	Sep-22	$ 110,377
9499152	On Prem SW Maint PowerPlan (Capital)	120	10.00%	Sep-22	$ 319,739
9499167	Cloud Based SW Maint Other (Capital)	120	10.00%	Sep-22	$ 153

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
9499173	Hardware (Capital)	120	10.00%	Sep-22	$ 109,116
9499179	Misc (Capital)	120	10.00%	Sep-22	$ 284,843
9499188	SLA Credit (Capital)	120	10.00%	Sep-22	$ (10,818)
9499197	IQGEO (Capital)	120	10.00%	Sep-22	$ 733,534
9657134	Execution Other (Capital)	119	10.08%	Oct-22	$ 2,339
9657429	Accenture Travel (Capital)	119	10.08%	Oct-22	$ (1,930)
9657480	Accenture Change Orders (Capital)	120	10.00%	Oct-22	$ 36,693
11545055	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 71,699
11545070	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 9
11545088	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 144,094
11545100	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 14,353
11545136	COMPUTER SOFTWARE	120	10.00%	Oct-22	$ 753,448
14125283	SuccessFactors Q1 2023	120	10.00%	Apr-24	$ 15,540
14125286	SuccessFactors Q3 2023	120	10.00%	Apr-24	$ 4,077
14125289	Workforce Q1 2023	120	10.00%	Apr-24	$ 5,885
9903643	COMPUTER SOFTWARE	36	33.33%	Sep-22	$ 33,102
9903688	COMPUTER SOFTWARE	36	33.33%	Sep-22	$ 340
10193070	Cloud SW Asset #2 (Nov) 3 year	36	33.33%	Dec-22	$ 167,126
10193073	NMEP Cloud Asset Nov (3 year)	36	33.33%	Dec-22	$ 733
10193095	Cloud SW Asset (Nov) 3 year	36	33.33%	Dec-22	$ (1,126)
10193107	Cloud Asset Nov	36	33.33%	Dec-22	$ 8,046
10193122	Cloud SW Asset Dec	36	33.33%	Dec-22	$ (435,871)
10193125	NMEP SW Asset Dec	36	33.33%	Dec-22	$ (3,660)
10193134	Cloud SW Asset Dec	36	33.33%	Dec-22	$ 67
10193143	Cloud SW Asset Dec	36	33.33%	Dec-22	$ 3,860
10209188	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 518,219
10209218	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 6,261
10209231	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 86,304
10209244	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 737,316
10209257	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 19,026
10209270	COMPUTER SOFTWARE	36	33.33%	Oct-22	$ 11,974
12771848	COMPUTER SOFTWARE	48	25.00%	Oct-22	$ 453,208
12779262	CLOUD SOFTWARE	48	25.00%	Oct-22	$ 173,858
	[redacted]				
	10/31/26 TOTAL				**$ 114,578,175**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1512

December 30, 2024

NW Natural - UG 520, Exhibit 1512 Page 1
Lead-Lag Test Year Summary

		Test Year Twelve Months Ended October 31, 2026				
1		Year 1 Revenue Requirement Exp	Revenue	Expense	Net	
2		$	Lag (Lead) Days	Lag (Lead) Days	Lag (Lead) Days	Weighted $
3	**Total Revenue Lag**		40.92			
4						
5	**Operations and Maintenance Expense**					
6	Purchased Gas	$ 400,075,400	40.9	40.2	0.7	$ 284,572,232
7	Labor - Payroll	$ 98,489,721	40.9	27.1	13.9	$ 1,365,821,395
8	Employee Benefits	$ 31,671,398	40.9	13.0	27.9	$ 884,970,482
9	Prepaid Insurance Expense	$ 7,252,188	40.9	-214.3	255.2	$ 1,850,977,744
10	Prepaid IT Expense	$ 12,588,880	40.9	-231.4	272.4	$ 3,428,773,843
11	Regulatory Fees	$ 4,635,902	40.9	-91.3	132.2	$ 612,756,052
12	Municipal Franchise Fees	$ 23,831,407	40.9	90.9	-50.0	$ (1,191,118,330)
13	Other O&M	$ 104,370,530	40.9	33.2	7.7	$ 800,486,074
14						
15	**Payroll Taxes**	$ 7,970,029	40.9	79.4	-38.5	$ (306,729,507)
16						
17	**Other Taxes**					
18	Federal/State	$ 48,837,998	40.9	36.5	4.4	$ 215,845,872
19	CAT	$ 4,898,147	40.9	75.0	-34.1	$ (166,930,663)
20	Property Taxes	$ 34,086,074	40.9	-45.5	86.4	$ 2,945,705,861
21	**Net of Revenue less Expense Lag**	**$ 778,707,673**	**40.9**	**27.1**	13.8	**$ 10,725,131,056**
22	Days					365
23	**Aver Daily Cash Working Capital Requirements - Oregon**					**$ 29,383,921**
24	**Aver Daily Cash Working Capital Requirements - System**					**$ 32,836,531**
25	**Cash Working Capital Factor**					**3.8%**

NW Natural - UG 520, Exhibit 1512 Page 2
Revenue Test Year Summary

		Test Year Twelve Months Ended October 31, 2026		
1			Year 1	
2			Revenues Billed	Lag (Lead) Days
3	Sale of Gas	$	1,068,558,200	
4	Transportation Revenues	$	17,144,034	
5	Service Lag			15.2
6	Billing Lag			0.0
7	Collection Lag			25.7
8	**Grand Total Revenues**	**$**	**1,085,702,234**	**40.9**
9	Misc Revenues	$	3,912,550	
10	Service Lag			15.0
11	Billing Lag			0.0
12	Collection Lag			30.0
13	**Total Other Revenues**	**$**	**3,912,550**	**45.0**
14				
15	**Total Revenue Lag**	**$**	**1,089,614,784**	**40.9**

NW Natural - UG 520, Exhibit 1512 Page 3
Expense Test Year Summary

		Test Year Twelve Months Ended October 31, 2026		
1		Year 1 Revenue Requirement Expense		Lag (Lead) Days
2		$		
3	**Operations and Maintenance Expense**			
4	Purchased Gas	$ 400,075,400		40.2
5	Service Lag		15.2	
6	Payment Lag		25.0	
7	Labor - Payroll	$ 98,489,721		27.1
8	Employee Benefits	$ 31,671,398		13.0
9	Prepaid Insurance	$ 7,252,188		-214.3
10	Prepaid IT	$ 12,588,880		-231.4
11	Regulatory Fees	$ 4,635,902		-91.3
12	Municipal Franchise Fees	$ 23,831,407		90.9
13	Other O&M	$ 104,370,530		33.2
14	**TOTAL O&M**	**$ 682,915,426**		**29.2**
15				
16	**Payroll Taxes**	$ 7,970,029		79.4
17				
18	**Other Taxes**			
19	Federal/State	$ 48,837,998		36.5
20	CAT	$ 4,898,147		75.0
21	Property Taxes	$ 34,086,074		-45.5
22	**TOTAL TAXES**	**$ 90,894,100**		**13.6**
23	**TOTAL REQUIRMENT**	**$ 773,809,526**		**27.3**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1513

December 30, 2024

NW Natural
UG 520 - Oregon Jurisdictional Rate Case
State Allocation Factors

Line No.	Allocation Factors - Summary	Oregon	Washington
1	Customers-all	87.840%	12.16%
2	Customers-Residential	87.660%	12.34%
3	Customers-Commercial	89.600%	10.40%
4	Customers-Industrial	92.340%	7.66%
5	Customers-The Dalles	76.410%	23.59%
6	3-factor	88.250%	11.75%
7	firm volumes	88.960%	11.04%
8	sales volumes	89.570%	10.43%
9	sendout volumes	91.280%	8.72%
10	sales/sendout volumes	90.430%	9.57%
11	Payroll	88.903%	11.10%
12	Admin Transfer	87.761%	12.24%
13	Employee Cost	88.463%	11.54%
14	Regulatory	70.000%	30.00%
15	Telemetering	87.037%	12.96%
16	Direct-Wa	0.000%	100.00%
17	Direct-Or	100.000%	0.00%
18	Gross plant direct assign	87.980%	12.02%
19	Transmission	98.751%	1.25%
20	Accumulated Depreciation	89.061%	10.94%
21	Rate Base	86.220%	13.78%
22	Distribution	85.767%	14.23%
23	Perimeter	93.750%	6.25%
24	Environmental Admin Costs	96.680%	3.32%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS EXHIBIT 1514

December 30, 2024

NW Natural
UG 520 - Exhibit 1514
Decoupling and WARM Updates

Decoupling Usage Baselines

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
02- Pre-2018 Residential	**Total**	107.8	90.2	78.7	55.6	33.5	21.9	16.6	16.0	18.2	40.6	77.8	107.9	**664.9**
02- Post-2018 Residential	**Total**	74.3	62.0	53.9	37.8	21.5	12.8	9.0	10.1	11.8	28.0	54.5	75.4	**450.9**
03 - Small Commerical	**Total**	483.7	432.6	400.0	287.1	202.6	128.5	110.0	107.5	110.4	194.8	343.5	489.6	**3,290.2**
31CSF - Commerical	**Total**	5,293.7	4,551.6	4,470.0	3,297.4	2,238.9	1,507.0	1,117.6	1,110.6	1,172.3	2,257.7	3,890.6	5,279.3	**36,186.7**

WARM and Decoupling Coefficients

02 - Residential	**0.15107**
03 - Small Commercial	**0.68985**
31CFS - Commerical	**7.41605**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS
EXHIBIT 1515

December 30, 2024

NORTHWEST NATURAL GAS COMPANY

RATE SCHEDULE H
LARGE VOLUME NON-RESIDENTIAL
HIGH PRESSURE GAS SERVICE (HPGS) RIDER
(continued)

Monthly Billing Rate (continued)

Cost Recovery Factors Primary 10-Year Term Effective November 1, 2025		
Year	**No Bonus Depreciation**	**With Bonus Depreciation**
Year 1	21.8%	21.2%
Year 2	20.3%	19.3%
Year 3	18.8%	18.1%
Year 4	17.5%	17.0%
Year 5	16.3%	15.9%
Year 6	15.1%	14.9%
Year 7	14.0%	13.8%
Year 8	12.8%	12.8%
Year 9	11.9%	11.9%
Year 10	10.9%	10.9%

(C)

(C)(C)

(C)(C)

Scheduled Maintenance Charge includes the costs associated with providing Scheduled Maintenance on HPGS Facilities as well as an annual charge of $10,087 per Customer for administrative services, which includes but is not limited to costs for managing the program, marketing, applying administrative and general overhead allocations, performing Customer credit evaluations, drafting the Customer agreements and site licenses, billing, warehousing and managing inventory of spare parts, monitoring, and dispatching. Scheduled Maintenance costs are initially based on expected labor and material costs known at the time the HPGS Agreement is executed. The labor component recovered through this charge includes the costs for administration. The Scheduled Maintenance Charge may be adjusted annually on the anniversary date of the execution of the HPGS Agreement to reflect any adjustments for differences between expected costs and actual costs, and to reflect any cost changes expected for the next 12-month period.

In addition to the Monthly Facility Charge and the Scheduled Maintenance Charge, the Company will bill and the Customer will be responsible to pay all actual costs associated with the Company's provision of Unscheduled Maintenance and Back-Up Services.

Unscheduled Maintenance will be billed as costs are incurred at actual costs for labor and materials plus overhead expenses.

(continue to Sheet H-6)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Seventeenth Revision of Sheet 2-1
Cancels Sixteenth Revision of Sheet 2-1

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Class Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Temporary Disconnection of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas equipment used for Domestic purposes by qualifying Residential Class Customers.

Service to a Vehicle Fueling Appliance is subject to the conditions set forth in Special Provisions 3 through 6 of this Rate Schedule.

MONTHLY RATE: Effective: November 1, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160.** The rates for service to a Vehicle Fueling Appliance shall be further adjusted as set forth in Special Provision 6 of this Rate Schedule. "Multi-Family" shall mean attached dwelling units of two or more attached units (for example, duplexes, apartments, condominiums or townhomes) that are individually metered on this Rate Schedule 2.

Minimum Monthly Bill: Customer Charge plus charges under **Schedule C** or **Schedule 15** (if applicable)

	Customer Charge	Base Rate	Base Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing	
Charge Type (Fixed / Variable):	Fixed Charge	Volumetric Charges (per therm)						
Residential Single-Family	$10.00	0.89903	0.00815	0.10274	0.43366	-0.00959	1.43399	(I)
Residential Multi-Family	$8.00	0.89903	0.00815	0.10274	0.43366	-0.00959	1.43399	(I)

(continue to Sheet 2-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Sixteenth Revision of Sheet 3-4
Cancels Fifteenth Revision of Sheet 3-4

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: November 1, 2025

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**. The rates for service to CNG vehicle fueling equipment shall be further adjusted as set forth in Special Provision 7 of this Rate Schedule.

FIRM SALES SERVICE CHARGES: (03CSF and 03ISF)						**Billing Rates [1]**	
Customer Charge (per month):						**$15.00**	
Volumetric Charges (per therm):	Base Rate	Base Adjustment	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Commercial	$0.77410	$0.00815	$0.10274	$0.43366	($0.05956)	**$1.25909**	(I)
Industrial	$0.51096	$0.00815	$0.10274	$0.43366	$0.03652	**$1.09203**	(I)
Standby Charge (per therm of MHDV) [3]:						**$10.00**	

[1] **Schedule C** and **Schedule 15** Charges shall apply, if applicable.
[2] The Commodity Component shown is the Annual Sales WACOG. The actual Commodity Component billed could be different for certain customers as described in the special provisions of this Rate Schedule
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be the Customer Charge plus any **Schedule C** and **Schedule 15** Charges.

Issued December 30, 2024
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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fifth Revision of Sheet 4-1
Cancels Fourth Revision of Sheet 4-1

RATE SCHEDULE 4
RESIDENTIAL MULTI-FAMILY SERVICE

APPLICABLE:
To Residential tenants that reside in a Participant Multi-Family Building.

MONTHLY RATE: **$11.78** Effective: November 1, 2025 (I)(C)

The monthly rate for service under this Rate Schedule 4 may be adjusted from time to time for the effects of changes approved by the Commission in a general rate case proceeding.

SPECIAL PROVISIONS:

1. Low-use gas appliances include gas range or cooktop, gas clothes dryer, and gas barbecue. All Natural Gas usage associated with low-use gas appliances served under this Schedule 4 will be metered and billed from the master meter that serves the Participant Building and will be collected from tenants in accordance with General Rule 17 of this Tariff and with Participant Building policy.

2. Customers billed under this Rate Schedule 4 are not subject to Schedule 301 Public Purposes Funding Surcharges.

3. Customers billed under this Rate Schedule 4 are not eligible for the following programs:

   Schedule 310—Oregon Low-Income Gas Assistance (OLGA)
   Schedule 320—Oregon Low-Income Energy Efficiency Programs (OLIEE)
   Schedule 350—Energy Efficiency Services and Programs - Residential and Commercial

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff, any other Schedules that by their terms or by the terms of this Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 | Sixth Revision of Sheet 15-1
Cancels Fifth Revision of Sheet 15-1

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES (OPTIONAL)

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part.

TERM OF SERVICE:
The Term of Service for monthly meter rentals and metering services provided under this Schedule is twelve (12) consecutive billing months. At the end of a full Term of Service, service under this Rate Schedule will continue on a billing month basis until terminated by either the Customer or the Company upon one (1) billing month advance notice.

MONTHLY METER RENTAL RATES:
Any Customer may pay to rent supplementary displacement type meters from the Company on a monthly basis calculated as follows: (T) (N)

$$= \frac{Net\ Present\ Value\ (\text{Total Cost to Serve Meter at Discount Rate } r \text{ over Period } t)}{12}$$

- The Rental Meter is the meter inclusive of an Encoder Receiver Transmitter (ERT), if necessary, as well as required fittings and components (e.g., swivel, gasket, flange, etc.) which can vary by meter type and size.
- Cost to Serve includes incremental capital-related costs (the cost of the Rental Meter) as well as any other costs customarily relating to recovery of the utility investment, including but not limited to capital depreciation, regulatory fees, and income and property taxes.
- Discount Rate *r* is the weighted cost of capital and cost of long-term debt authorized by the Commission in the Company's most recent general rate case. Period *t* is equal to the total depreciable life (in years) of the assembled meter set.

The Net Present Value calculation produces a levelized cost of the Company to serve the rental meter at Discount Rate *r* over Period *t*. Dividing this value by 12 produces the Monthly Meter Rental Charge.

The Company will consult with the Customer regarding available meters of sizes and pressures that meet their service requirements prior to entering into a rental agreement. The meter rental charge, which is calculated as a monthly rate as described above, is presented to the Customer prior to the rental period and installation at the Customer premises.

(N)
(D)
(D)

(continue to Sheet 15-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Sixth Revision of Sheet 15-2
Cancels Fifth Revision of Sheet 15-2

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS, AND METERING SERVICES (OPTIONAL)
(continued)

MONTHLY METER RENTAL RATES (Continued):
The following **diaphragm** meter sizes and associated monthly charges are retained under existing arrangements for billing purposes. These meters/charges are not available to new meter rental requests. (T) (T)

Applicable			
Meters Installed Prior to 9/24/2008	Meters Installed Prior to 4/26/2018	Meter Size (cf/hour)	Monthly Charge
XX		175	$0.81
	XX	200	$0.81
	XX	275	$1.00
XX		310	$1.00
	XX	415	$1.70
XX		425	$1.70
	XX	500	$1.70
XX		750	$4.07
XX		800	$4.07
		1400	$9.29
	XX	1450	$9.29
XX		2300	$14.68
	XX	2500	$14.68
	XX	3000	$23.33
XX		5000	$23.33
	XX	11000	$23.33
XX		16000	$23.33
	XX	18000	$23.33

The following **rotary** meter sizes and associated monthly charges are retained under existing conditions for billing purposes. These meters/charges are not available to new meter rental requests. (T)

Applicable			
Meters Installed Prior to 4/26/2018	Meter Size	Meter Capacity (cf/hour)	Monthly Charge
XX	8C175	800	$ 13.00

METERING SERVICES AND CHARGES:

Metering Service	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.76	
Advanced Automated Meter Reading (AAMR) Device1	---	$1,270.53	$55.53	(I)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145.00	---	---	(I)

[1]Site specific engineering design costs for AAMR will be added to the installation charge if needed.

(continue to Sheet 15-3)

Issued December 30, 2024 Effective with service on
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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fourteenth Revision of Sheet 27-1
Cancels Thirteenth Revision of Sheet 27-1

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this Rate Schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 2.**

MONTHLY RATE: Effective: November 1, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

	Base Rate	Base Adjustment	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$8.00	---	---	---	---	**$8.00**
Volumetric Charge (per therm)	$0.75591	$0.00815	$0.10274	$0.43366	($0.01532)	**$1.28514**

(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 15** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 30, 2024 Effective with service on
NWN OPUC Advice No. 24-26 and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Sixteenth Revision of Sheet 31-11
Cancels Fifteenth Revision of Sheet 31-11

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS:

Effective: November 1, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **See Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**. The rates for service to CNG vehicle fueling equipment shall be further adjusted as set forth in Provision No. 2 of the "SPECIAL CONDITIONS FOR COMPRESSED NATURAL GAS ("CNG") SERVICE FOR VEHICULAR USE" of this Rate Schedule.

FIRM SALES SERVICE CHARGES (31 CSF) [1]:					Billing Rates	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.36646	$0.00815	$0.43366	($0.03274)	**$0.77553**	(I)
Block 2: All additional therms	$0.33435	$0.00815	$0.43366	($0.03363)	**$0.74253**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10274**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.52**	
FIRM TRANSPORTATION SERVICE CHARGES (31 CTF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.33460	($0.00236)		$0.01352	**$0.34576**	(I)
Block 2: All additional therms	$0.30590	($0.00236)		$0.01248	**$0.31602**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

(continue to Sheet 31-12)

Issued December 30, 2024 Effective with service on
NWN OPUC Advice No. 24-26 and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fourteenth Revision of Sheet 31-12
Cancels Thirteenth Revision of Sheet 31-12

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: **Effective: November 1, 2025** (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM SALES SERVICE CHARGES (31 ISF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.27725	$0.00815	$0.43366	$0.03284	**$0.75190**	(I)
Block 2: All additional therms	$0.24995	$0.00815	$0.43366	$0.03208	**$0.72384**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10274**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.52**	
FIRM TRANSPORTATION SERVICE CHARGES (31 ITF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.29346	($0.00236)		$0.01140	**$0.30250**	(I)
Block 2: All additional therms	$0.26524	($0.00236)		$0.01047	**$0.27335**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from **SCHEDULE C** and **SCHEDULE 15**.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in **SCHEDULE 162** may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in **SCHEDULE 162** may also apply.

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fourteen Revision of Sheet 32-12
Cancels Thirteenth Revision of Sheet 32-12

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: **Effective: November 1, 2025** (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**
Customer Charge (per month, all service types):					**$675.00**
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	
32 CSF Volumetric Charges (per therm):					
Block 1: 1st 10,000 therms	$0.20046	$0.00815	$0.43366	$0.03160	**$0.67387**
Block 2: Next 20,000 therms	$0.16922	$0.00815	$0.43366	$0.03060	**$0.64163**
Block 3: Next 20,000 therms	$0.11735	$0.00815	$0.43366	$0.02890	**$0.58806**
Block 4: Next 100,000 therms	$0.06527	$0.00815	$0.43366	$0.02719	**$0.53427**
Block 5: Next 600,000 therms	$0.02786	$0.00815	$0.43366	$0.02597	**$0.49564**
Block 6: All additional therms	$0.01013	$0.00815	$0.43366	$0.02538	**$0.47732**
32 ISF Volumetric Charges (per therm):					
Block 1: 1st 10,000 therms	$0.14771	$0.00815	$0.43366	$0.02894	**$0.61846**
Block 2: Next 20,000 therms	$0.12472	$0.00815	$0.43366	$0.02838	**$0.59491**
Block 3: Next 20,000 therms	$0.08626	$0.00815	$0.43366	$0.02744	**$0.55551**
Block 4: Next 100,000 therms	$0.04795	$0.00815	$0.43366	$0.02652	**$0.51628**
Block 5: Next 600,000 therms	$0.02120	$0.00815	$0.43366	$0.02587	**$0.48888**
Block 6: All additional therms	$0.00772	$0.00815	$0.43366	$0.02554	**$0.47507**
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**
Pipeline Capacity Charge Options (select one):					
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10274**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.52**

(I)
(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, the Account 191 Adjustments may apply.

(continue to Sheet 32-13)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Sixteenth Revision of Sheet 32-13
Cancels Fifteenth Revision of Sheet 32-13

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: November 1, 2025** (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**

INTERRUPTIBLE SALES SERVICE CHARGES [1][4]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
32 CSI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.16328	$0.00815	$0.43366	$0.02912	**$0.63421**	(I)
Block 2: Next 20,000 therms	$0.13787	$0.00815	$0.43366	$0.02841	**$0.60809**	
Block 3: Next 20,000 therms	$0.09542	$0.00815	$0.43366	$0.02723	**$0.56446**	
Block 4: Next 100,000 therms	$0.05297	$0.00815	$0.43366	$0.02604	**$0.52082**	
Block 5: Next 600,000 therms	$0.02751	$0.00815	$0.43366	$0.02533	**$0.49465**	
Block 6: All additional therms	$0.00888	$0.00815	$0.43366	$0.02482	**$0.47551**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01222**	
32 ISI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.14180	$0.00815	$0.43366	$0.02871	**$0.61232**	(I)
Block 2: Next 20,000 therms	$0.11969	$0.00815	$0.43366	$0.02812	**$0.58962**	
Block 3: Next 20,000 therms	$0.08286	$0.00815	$0.43366	$0.02714	**$0.55181**	
Block 4: Next 100,000 therms	$0.04599	$0.00815	$0.43366	$0.02615	**$0.51395**	
Block 5: Next 600,000 therms	$0.02386	$0.00815	$0.43366	$0.02557	**$0.49124**	
Block 6: All additional therms	$0.00767	$0.00815	$0.43366	$0.02513	**$0.47461**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01222**	

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, the Account 191 Adjustments may apply.

(continue to Sheet 32-14)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 — Fourteenth Revision of Sheet 32-14
Cancels Thirteenth Revision of Sheet 32-14

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: November 1, 2025** (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in Schedule 160.

FIRM TRANSPORTATION SERVICE CHARGES (32 CTF or 32 ITF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Commercial						
Block 1: 1st 10,000 therms	$0.15197	($0.00236)		$0.00597	**$0.15558**	(I)
Block 2: Next 20,000 therms	$0.12913	($0.00236)		$0.00528	**$0.13205**	
Block 3: Next 20,000 therms	$0.09117	($0.00236)		$0.00413	**$0.09294**	
Block 4: Next 100,000 therms	$0.05320	($0.00236)		$0.00297	**$0.05381**	
Block 5: Next 600,000 therms	$0.03037	($0.00236)		$0.00228	**$0.03029**	
Block 6: All additional therms	$0.01523	($0.00236)		$0.00182	**$0.01469**	
Industrial						
Block 1: 1st 10,000 therms	$0.14349	($0.00236)		$0.00545	**$0.14658**	
Block 2: Next 20,000 therms	$0.12196	($0.00236)		$0.00490	**$0.12450**	
Block 3: Next 20,000 therms	$0.08610	($0.00236)		$0.00396	**$0.08770**	
Block 4: Next 100,000 therms	$0.05025	($0.00236)		$0.00303	**$0.05092**	
Block 5: Next 600,000 therms	$0.02868	($0.00236)		$0.00246	**$0.02878**	
Block 6: All additional therms	$0.01440	($0.00236)		$0.00210	**$0.01414**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 CTI or ITI) [3][4]:						
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Commercial						
Block 1: 1st 10,000 therms	$0.13508	($0.00236)		$0.00443	**$0.13715**	(I)
Block 2: Next 20,000 therms	$0.11482	($0.00236)		$0.00395	**$0.11641**	
Block 3: Next 20,000 therms	$0.08106	($0.00236)		$0.00317	**$0.08187**	
Block 4: Next 100,000 therms	$0.04727	($0.00236)		$0.00241	**$0.04732**	
Block 5: Next 600,000 therms	$0.02703	($0.00236)		$0.00194	**$0.02661**	
Block 6: All additional therms	$0.01356	($0.00236)		$0.00163	**$0.01283**	
Industrial						
Block 1: 1st 10,000 therms	$0.13504	($0.00236)		$0.00505	**$0.13773**	
Block 2: Next 20,000 therms	$0.11479	($0.00236)		$0.00453	**$0.11696**	
Block 3: Next 20,000 therms	$0.08106	($0.00236)		$0.00371	**$0.08241**	
Block 4: Next 100,000 therms	$0.04726	($0.00236)		$0.00288	**$0.04778**	
Block 5: Next 600,000 therms	$0.02704	($0.00236)		$0.00237	**$0.02705**	
Block 6: All additional therms	$0.01356	($0.00236)		$0.00203	**$0.01323**	(I)

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 15.
[2] Where applicable, the Account 191 Adjustments shall apply.
[3] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 15.

Issued December 30, 2024 — Effective with service on
NWN OPUC Advice No. 24-26 — and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 Twelfth Revision of Sheet 100-1
Cancels Eleventh Revision Sheet 100-1

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS

PURPOSE:
To list the temporary adjustments included in billing rates.

DESCRIPTION:
The temporary adjustments to rates reflected in this Schedule are the result of the Commission's approval of an application by NW Natural to defer certain revenues or expenses for later amortization in customer rates under the authority of ORS 757.259, OAR 860-022-0070, and OAR 860-027-0300. The details specific to each adjustment can be found in the respective Adjustment Schedules.

All adjustment amounts identified in this Schedule shall be in effect for a 12-month period commencing with the stated effective date, or for such other period approved by the Commission.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

TABLE OF TEMPORARY ADJUSTMENTS: Effective: November 1, 2025 (C)
All temporary adjustments are stated on a cent per therm basis.

Schedule 2: Residential Sales Service

		Firm Sales
	Applicable	Residential
Deferred Gas Cost Amortization (Schedule 162)	All Therms	($0.03509)
Rate Mitigation (Schedule 166)	All Therms	$0.00175
Net Curtailment and Entitlement Revenues (168)	All Therms	($0.00320)
Intervenor Funding (Schedule 172)	All Therms	$0.00094
Covid-19 Deferral (Schedule 173)	All Therms	$0.00217
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	$0.00040
Regulatory Rate Adjustment (Schedule 178)	All Therms	($0.00130)
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000
Regulatory Fee (Schedule 181)	All Therms	$0.00039
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.01652
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00270
Decoupling Adjustment (Schedule 190)	All Therms	($0.00255)
WARM True-up (Schedule 195)	All Therms	$0.00337
Meter Modernization Program Amortization (Schedule 151)	All Therms	$0.00431 (N)

Schedule 3: Basic Firm Sales - Non-Residential

		Firm Sales	
	Applicable	Commercial	Industrial
Deferred Gas Cost Amortization (Schedule 162)	All Therms	($0.03509)	($0.03509)
Net Curtailment and Entitlement Revenues (168)	All Therms	($0.00238)	($0.00175)
Intervenor Funding (Schedule 172)	All Therms		$0.00038
Covid-19 Deferral (Schedule 173)	All Therms	$0.00178	$0.00099
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	$0.00032	$0.00030
Regulatory Rate Adjustment (Schedule 178)	All Therms	($0.00097)	($0.00072)
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	$0.00000
Regulatory Fee (Schedule 181)	All Therms	$0.00031	$0.00029
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.01229	$0.00902
Industrial DSM (Schedule 188)	All Therms		$0.05973
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00221	$0.00124
Decoupling Adjustment (Schedule 190)	All Therms	($0.04924)	
WARM True-up (Schedule 195)	All Therms	$0.00789	
Meter Modernization Program Amortization (Schedule 151)	All Therms	$0.00000	$0.00213 (N)

(continue to Sheet 100-2)

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2025 (C)

Rate Schedule 27: Residential Heating Dry Out Service

	Applicable	FIRM SALES Commercial	
Deferred Gas Cost Amortization (Schedule 162)	All Therms	($0.03509)	
Net Curtailment and Entitlement Revenues (168)	All Therms	($0.00276)	
Covid-19 Deferral (Schedule 173)	All Therms	$0.00221	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	$0.00036	
Regulatory Rate Adjustment (Schedule 178)	All Therms	($0.00113)	
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	$0.00035	
Site Remediation Recovery Mechanism (Schedule 183)	All Therms	$0.01424	
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00276	
Meter Modernization Program Amortization (Schedule 151)	All Therms	$0.00374	(N)

Schedule 31: Non-Residential Firm Sales and Firm Transportation

		FIRM SALES		FIRM TRANSPORTATION		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	($0.03509)	($0.03509)			
Net Curtailment and Entitlement Revenues (168)	Block 1 Block 2	($0.00164) ($0.00150)	($0.00115) ($0.00104)			
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.00127	$0.00127	
Intervenor Funding (Schedule 172)	All Blocks		$0.00038		$0.00038	
Covid-19 Deferral (Schedule 173)	Block 1 Block 2	$0.00091 $0.00083	$0.00072 $0.00065	$0.00091 $0.00084	$0.00074 $0.00067	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1 Block 2	$0.00024 $0.00024	$0.00023 $0.00022	$0.00013 $0.00012	$0.00010 $0.00009	
Regulatory Rate Adjustment (Schedule 178)	Block 1 Block 2	($0.00069) ($0.00063)	($0.00049) ($0.00045)	($0.00070) ($0.00065)	($0.00054) ($0.00049)	
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1 Block 2	$0.00000 $0.00000	$0.00000 $0.00000	$0.00000 $0.00000	$0.00000 $0.00000	
Regulatory Fee (Schedule 181)	Block 1 Block 2	$0.00024 $0.00023	$0.00022 $0.00021	$0.00012 $0.00011	$0.00009 $0.00008	
Site Remediation Recovery Mechanism (Schedule 183)	Block 1 Block 2	$0.00847 $0.00774	$0.00595 $0.00537	$0.00867 $0.00794	$0.00652 $0.00590	
Industrial DSM (Schedule 188)	All Blocks		$0.05973			
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1 Block 2	$0.00114 $0.00104	$0.00090 $0.00081	$0.00114 $0.00104	$0.00092 $0.00083	
Decoupling Adjustment (Schedule 190)	All Blocks	($0.00828)				
Meter Modernization Program Amortization (Schedule 151)	Block 1 Block 2	$0.00196 $0.00179	$0.00144 $0.00129	$0.00198 $0.00181	$0.00192 $0.00174	(N) (N)

(continue to Sheet 100-3)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Twelfth Revision of Sheet 100-3
Cancels Eleventh Revision of Sheet 100-3

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2025 (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		FIRM SALES		FIRM TRANSPORTATION	
	Applicable	Commercial	Industrial	Commercial	Industrial
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	($0.03509)	($0.03509)		
Net Curtailment and Entitlement Revenues (168)	Block 1	($0.00101)	($0.00065)		
	Block 2	($0.00086)	($0.00055)		
	Block 3	($0.00060)	($0.00039)		
	Block 4	($0.00035)	($0.00023)		
	Block 5	($0.00016)	($0.00011)		
	Block 6	($0.00008)	($0.00006)		
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.00127	$0.00127
Intervenor Funding (Schedule 172)	All Blocks		$0.00038		$0.00038
Covid-19 Deferral (Schedule 173)	Block 1	$0.00064	$0.00008	$0.00011	$0.00008
	Block 2	$0.00055	$0.00007	$0.00010	$0.00007
	Block 3	$0.00038	$0.00005	$0.00007	$0.00005
	Block 4	$0.00022	$0.00003	$0.00004	$0.00003
	Block 5	$0.00010	$0.00001	$0.00003	$0.00002
	Block 6	$0.00005	$0.00001	$0.00001	$0.00001
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	$0.00021	$0.00019	$0.00005	$0.00004
	Block 2	$0.00021	$0.00018	$0.00005	$0.00004
	Block 3	$0.00019	$0.00017	$0.00003	$0.00003
	Block 4	$0.00018	$0.00016	$0.00002	$0.00002
	Block 5	$0.00017	$0.00015	$0.00001	$0.00001
	Block 6	$0.00016	$0.00015	$0.00001	$0.00001
Regulatory Rate Adjustment (Schedule 178)	Block 1	($0.00044)	($0.00030)	($0.00033)	($0.00027)
	Block 2	($0.00037)	($0.00026)	($0.00029)	($0.00024)
	Block 3	($0.00027)	($0.00020)	($0.00022)	($0.00018)
	Block 4	($0.00018)	($0.00012)	($0.00015)	($0.00013)
	Block 5	($0.00010)	($0.00009)	($0.00010)	($0.00009)
	Block 6	($0.00007)	($0.00006)	($0.00008)	($0.00007)
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000
Regulatory Fee (Schedule 181)	Block 1	$0.00021	$0.00018	$0.00005	$0.00004
	Block 2	$0.00020	$0.00017	$0.00004	$0.00004
	Block 3	$0.00019	$0.00016	$0.00003	$0.00003
	Block 4	$0.00017	$0.00015	$0.00002	$0.00002
	Block 5	$0.00016	$0.00015	$0.00001	$0.00001
	Block 6	$0.00016	$0.00014	$0.00001	$0.00001
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00521	$0.00336	$0.00377	$0.00305
	Block 2	$0.00442	$0.00285	$0.00322	$0.00261
	Block 3	$0.00310	$0.00201	$0.00231	$0.00187
	Block 4	$0.00179	$0.00117	$0.00140	$0.00114
	Block 5	$0.00084	$0.00058	$0.00085	$0.00069
	Block 6	$0.00039	$0.00028	$0.00049	$0.00040
Industrial DSM (Schedule 188)	All Blocks	$0.05973	$0.05973		
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00080	$0.00010	$0.00014	$0.00010
	Block 2	$0.00068	$0.00009	$0.00012	$0.00009
	Block 3	$0.00048	$0.00006	$0.00009	$0.00006
	Block 4	$0.00028	$0.00003	$0.00005	$0.00004
	Block 5	$0.00013	$0.00002	$0.00003	$0.00002
	Block 6	$0.00006	$0.00001	$0.00002	$0.00001
Meter Modernization Amortization (Schedule 151)	Block 1	$0.00134	$0.00096	$0.00091	$0.00076 (N)
	Block 2	$0.00113	$0.00081	$0.00077	$0.00064
	Block 3	$0.00079	$0.00056	$0.00055	$0.00045
	Block 4	$0.00044	$0.00031	$0.00032	$0.00026
	Block 5	$0.00019	$0.00014	$0.00018	$0.00015
	Block 6	$0.00007	$0.00005	$0.00009	$0.00008 (N)

(continue to Sheet 100-4)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Eleventh Revision of Sheet 100-4
Cancels Tenth Revision of Sheet 100-4

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2025 (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		INTERRUPTIBLE SALES		INTERRUPTIBLE TRANSPORT	
	Applicable	**Commercial**	**Industrial**	**Commercial**	**Industrial**
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	($0.03553)	($0.03553)		
Intervenor Funding (Schedule 172)	All Blocks		$0.00038		$0.00038
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.00127	$0.00127
Covid-19 Deferral (Schedule 173)	Block 1	$0.00035	$0.00012	$0.00007	$0.00008
	Block 2	$0.00029	$0.00010	$0.00006	$0.00006
	Block 3	$0.00021	$0.00007	$0.00004	$0.00005
	Block 4	$0.00012	$0.00004	$0.00003	$0.00003
	Block 5	$0.00007	$0.00002	$0.00002	$0.00002
	Block 6	$0.00003	$0.00001	$0.00001	$0.00001
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	$0.00018	$0.00018	$0.00004	$0.00004
	Block 2	$0.00018	$0.00017	$0.00003	$0.00003
	Block 3	$0.00017	$0.00017	$0.00002	$0.00002
	Block 4	$0.00016	$0.00016	$0.00001	$0.00001
	Block 5	$0.00015	$0.00015	$0.00001	$0.00001
	Block 6	$0.00015	$0.00015	$0.00000	$0.00000
Regulatory Rate Adjustment (Schedule 178)	Block 1	($0.00028)	($0.00027)	($0.00023)	($0.00025)
	Block 2	($0.00024)	($0.00023)	($0.00021)	($0.00022)
	Block 3	($0.00019)	($0.00018)	($0.00017)	($0.00017)
	Block 4	($0.00013)	($0.00012)	($0.00011)	($0.00012)
	Block 5	($0.00009)	($0.00009)	($0.00009)	($0.00009)
	Block 6	($0.00006)	($0.00006)	($0.00006)	($0.00007)
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000
Regulatory Fee (Schedule 181)	Block 1	$0.00018	$0.00017	$0.00004	$0.00004
	Block 2	$0.00017	$0.00017	$0.00003	$0.00003
	Block 3	$0.00016	$0.00016	$0.00002	$0.00002
	Block 4	$0.00015	$0.00015	$0.00001	$0.00001
	Block 5	$0.00015	$0.00015	$0.00001	$0.00001
	Block 6	$0.00014	$0.00014	$0.00000	$0.00000
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00317	$0.00303	$0.00259	$0.00278
	Block 2	$0.00269	$0.00257	$0.00221	$0.00238
	Block 3	$0.00190	$0.00181	$0.00159	$0.00171
	Block 4	$0.00110	$0.00105	$0.00097	$0.00104
	Block 5	$0.00062	$0.00060	$0.00059	$0.00063
	Block 6	$0.00027	$0.00026	$0.00034	$0.00037
Industrial DSM (Schedule 188)	All Blocks	$0.05973	$0.05973		
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00043	$0.00015	$0.00009	$0.00009
	Block 2	$0.00037	$0.00013	$0.00008	$0.00008
	Block 3	$0.00026	$0.00009	$0.00006	$0.00006
	Block 4	$0.00015	$0.00005	$0.00003	$0.00004
	Block 5	$0.00008	$0.00003	$0.00002	$0.00002
	Block 6	$0.00004	$0.00001	$0.00001	$0.00001
Meter Modernization Program Amortization (Schedule 151)	Block 1	$0.00089	$0.00075	$0.00056	$0.00062 (N)
	Block 2	$0.00075	$0.00063	$0.00048	$0.00052
	Block 3	$0.00052	$0.00044	$0.00034	$0.00037
	Block 4	$0.00029	$0.00024	$0.00020	$0.00022
	Block 5	$0.00015	$0.00013	$0.00011	$0.00012
	Block 6	$0.00005	$0.00004	$0.00006	$0.00006 (N)

(continue to Sheet 100-5)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Original Sheet 151-1

(N)

SCHEDULE 151
METER MODERNIZATION PROGRAM AMORTIZATION

PURPOSE:
To identify adjustments to Customer rates applicable to the Rate Schedules listed below pursuant to Commission Order 25-XXX in Docket UG 520 entered on Month Day, 2025.

DESCRIPTION:
The rate adjustments reflected in this Schedule establish the method by which NW Natural will amortize the balance in the Company's Meter Modernization Program (MMP) that was established in accordance with Commission Order 25-XXX, Docket UM 2311.

The adjustments to Customer rates reflect the amortization of the MMP account of this Schedule 151.

APPLICABLE:
To all classes of Customers taking service under the following Rate Schedules of the Tariff of which this Schedule 151 is a part:

Rate Schedule 2	Rate Schedule 31
Rate Schedule 3	Rate Schedule 32
Rate Schedule 27	Rate Schedule 33

GENERAL TERMS:
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE ADJUSTMENTS:
The Temporary Rate Adjustment applies to all customer classes (Sales and Transportation Service) and is calculated on an equal percent of margin by Rate Schedule and Customer class. The effect of this adjustment is reflected in the Temporary Rate Adjustment shown in the respective Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

(continue to Sheet 151-2)

(N)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Original Sheet 151-2

(N)

SCHEDULE 151
METER MODERNIZATION PROGRAM AMORTIZATION
(continued)

RATE ADJUSTMENTS (continued):
The temporary volumetric adjustment applicable to each Rate Schedule is shown in the table below:

Rate Schedule	Block	Adjustment		Rate Schedule	Block	Adjustment
2SF		$0.00431		31 CSF	Block 1	$0.00196
2MF		$0.00431			Block 2	$0.00179
03 CSF		$0.00332		31 CTF	Block 1	$0.00198
03 ISF		$0.00213			Block 2	$0.00181
27		$0.00374		31 ISF	Block 1	$0.00144
					Block 2	$0.00129
				31 ITF	Block 1	$0.00192
					Block 2	$0.00174
				32 CSI	Block 1	$0.00089
32 CSF	Block 1	$0.00134			Block 2	$0.00075
	Block 2	$0.00113			Block 3	$0.00052
	Block 3	$0.00079			Block 4	$0.00029
	Block 4	$0.00044			Block 5	$0.00015
	Block 5	$0.00019			Block 6	$0.00005
	Block 6	$0.00007		32 ISI	Block 1	$0.00075
32 ISF	Block 1	$0.00096			Block 2	$0.00063
	Block 2	$0.00081			Block 3	$0.00044
	Block 3	$0.00056			Block 4	$0.00024
	Block 4	$0.00031			Block 5	$0.00013
	Block 5	$0.00014			Block 6	$0.00004
	Block 6	$0.00005		32 CTI	Block 1	$0.00056
32 CTF	Block 1	$0.00091			Block 2	$0.00048
	Block 2	$0.00077			Block 3	$0.00034
	Block 3	$0.00055			Block 4	$0.00020
	Block 4	$0.00032			Block 5	$0.00011
	Block 5	$0.00018			Block 6	$0.00006
	Block 6	$0.00009		32 ITI	Block 1	$0.00062
32 ITF	Block 1	$0.00076			Block 2	$0.00052
	Block 2	$0.00064			Block 3	$0.00037
	Block 3	$0.00045			Block 4	$0.00022
	Block 4	$0.00026			Block 5	$0.00012
	Block 5	$0.00015			Block 6	$0.00006
	Block 6	$0.00008		33 (all)		$0.00000

(N)

Issued December 30, 2024 Effective with service on
NWN OPUC Advice No. 24-26 and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Sixth Revision of Sheet 167-1
Cancels Fifth Revision of Sheet 167-1

SCHEDULE 167
GENERAL ADJUSTMENTS TO RATES

PURPOSE:9=[
To identify adjustments made to the billing rates stated in the Rate Schedules listed below to reflect the effects of general rate changes approved by the Commission under the authority of ORS 757.210

DESCRIPTION:
The general rate changes shown in this Schedule 167 reflect the outcome of a Commission investigation in docket UG 520 initiated following a Company request to change rates due to increases or decreases in the cost of general utility operations. (C)

APPLICABLE:
To Customers taking service under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

RATE ADJUSTMENTS: Effective: November 1, 2025 (C)
The Base Rates stated in the listed Rate Schedules were adjusted as follows:

	Adjustment Amount			Adjustment Amount		
Schedule	**Customer Charge**	**Volumetric Charge**	**Schedule**	**Customer Charge**	**Volumetric Charge**	
02R	$0.00	$0.09860	03 CSF	$0.00	$0.07401	(R)(R) (R)
02MF	$0.00	$0.09860	03 ISF	$0.00	$0.03573	(R) (R)
27	$0.00	$0.10472				(R)

Schedule	Block	Amount	Schedule	Block	Amount	Schedul	Block	Amount	
31 CSF	Cust. Charge	$0.00	32 CSF	Cust. Charge	$0.00	32 CSI	Cust. Charge	$0.00	
	Block 1	$0.02858		Block 1	$0.01960		Block 1	$0.01494	(R)(R)(I)
	Block 2	$0.02607		Block 2	$0.01654		Block 2	$0.01262	(R)
31CTF	Cust. Charge	$0.00		Block 3	$0.01148		Block 3	$0.00873	
	Block 1	$0.02888		Block 4	$0.00638		Block 4	$0.00485	(R)
	Block 2	$0.02640		Block 5	$0.00272		Block 5	$0.00252	(R)
31ISF	Cust. Charge	$0.00		Block 6	$0.00099		Block 6	$0.00081	(R)(I)
	Block 1	$0.02096	32 ISF	Cust. Charge	$0.00	32 ISI	Cust. Charge	$0.00	(R)
	Block 2	$0.01890		Block 1	$0.01405		Block 1	$0.01261	(R)(I)(I)
31 ITF	Cust. Charge	$0.00		Block 2	$0.01187		Block 2	$0.01064	
	Block 1	$0.03228		Block 3	$0.00820		Block 3	$0.00737	(I)
	Block 2	$0.02918		Block 4	$0.00456		Block 4	$0.00409	(I)
				Block 5	$0.00202		Block 5	$0.00212	
				Block 6	$0.00073		Block 6	$0.00068	(I)(I)
			32 CTF	Cust. Charge	$0.00	32 CTI	Cust. Charge	$0.00	
				Block 1	$0.01330		Block 1	$0.00821	(R)(R)
				Block 2	$0.01130		Block 2	$0.00698	
				Block 3	$0.00797		Block 3	$0.00492	
				Block 4	$0.00466		Block 4	$0.00287	
				Block 5	$0.00266		Block 5	$0.00164	
				Block 6	$0.00133		Block 6	$0.00083	(R)(R)
			32 ITF	Cust. Charge	$0.00	32 ITI	Cust. Charge	$0.00	
				Block 1	$0.01268		Block 1	$0.01033	(I)(I)
				Block 2	$0.01078		Block 2	$0.00879	
				Block 3	$0.00761		Block 3	$0.00621	
				Block 4	$0.00444		Block 4	$0.00361	
				Block 5	$0.00254		Block 5	$0.00207	
				Block 6	$0.00127		Block 6	$0.00104	(I)(I)
						33	All	$0.00000	

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 30, 2024
NWN OPUC Advice No. 24-26

Effective with service on
and after November 1, 2025

Issued by: ***NORTHWEST NATURAL GAS COMPANY***
d.b.a. NW Natural

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 — Second Revision of Sheet 175-1
Cancels First Revision of Sheet 175-1

SCHEDULE 175
AMORTIZATION OF HORIZON 1 START-UP COST DEFERRAL

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the amortization of Horizon 1 Start-Up cost deferral (deferral docket UM 2132) over 10 years beginning November 1, 2022, subject to the terms of the stipulation approved in Order No. 21-246 with a rate spread as shown in Exhibit B of the Multi-Party Stipulation approved in Order No. 22-388 in dockets UG 435 and UG 411. These rates are included as Base Rate Adjustments in the rate schedules listed below and were first included in rates November 1, 2022, as filed with the Company's compliance filing in UG 435.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27
Rate Schedule 32	Rate Schedule 33	Rate Schedule 31

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2025 (C)
The adjustment amounts shown below are embedded in the Base Rate reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Adjustment		Rate Schedule/Class	Block	Adjustment	
2		$0.00168		31 CSF	Block 1	$0.00082	(I) (I)
					Block 2	$0.00040	(R)
03 CSF		$0.00123		31 CTF	Block 1	$0.00073	(R) (I)
03 ISF		$0.00074			Block 2	$0.00071	
27		$0.00136		31 ISF	Block 1	$0.00057	
					Block 2	$0.00054	
				31 ITF	Block 1	$0.00108	
					Block 2	$0.00121	(I)
				32 CSI	Block 1	$0.00002	(R)
32 CSF	Block 1	$0.00046			Block 2	$0.00030	(I)
	Block 2	$0.00036			Block 3	$0.00025	
	Block 3	$0.00031			Block 4	$0.00018	
	Block 4	$0.00022			Block 5	$0.00011	(I)
	Block 5	$0.00013			Block 6	$0.00006	(R)
	Block 6	$0.00006		32 ISI	Block 1	$0.00001	(R)
32 ISF	Block 1	$0.00001			Block 2	$0.00009	(R) (I)
	Block 2	$0.00008			Block 3	$0.00007	(I)
	Block 3	$0.00007			Block 4	$0.00005	(I) (I)
	Block 4	$0.00005			Block 5	$0.00003	(I)
	Block 5	$0.00003			Block 6	$0.00002	(R)
	Block 6	$0.00002		32 CTI	Block 1	$0.00001	(R)
32 CTF	Block 1	$0.00001			Block 2	$0.00005	(R) (I)
	Block 2	$0.00014			Block 3	$0.00004	(I)
	Block 3	$0.00012			Block 4	$0.00003	(I)
	Block 4	$0.00008			Block 5	$0.00002	
	Block 5	$0.00005			Block 6	$0.00001	
	Block 6	$0.00003		32 ITI	Block 1	$0.00000	(I) (R)
32 ITF	Block 1	$0.00001			Block 2	$0.00005	(R) (I)
	Block 2	$0.00006			Block 3	$0.00004	(I)
	Block 3	$0.00005			Block 4	$0.00003	(I)
	Block 4	$0.00004			Block 5	$0.00002	(I) (I)
	Block 5	$0.00002			Block 6	$0.00001	
	Block 6	$0.00001		33		$0.00002	

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 — Fourth Revision of Sheet 182-1
Cancels Third Revision of Sheet 182-1

SCHEDULE 182
RATE ADJUSTMENT FOR ENVIRONMENTAL COST RECOVERY

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the collection of $5.0 million per year for the recovery of costs related to environmental remediation expenses, in accordance with Order No. 15-049 in Docket UM 1635 and UM 1706 entered by the Public Utility Commission of Oregon on February 20, 2015.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27
Rate Schedule 32	Rate Schedule 33	Rate Schedule 31

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2025 (C)
The Adjustment amounts shown below are calculated based on equal percent of margin by Rate Schedule and Customer class. The adjustment amount is embedded in the Base Rate reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Base Rate	Schedule	Block	Base Rate Adjustment	
2		$0.00788	31 CSF	Block 1	$0.00659	(R) (I)
				Block 2	$0.00323	(R)
03 CSF		$0.00696	31 ISF	Block 1	$0.00270	(I)
03 ISF		$0.00575		Block 2	$0.00254	(I)
27		$0.00490	31 CTF	Block 1	$0.00369	(R)
				Block 2	$0.00358	
			31 ITF	Block 1	$0.00331	(R)
				Block 2	$0.00374	(I)
			32 CSI	Block 1	$0.00010	(R)
32 CSF	Block 1	$0.00259		Block 2	$0.00144	
	Block 2	$0.00205		Block 3	$0.00122	
	Block 3	$0.00175		Block 4	$0.00087	
	Block 4	$0.00124		Block 5	$0.00051	
	Block 5	$0.00072		Block 6	$0.00030	
	Block 6	$0.00035	32 ISI	Block 1	$0.00015	
32 ISF	Block 1	$0.00018		Block 2	$0.00129	
	Block 2	$0.00150		Block 3	$0.00110	
	Block 3	$0.00128		Block 4	$0.00078	
	Block 4	$0.00091		Block 5	$0.00047	
	Block 5	$0.00054		Block 6	$0.00028	
	Block 6	$0.00028	32 CTI	Block 1	$0.00012	
32 CTF	Block 1	$0.00018		Block 2	$0.00102	
	Block 2	$0.00173		Block 3	$0.00086	(R)
	Block 3	$0.00147		Block 4	$0.00060	(I)
	Block 4	$0.00103		Block 5	$0.00034	(R)
	Block 5	$0.00059		Block 6	$0.00019	
	Block 6	$0.00032	32 ITI	Block 1	$0.00009	
32 ITF	Block 1	$0.00011		Block 2	$0.00107	(R)
	Block 2	$0.00120		Block 3	$0.00091	
	Block 3	$0.00101		Block 4	$0.00063	(I)
	Block 4	$0.00071		Block 5	$0.00036	(R)
	Block 5	$0.00041		Block 6	$0.00020	
	Block 6	$0.00022	33 (all)		$0.00009	(R)

Issued December 30, 2024
NWN OPUC Advice No. 24-26

Effective with service on
and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 | Fifth Revision of Sheet 187-1
Cancels Fourth Revision of Sheet 187-1

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the Company's recall of Mist storage capacity for use by the Company's core Sales Service Customers.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2   Rate Schedule 3   Rate Schedule 31
Rate Schedule 27   Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2025 (C)
The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule	Block	Mist Recall Base Adjustment		Schedule	Block	Mist Recall Base Adjustment
2		$0.00000		31 CSF	Block 1	$0.00000
03 CSF		$0.00000			Block 2	$0.00000
03 ISF		$0.00000		31 ISF	Block 1	$0.00000
27		$0.00000			Block 2	$0.00000
32 CSF	Block 1	$0.00000		32 CSI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
32 ISF	Block 1	$0.00000		32 ISI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000

(R)(R)

(R)(R)

GENERAL TERMS:
Service under this Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 30, 2024 | Effective with service on
NWN OPUC Advice No. 24-26 | and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Seventeenth Revision of Sheet 190-1
Cancels Sixteenth Revision of Sheet 190-1

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM

PURPOSE:
To (a) describe the partial decoupling mechanism established in accordance with Commission Order 12-408 in Docket UG 221, Commission Order 18-419 in Docket UG 344, Commission Order 20-364 in Docket UG 388, Commission Order 24-359 in Docket UG 490, and Commission Order 25-XXX in Docket UG 520; (b) identify the adjustment applicable to rates under the Rate Schedules listed below. (N)

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Rate Schedule 2	Rate Schedule 3 CSF
	Rate Schedule 31 CSF

ADJUSTMENT TO RATE SCHEDULES: **Effective: November 1, 2025** (C)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules:	($0.00255)
Commercial Rate Schedule 3:	($0.04924)
Commercial Rate Schedule 31:	($0.00828)

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

1. As described in detail below, the Company will calculate the difference between weather-normalized usage and the calculated baseline usage for each Residential and Commercial Customer group. The Residential customer group is bifurcated by premises that were connected to the system prior to January 1, 2018, and for those connected on or after January 1, 2018. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group.

   The Company shall defer and amortize, with interest, 100% of the distribution margin differential in a sub-account of Account 186. The deferral will be a credit (accruing a refund to customers) if the differential is positive, or a debit (accruing a recovery by the company) if the differential is negative.

(continue to Sheet 190-2)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25 Fourteenth Revision of Sheet 190-2
Cancels Thirteenth Revision of Sheet 190-2

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline use-per-customer is:

   Residential (premise connected prior to January 1, 2018): 664.89 (C)
   Residential (premise connected on or after January 1, 2018): 450.95 (C)

   Commercial (Schedule 3): 3,290.24 (C)
   Commercial (Schedule 31): 36,186.74 (C)

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 520. The weather data is taken from the stations identified in **Rule 24**. (C)

   Step One. For the heating season months of December through March, usage is normalized by taking the difference between normal and actual heating degree days for each district using a base of 59 degrees for Residential and 58 degrees for Commercial. Usage for the heating season months of November, April and May will be normalized by the actual WARM effect attributable to the month that is included in customer bills for rate schedules 2 and commercial 3. For commercial schedule 31, no normalization will be done in November, April and May.

   Step Two. This step derives the per-therm customer variance by multiplying the heating degree-day difference by the usage coefficient of .15107 for Residential (Schedule 2) variances, .68985 for Commercial (Schedule 3) variances, and 7.41605 for Commercial (Schedule 31) variances. (C)(C) (C)

   Step Three. The per-therm customer variance is multiplied by the appropriate customer count, by district, with the sum of the district results representing the normalized therm amount.

4. Baseline usage will be adjusted to reflect actual customers billed each month.

5. The per therm distribution margins to be used in the deferral calculation effective November 1, 2025 is $0.90718 per therm for Residential (Schedule 2) customers and $0.78225 per therm for Commercial (Schedule 3) customers and $0.35998 per therm for Commercial (Schedule 31) customers. (C)(I)(I) (I)

6. Coincident with the Company's annual Purchased Gas Cost and Technical Rate Adjustment filing, the Company shall apply an adjustment to Residential and Commercial rates to amortize over the following 12 months, the balance in the balancing account as of June 30.

7. This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to review by the Commission at least once every two (2) years.

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 30, 2024 Effective with service on
NWN OPUC Advice No. 24-26 and after November 1, 2025

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

9. Upon request, the Company will provide Customer with historical billing information that reflects bills with and without the WARM adjustment for any month during the WARM Period.

10. Should a change to the margin rate occur during the WARM Period, the equivalent therms used in the calculation of the WARM adjustment will be based on the entire billing period, and then prorated based upon the number of days applicable to each margin rate. The pro-rated therms are then multiplied by the applicable margin rate to determine the WARM adjustment for each rate period. Example: If a margin rate change occurred on January 1, a bill with a bill period between December 25 and January 24 would be prorated based upon 6 days at the prior margin rate and 24 days at the new margin rate. The calculations performed under the provisions of Special Conditions 2 and 3 will apply to each prorated period separately, except that the total WARM adjustment for each bill will not exceed the maximum (increase or decrease) WARM adjustment specified in Special Conditions 2 and 3.

WARM FORMULA:

1. The Formula is: WARM Adjustment = $\sum_{1}^{T}(HDD_{n,t} - HDD_{a,t}) * B * Mrgn$

   Where:

   T = the days covered by the meter read dates for an individual customer's bill
   HDDn = the 25 year average of heating degree-days for each day determined using a 25-year average temperature published by the National Oceanic and Atmospheric Administration (NOAA) as adopted for use with the Company's most recent general rate proceeding.
   HDDa = the actual heating degree-days for each day based on the individual customer's actual beginning and ending meter read dates
   B = the statistical coefficient relating heating degree-days to therm use determined in the most recent general rate case, or other Commission authorized proceeding.
   Mrgn = the relevant Rate Schedule margin defined as the current Billing Rate less the current Commodity Rate, Pipeline Capacity Charge, and any Temporary Adjustments.

2. For purposes of calculating the WARM Adjustment, the following shall apply:

   a. A Heating Degree Day (HDD) is defined as the extent by which the daily mean temperature falls below a specified set point on a specified day. The HDD calculation uses a set point temperature of 59 degrees Fahrenheit for the **Rate Schedule 2** calculation, and 58 degrees Fahrenheit for the **Rate Schedule 3** calculation;

   b. The statistical coefficients to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing November 1, 2025 are: (C)

Rate Schedule 2:	0.15107	Rate Schedule 3:	0.68985	(C)(C)

(continue to Sheet 195-4)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 — Tenth Revision of Sheet 195-4
Cancels Ninth Revision of Sheet 195-4

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM FORMULA: (continued)

c. The applicable margins to be used in the calculation of the WARM Adjustment Factor effective November 1, 2025 are: (C)

Rate Schedule 2:	$0.90718	Rate Schedule 3:	$0.78225

(I)(I)

Weather data used in the calculation of HDD for each customer shall be from the same weather stations and weather zones that are used in the determination of thermal units as set forth in **Rule 24.**

WARM BILL EFFECTS:
The following table depicts the impact on Residential **Rate Schedule 2** and Commercial **Rate Schedule 3** customer bills, respectively, at specified variations in HDDs.

2R	RESIDENTIAL			COMMERCIAL	
HDD Variance (+ or -)	Equivalent therms	Total Monthly WARM adjustment (+ or -)		Equivalent therms	Total Monthly WARM adjustment (+ or -)
1	0.1511	$0.14		0.6899	$0.54
5	0.7554	$0.69		3.4493	$2.70
10	1.5107	$1.37		6.8985	$5.40
15	2.2661	$2.06		10.3478	$8.09
20	3.0214	$2.74		13.797	$10.79
25	3.7768	$3.43		17.2463	$13.49
30	4.5321	$4.11		20.6955	$16.19
35	5.2875	$4.80		24.1448	$18.89
40	6.0428	$5.48		27.594	$21.59
45	6.7982	$6.17		31.0433	$24.28
50	7.5535	$6.85		34.4925	$26.98

(I)(I)

To calculate variations beyond or in-between specified levels, multiply the desired HDD variance by the applicable statistical coefficient, and then multiply that sum by the applicable margin.

To obtain the cent per therm effect of the Warm Adjustment, divide the WARM Adjustment by the number of therms used during the billing month.

(continue to Sheet 195-5)

Issued December 30, 2024
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Effective with service on
and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Fourteenth Revision of Sheet 195-5
Cancels Thirteenth Revision of Sheet 195-5

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM BILL EFFECTS (continued):

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **Rate Schedule 2** customer where the billing rate is $1.43399 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129 therms: (I)

HDD Differential:	Normal HDDs:	600 HDDs	
	Actual HDDs:	650 HDDs	
	HDD variance:	600 – 650 = -50 HDDs	
Equivalent Therms:	HDD variance:	-50 HDDs	
	Statistical coefficient:	0.15107	(C)
	Equivalent therms:	-50 x 0.15107 = -7.5537 therms	(C)
Total Warm Adjustment:	Equivalent therms:	-7.5537 therms	(C)
	Margin Rate:	$0.90718	(I)
	Total WARM Adj.:	-7.5537 x $0.90718 = ($6.85260)	(R)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	($6.85260)	(R)
	Monthly usage:	129 therms	
	Cent/therm Adj.:	($6.85260) / 129 = ($0.05312)	(R)
Billing Rate per therm:	Current Rate/therm:	$1.43399	(I)
	WARM cent/therm Adj.	($0.05312)	(R)
	WARM Billing Rate:	$1.38087 + ($0.05312) = $1.38087	(I)
Total WARM Bill:	Customer Charge:	$10.00	
	Usage Charge:	$1.38087	(I)
	Total	(129 x $1.38087) + $10.00 = $188.13	(I)

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other Schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fourth Revision of Sheet 196-1
Cancels Third Revision of Sheet 196-1

SCHEDULE 196
ADJUSTMENT FOR CERTAIN EXCESS DEFERRED INCOME TAXES RELATED TO THE 2017 FEDERAL TAX CUTS AND JOBS ACT

PURPOSE:
To amortize deferred amounts to Customers on the Rate Schedules listed below pursuant to the Third Stipulation adopted by Commission Order No. 19-105 in docket UG 344 entered on March 25, 2019, Order No. 20-364 in docket UG 388 entered on October 16, 2020, and Order No. 22-388 in docket UG 435 entered on October 24, 2022.

DESCRIPTION:
The rate adjustments reflected in this Schedule will amortize deferred amounts to Customers reflecting the net benefit of the excess deferred income taxes (EDIT) associated with Plant that result from the 2017 federal Tax Cuts and Jobs Act (TCJA).

The adjustment to Customer rates for the amortization of the portion of EDIT associated with Plant will occur until such time as the balance is fully amortized or the amortization schedule is otherwise changed in the Company's next general rate case with Commission approval. The total amount to be amortized is a credit of $125.1 million, which will be amortized at $3.2 million per year, prior to full (C)
revenue gross up.

This rate adjustment first became effective commencing November 1, 2020.

Applicable:
To all Customers taking service under the following Rate Schedules of this Tariff of which this Schedule 196 is a part:

Rate Schedule 2	Rate Schedule 31
Rate Schedule 3	Rate Schedule 32
Rate Schedule 27	Rate Schedule 33

(continue to Sheet 196-2)

Issued December 30, 2024
NWN OPUC Advice No. 24-26

Effective with service on
and after November 1, 2025

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Sixth Revision of Sheet 196-2
Cancels Fifth Revision of Sheet 196-2

SCHEDULE 196
ADJUSTMENT FOR CERTAIN EXCESS DEFERRED INCOME TAXES RELATED TO THE 2017 FEDERAL TAX CUTS AND JOBS ACT
(continued)

RATE ADJUSTMENTS: **Effective: November 1, 2025** (C)
The effect of this adjustment is included in the temporary rate and base rate for Plant. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED

The volumetric adjustment applicable to each Rate Schedule is shown in the table below:

Rate Schedule	Block	Rate Adjustment (per therm)		Rate Schedule	Block	Rate Adjustment (per therm)	
2		($0.00751)		32 ITF	Block 1	($0.00097)	(R)(R)
03 CSF		($0.00564)			Block 2	($0.00082)	(I)
03 ISF		($0.00272)			Block 3	($0.00058)	(R)
27		($0.00798)			Block 4	($0.00034)	
31 CSF	Block 1	($0.00218)			Block 5	($0.00019)	
	Block 2	($0.00199)			Block 6	($0.00010)	
31 CTF	Block 1	($0.00220)		32 CSI	Block 1	($0.00114)	
	Block 2	($0.00201)			Block 2	($0.00096)	
31 ISF	Block 1	($0.00160)			Block 3	($0.00067)	
	Block 2	($0.00144)			Block 4	($0.00037)	
31 ITF	Block 1	($0.00246)			Block 5	($0.00019)	
	Block 2	($0.00222)			Block 6	($0.00006)	
32 CSF	Block 1	($0.00149)		32 ISI	Block 1	($0.00096)	
	Block 2	($0.00126)			Block 2	($0.00081)	
	Block 3	($0.00087)			Block 3	($0.00056)	
	Block 4	($0.00049)			Block 4	($0.00031)	
	Block 5	($0.00021)			Block 5	($0.00016)	
	Block 6	($0.00008)			Block 6	($0.00005)	
32 ISF	Block 1	($0.00107)		32 CTI	Block 1	($0.00063)	
	Block 2	($0.00090)			Block 2	($0.00053)	
	Block 3	($0.00063)			Block 3	($0.00038)	
	Block 4	($0.00035)			Block 4	($0.00022)	
	Block 5	($0.00015)			Block 5	($0.00013)	
	Block 6	($0.00006)			Block 6	($0.00006)	
32 CTF	Block 1	($0.00101)		32 ITI	Block 1	($0.00079)	
	Block 2	($0.00086)			Block 2	($0.00067)	
	Block 3	($0.00061)			Block 3	($0.00047)	
	Block 4	($0.00035)			Block 4	($0.00028)	
	Block 5	($0.00020)			Block 5	($0.00016)	
	Block 6	($0.00010)			Block 6	($0.00008)	(R)(R)
				33 (all)		$0.00000	

(continue to Sheet 196-3)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 — Fourth Revision of Sheet 197-2
Cancels Third Revision of Sheet 197-2

SCHEDULE 197
AMORTIZATION OF PENSION BALANCING ACCOUNT
(continued)

RATE ADJUSTMENTS (continued):
The volumetric adjustment applicable to each Rate Schedule is shown in the table below:

Rate Schedule	Block	Adjustment		Rate Schedule	Block	Adjustment
2		$0.01124		31 CSF	Block 1	$0.00939
					Block 2	$0.00461
03 CSF		$0.00993		31 ISF	Block 1	$0.00385
03 ISF		$0.00820			Block 2	$0.00362
27		$0.00699		31 CTF	Block 1	$0.00526
					Block 2	$0.00510
				31 ITF	Block 1	$0.00473
					Block 2	$0.00533
				32 CSI	Block 1	$0.00014
32 CSF	Block 1	$0.00369			Block 2	$0.00205
	Block 2	$0.00293			Block 3	$0.00174
	Block 3	$0.00249			Block 4	$0.00124
	Block 4	$0.00176			Block 5	$0.00073
	Block 5	$0.00103			Block 6	$0.00043
	Block 6	$0.00051		32 ISI	Block 1	$0.00021
32 ISF	Block 1	$0.00025			Block 2	$0.00184
	Block 2	$0.00214			Block 3	$0.00157
	Block 3	$0.00182			Block 4	$0.00112
	Block 4	$0.00129			Block 5	$0.00067
	Block 5	$0.00077			Block 6	$0.00039
	Block 6	$0.00040		32 CTI	Block 1	$0.00017
32 CTF	Block 1	$0.00026			Block 2	$0.00145
	Block 2	$0.00247			Block 3	$0.00123
	Block 3	$0.00209			Block 4	$0.00086
	Block 4	$0.00147			Block 5	$0.00049
	Block 5	$0.00084			Block 6	$0.00027
	Block 6	$0.00046		32 ITI	Block 1	$0.00013
32 ITF	Block 1	$0.00016			Block 2	$0.00153
	Block 2	$0.00171			Block 3	$0.00129
	Block 3	$0.00145			Block 4	$0.00090
	Block 4	$0.00101			Block 5	$0.00052
	Block 5	$0.00058			Block 6	$0.00028
	Block 6	$0.00032		33 (all)		$0.00013

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Direct Testimony of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1600

December 30, 2024

EXHIBIT 1600 – DIRECT TESTIMONY – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company").

A. My name is Robert J. Wyman. My current position is Rates and Regulatory Economist for NW Natural. I am responsible for economic analysis, short-term load forecasting of residential and commercial rate classes, cost of service, and rate spread and rate design. I have been a witness and supported witnesses and created technical work papers for multiple rate and advice proceedings filed with the Oregon and Washington utility commissions on behalf of NW Natural.

Q. Please summarize your educational background and business experience.

A. I hold a Bachelor of Science in Economics from the Robert D. Clark Honors College at the University of Oregon and a Master of Arts in Applied Economics from the University of Michigan. Prior to attending graduate school I was employed by ECONorthwest, an economics consultancy, and worked in the firm's economic development and transportation practice area. I was responsible for the technical analysis on and consultation for dozens of projects, largely in the Pacific Northwest and Western states. I joined NW Natural in 2016 as a Rates and Regulatory Analyst. I have over 15 years of professional experience including 8 years of consulting with a focus on public finance and policy, urban economics, and financial feasibility (benefit-cost) analysis as well as nearly 9 years as an analyst and economist in the energy industry with a focus on load forecasting, cost of service, and rate spread and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology for NW Natural's weather normalized use-per-customer ("UPC") forecast for the Residential and Commercial rate classes, present the Long-Run Incremental Cost ("LRIC") study, and describe the Company's rate spread and rate design proposal. At the end of this testimony, I describe how the rate spread proposal will allocate incremental revenue requirement to each NW Natural Oregon Tariff rate schedule ("RS"), excluding RS 4, RS 15, RS 33, RS 90 and special contract schedules. Separately, I propose tariff changes for RS 15 (Charges for Special Metering Equipment, Rental Meters, and Metering Services).

Q. Would you please summarize your testimony?

A. My testimony is made up of three distinct sections: (1) The Company's UPC forecasting methodology; (2) the LRIC study methodology and a summary of results; and (3) proposed changes to rate design, as well as the rate spread proposal to be applied to the incremental revenue requirement for this case. First, I will detail the UPC forecasting methodology (referred here as the "UPC Forecast") and explain how it is used in conjunction with the Company's customer forecast to create a short-term weather normalized volume forecast for the Residential and Commercial rate classes. The normalized volume forecast is used to support the determination of the proposed revenue requirement presented in NW Natural/1500, Walker. Second, I will outline NW Natural's LRIC study methodology and will show the incremental cost inputs by capital investment and operations expense categories, on a rate schedule basis. Third, I present and discuss proposed rate design changes. Finally, I will show how the Company proposes to spread the incremental revenue requirement across rate schedules.

My testimony explains how the UPC Forecast was derived using an autoregressive model specification to interpret the relationship between temperature and commodity usage to create weather normalized revenues for the Residential and Commercial firm sales service rate classes for the test year of November 1, 2025, through October 31, 2026 ("Test Year"). I also explain how the Company derived Test Year revenues for the Industrial and Commercial interruptible sales and transportation service rate classes.

This testimony also explains how the LRIC study is used to assign incremental revenue requirement to rate schedules based on "cost causality" (i.e., how much of the capital investment costs and operations and maintenance ("O&M") expenses required to serve the Company's customers can be attributable to each rate schedule). The LRIC study filed with this case indicates that the Large Commercial, Industrial, and Transportation rate schedule classes are paying more than their determined cost of service under present rates, which is consistent with past rate case results. The study also indicates that the RS 2 Residential and RS 27 Dry-Out rate schedules are paying less than their determined cost of service, a result that is consistent with the results from the Company's last rate case, UG 490. Finally, the study indicates that RS 3 Basic Firm Sales Service Non-Residential (Commercial) ("RS 3 General Commercial") is paying just above the determined cost of service whereas the Company's prior LRIC study presented in UG 490 indicated this schedule was paying under its determined cost of service. I discuss reasoning for this shift in RS 3 General Commercial determined cost of service relative to parity.

Next, I discuss proposed changes to the RS 4 Residential Multi-Family Service rate and tariff changes for RS 15 (Charges for Special Metering Equipment, Rental Meters, and Metering Services), both of which are presented at NW Natural/1515, Walker.

Then, I describe the methodology by which NW Natural proposes to spread the incremental revenue requirement. The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the LRIC study, with a small deviation for RS 3 General Commercial which I discuss in testimony. I describe the following three-step rate spread proposal for all rate schedules in full later in my testimony. First, for RS 2 Residential and RS 27 Dry-Out, NW Natural proposes to use a separate cap for each rate schedule that slightly moves its relative position closer to parity with respect to the LRIC study results, because these schedules are paying less than their cost to serve at current rates. The Company proposes a cap for RS 3 General Commercial that allocates slightly more than the average margin increase to this schedule, although the LRIC study indicates this schedule is paying just above its cost to serve at present rates. Second, the Company proposes to apply a floor that is set below the level that produces an equal percent of margin increment to all rate schedules with a LRIC study indicated parity ratio above 1.29[1]. As a result of the application

[1] A ratio of 1.00 indicates rate parity, and a ratio above and below 1.00 indicates a rate schedule is overpaying and underpaying its LRIC study indicated cost of service, respectively.

of the floor, the relative position to parity of the applicable rate schedules with respect to the overall indicated LRIC study results will decrease, reflecting the fact that these classes are paying more than their cost to serve at current rates. Third, the remaining revenue requirement is allocated to all remaining rate schedules to reflect the LRIC study results, which indicate that while those schedules are overpaying their cost to serve at present rates, they are not overpaying at the same relative level as those with parity ratios over 1.29. This final step allocates the remaining revenue requirement on an equal percent of margin basis among all remaining rate schedules.

As a result of this three-step proposal, the RS 2 Residential, RS 3 General Commercial, and RS 27 Dry-Out rate schedules will receive a revenue requirement spread slightly greater than an equal percent of margin share calculated across all rate schedules, with the greatest relative increase being applied to RS 27 Dry-Out. The Large Commercial, Industrial, and Transportation rate classes will all receive a revenue spread less than an equal percent of margin share. The Company's proposal equitably distributes the incremental revenue requirement such that the rate classes as a whole are moved closer to parity based on their indicated cost causation, except for RS 3 General Commercial which is allocated an amount meant to roughly retain its indicated parity. The proposal described above is an incremental approach; it moves all rate classes closer to parity or generally maintains parity, and does so in a manner that works to minimize rate shock.

Next, I note that the Company is not proposing any rate design changes in this proceeding and briefly discuss the Company's view that monthly fixed charges can be used to smooth the Company's bills across the entire year, resulting in lower winter bills at a time when a customer's other energy bills may be increasing, as well as promote rate equity for the residential rate class.

Finally, the rate spread section of this testimony shows the proposed spread of incremental revenue requirement by rate schedule and the corresponding average monthly bill impact.

Q. Are you introducing any exhibits with your testimony?

A. Yes. I am sponsoring Exhibits 1601, 1602, 1603, and 1604. NW Natural/1601, Wyman is a summary of the Company's long-run incremental cost study by rate schedule. NW Natural/1602, Wyman presents the rate spread allocation proposal methodology. NW Natural/1603, Wyman indicates the incremental revenue requirement allocation by rate schedule, as well as the bill impact and rate increase by rate schedule. NW Natural/1604, Wyman presents the proposed rates by rate schedule and rate block.

II. TEST YEAR CUSTOMER AND NORMALIZED VOLUME FORECAST

Q. What is the Test Year customer and normalized volume forecast?

A. The Test Year customers and volumes are forecasted separately. The volume forecast is a short-term, weather normalized load forecast that is built using the following steps:

1. Weather data are collected to produce a 25-year historical benchmark for normal weather.
2. Actual weather data are paired with actual load data on a billing cycle and rate schedule basis. The paired data are used in a statistical regression analysis,

as described below, to produce weather normalized UPCs for the Residential and Commercial rate classes for the Test Year period (i.e., the UPC Forecast).

3. For these rate classes, the UPC Forecast is multiplied by the customer forecast to derive the weather normalized volume forecast.

The weather normalized volume forecast is used to calculate revenues at existing rates in the proposed revenue requirement presented in NW Natural/1501, Walker. In addition to being a revenue requirement input, the UPC Forecast is also used to create the design day load factor, which is an important input to the LRIC study.

Q. Please describe the customer forecast methodology.

A. For the Residential and Commercial firm sales service rate classes, Test Year forecasted customer counts were developed by adding new customers to the existing customer base. Customer attrition, or loss of customers, was deducted from the existing customer base. New customers, which are largely driven by new premises served on the system, are based on historical regional business and employment growth trends, housing starts forecasts, housing permitting activity, as well as other economic factors. The customer growth forecast used for purposes of developing additional volumes and revenues is the same forecast used for producing incremental capital expenditures that make up gross plant in the Test Year rate base.

Q. Please describe the UPC Forecast methodology.

A. The purpose of the UPC Forecast is to estimate weather normalized usage for the Residential and Commercial firm sales service rate classes on a per customer basis. The forecast relies on the relationship between weather (including temperature, which is translated into heating degree days, or “HDDs”, as well as other variables such as solar radiation and wind speed) and load demand by rate schedule and time of year (measured in daily increments)[2], as well as economic factors which I describe in greater detail below. To develop the UPC Forecast, I:

- Collected daily high and low temperature data from weather stations identified in Rule 24, Sheet RR-24.1, of NW Natural’s Oregon Tariff for the period June 1, 1999 through May 31, 2024 for two purposes. The first purpose was to have recent actual weather data to statistically analyze against recent actual usage, and the second purpose was to produce a 25-year historical benchmark for normal weather. Where gaps in the data are present, I use additional National Oceanic and Atmospheric Administration (“NOAA”) observed weather stations as backups to the tariffed stations to estimate normalized heating degree days using a simple linear regression which estimates the relationship between temperature readings at like stations.
- Matched actual therm usage and actual HDDs for the period of January 2012 through May 2024. As part of this process, I used load data on a billing cycle basis, and matched actual weather observations with the days between cycle

[2] A heating degree day is a unit of measurement that is calculated by subtracting the average temperature for a day from a base set point temperature, where the average temperature is lower than the base set point temperature. Heating degree days are additive in that the sum of the daily heating degree days over the course of the month is taken to represent that month’s weather. Where the average temperature is higher than the base set point temperature, zero (rather than negative) heating degree days are recorded. Heating degree days are a common unit of measurement that allows for an analysis of increasing load demand as a function of increasingly colder weather.

meter read dates. This process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. I then created a weighting of the number of days, customers, and HDDs associated with each billing cycle for each schedule in the Residential and Commercial customer classes. I used a 59-degree Fahrenheit base for residential schedules and a 58-degree Fahrenheit base for Commercial schedules as temperature set points to convert temperature observations to HDDs.[3]

- Aggregated the cycle-based therm usage as well as the days, customers, and HDDs weights by month. I used these monthly aggregates to regress therm use per premise per day against HDDs per day (as well as additional weather and economic variables), using a type of econometric time series model specification which I describe in greater detail below. I created a model estimation for every firm sales service schedule in the Residential and Commercial customer classes (including a model for each of the two Residential customer class Decoupling Mechanism baselines: Premises connected prior to January 1, 2018 and premises connected on and after that

[3] The set point is estimated to be the temperature at which customers begin to use energy for heating purposes. To obtain the best linear relationship for statistical purposes in relating usage to temperature, using the set point that provides the best fit as to when heating begins is important. The Company used the 59-degree Fahrenheit base for Residential schedules and 58-degree Fahrenheit base for Commercial schedules as our temperature set points for HDDs because these values produce the best linear relationship between therm load and HDDs within our service territory (i.e., these set points achieve the strongest linear function at approximately the point where there is a heating load response to average ambient outside temperature). We use the set points to linearize the relationship so that we can use simplified time series model specification to derive weather normalized load by month and rate schedule.

date). For each model, I tested four categories of coefficients that explain usage per customer per day as a function of: (1) weather, including heating usage per HDD per day; (2) base usage by month; (3) non-weather factors that account for the shift in energy usage patterns after the COVID-19 pandemic as well as energy efficiency from ongoing demand side management and macroeconomic indicators such as industrial production and gross domestic product; and (4) temporal effects on usage from prior periods.

- Developed normal daily HDDs using daily HDD values derived from the benchmark 25-year weather data set.
- Used the econometrically estimated coefficients to build the weather normalized UPC Forecast on a daily basis using the 25-year HDD benchmark.

Q. Please describe the specification for the statistical forecast model.

A. I used an Autoregressive Integrated Moving Average ("ARIMA") time series model to estimate weather normalized load per customer per day as the weighted function of the number of days, customers, and HDDs associated with each billing cycle in the model period. An ARIMA model is a type of time series model specification for data observations that occur across equal intervals of time. The model is used to help forecast future values in the series by each value against a chosen number of lagged values (the autoregressive term); lags of moving averages may be chosen as well. ARIMA models are denoted as ARIMA(p,d,q) where p is the number of time lags in the autoregressive term; d indicates the number of times the independent variables are differenced; and q is the number of lags of moving averages. Together, these terms help fit the time series model by accounting for different temporal effects on usage that are associated with prior periods.

Q. Has the Company used the ARIMA model specification for its weather normalized load forecast in prior rate case filings?

A. Yes. I have used an ARIMA time series model to calculate the UPC Forecast for the Company's prior three Oregon general rate cases, UG 388, UG 435, and UG 490. In each proceeding, Staff supported the use of an ARIMA model specification for short-term normalized load forecasting purposes, noting that "ARIMA models are used by all Oregon regulated utilities and remain the standard approach."[4] Further, in its UG 435 Opening Testimony, Staff found "the Company's forecast methodology and revised data inputs to be accurate and the forecast to be reasonable."[5] Finally, in its UG 490 Opening Testimony, Staff noted that it "has no major concerns with [NW Natural's] overall load forecast methodology. In general, [NW Natural] uses industry standard methodologies and is receptive to feedback regarding model improvements."[6]

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[4] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Ryan Bain, Staff/400 at 4, lines 4-16 (Apr. 22, 2022).

[5] *Id.* at 9, lines 3-5.

[6] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 2, lines 19-20, and at 3, lines 1-2 (Apr. 18, 2024).

Q. Do you agree with Staff that the Company is receptive to feedback regarding UPC Forecast model improvements?

A. Yes. For UG 490, I implemented recommendations from the Oregon Citizens' Utility Board ("CUB") and Staff that they introduced in UG 435 testimony. CUB and Staff recommended employing more weather data beyond HDDs such as wind chill and solar radiation as a proxy for observed weather, including HDDs in multiple explanatory variables, controlling for days of the week, and continuing to examine how structural economic and social impacts related to the COVID-19 global pandemic (such as the continued prevalence of remote work) affects the UPC Forecast.[7] In UG 490, I tested and then implemented each recommendation that I concluded increased model estimation efficacy.

Q. In NW Natural's most recent rate case (UG 490), did the Commission Staff recommend modifications to the UPC Forecast model specification?

A. Yes. Staff made the following recommended changes to the Company's UPC Forecast methodology with the goal of "improving transparency and model flexibility" in future model iterations:

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;

[7] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Direct Testimony of Robert J. Wyman, NW Natural/1800 at 11-13 (Dec. 29, 2023).

3. Use monthly dummies as opposed to the natural logarithm of the number of weekend and holiday days in each month; and
4. Drop variables with very small effects.[8]

Further, Staff recommended a unique set of model specification changes for each rate class in the UPC Forecast.[9] Staff did not, however, propose a revenue requirement adjustment in UG 490, indicating that any adjustment in that case would not be significant.[10]

Q. Did other intervenors to UG 490 recommend modifications to the UPC Forecast model specification?

A. No. The other intervenors did not provide recommendations with regards to the UPC Forecast.

Q. In UG 490, how did Staff implement its recommended methodological changes to the UPC Forecast?

A. Staff used a process called the Hyndman-Khandakar algorithm to automatically select an ARIMA(*p*,*d*,*q*) model parameterization for each rate class. This process, in Staff's view, produced satisfactory results for RS 2 Residential, RS 27 Dry-Out, and RS 31 Commercial Sales Firm. Where the algorithm performed poorly in parameterizing the overall Commercial class, RS 3 Commercial, and RS 32 Commercial Sales Firm, by forecasting summer load higher than historical

[8] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 3 (Apr. 18, 2024).

[9] *Id.,* at 3.

[10] *Id.,* at 3.

consumption norms, Staff overrode the model and selected the parameterization. Staff's manual parameterization introduced multiplicative seasonal components to the ARIMA model in the form of ARIMA(*p*,*d*,*q*)*(*P*,*D*,*Q*)*s* where *s* indicates the number of lagged multiplicative seasonal autoregressive *P* and moving average *Q* terms, seasonally differenced *D* times. Staff indicated that where applied, the seasonal differencing parameters account for the seasonal variation in rate class usage instead of the monthly indicator variables which it recommends be removed from the model specification.

Staff recommended modifications to the model specifications that include, depending on the rate class: Changes to (or exclusion of) the monthly indicator variables, addition of a squared HDD term to control for the non-linear effects of weather, and exclusion of various explanatory variables (notably: weather terms) that Staff found did not produce meaningful coefficients.[11]

Q. How did the Company respond to Staff's recommendations in UG 490?

A. In UG 490, I was unable to fully reproduce the results of Staff's forecast results and was therefore unable to test the results for forecast performance and fit using my own testing procedures. A driver of the lack of replicability was the fact that Staff and the Company used two different software systems: Staff produced its regression results using *R*, an open-source statistical computing software, while the Company used a statistical software package called Stata.

[11] *Id.*, at 4-19.

I agreed with Staff's characterization that the Company is receptive to feedback regarding model improvements and that nearly all econometric models have room for improvement. I noted that model replicability and simplicity are important so that results and test statistics can be calculated across software platforms, and so that others can independently verify the results. Finally, I proposed to further examine Staff's recommendations prior to the Company's next general rate case filing at which time I would address whether I had implemented (or explain my reasoning for not implementing) each recommendation.[12]

Q. Did the Company examine Staff's recommendations for this general rate case filing?

A. Yes. I examined all of Staff's recommendations from UG 490 and implemented them for this UPC Forecast as I describe further below. With additional time to fully understand the effects of Staff's recommendations and test model forecasting performance and fit, I conclude that many of Staff's recommendations improve the UPC Forecast models. These recommendations, which produce marginally better test statistics, drive negligible differences in the UPC Forecast results for the Residential rate class. The recommendations produce more substantive (and higher) UPC Forecast results for the Commercial rate class compared to methodologies I employed in prior proceedings. For this proceeding, I evaluated Staff's recommendations based on ease of replicability, as well as performance

[12] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Reply Testimony of Robert J. Wyman, NW Natural/3900, at 9-10 (Jun. 4, 2024).

against out-of-sample backcast testing conducted across varying historical data vintages, and comparison of mean absolute percentage error across forecasted model results. Further, I examined model residuals based on density around a normal distribution as presented by Staff in UG 490 in addition to other metrics that I have employed in prior rate proceedings such as the Durbin-Watson test statistic.

Q. Did the Company apply Staff's recommendations to the ARIMA model specification and indicator variable selection process in this case?

A. Yes. As I noted above, I have implemented many of Staff's recommended modifications to the ARIMA model specification and indicator variable selection process for this proceeding. In summary, I:

1. Used a Stata module called "arimaauto" to recommend an algorithmically parameterized ARIMA model for each rate schedule in the UPC Forecast. This command uses a Stata-adjusted Hyndman-Khandakar algorithm. I used the output of arimaauto as baseline model specification and note deviations later in this testimony.
2. Included non-linear weather terms, such as a squared HDD term as suggested by Staff.
3. Reverted to monthly indicator (dummy) variables with no interaction with number of weekend and holiday days in each month.
4. Dropped variables (mostly weather-related) with very small effects.

Below, I describe in greater detail my selection process for each firm sales service rate schedule in the UPC Forecast. I address whether I have implemented (or explain my reasoning for not implementing) Staff's recommendations for each of these rate schedules.

Q. Please describe the changes in the UPC Forecast methodology from NW Natural's latest rate case, UG 490.

A. I used consistent data collection, actual weather, load data alignment, and weighting methods to prepare the UPC Forecast. Similarly, I used an ARIMA time series model specification to produce the final UPC Forecast regression coefficients. Other than applying many of Staff's recommendations to the model specification process, I did not substantially change the UPC Forecast methodology. For the Commercial rate schedules, however, I now employ a macroeconomic variable as well as a "snow factor" (depending on the model), both of which I describe below.

Q. Please describe the weather variables included in the UPC Forecast in this case.

A. Consistent with UG 490, I evaluated the forecasting effectiveness of including weather variables that are in addition to the standard HDDs that I have included in all past iterations of the forecast, including: effective temperature, precipitation, solar radiation, and wind speed and wind chill explanatory variables. The data used to create these variables are sourced from a third-party and are employed in the Company's Integrated Resource Plan ("IRP") long-term resource planning forecast models.[13] The use of multiple variables that measure HDDs "can capture the dynamic nature of heat loss."[14] Using day-before HDDs, for instance, can help model how heat loss in a building from one cold weather day prior can impact natural gas consumption the following day. I have found that including such observations can make small improvements to the model forecast.

The effective temperature is an equal weighted measure of the prior day and current day temperature, converted into HDDs, which works to control for heat loss that may occur on a specific calendar day because of weather observed the prior day. The wind chill value is calculated based on a relationship between wind speed and the difference between a temperature set point and observed temperature for that day.[15] The set point in this case is the temperature cut-off where any value higher produces no wind chill effect (e.g., the temperature point at which combined wind speed and temperature does not create wind chill impacts). This set point was determined in the cited study to be 14 degrees Celsius, or about 57.2 degrees Fahrenheit.[16]

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[13] See, for instance, discussion of daily demand drivers in the NW Natural 2022 Integrated Resource Plan, Docket No. LC 79, at pages 97-100. The Company sources hourly weather data for various airports throughout its service territory to be used in its IRP models from an IBM business partner called DAI Source.

[14] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Sudeshna Pal, CUB/300 at 6, lines 11-14, and at 7, lines 1-7 (Apr. 22, 2022).

[15] Yabsley, Warren and Shirley Coleman. *Using Data Analytics for Business Decisions in the UK Energy Sector – a Case Study Integrating Gas Demand with Weather Data.* International Journal of Oil, Gas and Coal Technology. May 2, 2019. Vol. 21, No. 1, pages 109-129.

[16] *Id.*

Using the effective temperature as well as historical snowfall data from NOAA, I created a "snow factor" variable for modeling the Commercial rate class schedules in this proceeding. I calculated the factor by multiplying the effective temperature by a binary indicator of whether snow was present on a given day or not so that the combination of colder weather in addition to the presence of snow is weighted heavier compared to warmer weather that precedes snow melt. I found that this factor did not improve the forecasting ability of the Residential rate class model, but it did so for the Commercial rate class schedules, therefore I only included it in the models for the Commercial rate class schedules.

I found that a modeling approach where a "composite weather variable" is created by using a formula to combine multiple weather variables into one variable did not improve model efficacy relative to other model specifications I tested. Using the weather variables noted above as standalone variables while including interaction effects, as I describe below, is consistent with the Company's IRP resource planning forecast methodology.

Q. Please describe how HDDs are included in multiple explanatory variables within the UPC Forecast using interaction effects.

A. The UPC Forecast includes explanatory variables that have interactive effects between the additional weather variables and effective temperature HDDs, in addition to the standard HDD variable employed in model iterations prior to UG 490. Variables with interactive effects recognize that demand can be different on a cold rainy day relative to a warmer rainy day, or that wind chill has a larger impact on demand as temperatures decrease. Using the effective temperature, as noted above, helps to control for temperature observed in the prior day and can help explain how, for instance, a cold rainy day yesterday could result in heat loss that impacts how long it will take a furnace to reach desired temperature on the thermostat today.

Q. Please describe how the UPC Forecast controls for monthly fixed effects and weekend days.

A. In model iterations prior to UG 490, I used a simple indicator variable for each month to control for differences in base load demand throughout the year. For UG 490, I included monthly indicator variables that are the natural log of the number of weekend and holiday days in each month, while dropping the constant term. The natural log transformation of the monthly indicator variable presents as a demand elasticity, rather than a linear, relationship to measure impact of non-standard working days on base load demand. For this proceeding, I have reverted to the prior methodology per Staff's recommendation, which suggested using monthly fixed effects to control for seasonality for the Residential rate class[17] while including one variable for number of weekend days per month to model how base load consumption patterns vary by month based on number of non-standard working days, especially as it relates to residential demand (e.g., number of days in a given month more likely to be spent at home using natural gas for non-heating related uses such as cooking and heating water for showers and laundry). For the Commercial rate class, I removed the monthly fixed effects from the model and

[17] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 4 (Apr. 18, 2024).

instead used the ARIMA(*p,d,q*)*(*P,D,Q*)*s* multiplicative seasonal model specification as recommended by Staff to account for seasonal variation in usage, but did use the weekend days variable to control for days that, depending on the business sector, commercial customers could be closed or operating for fewer hours.

Q. Please explain how the Company treats the constant term in its UPC Forecast.

A. For the Residential rate class, I chose to drop the constant term so that the UPC Forecast model produces one base load coefficient associated with each of the 12 months of the year, which is consistent with prior rate proceedings. This makes building the weather normalized UPC values on a daily and monthly basis straightforward, because each model coefficient can be matched to a specific period of time within the year. Alternatively, if I were to retain the constant term, I would have to choose one or more months to drop, in which case the constant term coefficient would instead take on the base load attributes of the dropped variable(s). For the Commercial rate class, I retained the constant term because the ARIMA(*p,d,q*)*(*P,D,Q*)*s* multiplicative seasonal model specification accounts for the seasonality leaving the constant term to pick up the base load attributes.

Q. Please describe how the UPC Forecast estimates demand-side management ("DSM") savings.

A. Consistent with UG 490 methodology, for this UPC Forecast I have created a DSM variable and use the forecasting power of the ARIMA model specification to control for DSM savings in the Test Year rather than use a post-estimation adjustment based on anticipated programmatic savings. I used historical savings based on energy efficiency measures deployed since 2012, broken down by heating and non-heating related savings based on savings measure type, as reported by the Energy Trust of Oregon. I then converted these savings into a savings per premise per day explanatory variable to appropriately align with the dependent variable – demand per premise per day. While the model may not anticipate all programmatic savings, it now uses historical actual savings to inform short-term forecasted savings without having to rely on post-estimation demand adjustments.

Q. Please describe how the UPC Forecast estimates macroeconomic effects.

A. I have included, consistent with UG 490, an indicator variable that controls for behavioral changes that impact natural gas demand since the COVID-19 pandemic statewide stay-at-home order was issued for Oregon in March 2020. This variable is meant to capture longer-term post-pandemic changes to consumption patterns, especially patterns that influence residential and commercial demand such as higher rates of working from home. Additionally, for the Commercial rate classes, I have added a variable from the Oregon Office of Economic Analysis that indexes United States industrial production as a proxy measure of the year-over-year performance of the macro economy.

Q. Please describe the Company's ARIMA model specification selection process.

A. Per Staff's recommendation, I used the Stata arimaauto module to auto-parameterize, in ARIMA(p,d,q) or ARIMA(p,d,q)*(P,D,Q)s terms, every rate schedule modeled for the UPC Forecast. I did not, however, select the arimaauto model parameters for all schedules but rather used the module as a starting point for model specification evaluation. I compared the auto-parameterized models against models with slightly different terms, relying foremost on Durbin-Watson test statistics, r-squared values, and root mean squared error results to assess model efficacy and choose appropriate ARIMA *p* and *q* terms.[18] I relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load forecast data variables with the ARIMA *d* term to ensure model stationarity. Further, I plotted model residuals to check for non-uniformity. I consulted the Akaike Information Criterion ("AIC") and the Bayesian Information Criterion ("BIC") metrics to evaluate the performance of models under varying *p* and *q* term specifications against one another.[19] Finally, I performed "backcast" tests as I describe below, to assess the forecasting abilities of the auto-parameterized models against non-auto-parameterized models.

Q. Please describe the issue of non-stationarity and how it could impact the UPC Forecast model.

A. Non-stationarity in the UPC Forecast model variables can occur when their statistical properties vary over time. A utility's customer count is an example, for instance, because it generally increases over time but not at a constant rate. New customers spurred by housing construction are more likely to start service in

[18] The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. A value of 2 indicates no autocorrelation. A value less than 2 indicates positive autocorrelation, and a value greater than 2 indicates negative autocorrelation.

[19] When comparing models with the same variables but different *p* or *q* terms, in general the model with the lower AIC and BIC metric is preferable.

summer months than winter months. As such, the UPC Forecast model could contain non-stationary inputs which is why using the Augmented Dickey-Fuller test is helpful for determining whether the *d* differencing term is necessary.

Q. Please summarize the explanatory variable selection process.

A. I also relied on Durbin-Watson test statistics, r-squared values, and mean squared errors, as well as AIC/BIC metrics, to assess the choice of observed weather variables, monthly indicator variables, weekend days variable, weather-temperature interaction term variables, and COVID-19, macroeconomic, and DSM variables to optimize model estimation.

Q. Did the Company perform a "backcast" test to assist in the model optimization process?

A. Yes. A backcast test evaluates how well a model can estimate actual known out-of-sample values using historical (actual) data. I performed an analysis using three backcast tests of varying data vintages to compare model forecast performance against actual load data, for both residential and commercial rate schedules. Models are evaluated against each other by calculating and comparing mean absolute percent error ("MAPE") value to test model accuracy and performance. I selected the model specifications with the lowest MAPE for the UPC Forecast.

Q. Does the ARIMA model perform better at weather normalizing load compared to other types of models?

A. Yes. I found that the ARIMA model outperforms both simple linear regression and vector autoregressive models when compared against the model test statistics and metrics as well as backcast tests as discussed above.

Q. How are the results of the ARIMA model interpreted and evaluated?

A. The final output of the ARIMA models is an estimation of weather normalized use per customer per day for each evaluated rate schedule (the dependent variable). The monthly indicator variables (or, in the absence of these variables, the constant term) represent customer baseload demand. The customer heat load use coefficient is expressed as incremental demand per HDD per customer. The additional weather variables and interaction terms are similarly expressed as incremental demand per unit (e.g., inch of precipitation, degree of wind chill or effective temperature HDD) per customer. The macroeconomic and DSM variables represent structural customer baseload demand that cannot be accounted for based on weather or time of year. After running the ARIMA models to produce these coefficients, I used statistical software to evaluate the model estimation output against the 25-year daily normal HDD values to derive a normalized use per customer per day by month.[20] The additional weather variables were also evaluated against historical daily normal values. The model output incorporated the effects of the ARIMA autoregressive and moving average terms on base and heat load use into the use per customer estimation. I repeated this process for every firm sales rate schedule in the Residential and Commercial customer classes.

[20] I used the Stata statistical software package and developed use per customer estimations based on model results using the "predict" command after running the ARIMA model.

Q. Please describe the model specification for each firm sales rate schedule modeled in the UPC Forecast.

A. Below, I describe the model specification for each rate schedule in the UPC Forecast and address whether I have implemented (or explain my reasoning for not implementing) each of Staff's recommendations.

1. RS 2 Residential Sales Service

For the class-wide RS 2 Residential model, I implemented Staff's recommendations to include monthly fixed effects to control for seasonality and a squared HDD term to control for non-linear effects of weather and exclude weather terms that did not produce meaningful coefficients.[21] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0) or a one order differenced specification of ARIMA(2,1,2)(0,0,0)$_{[2]}$. Staff, in UG 490, recommended an ARIMA(1,1,1) specification.[22] I found, however, that a specification of ARIMA(2,0,2)(0,0,0)$_{[2]}$ produces optimal test statistics and better backcast predictive fit compared to these other specifications.[23] The model is as follows, where *m* is month and *y* is year:

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[21] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 4 (Apr. 18, 2024).

[22] *Id.,* at 4.

[23] I use the word "optimal" here and elsewhere in this testimony instead of adjectives such as "larger" or "smaller" because not every test statistic is evaluated based on magnitude. The Durbin-Watson test statistic for autocorrelation, for instance, takes a value from 0 to 4. The optimal value, which indicates no autocorrelation, is 2.

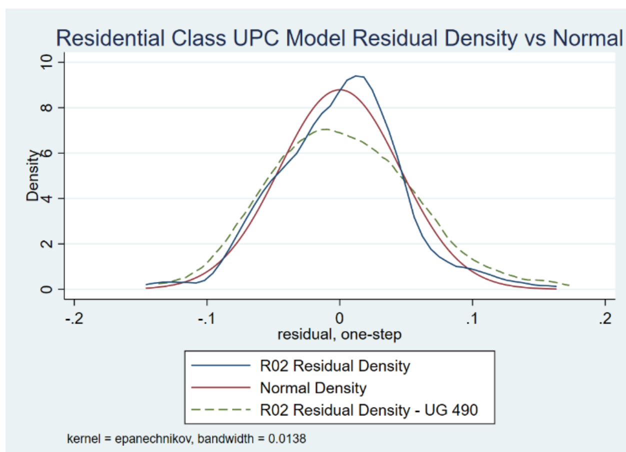
$$\frac{R2\ UPC}{Day}m,y = \beta_1\frac{R2\ HDD}{Day} + \beta_2\left(\frac{R2\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day} + \beta_5 Jan_{=1} \ldots$$

$$+ \beta_{16}Dec_{=1} + \beta_{17}SinceCovidMnths_{=1} + \beta_{18}\frac{ResidentialDSM}{Day} + \beta_{19}WeekendDays$$

$$+ ARIMA(2{,}0{,}2)(0{,}0{,}0)_{[2]}$$

This model produces a normalized UPC value of 650.7 therms annually. The model produces a UPC about one percent lower compared to the model specification used in UG 490. Figure 1 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 490. As Figure 1 indicates, this class-wide model has residuals that more closely align with a normal distribution compared to the UG 490 model.

Figure 1



2. RS 3 Basic Firm Sales Non-Residential Service - Commercial

I implemented Staff's recommendations for the RS 3 Basic Firm Sales Non-Residential Service – Commercial ("RS 3 General Commercial") model specification to remove the monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that did not produce meaningful coefficients.[24] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,1,2)(0,0,0)$_{[2]}$ or a one order differenced specification of ARIMA(1,1,0). Staff, in UG 490, recommended an ARIMA(0,1,1)(1,2,1)$_{[12]}$ specification.[25] I found, for this proceeding, that a slightly different specification with the same order of multiplicative seasonal ARIMA periods of ARIMA(2,0,2)(2,1,2)$_{[12]}$ produces optimal test statistics and better backcast predictive fit compared to these other specifications. The model is as follows:

$$\frac{C3\ UPC}{Day}m,y = \beta_1\frac{C3\ HDD}{Day} + \beta_2\left(\frac{C3\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day}$$

$$+ \beta_5 SinceCovidMnths_{=1} + \beta_6\frac{SnowFactor}{Day} + ARIMA(2,0,2)(2,1,2)_{[12]}$$

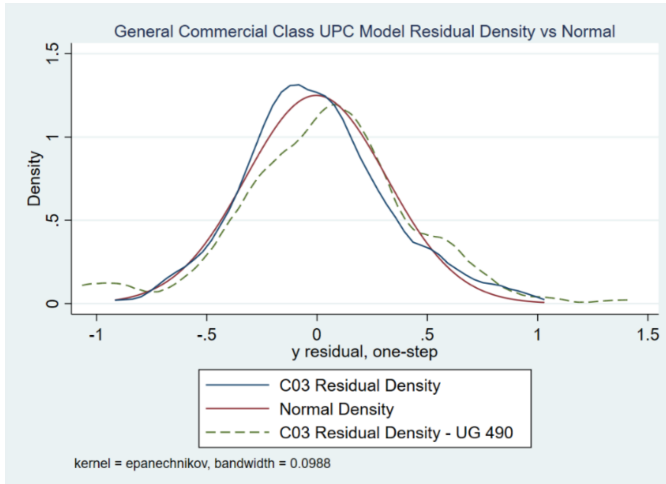
This model produces a normalized UPC value of 3,290.2 therms annually. The model produces a UPC about 11 percent higher compared to the UG 490 model, which is attributable to both estimated increases in actual per customer demand as well as to the new model specification (an observation Staff noted in UG 490).[26] Figure 2 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 490. As Figure 2 indicates, this model has residuals that more closely align with a normal distribution compared to the UG 490 model.

[24] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 9 (Apr. 18, 2024).

[25] *Id.,* at 9.

[26] *Id.,* at 11. Staff observed: “Staff’s forecast slightly increases the Test Year load forecast for commercial customers, primarily through a higher forecasted peak consumption in winter months.”

Figure 2



3. RS 27 Residential Heating Dry-Out Service

I implemented Staff's recommendations for the RS 27 Residential Heating Dry-Out Service ("RS 27 Dry-Out") model specification to include monthly fixed effects and exclude weather terms "with a negligible effect on the model."[27] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)[2] or a one order differenced specification of ARIMA(1,1,0). Staff, in UG 490, recommended an ARIMA(1,0,0) specification.[28] I found, for this proceeding, that Staff's recommended model specification produces optimal test statistics and better backcast predictive fit compared to these other specifications. The model is as follows:

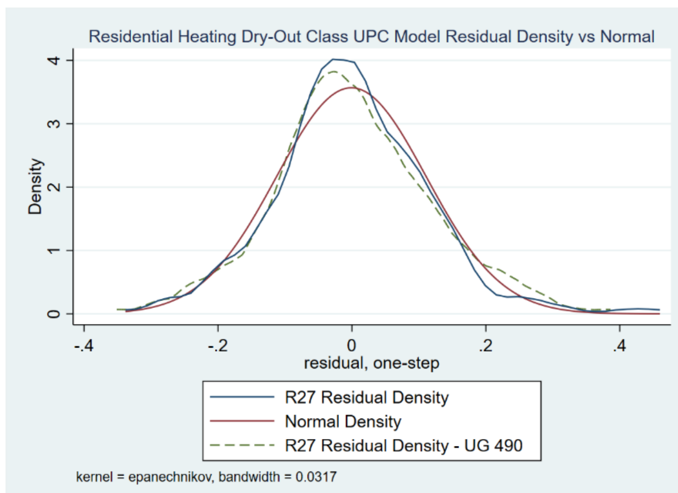
$$\frac{R27\ UPC}{Day}m,y = \beta_1\frac{R27\ HDD}{Day} + \beta_2\frac{Precipitation}{Day} + \beta_3 Jan_{=1} + \beta_4 Feb_{=1} + \beta_5 Mar_{=1} + \beta_6 Apr_{=1} + \beta_7 May_{=1} + \beta_8 Jun_{=1}$$
$$+ \beta_9 SummerMnths_{=1} + \beta_{10} Oct_{=1} + \beta_{11} Nov_{=1} + \beta_{12} Dec_{=1} + ARIMA(1,0,0)$$

[27] *Id.*, at 12.

[28] *Id.*, at 11.

This model produces a normalized UPC value of 532.4 therms annually, which is just under seven percent lower than the UPC value estimated for UG 490. Figure 3 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 490. As Figure 3 indicates, this model produces residuals similar to that of the UG 490 model but are slightly higher compared to a normal distribution. Results of the backcast test, as measured by the MAPE, however, suggest that this model is an improvement over the UG 490 model.

Figure 3



4. RS 31 Non-Residential Firm Sales Service - Commercial

Staff recommended a model specification for RS 31 Non-Residential Firm Sales Service – Commercial (“RS 31 Commercial Firm Sales”) load forecast that is the same as RS 27 Dry-Out.[29] I find, however, that a model specification that

[29] *Id.*, at 14.

implements the "substantive changes"[30] Staff recommended for RS 32 Large Volume Non-Residential Firm Sales Service – Commercial ("RS 32 Large Volume Commercial Firm Sales") produces more optimal test statistics and better backcast predictive fit. Therefore, for this proceeding, I implemented a model that is close to that which Staff recommended for UG 490 for RS 32 Large Volume Commercial Firm Sales. I include no monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that did not produce meaningful coefficients. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)$_{[2]}$ or a one order differenced specification of ARIMA(2,1,2)(0,0,0)$_{[2]}$. Staff, in UG 490, recommended an ARIMA(1,0,0) specification.[31] For this proceeding, I chose a model specification of ARIMA(1,0,1)(1,1,1)$_{[12]}$, which is similar to the specification Staff recommended for RS 32 Large Volume Commercial Firm Sales in UG 490. The model is as follows:

$$\frac{C31\,UPC}{Day}m,y = \beta_1\frac{C31\,HDD}{Day} + \beta_2\left(\frac{C31\,HDD}{Day}\right)^2 + \beta_3\frac{SolarRadiation}{Day} + \beta_4\frac{SolarRadiation * EffectiveTemp}{Day}$$
$$+ \beta_5 SinceCovidMnths_{=1} + \beta_6 WeekendDays_{=1} + \beta_7 IndustrialProductionIndex$$
$$+ ARIMA(1,0,1)(1,1,1)_{[12]}$$

This model produces a normalized UPC value of 36,186.7 therms annually, which is just over four percent higher than the UPC value estimated for UG 490. Figure 4 below indicates the residual errors density compared to both a normal

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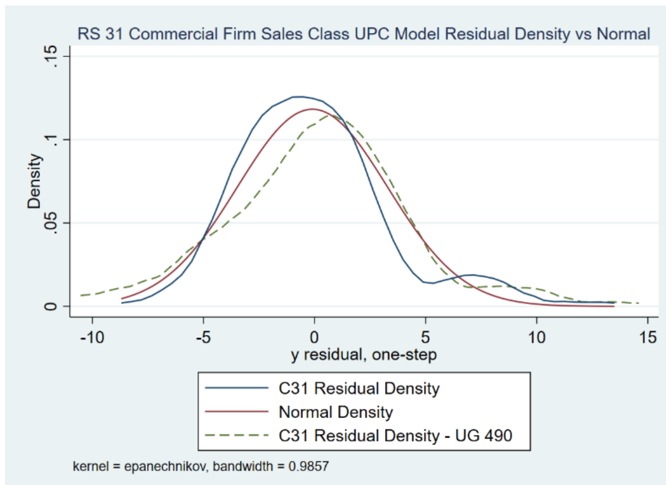
[30] *Id.,* at 16.

[31] *Id.,* at 14.

distribution as well as the model specification from UG 490. As Figure 4 indicates, this model produces residuals similar to that of the UG 490 model but are slightly higher compared to a normal distribution. Results of the backcast test, as measured by the MAPE to test for predictive fit, however, suggest that this model is an improvement over the UG 490 model.

Figure 4



5. RS 32 Large Volume Non-Residential Firm Sales Service - Commercial

As noted above, Staff recommended "substantive changes" to the RS 32 Large Volume Commercial Firm Sales load forecast.[32] For this proceeding, I implemented a model that is close to that which Staff recommended for UG 490. Per Staff's recommendations, I include no monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that did not produce meaningful coefficients. The arimaauto auto-parameterization module suggested

[32] *Id.*, at 16.

a non-differenced specification of ARIMA(1,0,0) or a one order differenced specification of ARIMA(1,1,0). Staff recommended an $ARIMA(1,0,0)(1,2,1)_{[12]}$ specification.[33] I found, for this proceeding, that a model specification that is close to Staff's recommendation from UG 490 produces optimal test statistics and better backcast predictive fit compared to these other specifications. This model specification is $ARIMA(1,0,1)(1,1,1)_{[12]}$ and is the same specification I used for RS 31 Commercial Firm Sales. The model is as follows:

$$\frac{C32\ UPC}{Day}m,y = \beta_1\frac{C32\ HDD}{Day} + \beta_2\left(\frac{C32\ HDD}{Day}\right)^2 + \beta_3\frac{SolarRadiation}{Day} + \beta_4\frac{SolarRadiation * EffectiveTemp}{Day}$$
$$+\ \beta_5 SinceCovidMnths_{=1} + \beta_6 WeekendDays_{=1} + \beta_7 IndustrialProductionIndex$$
$$+\ ARIMA(1,0,1)(1,1,1)_{[12]}$$

This model produces a normalized UPC value of 92,474.1 therms annually, which is just over four percent higher than the UPC value estimated for UG 490. Figure 5 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 490. As Figure 5 indicates, this model produces residuals that much more closely align to a normal distribution compared to the UG 490 model.

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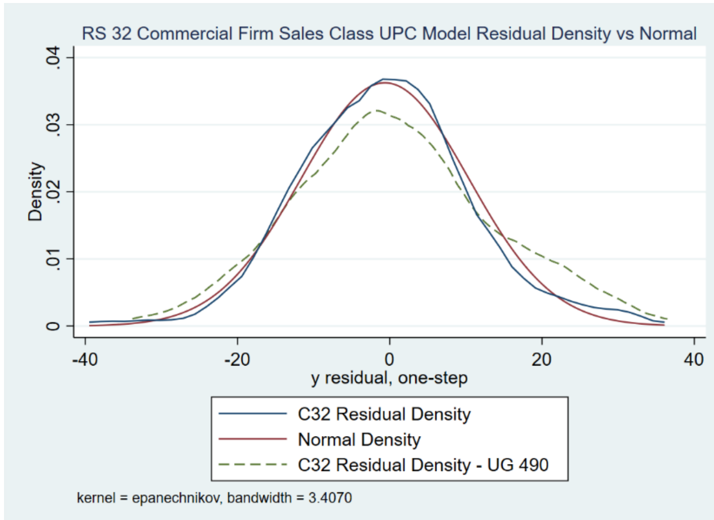
[33] *Id.*, at 16.

Figure 5



Q. Have you calculated UPCs for the subset of residential premises taking service on RS 2 Residential that represent existing service connections ("Existing Premises UPC") and new service connections ("New Premises UPC") for purposes of creating a bifurcated baseline for the Company's Decoupling mechanism?

A. Yes. Per UG 490 Order No. 24-359, the Commission directed the Company to bifurcate its decoupling revenue calculation based on whether each premises that is taking service on RS 2 Residential was connected to the Company's system on or after January 1, 2018.[34] Therefore, for this proceeding I have calculated two additional UPCs for customers taking service on RS 2 Residential: (1) Existing Premises UPC for customers residing in premises connected before January 1, 2018; and (2) New Premises UPC for customers residing in premises connected

[34] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 19 (Oct. 25, 2024).

on or after January 1, 2018. For premises connected before January 1, 2018, I use the same model specification as the residential class-wide model I presented above. This produces an Existing Premises UPC of 664.9 therms annually. For premises connected after January 1, 2018, I use the same model specification except with an ARIMA specification of ARIMA(1,0,0) which introduces fewer autoregressive and no moving average lags to the shorter analysis period. This model produces a New Premises UPC of 450.9 therms annually. These two weather normalized UPCs are used to set the Company's bifurcated Decoupling mechanism baselines.

Q. Please describe the Existing Premises UPC and New Premises UPC data collection and parameters.

A. I queried the Company's Customer Information System ("CIS") for all bills generated for Oregon residential premises that had a service connection initiated both before and on or after January 1, 2018. In developing the Company's Decoupling mechanism bifurcation proposal for UG 490, I found that in general there is a about a four-month delay between when a service is initialized and when the bills show therm load. Therefore, I did not include load data for the period January 2018 through April 2018 for estimating the New Premises UPC.

Q. Why is there generally a delay between service initialization at new premises and observable therm load?

A. The initialization of service may not coincide with the installation of all appliances, and there may be a gap between when the premise is completed, is placed on the market and sold, and when a new household fully moves in; due to these reasons, there could be multiple billing periods between when a service is initialized and when it begins to produce data adequate for establishing a normalized annual use. For some new construction premises, a developer may opt for dry-out service and therefore the premise will be on RS 27 Dry-Out for several months prior to it being ready for habitation, at which point it is placed on RS 2 Residential service. Due to this gap between service initialization and full habitation, I did not include load data for the first four months after January 1, 2018 in my New Premises UPC analysis.

Q. Please summarize the results of the UPC Forecast.

A. I agree with Staff that the model changes for each individual rate schedule, as described above, "help the model be more flexible and help improve interpretability."[35] Implementing Staff's recommendations fully or partially, depending on the rate schedule, resulted in improved test statistics and measures of backcast predictive fit. The chosen ARIMA model specifications produce a weather normalized Test Year UPC Forecast of 650.7 therms annually for the Residential class (with bifurcated results of 664.9 and 450.9 therms annually for Existing and New Premises, respectively), and 4,310.3 therms annually for the Commercial Firm Sales class. I appreciate Staff's continued work with the Company to explore methods for improving the UPC Forecast model predictive capabilities and interpretability.

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[35] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 9 and 15 (Apr. 18, 2024).

Q. How are the customer forecast and UPC Forecast used to create Test Year volumes that generate revenues at existing rates for the proposed revenue requirement?

A. The Company calculates Residential and Commercial Firm Sales class Test Year monthly volumes by multiplying the weather normalized forecasted UPCs for each residential and commercial firm sales rate schedule by the forecasted monthly end-of-period customer counts.

Q. How are Test Year volumes built for the Industrial Sales as well as the Commercial and Industrial Transportation classes?

A. Test Year volumes for the Industrial Sales as well as the Commercial and Industrial Transportation classes are developed using a customer-specific methodology ("Industrial Forecast"). This customer-specific Industrial Forecast begins with a recent 12-month period of actual usage and customers and is then adjusted by the Company's large customer and major accounts subject matter experts for changes in projected load usage, and customer additions, losses, and rate schedule changes that arise from the service election period.

Q. Where are the Test Year volumes used to build the revenues for the revenue requirement presented?

A. The derivation of Test Year revenues from the customer and volume forecasts is presented in detail by customer class as NW Natural/1503, Walker and is shown in summary at NW Natural/1501, Walker.

Q. What are the Company's other uses for the UPC Forecast?

A. The Company uses the UPC Forecast to develop the design day load factor for the LRIC study, as discussed below. The UPC Forecast is also used to estimate throughput volumes for the annual purchased gas adjustment ("PGA"). The methodology for calculating the UPC Forecast is consistent between the PGAs and rate case filings. Certain inputs and outputs of the UPC Forecast are also used for calculating the WARM and Decoupling rate mechanism adjustments, as described in Mr. Walker's testimony NW Natural/1500, Walker.

Q. What are the statistical coefficient outputs produced by the UPC Forecast for WARM and Decoupling rate mechanism adjustments?

A. The formula for producing the statistical coefficient outputs that drive the WARM billing adjustment ("WARM Adjustment Factor") is described in the Company's Schedule 195 tariff. I produced the statistical coefficient outputs using the ARIMA model specification developed for the UPC Forecast, but with one weather variable to estimate HDD effects on heating load per the WARM Adjustment Factor formula presented in Schedule 195.[36] The statistical usage coefficients to be used in the calculation of the WARM Adjustment Factor, defined in Schedule 195 as β, are 0.15107 for RS 2 Residential and 0.68985 for RS 3 General Commercial. These statistical usage coefficients, along with that of RS 31 Commercial Firm Sales, 7.41605, are also used to calculate the variance between weather normalized

[36] NW Natural's Oregon Tariff, Sheet 195-3, Schedule 195 Weather Adjusted Rate Mechanism (WARM Program) (continued).

usage and actual usage for the Company's Decoupling mechanism, as described in Schedule 190.[37]

Q. Have you submitted work papers based on this section of your testimony?

A. Yes, I have submitted two work papers. The first is the normal weather model that derives the 25-year historical benchmark for normal weather. The second is the ARIMA analysis that derives the weather normalized UPC Forecast.

III. LONG-RUN INCREMENTAL COST (LRIC) STUDY

A. Long-Run Incremental Cost Study Purpose, Principles, and Inputs

Q. What purpose does a cost of service study serve?

A. The overall objective of a cost of service study, including an LRIC study, is to apportion the incremental revenue requirement to rate schedules based on each schedule's specific cost to serve (this is true of other types of cost of service studies, such as those based on embedded costs). Whereas an embedded cost study is based on historical test year installed costs (e.g., gross plant and the accumulated depreciation on those capital assets) of assets in-service and expenses (e.g., for operations, maintenance, taxes), a long run cost of service study evaluates the marginal (incremental) costs borne by each rate schedule with the addition of one new customer and how that impacts the on-going provision of utility service.[38] By understanding the long run incremental costs by rate schedule,

[37] NW Natural's Oregon Tariff, Sheet 190-2, Schedule 190 Partial Decoupling Mechanism.

[38] In practice, a cost of service study can and usually does apportion costs using both an embedded and incremental approach, depending on the type of cost. For instance, an incremental cost study may use historical installed costs forecasted to the Test Year as a basis to then allocate those costs to specific schedules based on the incremental costs of an additional customer to that schedule.

the LRIC study methodology is able to apportion a utility's storage, transmission, and distribution costs, as well as operating expenses (i.e., all of the components of revenue requirement) based on cost causation. As a general rule, cost causation is an influential factor in parties' discussions on how to allocate costs to specific rate schedules for rate spread; therefore, it serves the utility well to understand the engineering and economic cost differences between customer classes and/or rate schedules.

Q. Has the Public Utility Commission of Oregon ("Commission") stated its preference for cost of service study methodology?

A. Yes. The Commission, in Order No. 85-832 (docket No. UG 14), directed that an LRIC study is "preferable" to an embedded cost approach because the methodology for developing long-run incremental costs better estimates the point where customers, either individually or as part of a rate class, are paying the costs associated with their service. This point is used as the basis for price setting and the spreading of revenue requirement.

Q. Please describe the economic principles that underlie an LRIC study.

A. Incremental long run cost studies (and cost of service studies in general) allocate costs based on cost causation to identify how the incremental revenue requirement should be allocated to rate schedules in order to move closer to *Pareto*

Optimality.[39] The reasonable allocation of costs is determined by understanding the specific customer characteristics associated with each class and rate schedule in order to equitably allocate costs. Characteristics can include peak day demand and average usage characteristics, service type (firm vs. interruptible, sales vs. transportation), customer service needs, and average mains and service lines costs. A cost of service study works to identify not only how each characteristic of a rate class contributes to overall costs, but how these characteristics contribute to the utility's fixed and variable costs.

Economists have derived the principles of "subsidy-free prices" and "stand-alone costs" ("SAC") as a means for achieving *Pareto Optimality*. Subsidy-free pricing is achieved when the price of a good or service charged to a group of customers exceeds its marginal cost ("MC") but is less than the cost these customers otherwise would have incurred individually (e.g., the SAC). Prices set at a subsidy-free level provide customers economies of scale given that all customers are paying a portion of the fixed system costs where (Price > MC) while achieving equitable cost sharing of common costs. While the sharing of fixed and other common system costs is the most equitable outcome for customers, local distribution companies must be aware that price does not exceed the SAC to serve

[39] *Pareto Optimality* is a state of allocation equilibrium where participants cannot be made collectively or individually better off given a change in cost or price, without also making other participants worse off. Cost of service studies generally measure the relationship between current utility rates and pareto optimal rates, on a rate class or rate schedule basis, as a "parity ratio" where a value of 1.00 indicates customers in that group are paying no more and no less than their full cost to serve. A change to the rate that results in deviation from 1.00 would signal either cost subsidization (greater than 1.00) or cost subsidy (less than 1.00).

customers because customers would in theory be unwilling to take service (and/or move to the next best economic alternative) if prices exceed SAC. Therefore, the level of price is key to ensuring customer equity is achieved between rate classes/schedules with common utility costs fairly identified and allocated.

Q. Please describe the specific purpose of the LRIC study methodology presented in this testimony.

A. The LRIC study methodology presented in this testimony is an economics exercise that evaluates how much of the Company's incremental capital investment and carrying costs, and operations and other expenses required to serve its customers, can be directly and indirectly attributable to each rate schedule. The costs and expenses that form a basis for the LRIC study follow the Company's Test Year for the 12 months ended October 31, 2026.

The LRIC follows three main steps: (1) classification; (2) functionalization; and (3) allocation. Classification splits costs into three characteristics related to their marginal cost characteristic: (a) demand costs are closely related to plant in-service, are generally fixed, but are influenced by design day peak demand and average throughput; (b) energy costs are variable and are directly related to therms consumed; and (c) customer costs can be fixed or variable and related to the number of customers taking service. Functionalization places costs that make up the revenue requirement into categories based on broad utility functions and is based on Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts categorization. Incremental capital costs and O&M expenses are used as a basis for allocating the long run incremental system cost to each rate schedule. The Test Year proposed cost allocation to each schedule is based on this incremental system cost and is further informed by the organization of the proposed Test Year revenue requirement into the following buckets of costs: commodity, meter reading and billing, meters and services, system core, transmission, and gas storage. The process of organizing the revenue requirement into these buckets is called functionalization. Each functionalized cost item is then assigned to each individual rate schedule through allocation factors. Allocation, the final step, can assign cost items through indirect or direct assignment. I describe below how costs that are directly assigned are allocated through special studies to specific rate schedules.

After allocating all revenue requirement cost elements, the LRIC study calculates the relative ratio of revenue to incremental costs for each rate schedule at present rates. This ratio is used to understand cross-subsidies between rate schedules at current rates and can be used by the Company to inform its rate spread and rate design proposals.

Q. What costs does the LRIC study directly assign through special studies?

A. I directly assigned costs for the following items based on studies conducted using Company data such as job orders, engineering and other Geographic Information Systems ("GIS") data, accounting data, and billing and usage data:

- Distribution mains
- Service lines

- Meter sets and regulators
- Certain customer accounts services

Note that for some costs, such as distribution mains, I directly assign only a portion of the total costs; the remainder is assigned using indirect allocators. I describe how these special studies allocate costs in detail below.

Q. Please discuss what is considered incremental and non-incremental for purposes of the LRIC study.

A. The term "incremental" refers to the cost categories that are attributable to the addition of a single new customer. As noted above, the LRIC study cost categories can include both capital investments (e.g., mains) and O&M expenses (e.g., account services). An example of incremental capital cost versus a non-incremental capital cost would be a meter set and regulator versus service center buildings or field technician vehicles. The reason a meter set is an incremental cost is because each customer requires a meter in order to be served. Service center buildings and field vehicles do not fall into the incremental cost category because they serve large areas of service territory and are not a direct function of the number of customers or customer growth. Further, O&M expenses can be incremental and non-incremental. For every new customer, there are incremental costs associated with generating monthly bills and processing payments. Each call center employee serves many customers; however, one incremental customer does not equate to the onboarding of a fraction of a full-time equivalent ("FTE") position. After some amount of incremental customer growth, however, a decision must be made whether to onboard an additional FTE position. The LRIC study does apportion O&M costs on a per customer basis as explained in my testimony below.

Q. Please explain how the LRIC study is presented with this rate case.

A. The full Excel-based LRIC study model is submitted in its entirety as a Standard Data Request (SDR) response and a work paper accompanying this rate case. Each of the special studies is similarly submitted as work papers; the output from each study is summarized in a tab in the LRIC study, with an index identifying the external spreadsheet file(s).

B. NW Natural's LRIC Study Inputs and Methodology

Q. Have you prepared an LRIC study for this proceeding?

A. Yes. NW Natural/1601, Wyman presents the results of NW Natural's LRIC study. The exhibit shows the indicated LRIC study summary results and the LRIC-indicated spread of NW Natural's proposed revenue requirement by rate schedule.

Q. How does your LRIC study methodology differ from the methodology used in the Company's last rate case filing, UG 490?

A. Generally, NW Natural's LRIC study methodology is similar to the methodology used in the Company's last rate case filing, UG 490. There are two notable modifications, both of which are based on AWEC recommendations. I describe these changes in more detail later in this testimony. The modifications update two allocators:

- For the Design Day Peak and Average Allocator labeled *Dist-1*, I now apply an interruptible customer demand discount of fifty percent consistent with the

System Core Mains Allocators *Dist-5* (less than four inches) and *Dist*-6 (greater than or equal to four inches); and

- For the Average Service Line Installed Cost Allocator labeled *Line-1*, I now apply methodology consistently across all rate schedules (and thereby I remove the *Line-2* allocator which had previously directly allocated large customer service line costs to the Large Commercial and Industrial rate classes only).

Q. How is your discussion of the LRIC study methodology organized?

A. The individual LRIC study inputs and methodology discussion sections are organized as follows:

1. Design Day Load Factor
2. Functionalized Incremental Plant Investment Costs
3. Operations and Maintenance (O&M) Expense
4. LRIC Study Insights and Outcomes

1. Design Day Load Factor

Q. What is the design day load factor?

A. The load factor is a ratio measure of each rate schedule's contribution to the design day peak load. For purposes of this LRIC study, I consider design day load on an Oregon basis and attributable to Oregon customers only. While load could potentially peak for other reasons on other systems, load peaks for NW Natural are a matter of space heating requirements and are therefore directly related to weather.

Q. How is the design day load factor value interpreted?

A. The design day load factor is the ratio of normalized average usage to the estimated design day peak usage, expressed as a percentage. A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage (i.e., it indicates the rate schedule has high weather sensitivity as load peaks during cold weather events). A high load factor indicates less weather sensitivity and more predicable base load usage throughout the year. Residential rate schedules, which use gas most significantly for heating purposes, are expected to have lower load factors relative to Industrial rate schedules that are more heavily comprised of processing load customers that use gas for purposes not tied directly to weather, such as the manufacturing of goods.

Q. How does the LRIC study use the design day load factor?

A. The load factor is the basis for the design day (peak) and annual throughput (average) allocator that the LRIC study uses to allocate (in full or in part) distribution mains and assets, system core mains, and transmission main investment to each rate schedule. The "Design Day Peak and Average Allocator" is a weighted ratio of each rate schedule's contribution to the load factor-derived peak day deliveries and average throughput. Rate schedules with lower load factor ratios require more excess system capacity investment to meet design day load relative to higher load factor schedules, assuming equivalent annual load, and are therefore allocated more of these investment costs relative to higher load factor schedules.

Q. How is the design day load factor calculated for this LRIC study?

A. The design day load factor for each rate schedule was estimated using the UPC Forecast for the Residential and Commercial sales customer classes, and the Company's Industrial Forecast for the remaining schedules.

The ARIMA-based UPC Forecast analysis described earlier in this testimony produced base and heat load coefficients for each rate schedule in the Residential and Commercial sales customer classes. I used the statistical software that produced these coefficients to model the normalized load numerator for the load factor ratio using the historical 25-year HDD average. As part of its resource planning processes, the Company has estimated an 11-degree Fahrenheit design day temperature, which I converted to HDDs. Using the UPC Forecast derived coefficients, I then estimated the design day load factor denominator.[40]

Large Commercial interruptible and transportation service and Industrial schedules in rate classes RS 31 and RS 32 are not included in the UPC Forecast analysis, as well as schedule RS 3 Industrial. Customers in these classes were not included in the UPC Forecast because the Company maintains a separate customer-specific Industrial Forecast for these customers that is routinely updated by its subject matter experts. The Industrial Forecast Test Year volumes are the

[40] For NW Natural's 2022 IRP, the Company used a probabilistic planning standard to forecast peak load as function several key drivers. This planning standard sets a daily resource capacity requirement such that the Company would be 99 percent certain it would be capable of meeting load going into any winter. Using this methodology, the Company has calculated an average system weighted temperature around this planning standard of roughly 11-degrees Fahrenheit.

basis for the normalized load numerator for the load factor ratio. For the denominator, I queried historical load data by month and by day (where available) for all customers in these rate classes beginning January 2016. I calculated a maximum daily delivery volume ("MDDV") for each customer by year and aggregated these volumes by rate schedule. Then, I weighted each year's MDDV values by Test Year customer counts for each rate schedule and used this factor to gross up (or down) each year's MDDV total. Finally, I took the average aggregate MDDV value from the period January 2019 through September 2024. This value is the basis for the design day load factor denominator.

Q. How did the Company weight the MDDV values in the design day factor calculation?

A. I weight each year's MDDV values by Test Year customer counts for each rate schedule, which is Staff's preferred approach.[41] This approach accounts for the full peak demand generated by new Test Year customers by adjusting demand for the years prior to their taking service for each rate schedule. Therefore, zero demand is not assumed for these new customers for the years prior to their taking service, helping to ensure that capacity factors are not overestimated, which would result in underestimating the capacity burden that some rate schedules may put on the system during peak days. I note that this approach is only valid when using customer counts incremental to the Test Year; simply using year-to-year customer

[41] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Scott Gibbens, Staff/1600 at 11, lines 11-22 (Apr. 22, 2022).

count differences would risk overestimating the capacity burden as a business could close and be replaced the next year by a new business at the same location, resulting in zero incremental customers.

Q. What were the results of the design day load factor analysis?

A. For the purposes of this LRIC study, I estimate an overall load factor for Oregon rate schedules of 28.7 percent, with a firm load factor of 25.6 percent and a transportation load factor of 54.9 percent. The RS 2 Residential load factor is about 21.6 percent, meaning normal load for this schedule is a little more than one-fifth of its design day load. The RS 3 Commercial load factor is about 23.8 percent, while the Large Commercial rate schedules have estimated load factors ranging from 30.0 percent to 56.7 percent; the Industrial rate schedules have estimated load factors ranging from 33.6 percent to 66.1 percent.

Q. Did the Company update the Design Day Peak and Average Allocator for the LRIC Study?

A. Yes. In UG 490, AWEC recommended that the Design Day Peak and Average Allocator (labeled *Dist-1*) in the LRIC study include an interruptible rate schedule demand discount for allocation of costs such as regulating equipment and compressor stations.[42] For this proceeding, I now apply an interruptible customer demand discount of fifty percent consistent with the system core mains allocation methodology described below. I discuss the interruptible customer demand

[42] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Reply Testimony of Robert J. Wyman, NW Natural/3900 at 18 (Jun. 4, 2024).

discount and its reasonableness in greater detail below. I note here that regulating equipment and compressor station investments are not just design capacity assets but also help to manage natural gas flows throughout the winter (and the entire year) and therefore do provide benefit for interruptible customers which is why I use a fifty percent discount instead of a one hundred percent discount.

Q. Does the Company rely solely on the peak and average methodology for allocation of capacity costs in the LRIC study?

A. No. On its own, the Design Day Peak and Average Allocator does not fully capture the entirety of the system's cost causation among all rate schedules, which is why I also employ an "average and excess" and "winter to summer average excess" allocation methodologies in my LRIC study. The Company also agrees that its natural gas system is built based on design day demands, which is why the design day load factor is a key input into the LRIC study cost causation modeling methodology. It follows, however, that cost causation for some investments such as a portion of distribution mains and transmission mains are allocated based on demand throughput based on a rate schedule's contribution to capacity needs. It also follows that cost causation for some investments, such as a portion of distribution (system core) mains and underground storage, are better allocated based on a rate schedule's contribution to capacity demands at peak times. The Company uses both methodologies to balance the assignment of cost causation among disparate investment categories from high volume to lower volume, but peakier, customer classes.

2. Functionalized Incremental Plant Investment Costs

Q. Please outline the specific components of functionalized incremental plant investment costs evaluated in your study.

A. The functionalized incremental plant cost categories evaluated in this study include:

a) Distribution mains and assets, which are required for various purposes over time as the system grows, including mains to serve new customers and mains installed for safety and reliability purposes. The LRIC study directly allocates a portion of these mains costs, based on an analysis of average installation cost per foot and length by rate schedule. The remainder of distribution mains costs are allocated based on the peak and average allocator. Distribution mains are designated in the Company's plant accounting records as those less than four inches in diameter, and those four inches or greater.

b) System core mains, which are the balance of mains not attributable to distribution mains. System core mains, for the purpose of this LRIC study, constitute the distribution pipeline that transport gas from the interstate pipeline to delivery points on the Company's system (e.g., gate stations) and interconnect with smaller diameter mains used to serve areas with customers such as neighborhoods, commercial strips, or industrial districts.

c) System reinforcements, which are mains related to capacity increases.

d) Transmission mains, which constitutes the pipeline that transports gas from the interstate pipeline to delivery points on the Company's system.

e) Storage, which includes the costs associated with underground storage, a primarily winter peaking resource.

f) Service lines, which includes costs associated with the piping and trenching from meter set to distribution main, and distribution main tie-in.

g) Meter set and regulator assemblies, which includes the cost of the meter and regulator, as well as the pipe fittings, bracket assemblies labor, and shop time required for assembly.

h) General and Intangible Plant includes many of the assets used to serve all customers such as computers and software, as well as communications equipment.

i) Land and Structures are the physical assets the Company uses for its operations.

a. Distribution Mains and Assets

Q. Did you conduct a special study to directly assign distribution mains costs to individual rate schedules?

A. Yes, I directly assigned a portion of distribution mains costs using a special study. Costs not directly assigned are allocated based on the design day peak and average allocator.

Q. What were the inputs used to calculate the directly allocated distribution mains costs?

A. The main extension costs were evaluated using nine calendar years (2015 – 2023) of historical accounting data of Oregon main extension job orders. The accounting data include the total cost (excluding construction overhead) and footage installed per job, pipe size and material, and are delineated by service type (conversion vs new construction), and market segment. The market segments analyzed are as follow:

- Residential-single family new construction ("Residential New")
- Residential-single family conversion ("Residential Conversion")
- Commercial / Industrial ("Com/Ind")

In addition to the nine years of job orders data, I used a main extension forecast that is produced annually by the Company's Business Analytics team, for 2024 through the Test Year. This forecast uses three categories of extensions: Commercial mains, Residential mains, and system expansion main extensions. The third category is overwhelmingly made up of new construction residential connections. The forecast is expressed in terms of mains footage and cost per foot.

Neither the main extension jobs order data nor the forecast includes a rate schedule breakout. I delineate by market segment, however, based on several factors, including location of the main extension, pipe size, and the type of customers most likely to take service on the extension.

Q. How were the directly allocated distribution mains costs calculated?

A. I used the main extension jobs order data to calculate the 9-year median cost per foot and median main length installed by market segment. Additionally, I used the same dataset to calculate the 9-year median cost per foot and median main length installed by pipe size (less than four inches, or greater than or equal to four inches) and material (polyethylene or wrapped steel). The average cost of main extension is based on accounting data that are expressed in nominal dollars. Therefore, for purposes of the Test Year, I escalated the nominal main extension costs per foot to forecasted Test Year values using an inflation index that I equally weighted using two data sources ("Inflation Index").[43] The escalated values were used to create the median Test Year cost per foot input for the LRIC study.

Q. How did you assign the median distribution main extension *cost per foot* for each market segment and pipe size to a rate schedule?

A. I used a weighting methodology that employs three inputs: (1) the Company's main extension forecast, weighted using a ratio of incremental customers added by way of conversion off existing main and those added through system expansion; (2) the job orders data by market segment; and (3) the job orders data by pipe size. For every rate schedule, I used a 50-50 weighting ("Segment Weight") to assign costs based on the forecast and the 9-year actual median cost per foot by market segment. For the Commercial and Industrial rate schedules, I further assigned costs by pipe size and type. I used pipe sizes and type for the large customer schedules as a method for further weighting main costs across schedules with wide variations in customer sizes, loads, and physical location off-main.

I assigned the Residential Conversion market segment to RS 2 Residential, the Residential New market segment to RS 27 Dry-Out, and the Com/Ind market segment to both RS 3 Commercial and RS 3 Industrial customers. Due to the

[43] I equally weighted inflation forecasts from two sources: (1) The Company's real long-term discount rate assumption used by its Strategic Planning Team for IRP development; (2) Oregon Economic and Revenue Forecast, Table Other Economic Indicators: CPI Urban Consumers. Page 54, September 2024.

large number of RS 3 Commercial customers on the system, I used Company GIS data to query a randomized sample of these customers to estimate the pipe size of the mains that customers in this rate class have been connected to historically. Using these GIS data, I calculated the ratio of customers connected to mains of less than four inches and greater than or equal to four inches and used this ratio to assign costs once the Segment Weight had been applied. The RS 3 Industrial mains costs were assigned similarly.

For the RS 31 and RS 32 rate classes, I applied the same Com/Ind Segment Weight as used for the RS 3 rate class. Mains costs were further delineated by rate schedule using the historical GIS pipe size data. For these larger schedules, I categorized mains connections by both pipe size and material due to the large variations in mains sizes and types that serve these customers.

Q. How did you assign the median distribution main extension *length* for each market segment and pipe size to a rate schedule?

A. I used a similar methodology as described above to calculate the median main extension length (in feet) for each schedule. For RS 2 Residential and RS 27 Dry-Out, I used the Company's main extension and customers forecasts. For the Commercial and Industrial schedules, I used 6-year median installed feet of mains by pipe size and material type to estimate main extension lengths for three categories: Small Com/Ind, Large Commercial, and Large Com/Ind.

Q. How were the directly allocable distribution mains costs calculated and allocated?

A. First, I estimated the feet of Oregon mains on the Company's system not attributable to main extensions serving customers. I used feet of mains reported in the Company's FERC Distribution Report as a basis for total mains footage, categorized by pipe size.[44] Next, I used the historical GIS pipe size data to estimate what percentage of customers in each rate schedule are connected to distribution mains of less than four inches and equal to or greater than four inches. Using the distribution main extension median installed feet described above, I calculated the feet attributable to these customer classes by pipe diameter category. The remaining unattributable feet were classified as system core mains. I used an average cost of installed mains, weighted by pipe material, to get an estimated cost per foot. I then allocated these attributable mains to rate schedules based on share of overall attributable costs.

b. System Core Mains

Q. How did you calculate the share of distribution mains to classify as system core mains?

A. The remainder of the feet of mains reported on the FERC Distribution Report and not determined to be directly allocable distribution mains above was classified as system core mains.

[44] The FERC Distribution Report is created annually by the NW Natural Engineering Department. It is used by the Plant Accounting team to validate that the feet of mains reported in the Company's asset management accounting databases is correct.

Q. How did you assign the system core mains costs to each rate schedule?

A. I used an average and excess method for distributing the system core mains costs to the rate schedules based on two allocations: total throughput and firm demand. The total throughput allocator is based on the design day load factor (i.e., the "average") and distributes costs across all schedules. The firm demand allocator is based on one minus the design day load factor (i.e., the "excess") and similarly distributes costs across all rate schedules.

Q. Did the Company update how system core mains are allocated?

A. Yes. I made a small adjustment to how the design day load factor is applied to system core mains of less than four inches and of greater than or equal to four inches. I had previously used the system design day load factor for both categories of mains sizes. For this proceeding, I used the sales firm design day load factor for system core mains of less than four inches and used a load factor for the Commercial and Industrial rate classes for system core mains of greater than or equal to four inches. This update recognizes the differences in the design day load factor between customers more likely to be associated with system core mains of less than four inches and of those associated with system core mains of greater than or equal to four inches.

Q. Does the system core mains allocation make an adjustment for interruptible peak day deliveries?

A. Yes. The system core main allocation includes interruptible peak day deliveries, adjusted with a fifty percent credit. This methodology is consistent with the Company's LRIC study filed with UG 490 and was recommended by Staff in its UG

435 Opening Testimony, which asserted that interruptible customers "receive tangible benefits from peak day planning investments" because they are "seldom, if ever interrupted" and therefore should be allocated a portion of these resource costs.[45] The Company notes that regardless of the number of curtailment events, interruptible customers do present a demand side resource for the sole reason they *can* be curtailed to alleviate supply and capacity constraints. As such, I believe that including an allocation to interruptible customers at fifty percent of the standard firm demand allocation that is allocated to firm customers, as Staff recommended, remains reasonable.

Q. Please elaborate why the Company finds the interruptible customer demand discount of fifty percent is reasonable.

A. The LRIC study is a theoretical economic costing exercise that attempts to estimate the point where customers, either individually or as part of a rate class, are paying the costs associated with their service as a basis for discussions of price setting and rate spread. The Company agrees that interruptible customers provide system planning benefits and these benefits are reflected in the rates that are charged to these customers. Valuing and assigning these benefits are not straightforward and raise the question of how (and to what extent) to allocate costs based on requirements and obligations in the tariffed rate compared to how the system is used in practice. On one hand, interruptible customers benefit from the

[45] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Scott Gibbens, Staff/1600 at 13, lines 11-14 (Apr. 22, 2022).

reliability and capacity built for the design day standard of the system. Not all interruptions occur due to capacity constraints from peaking on the system under normal operating conditions; some occur for reasons outside the utility's control (e.g., third-party damage to infrastructure). On the other hand, the Company notes that regardless of the number of demand response events, interruptible customers do present a demand side resource for the sole reason they *can* be interrupted to alleviate supply and capacity constraints.

c. System Reinforcements

Q. Please briefly describe system reinforcements.

A. System reinforcements are incremental infrastructure requirements when operating pressure is projected to drop below a certain level. The purpose of system reinforcements is to maintain safe and reliable pressure throughout the system, and to assure reliable service to firm customers.

Q. What are the methods used to calculate the incremental system capacity and reinforcement main investment?

A. Incremental system reinforcement costs were calculated using over six years of historical system reinforcement capital spend (2018 – 2024), forecasted from October 2024 through the Test Year. For each year, I multiplied the system reinforcement capital investment by an allocation factor based on Oregon volumes to calculate the Oregon-only system reinforcement expenditures.

I calculated an incremental investment cost per therm for all rate classes based on incremental estimated design day load added to the system over the same period. I applied this per therm investment cost only to those rate schedules that contributed to incremental design day load over the analysis period. Finally, I multiplied the per therm cost by each schedule's UPC to estimate the total incremental capacity investment.

Q. How were the system reinforcement costs allocated?

A. Incremental system reinforcement investments are triggered by firm service commitments, but interruptible customers benefit from greater system resiliency which reduces the possibility of curtailment. For the same reasons explained above for system core mains, I allocated to interruptible customers that had incremental design day load fifty percent of the standard firm demand allocation on a per therm basis.[46] I allocated total costs based on the total weighted product of each schedule's incremental cost per customer and total customers.

d. Transmission Mains

Q. How were the transmission mains costs allocated?

A. Transmission mains costs were allocated using an average of three allocators: design day peak and average allocator, system core mains allocator, and the capacity incremental investment (system reinforcement) allocator.

e. Gas Storage

Q. How were underground gas storage costs allocated?

A. Underground gas storage plant costs were allocated to sales customers only, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales. This measure allocates costs based on contribution to

[46] Note that the UG 435 LRIC study did not apportion any system reinforcement costs to interruptible rate schedules.

average peak loads compared to a period of average base loads. I halved this ratio for interruptible sales customers to acknowledge the possibility of service interruptions that could coincide with a winter peaking event.

Q. Were any underground storage costs classified as balancing and allocated to the Transportation class?

A. No. The LRIC study does not classify any storage costs as balancing for allocation to the Transportation class. NW Natural generally will utilize the interstate pipeline for daily and/or monthly system balancing, not underground storage assets. However, it is possible that our underground storage assets could be utilized for balancing all customer classes, including Transportation. Any underground storage costs that could potentially be allocated to the Transportation class would be negligible.

f. Service Lines

Q. How were service line installation costs and average footage installed by rate schedule determined through your special study?

A. The calculation of average services cost per foot and the average footage installed was derived using eight years of historical accounting data of Oregon services job orders (2016 – 2023) for customer service installations by market segment. These data are very similar to those of the Oregon mains orders; the orders include the total cost (excluding construction overhead), footage installed per job, and pipe size and material. The important distinction is that the services orders are associated with customers on specific rate schedules.

Services costs for RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out were calculated using an eight-year average of job costs per foot. Due to the small job sample size for the Commercial and Industrial schedules in the RS 31 and RS 32 classes, I used historical data to calculate a weighted median cost per foot. Using a GIS data query for services connection footage by rate schedule historically, I estimated services cost by customer per rate schedule by multiplying the median footage by median cost per foot. I used the Inflation Index to inflate nominal dollars to Test Year values.

Q. Did the Company update its Service Line Cost Allocator?

A. Yes. In UG 490, AWEC recommended that service lines be allocated consistently across all rate schedules based on the Average Service Line Installed Cost Allocator methodology (labeled *Line-1* in the LRIC study). AWEC argued, in UG 490, that *Line-1* used a marginal costing approach while *Line-2,* which was applied only for RS 31 and RS 32 cost allocation, was based on a replacement costing approach.[47] For this proceeding, I now apply the *Line-1* methodology consistently across all rate schedules (and thereby I remove the effects of the *Line-2* allocator from the LRIC study).

[47] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Reply Testimony of Robert J. Wyman, NW Natural/3900 at 21 (Jun. 4, 2024).

g. Meter Sets and Regulators

Q. Please outline how your special study calculated costs for meter sets and regulators.

A. I ran a customer query out of NW Natural's CIS that included each actively billed customer's meter set model number and delivery pressure. A summary of this CIS data provided the counts of meter set models by rate schedule. NW Natural's Engineering Department maintains an engineering cost memo that provides the assembly and capital cost for each assembled meter set (by meter model number) with regulator. I calculated weighted-average cost using the costs from the engineering cost guide and meter counts by rate schedule to derive the capital investment cost by customer by rate schedule.

Q. How were meters and regulators plant investment costs allocated to rate schedules?

A. I converted the average meter cost per customer per rate schedule to share of overall meters and regulators costs using customer count as a weight.

h. General and Intangible Plant

Q. How was general plant allocated to rate schedules?

A. I used a common allocator that was built using three factors: (1) net allocated plant balances for the storage, distribution, and transmission functions; (2) total O&M expense allocation; and (3) customer count. I created the common allocator using an equal weight of each of these three factors. These factors together represent a mix of each rate schedule's share of overall utility capital investments and operating expenses, accounting for the relationship between costs and customer count.

Q. How was intangible plant allocated to rate schedules?

A. I similarly used the common allocator to allocate intangible plant, as I considered these common costs.

i. Land and Structures

Q. How were land and structures allocated?

A. I allocated the general land and structures plant balances based on functionalized storage, transmission, and distribution plant. For land and structures attributable to certain functions, I allocated the balance based on plant associated with that function only (e.g., storage related land and structures are allocated based on storage plant).

3. O&M Expenses

Q. Please describe the categories of O&M expenses evaluated in the LRIC study.

A. Below, I describe how I allocate two categories of O&M expenses. The first, O&M expenses associated with capital investments, are the on-going O&M expenses required to keep plant assets operational and efficient. The expenses are associated with the assets: gas storage, transmission, and distribution. The second category, common O&M expenses, are associated with common cost items required to keep the entire system running, such as administrative and office expense, wages and salaries, and customer service and billing.

Q. How are O&M expenses associated with capital investments evaluated in the LRIC study for rate making and rate allocation purposes?

A. O&M expenses associated with capital investments (e.g., the on-going operations and maintenance costs associated with the gas storage assets, or the distribution system, for instance) are allocated to rate schedules in the LRIC study by applying an "investment carrying charge" to calculate the incremental revenue requirement associated with each category of investment. The carrying charge includes cost of capital (debt and equity), taxes, and depreciation to calculate the carrying percentage assigned to each category of investment. The investment carrying charge percentage is multiplied by each category of capital investment to calculate each rate schedule's annual revenue requirement. This indicated revenue requirement by rate schedule for each incremental capital investment category is weighted by each schedule's contribution to the overall cost and converted into an allocation factor. This allocation factor is used to apportion the incremental expenses associated with capital investments to each rate schedule based on cost causation.

Q. What are the categories of common O&M expenses that were evaluated in the LRIC study?

A. The two major categories of common O&M expenses evaluated were: (a) Customer Service and Billing; and (b) Administrative and General. I explain how these expenses were allocated to the rate schedules below.

a. Customer Service and Billing

Q. What are the categories of customer service and billing O&M expenses that were evaluated in the LRIC study?

A. The LRIC study includes a special study based on the following categories of O&M customer service-related expenses for direct allocation:

- Gas Scheduling, which includes departments that schedule underground storage injections/withdrawals, as well as control the distribution system's daily operations.
- Gas Planning, which are operations that include, short- and long-term gas acquisitions, planning, and analysis (e.g., gas purchasing and hedging activities).
- Major Accounts Services, which is the team that interacts primarily with large commercial and industrial customers through the service election process, coordinates billing and addresses billing issues, as well as coordinates new large customer acquisitions.
- Accounts Services, including billing, payment processing, metering, collections, and construction field services.

Q. How were gas planning and gas scheduling costs evaluated and assigned to each rate schedule?

A. The gas scheduling and gas planning cost centers were evaluated using the O&M budget cost center for the Gas Scheduling and Planning Department. Cost categories include total salaries, administrative costs, and FTE counts for each cost center. These values are used to evaluate per customer costs for the LRIC study, based on average hours spent on each customer at a calculated average labor rate.

The gas scheduling cost center was broken out into two functions: gas storage operations and gas control operations. Costs associated with gas storage operations were allocated to firm sales rate schedules only. Gas control operations costs were allocated to all schedules based on three factors: (1) service type (sales firm, sales interruptible, or transportation); (2) normalized annual throughput; and (3) the amount of time gas management staff estimate they spend working with customers of each service type.

The gas planning cost center was allocated to all service types based on the amount of time gas management staff estimate they spend working with customers of each service type. Costs are largely allocated to sales customers since little staff time is devoted to transportation customers that are responsible for procuring their own gas commodity.

Once costs were assigned to each service type, they were directly allocated to each rate schedule based on weighted customer counts within that service type.

Q. How did NW Natural evaluate Major Accounts Services costs?

A. Major Accounts Services costs were allocated only to the large RS 31 and RS 32 Commercial and Industrial rate classes, as well as RS 3 Industrial. Costs were further allocated to sales and transportation rate schedules based on reported staff time spent interfacing with each service type.

Q. How were all other Accounts Services costs evaluated?

A. For all other Accounts Services costs, NW Natural conducted a "Meter-to-Cash" study, that evaluated the incremental costs associated with providing these services to customers. The study evaluated the following cost center groups in the Company that directly serve customers:

- Accounts Services (meter reading scheduling, payment processing, collections)
- Contact Center (customer call center)
- Resource Management Center (field services scheduling/dispatch)
- Construction Field Services (field technicians and field scheduling)
- Office Services (bill printing)
- Treasury (costs that pertain only to payment processing)
- Information Technology (costs related to computer support for processes that support meter reading, payments, and Company website)

Q. What is the purpose of the Meter-to-Cash study?

A. The Meter-to-Cash study was first developed by the Company in 2015. It was developed to estimate the incremental costs of customer additions associated with the Accounts Services functions listed above. The 2015 analysis was developed over several months, through meetings with managers and subject matter experts associated with each of the Accounts Services functions. These meetings helped to determine what individual cost centers and expense items should be associated with each activity, as well as what costs and activities are associated with three categories of rate schedules: Residential, Small Commercial, and Large Commercial / Industrial. Data were collected after these informational interviews were complete. Costs that are not directly tied to customer count were not included in the Meter-to-Cash study (e.g., software upgrade costs are not necessarily correlated to customer additions and are therefore not included).

Q. Has the Meter-to-Cash study been updated?

A. Yes. The Meter-to-Cash study was updated in 2023, and again in 2024, to reflect current operations and Accounts Services functions. Updates are developed with input from subject matter experts across the Company, using similar methodology as the initial 2015 study. The updated study is the basis for incremental Accounts Services costs for this LRIC study.

Q. What data were collected and what criteria were used for its inclusion in the Meter-to-Cash study?

A. Incremental O&M cost estimates in the Meter-to-Cash study were based on data collected from the Company's engineering, accounting, and customer contact teams. Data were vetted with the help of supervisors and managers of these teams as well as individual cost centers. The expenses identified as part of the Meter-to-Cash process were identified by cost center and were determined to be appropriate for inclusion in this incremental cost study based on the following criteria: If it were determined an additional forecasted customer would make a direct cost change within the cost center associated with these groups, and this direct cost was measurable, the cost would be included. Costs that are not tied to functions provided by the cost centers listed above for the direct service of customers were not included in the Meter-to-Cash study.

Q. How were the incremental Meter-to-Cash costs allocated to the rate schedules for the LRIC study?

A. After identifying the incremental costs, the LRIC study broke out each cost center's budget into five categories:

1. Meter Reading
2. Billing
3. Payment Processing
4. Collections (costs that pertain to payment processing)
5. Other Activities

Within each category of budget, costs are evaluated as payroll versus non-payroll. An incremental cost per customer was derived by taking the above categories and apportioning the cost into the three broad categories of rate schedules. I weighted these class-based average costs by rate schedule customer count to create an indirect allocator for customer service and billing O&M expenses.

Q. Did you directly allocate any additional customer services-related O&M expenses?

A. Yes. I examined the Company's Oregon allocated O&M expenses by type and cost center. Any costs identified as relating specifically to Residential, Residential and Commercial, or Commercial and/or Industrial classes were directly allocated to rate schedules as appropriate based on weighted customer count.

b. Administrative and General Expenses

Q. How were administrative and general expenses allocated?

A. I allocated most of the administrative and general expenses costs based on the customer-weighted customer services cost allocator described above. Some costs, such as pension expense, I based on the allocation of salaries and wages cost components.

4. LRIC Study Insights and Outcomes

Q. Upon what basis is margin revenue at current rates compared against the margin revenue with the proposed incremental revenue requirement?

A. The LRIC study compares the ratio of Margin Revenue at Current Rates (see line 20 of the LRIC study results, Exhibit NW Natural/1601, Wyman) against the LRIC Based Target Margin (line 21), which is the margin revenue amount including the proposed incremental revenue requirement. This ratio is used to derive the Current Margin Revenue to LRIC Based Target Margin (line 23), and then the Parity Ratio at Present Rates (line 23a), which indicates each rate schedule's position relative to cost parity (i.e., the point that the schedule as a whole is neither over- nor under-paying its LRIC study determined cost of service).

Q. Does the Margin Revenue at Current Rates figure contain any commodity-related revenues for any of the rate schedules?

A. No. The Margin Revenue at Current Rates figure presented on line 20 does not contain any commodity-related revenues, including commodity cost related to "line loss" (e.g., unaccounted for gas). Commodity-related costs are pass-through costs and are therefore fully offset against commodity-related revenues, producing no net change to margin revenues.

Q. Does the Margin Revenue at Current Rates figure contain any emissions or environmental compliance related revenues for any of the rate schedules?

A. No. The Margin Revenue at Current Rates figure presented on line 20 does not contain any revenues that the Company has collected for compliance with Oregon Department of Environmental Quality's invalidated Climate Protection Program ("CPP"). CPP-related costs are similar to commodity-related costs in that they are pass-through and are fully offset against revenues, producing no net change to margin revenues. Further, as explained in NW Natural/1500, Walker, all Schedule 198 (renewable natural gas investments) have been removed from the revenue requirement calculation and are therefore not contemplated by the LRIC study.

Q. What do the results of the LRIC study indicate?

A. The LRIC study-indicated Parity Ratio at Present Rates for each rate schedule is illustrated in Table 1 below. A parity ratio below the value of 1.00 indicates that customers on a given schedule are underpaying their LRIC study determined cost of service. A value over 1.00 indicates that customers on a given rate schedule are paying more than their cost of service at margin rates. Per Table 1 below, the results of the LRIC study indicate that the RS 2 Residential and RS 27 Dry-Out rate schedules are paying less than their full cost of service at present rates while the remaining rate schedules are paying more than their cost to serve (with RS 3 General Commercial paying just slightly above the determined cost of service).

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	**0.97**	**1.01**	**1.15**	**0.77**	**1.34**	**1.42**	**1.38**	**1.15**
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	**1.29**	**1.30**	**1.64**	**1.26**	**1.13**	**1.09**	**2.62**	**1.25**

The class-wide LRIC study indicated parity ratios are as follow: 0.97 for the Residential schedule; 1.01 for the Small Commercial schedule; 1.29 for Large Commercial Sales schedules; and 1.27 for the Industrial and Transportation schedules.

Q. How do these results compare with the Company's last filed LRIC study?

A. This LRIC study and the Company's last study, filed with UG 490, both indicate that the RS 31 and RS 32 rate classes are paying more than their determined cost of service under present rates. The LRIC study in this rate case, however, indicates that nearly all schedules have moved closer to parity. Both studies also indicate that RS 2 Residential and RS 27 Dry-Out customers are paying less than their determined cost of service. The RS 2 Residential parity ratio is slightly higher than the UG 490 indicated ratio (while still underpaying the determined cost of service, the LRIC study indicates the gap has narrowed). The RS 3 General Commercial parity ratio has moved from below parity in UG 490 (0.95) to a parity ratio of 1.01, indicating these customers are paying just slightly above the determined cost of service. Based on the data and methods used to calculate incremental cost for this LRIC study, as described earlier in this testimony, I find that RS 27 Dry-Out customers have the lowest Relative Margin-to-Cost Ratio at the Company's current rates consistent to UG 490.

Q. Why has the RS 3 General Commercial moved from below parity to above parity?

A. There are multiple reasons for the upward pressure on the RS 3 General Commercial parity ratio between UG 490 and this proceeding. First, the adopted UG 490 rate spread allocated 1.3 times the overall margin increase from that proceeding to this rate schedule, which is 30 percent higher than the margin increase (1.0 times) that would have maintained the same relative parity. Second, as noted earlier in this testimony, the RS 3 General Commercial UPC model produces a weather normalized UPC about 11 percent higher compared to the UG 490 model, which is attributable to both estimated increases in actual per customer demand as well as to the new model specification (an observation Staff noted in UG 490).[48] This schedule, therefore, is credited with more Test Year margin revenues in the LRIC study relative to UG 490 due to incremental margin rates set above parity as well as higher demand.

Q. Why has RS 27 Dry-Out not moved closer to parity?

A. The adopted UG 490 rate spread also allocated 1.3 times the overall margin increase to RS 27 Dry-Out but the parity ratio moved slightly further away from

[48] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900 at 11 (Apr. 18, 2024). Staff observed: "Staff's forecast slightly increases the Test Year load forecast for commercial customers, primarily through a higher forecasted peak consumption in winter months."

1.00. The RS 27 Dry-Out UPC model produces a weather normalized UPC about seven percent lower compared to the UG 490 model, yet the Test Year customer forecast is about 14 percent higher. Therefore, the LRIC study apportions more customer-related fixed costs to this schedule relative to UG 490, and lower demand results in fewer relative margin revenues credited in the Test Year.

Q. Overall, are the rate classes are moving closer to parity?

A. Yes. Although direct comparison of parity ratios across LRIC studies is not straightforward due to changes in investment mix, customer makeup and service elections, and changes to overall throughput and design day demand, the Company believes that its incrementalism approach to rate spread has helped to move all rate classes closer to parity over multiple rate proceedings. For instance, the UG 435 LRIC study indicated seven rate schedules having a parity ratio of above 1.75; this LRIC study indicates just one schedule with a parity greater than this value.

Q. Has the Company conducted a cost of service analysis for any other schedule not included in the LRIC study?

A. Yes. The Company has updated the cost of capital components and the O&M assumptions of its cost of service analysis for tariff Schedule 4 – Residential Multi-Family Service ("Schedule 4").[49]

[49] The Company also has updated the cost of capital components and O&M assumptions of its cost of service analysis for tariff Schedule H – Large Volume Non-Residential High Pressure Gas Service Rider.

The Company also requests revisions to tariff Schedule 15 – Charges for Special Metering Equipment, Rental Meters, and Metering Services ("Schedule 15") to replace the existing meter rental rates for diaphragm and rotary meters with a descriptive formula that defines the calculation of the rental meter rate based on the cost of meter requested.[50]

Q. What is tariff Schedule 4?

A. Tariff Schedule 4 is applicable only to residential tenants that reside in participating multi-family buildings. The tariff is based on the special provision that the service is for low-use gas appliances such as cooktops, and not for space heating. Customers taking service on this schedule are charged a base monthly rate.

Q. Please describe the Schedule 4 cost of service analysis.

A. The Company updated its Schedule 4 cost of capital to reflect the updated cost of debt as filed in this case. The analysis also updates the annual O&M expense to reflect the 2024 Meter-to-Cash study described earlier in my testimony.

Q. Please summarize the results of the Schedule 4 analysis.

A. The results of the analysis increase the Schedule 4 base monthly rate from $11.32 to $11.78, an increase of 4.1 percent.

Q. What is tariff Schedule 15?

A. Tariff Schedule 15 is an optional tariff schedule that enables customers to rent meters and metering services based on a monthly charge currently specified in the tariff for both diaphragm and rotary meters. Schedule 15 includes the terms and

[50] This excludes diaphragm and rotary meters listed on Sheet 15-2 where monthly charges have been retained under existing arrangements for billing purposes based on meter type and installation date.

conditions of meter rental, as well as rates for various rotary and diaphragm meter sizes. Customers taking service under Schedule 15 enter into a rental meter agreement with the Company.

Q. Why is the Company proposing revisions to Schedule 15?

A. Currently, Schedule 15 includes two tables of meters (one for diaphragm meters and one for rotary meters) delineated by size and capacity with a corresponding monthly charge rate on Sheet 15-1. The meters found on these tables, however, may not always match the Company's inventory in stock because meter inventory and their related costs can change periodically. NW Natural's Engineering department conducts research and testing on various meters and determines the meters that should be included in NW Natural's meter inventory. Instead of filing frequent tariff changes to keep up with the meters that are in inventory (especially where inventory changes do not align with general rate case proceedings), NW Natural proposes that it would be more efficient to include a cost of service formula in the tariff rather than list specific rates based on meters that may or may not be in inventory. The formula, an explanation of how to use it to calculate the monthly meter rental rate, and any necessary definitions would be included in the Schedule 15 tariff. Under the Company's proposal, customers taking service under Schedule 15 will enter into a rental meter agreement with the Company that will reflect the meter rental rate as calculated in the formula found in the tariff.

Q. How will the Company communicate the Schedule 15 monthly meter rental rates to customers?

A. The Company is proposing to replace the current rates listed in the Schedule 15 tariff for diaphragm and rotary meters on Sheet 15-1 with a descriptive formula that will calculate the rate applied to rental meters regardless of size. NW Natural will continue the practice of consulting with customers choosing to rent supplementary meters regarding available meters that meet their service requirements prior to entering into a rental agreement that will include the rental meter charge as determined by the formula. Thereafter, it is expected that rental meter charges will be updated when the Company's authorized cost of capital changes, typically with each general rate case effective date.

Q. Please describe the proposed Schedule 15 formula.

A. The Schedule 15 formula is the same as the one that is currently used to calculate the monthly meter rental rates, which in summary is the net present value of the cost of service of the meter divided by 12. The cost to serve is generally comprised of the cost of the rental meter and other costs customarily related to the revenue requirement of utility investment, including, but not limited to, depreciation expense, return on investment, income taxes, property and other taxes, and operating maintenance costs and revenue-sensitive costs. The cost of the rental meter is inclusive of an Encoder Receiver Transmitter (ERT), if necessary, as well as required fittings and components (e.g., swivel, gasket, flange) which can vary by meter type and size. Additional description of the components of the formula are described in the proposed tariff changes which can be found at NW Natural/1515, Walker/5-6.

Q. How many meters are currently being rented under Schedule 15?

A. As of November 2024, there are 581 diaphragm and rotary meters of the types listed on Sheet 15-1 being rented to customers under Schedule 15, which is 62 percent of all meters being rented by customers in Oregon (the remainder being meters of the types listed, and installed prior to the dates indicated, on Sheet 15-2).

Q. Is the Company proposing any other changes to Schedule 15?

A. Yes. The Company is proposing to increase the Administrative Set-Up / Consultation and Technical Assistance Fees found on Sheet 15-2 from $100.00 to $145.00. These new rates are based on updated current labor rates for customer field service technicians inclusive of payroll overhead and vehicle costs using an assumption that these tasks require one and a half hours to complete on average.

Q. Where are the proposed changes to Schedule 15 presented?

A. The proposed changes to the Schedule 15 tariff are presented at NW Natural/1515, Walker/5-6.

Q. Do the Company's proposed changes to Schedule 4 or Schedule 15 impact any other rate schedules?

A. No. The purpose of these changes is to continue to align the costs borne by customers using services under Schedule 4 and Schedule 15 to those customers only.

IV. RATE DESIGN & RATE SPREAD

Q. What is the purpose of the rate design and rate spread section of your testimony?

A. The purpose of this section of my testimony is to:

- Discuss the Company's approach to rate design for this proceeding;
- Summarize NW Natural's incremental revenue requirement request;
- Discuss the results of the LRIC study and how it relates to rate spread;
- Describe the methodology for how the Company proposes to spread incremental revenue; and
- Show the revenue requirement spread by rate schedule and the corresponding average bill impact.

1. Rate Design

Q. Is the Company proposing any rate design changes in this proceeding?

A. No. The Company is not proposing any changes to rate design in this proceeding.

Q. Is the Company proposing to maintain a uniform volumetric rate for both single-family and multi-family residential customers taking service under RS 2 Residential?

A. Yes. The proposed rate spread maintains a uniform volumetric rate for single-family and multi-family customers taking service under RS 2 Residential, even though the existing monthly fixed charge is $2.00 lower for the multi-family residential cohort ($8.00 compared to $10.00 for the single-family residential cohort). This rate design avoids arbitrariness in the residential volumetric price signal on an intra-class basis while apportioning rates that recognize differing costs of service across premises types (single-family vs multi-family).

Q. How does the residential class rate design constitute sound rate design?

A. The Company's residential rate design maintains a uniform volumetric price signal for the residential rate class in order to promote a fair apportionment of revenue requirement across the Residential rate class, while avoiding different volumetric price signals on an intra-class level. The Company's proposal is responsive to the principle of fairness presented as "Attributes of a Sound Rate Structure" developed by James C. Bonbright ("Bonbright Principles"). The sixth principle seeks to avoid "arbitrariness and capriciousness" while attaining equity in three dimensions: "(1) Horizonal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant)."[51] The Company's proposal avoids arbitrariness in the volumetric price signal on an intra-class basis while apportioning rates that recognize differing costs of service across residential premises types (single-family vs multi-family).

Q. While the Company is not proposing any change to the monthly residential fixed charges in this case, can increasing the monthly fixed charge be beneficial for residential customers in future cases?

A. Yes. As I discussed in UG 490, the Company collects about one-fifth of its fixed costs through the fixed charge component of its RS 2 Residential rate, relying on

[51] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 383-384.

collection of the remaining four-fifths through the volumetric rate component that produces revenues that vary seasonally and year-to-year based on weather.[52] When more fixed costs are collected through a higher monthly fixed charge, less of the revenue requirement is collected through the volumetric rate. This works to smooth the Company's bills across the entire year, resulting in lower winter bills at a time when customer's other energy bills may be increasing as well. Since NW Natural is a single-peaking utility, higher monthly fixed charges put a greater share of cost recovery on bills when they are the lowest: During the summer months. The outcome for customers are more predictable, and flatter, bills throughout the entire year. Finally, for residential customers enrolled in the bill discount program, the discount is applied by the same discount percentage on both the fixed monthly and volumetric charge rates.

Q. Does the Company have evidence that at least some residential customers prefer smoother bills throughout the entire year?

A. Yes. The Company's Equal Pay plan, which spreads bills evenly throughout the entire year, is in practicality an individualized 100 percent monthly fixed charge. As of June 2024, roughly 12 percent of the Company's Oregon residential customers have opted into paying a fixed bill through the Equal Pay plan, including about 3,300 customers that are also enrolled in the bill discount program.

[52] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Direct Testimony of Robert J. Wyman, NW Natural/1800, at 60 (Dec. 29, 2023).

Q. Can increasing the monthly fixed charge promote rate equity for residential customers?

A. If properly designed, yes. As I noted above, a substantial portion of RS 2 Residential fixed costs are collected on the volumetric rate. The amount that is collected on the volumetric rate varies based on weather (for heating load) but also varies based on the number and type of appliances that a customer has installed, as well as housing characteristics: square footage, tightness of building envelop, age of home which influences standards and materials used in its construction. Fewer fixed costs are collected from lower usage residential customers compared to higher usage residential customers. Lower monthly fixed charges cause greater upward pressure on the volumetric rate, thereby causing intra-class subsidization that flows from the higher usage customers to the lower usage customers. As the Company explores further conservation and new appliance mixes in residences like hybrid systems, such a rate design could be key to fairness between residential customers with varying usages. A higher monthly fixed charge, which produces downward pressure on the volumetric charge, mitigates a cross-subsidy that benefits lower usage customers and promotes rate equity for higher usage customers.

2. Rate Spread

Q. What is NW Natural's total incremental revenue requirement?

A. NW Natural has filed for an incremental revenue requirement of $59.4 million in this case. See NW Natural/1500, Walker.

Q. Is any of the $59.4 million of incremental revenue requirement attributable to special contract customers?

A. No. The special contract customers are not allocated any of the incremental revenue requirement given they are under fixed cost contracts.

Q. How does the LRIC study relate to rate spread?

A. The LRIC study provides the incremental capital investment and O&M costs, by functional category, and gives insights into cost causation across customer classes. In theory, spreading the incremental revenue requirement such that all schedules have a Parity Ratio at Present Rates of 1.00 would align all customers to their indicated level of cost causation. In practice, rate spread (and rate design) tends to deviate from this strict application of cost study results, given such a change in the short-run would violate principles of rate shock and smoothing, neither of which are in the Company's or the customer's interests. It is also important to balance the interests of rate equity with rate volatility. The LRIC study does, however, provide a baseline for incremental revenue requirement allocation by rate schedule.

Q. What are NW Natural's thoughts on using the LRIC study results to spread revenue requirement?

A. NW Natural values the LRIC study outputs as a baseline for understanding the basis of cost causality among the rate classes. Of course, as stated above, there are other important factors that should be considered, most importantly the idea that equitable distribution of the rate spread should be balanced with customer rate impacts. If the Company were to spread revenue requirement across rate schedules strictly in a way that results in each rate schedule paying its share of its long-run incremental costs (i.e., if all schedules were suddenly brought to parity with their indicated cost causality), such a shift would result in rate shock for many customers and perhaps inadvertently signal rate volatility. The Company does not have a rigid standard for what constitutes rate shock, but rather analyzes its LRIC study results on a case-by-case basis in conjunction with regulatory precedent, principles, and the specific nature of the rate increase in the rate case.

Table 2 below shows the amount of incremental revenue requirement that would need to be spread to each rate schedule in order to put each class in line with paying its long-run incremental costs per the results of this LRIC study. The sum total of the amounts in Table 2 equals the full incremental revenue requirement in this case of $59.4 million. The values in this table are derived at line 19b of the LRIC Summary of Results, Exhibit NW Natural/1601, Wyman.

Table 2
LRIC Study Indicated Total Incremental
Revenue Requirement Deficiency (Sufficiency),
by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Target Revenue	$55,564,596	$11,924,131	($124,772)	$336,330	($1,978,461)	($256,253)	($709,776)	($5,080)
RATE SCHEDULE	**32CSF**	**32ISF**	**32CTF**	**32ITF**	**32CSI**	**32ISI**	**32CTI**	**32ITI**
LRIC Study Determined Target Revenue	($2,340,848)	($654,183)	($355,545)	($950,844)	($82,882)	$6,203	($321,133)	($676,386)

As seen in Table 2 above, RS 2 Residential customers would bear the largest share of the incremental revenue requirement increase, followed by RS 3

Commercial, if the Company were to adhere strictly to the indicated LRIC study results. RS 27 Dry-Out would also realize an increase. On a percent of total revenue basis, the indicated increase would be 8.8 percent and 4.7 percent for the RS 2 Residential and RS 3 General Commercial rate schedules, respectively. The customers within the RS 31 and RS 32 rate classes would all realize rate reductions under such a scenario, the one exception being RS 32 Industrial Sales Interruptible.

NW Natural believes that the factors of fairness and minimizing rate impact weigh in favor of not realigning rates completely to their indicated cost causality based on the results of the LRIC study in this rate case, which would require higher rate increases for some schedules while others receive decreases. A strict application of the LRIC results across all rate schedules would not be consistent with fundamental principles of rate design and rate structure, such as the third Bonbright Principle: "Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and with a sense of historical continuity."[53] Further, the Commission has stated that it is not inclined to raise some rates while reducing others without compelling evidence that immediate action is warranted.[54]

The Company understands that rate design principles, such as the Bonbright Principles, taken together, can be overlapping in nature and they do not

[53] *Id*. at 383.

[54] *In the Matter of Avista Corporation, Request for a General Rate Revision*, Docket No. UG 284, Order No. 15-054 at 5 (Feb. 23, 2015).

offer any rules of priority. Ratemaking consists of finding a reasonable balance between these guidelines, where strict application of economic principles of optimum pricing may yield to regulatory, historical, and social factors.

Q. Please describe the Company's rate spread proposal.

A. The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the LRIC study across all rate classes, using a methodology similar to what it proposed in its last rate proceeding. I describe the Company's rate spread methodology in detail below. First, for RS 2 Residential and RS 27 Dry-Out, I propose to use a separate cap for each rate schedule that slightly moves each of these schedule's relative position closer to parity with respect to the LRIC study results, because these schedules are paying less than their cost to serve at current rates. I propose a cap for RS 3 General Commercial that allocates slightly more than the average margin increase to this schedule. Second, the Company proposes to apply a floor that is set below the level that produces an equal percent of margin increment to all rate schedules with an LRIC study indicated parity ratio above 1.29. As a result of the application of the floor, the relative position to parity of the applicable rate schedules with respect to the overall indicated LRIC study results will decrease, reflecting the fact that these classes are paying more than their cost to serve at current rates. Third, the remaining revenue requirement is allocated to all remaining rate schedules to reflect the LRIC study results, which indicate that while these schedules are overpaying their cost to serve at present rates, they are not overpaying at the same relative level as those with parity ratios over 1.29. This final step allocates the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules, which include RS 3 Industrial, RS 31 Industrial Transportation Firm, RS 32 Industrial Transportation Firm, and RS 32 Commercial and Industrial Sales Interruptible, and RS 32 Industrial Transportation Interruptible.

The Company's proposal equitably distributes the incremental revenue requirement such that the rate classes as a whole are moved closer to parity based on their indicated cost causation, except for RS 3 General Commercial which is allocated an amount meant to roughly retain its indicated parity. The proposal described above is an incremental approach; it moves all rate classes closer to parity but does so in a manner that works to minimize rate shock. It does this by balancing the impact to residential customers while making incremental steps to towards the LRIC study indicated parity for larger volume customers who are farthest from parity.

Q. Please describe the methodology NW Natural proposes to use to spread the $59.4 million incremental revenue requirement.

A. NW Natural proposes a multi-step process for spreading the $59.4 million incremental revenue requirement:

1. Apply a cap equal to 1.04 times the overall incremental margin increase of 9.4 percent to RS 2 Residential. This cap is equal to a 9.8 percent margin increase.
2. Apply a cap equal to 1.01 times the overall incremental margin increase of 9.4 percent to RS 3 General Commercial. This cap is equal to a 9.5 percent margin increase.

3. Apply a cap equal to 1.30 times the overall incremental margin increase of 9.4 percent to RS 27 Dry-Out. This cap is equal to a 12.3 percent margin increase.
4. Apply a floor equal to 0.64 times the overall incremental margin increase of 9.4 percent to the Transportation rate class plus any other rate schedules with a LRIC study indicated parity ratio above 1.29. This floor is equal to a roughly 6.0 percent margin increase.
5. After the caps and floor have been applied, allocate the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules. This step results in the same proposed margin increase for each of the remaining schedules, equal to roughly a 7.0 percent increase. The effect of this step would be the same as applying a floor equal to 0.74 times the overall incremental margin increase in this case. In effect, these rate schedules would receive an increase just one percent point higher than the rate schedules with parity ratios above 1.29.

The caps of 1.04 for RS 2 Residential and 1.30 for RS 27 Dry-Out represent an approximation of the inverse mathematical relationship between the parity ratio of each rate class and schedule and unit parity of 1.00. For instance, Residential class (0.97 parity ratio): 1.00/0.97≈1.04. The same logic is used to apply the floor for the rate schedules with parity ratios above 1.29, which have an average parity of 1.57 (1.00/1.57≈0.64).

Q. Do you present this rate spread methodology in an exhibit to this testimony?

A. Yes. I present this rate spread allocation proposal methodology in Exhibit NW Natural/1602, Wyman.

Q. Please describe how this rate spread proposal impacts each rate class relative to an equal percent of margin spread.

A. The RS 2 Residential and RS 3 General Commercial rate schedules will receive a revenue spread slightly greater than an equal percent of margin share calculated across all rate schedules. RS 27 Dry-Out will receive the highest relative increase, at 30 percent higher than an equal percent of margin share. The rate schedules with a parity ratio above 1.29 will receive a revenue spread less than an equal percent of margin share. The remaining rate schedules, as indicated above, will also receive a revenue spread less than an equal percent of margin share, but at a slightly higher rate relative to other rate schedules in RS 31 and RS 32 rate classes.

Q. How does this rate spread proposal impact the LRIC study indicated parity ratios?

A. This rate proposal moves the parity ratio for every rate schedule closer to unity (e.g., to a value of 1.0), except for RS 3 General Commercial which is allocated an amount meant to roughly retain its indicated parity while balancing rate impacts for other rate classes. The Parity Ratio at Proposed Rates is presented at line 26b of the LRIC Study Summary of Results, Exhibit NW Natural/1601, Wyman.

Q. Are there any components of the $59.4 million revenue requirement that are already included, but are removed and spread separately?

A. Yes. We must first remove the temporary plant excess deferred income taxes ("EDIT") amortization credit of $4.5 million from the $59.4 million incremental revenue requirement in order to calculate a billing adjustment for Schedule 196.

Q. Please explain how NW Natural proposes to spread the plant EDIT amortization credit.

A. The Company proposes to spread the plant EDIT credit to all rate schedules using the same rate spread methodology as described above.

Q. Are there any additional rate proposals that you address after the base revenue requirement of $59.4 million has been applied?

A. Yes. The Company proposes to spread the proposed Meter Modernization Program deferral of $2.6 million on an equal percent of margin basis (to be included as a temporary rate adjustment) to all rate schedules after the proposed $59.4 million incremental revenue requirement has been spread as described above. For additional information about the Meter Modernization Program, please refer to NW Natural/900, Karney.

Q. As part of this rate spread methodology, is the Company proposing to make changes to its fixed monthly charges?

A. No. The Company does not propose any changes to its fixed monthly charges for any rate schedules in this proceeding.

V. RESULTS AND BILL IMPACTS

Q. What is the rate impact to firm sales customers for the revenue requirement components?

A. Table 3 below shows the combined incremental revenue requirement of $59.4 million net of the $4.5 million plant EDIT credit (i.e., margin revenues only) with average bill increase presented in this case for firm sales customers. These impacts are also presented in Exhibit NW Natural/1603, Wyman.

Table 3
Incremental Revenue Requirement (Margin Revenues)
and Average Bill Increase,
Firm Sales Customers Only

Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
02 R	$ 41,058,890	6.5%
27	$ 96,731	7.7%
03 C	$ 14,547,637	6.0%
03 I	$ 186,523	3.4%
31 C Firm Sales	$ 651,298	3.3%
31 I Firm Sales	$ 207,937	2.5%
32 C Firm Sales	$ 920,133	2.6%
32 I Firm Sales	$ 253,255	2.1%
Total All Schedules**	$ 59,375,658	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in NW Natural/1500, Walker. The total represents all rate schedules, not just the ones presented in Table 3 above.

Q. What is the rate impact to firm sales customers for all of the rate components presented in this case combined?

A. Table 4 below shows the combined incremental revenue requirement (total revenues combined) and average bill increase of all the rate components presented in this case for firm sales customers. This table includes the incremental revenue requirement shown in Table 3 above combined with the impacts of the proposed Meter Modernization Program deferral.

Table 4
Combined Incremental Revenue Requirement (All Revenues)
and Average Bill Increase for all Rate Components,
Firm Sales Customers Only

Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
02 R	$ 42,853,655	6.8%
27	$ 100,185	8.0%
03 C	$ 15,200,226	6.3%
03 I	$ 197,642	3.6%
31 C Firm Sales	$ 695,987	3.5%
31 I Firm Sales	$ 222,161	2.7%
32 C Firm Sales	$ 983,042	2.8%
32 I Firm Sales	$ 270,546	2.2%
Total All Schedules**	$ 62,064,430	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in NW Natural/1500, Walker. The total represents all rate schedules, not just the ones presented in Table 4 above.

Q. Does your testimony present the revenue and rate changes applicable to all other rate schedules as well?

A. Yes. NW Natural/1603, Wyman shows the revenue increases and average bill impacts by rate schedule for the revenue requirement effects and for the combined rate components shown in Table 3 and Table 4 above. NW Natural/1604, Wyman contains the volumetric rate increases by rate schedule and block.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibits of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBITS 1601-1604

December 30, 2024

EXHIBITS 1601-1604 – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1601

December 30, 2024

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Long-Run Incremental Cost Study
Summary of Results
Exhibit NW Natural/1601, Wyman

Line No.			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
		CUSTOMER CLASS	Residential	Commercial	Industrial	Commercial	Commercial	Commercial	Industrial	Industrial	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial				
		SERVICE TYPE	Sales	Sales	Sales	Sales	Sales	Transportation	Sales	Transportation	Sales	Sales	Transportation	Transportation	Sales	Sales	Transportation	Transportation	Transportation	
			Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Firm	Interruptible	Interruptible	Interruptible	Interruptible		Special
		RATE SCHEDULE -->	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI	33T	Contracts
	STATISTICS	**Totals**																		
1	TY ANNUAL THERM DELIVERIES *(excl. special contract)*	1,047,487,551	416,418,766	196,563,124	5,220,344	923,707	23,738,500	2,476,657	10,630,853	224,344	49,658,607	22,726,355	5,956,362	90,250,845	23,405,629	28,706,209	7,072,948	163,514,304	0	73,792,136
2	TY AVG CUSTOMERS - END OF PERIOD	707,262	643,664	59,713	335	1,735	656	58	173	6	537	87	28	102	39	53	3	73	0	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER	1,481	647	3,292	15,583	532	36,187	42,701	61,450	37,391	92,474	261,222	212,727	884,812	600,144	541,627	2,357,649	2,239,922	0	10,541,734
	AVERAGE WINTER SALES	121,568,519	55,335,955	25,047,154	494,194	135,487	3,003,437	309,206	1,017,386	19,723	5,786,493	2,172,531	642,085	8,360,074	2,400,598	2,580,699	674,703	13,588,796	0	
	AVERAGE SUMMER SALES	52,781,669	14,162,936	7,787,898	307,831	16,722	927,941	102,320	767,675	18,145	2,444,798	1,638,213	346,106	6,612,176	1,457,774	2,136,751	496,910	13,557,476	0	
4	ESTIMATED DESIGN DAY LOAD FACTOR	28.7%	21.6%	23.8%	36.6%	20.8%	30.0%	42.1%	46.5%	33.6%	36.7%	66.1%	50.6%	59.8%	52.7%	63.2%	56.7%	53.3%	0.0%	
	4a Average Daily Deliveries	2,869,829	1,140,873	538,529	14,302	2,531	65,037	6,785	29,126	615	136,051	62,264	16,319	247,263	64,125	78,647	19,378	447,984	0	
	4b Peak Day Deliveries	9,935,559	5,293,852	2,261,656	39,101	12,190	216,568	16,104	62,678	1,831	370,494	94,158	32,229	413,305	121,748	124,411	34,193	841,038	0	
	LRIC Cost Allocation Factors - Capital Cost Indirect Allocators																			
5	Distribution Main Design Day Peak & Average	100.00%	53.19%	23.27%	0.46%	0.12%	2.37%	0.20%	0.80%	0.02%	4.32%	1.39%	0.42%	5.84%	0.81%	0.90%	0.24%	5.65%	0.00%	0.00%
6	System Core Mains	100.00%	52.34%	22.80%	0.44%	0.12%	2.30%	0.19%	0.75%	0.02%	4.15%	1.29%	0.40%	5.45%	1.04%	1.18%	0.58%	6.96%	0.00%	0.00%
7	Capacity Incremental (System Reinforcement)	100.00%	51.23%	24.18%	0.64%	0.00%	0.00%	0.00%	0.00%	0.00%	6.11%	2.80%	0.73%	11.10%	1.44%	1.77%	0.00%	0.00%	0.00%	0.00%
8	Transmission Mains	100.00%	52.25%	23.42%	0.51%	0.08%	1.56%	0.13%	0.52%	0.01%	4.86%	1.83%	0.52%	7.46%	1.10%	1.28%	0.27%	4.20%	0.00%	0.00%
9	Storage Winter Sales / Summer Sales Excess Ratio	100.00%	62.73%	26.30%	0.28%	0.18%	3.16%	0.00%	0.38%	0.00%	5.09%	0.81%	0.00%	0.00%	0.72%	0.34%	0.00%	0.00%	0.00%	0.00%
10	Service Lines	100.00%	80.20%	18.32%	0.24%	0.12%	0.37%	0.04%	0.10%	0.00%	0.34%	0.05%	0.02%	0.08%	0.03%	0.03%	0.00%	0.06%	0.00%	0.00%
11	Meters Average Installed Cost	100.00%	78.85%	16.72%	0.36%	0.21%	0.95%	0.09%	0.32%	0.01%	1.17%	0.28%	0.08%	0.30%	0.15%	0.16%	0.01%	0.33%	0.00%	0.00%
12	Account Service Cost per Customer	100.00%	89.50%	8.38%	0.05%	0.24%	0.66%	0.06%	0.17%	0.01%	0.54%	0.09%	0.03%	0.10%	0.04%	0.05%	0.00%	0.07%	0.00%	0.00%
13	Common Cost (Administrative, General Plant, etc.)	100.00%	75.74%	19.74%	0.32%	0.18%	0.81%	0.09%	0.28%	0.01%	1.08%	0.28%	0.07%	0.56%	0.19%	0.19%	0.03%	0.44%	0.00%	0.00%
	**For all allocation factors, including direct allocators and incremental expense allocators, refer to the "LRIC Allocators" tab.*																			
14	Total Rate Base by Functional Classification																			
	14a Meter Reading & Billing Costs	$28,593,907	$17,988,554	$7,995,224	$93,396	$37,768	$401,158	$34,376	$105,230	$3,241	$649,816	$161,413	$47,230	$481,251	$106,955	$100,756	$23,811	$363,728	$0	$0
	14b Meters & Services Costs	$719,884,795	$452,882,719	$201,289,043	$2,351,341	$950,848	$10,099,629	$865,446	$2,649,286	$81,595	$16,359,877	$4,063,758	$1,189,066	$12,116,064	$2,692,728	$2,536,651	$599,460	$9,157,283	$0	$0
	14c Core Main Costs	$917,457,892	$577,176,831	$256,533,021	$2,996,669	$1,211,809	$12,871,482	$1,102,968	$3,376,385	$103,989	$20,849,862	$5,179,061	$1,515,406	$15,441,330	$3,431,750	$3,232,838	$763,983	$11,670,509	$0	$0
	14d Transmission Costs	$251,717,608	$158,356,664	$70,383,479	$822,179	$332,477	$3,531,474	$302,615	$926,359	$28,531	$5,720,456	$1,420,949	$415,773	$4,236,548	$941,549	$886,975	$209,609	$3,201,970	$0	$0
	14e Gas Storage Costs	$376,068,291	$244,748,862	$108,781,506	$1,270,722	$513,861	$5,458,086	$0	$1,431,739	$0	$8,841,276	$2,196,154	$0	$0	$1,455,216	$1,370,868	$0	$0	$0	$0
15	**Total Rate Base**	$2,293,722,494	$1,451,153,631	$644,982,274	$7,534,306	$3,046,763	$32,361,828	$2,305,405	$8,488,998	$217,357	$52,421,287	$13,021,335	$3,167,475	$32,275,194	$8,628,199	$8,128,088	$1,596,863	$24,393,490	$0	$0
16	**Proposed Rate of Return**	*7.658%*																		
17	**Total Return on Rate Base at 10.4% ROE**	$175,653,269	$111,129,345	$49,392,743	$576,977	$233,321	$2,478,269	$176,548	$650,087	$16,645	$4,014,422	$997,174	$242,565	$2,471,634	$660,747	$622,449	$122,288	$1,868,053	$0	$0
18	**Revenue at Current Rates** *(incl misc rev)*	$1,030,200,353	$634,454,777	$254,696,468	$5,370,888	$1,268,018	$23,119,224	$1,129,431	$8,968,560	$97,130	$41,044,837	$16,009,003	$1,073,885	$7,205,891	$12,816,545	$15,222,405	$551,185	$5,507,172	$0	$1,664,933
	18a Cost of Gas Commodity	$400,075,400	$216,587,736	$102,236,411	$2,715,205	$480,440	$12,346,866	$0	$5,529,319	$0	$25,828,434	$11,820,432	$0	$0	$10,119,423	$12,411,134	$0	$0	$0	$0
	18b O&M and Other Operating Revenue Deductions	$496,327,585	$346,863,747	$111,974,211	$1,997,626	$792,148	$6,936,936	$775,651	$2,299,173	$77,121	$9,607,169	$2,743,310	$585,477	$4,098,672	$1,984,252	$2,198,081	$205,722	$3,188,289	$0	$0
	18c Net Operating Revenues	$133,797,368	$71,003,294	$40,485,846	$658,058	($4,570)	$3,835,422	$353,780	$1,140,068	$20,009	$5,609,234	$1,445,261	$488,408	$3,107,219	$712,870	$613,190	$345,464	$2,318,883	$0	$1,664,933
19	**Incremental Net Operating Revenue Deficiency (Sufficiency)**																			
	19a *Net-to-Gross Revenue Sensitive Factor:*	*141.2%*																		
	19b **Component LRIC Target Increase by Schedule** *(incl. Corporate Activity Tax, credit for special contract revenues)*	$59,375,097	$55,564,596	$11,924,131	($124,772)	$336,330	($1,978,461)	($256,253)	($709,776)	($5,080)	($2,340,848)	($654,183)	($355,545)	($950,844)	($82,882)	$6,203	($321,133)	($676,386)	$0	$0
20	**Margin Revenue at Current Rates** *(incl misc rev)*	$630,124,953	$417,867,041	$152,460,057	$2,655,683	$787,578	$10,772,358	$1,129,431	$3,439,241	$97,130	$15,216,403	$4,188,571	$1,073,885	$7,205,891	$2,697,122	$2,811,271	$551,185	$5,507,172	$0	$1,664,933
21	**LRIC Based Target Margin**	$689,500,049	$473,431,638	$164,384,188	$2,530,911	$1,123,908	$8,793,898	$873,178	$2,729,464	$92,050	$12,875,555	$3,534,388	$718,340	$6,255,047	$2,614,240	$2,817,474	$230,052	$4,830,786	$0	$1,664,933
22	Current Revenue to Proposed Cost *(Includes Cost of Gas)*	0.95	0.92	0.96	1.02	0.79	1.09	1.29	1.09	1.06	1.06	1.04	1.49	1.15	1.01	1.00	2.40	1.14	1.00	1.00
23	Current Margin Revenue to LRIC Based Target Margin	0.91	0.88	0.93	1.05	0.70	1.22	1.29	1.26	1.06	1.18	1.19	1.49	1.15	1.03	1.00	2.40	1.14	1.00	1.00
	23a **Parity Ratio at Present Rates**	1.00	0.97	1.01	1.15	0.77	1.34	1.42	1.38	1.15	1.29	1.30	1.64	1.26	1.13	1.09	2.62	1.25	1.00	1.00
24	Target Increase as Percent of Total Present Revenue	5.8%	8.8%	4.7%	-2.3%	26.5%	-8.6%	-22.7%	-7.9%	-5.2%	-5.7%	-4.1%	-33.1%	-13.2%	-0.6%	0.0%	-58.3%	-12.3%	0.0%	0.0%
	24a Target Increase as Percent of Present Margin Revenue *(less special contract revenue)*	9.4%	13.3%	7.8%	-4.7%	42.7%	-18.4%	-22.7%	-20.6%	-5.2%	-15.4%	-15.6%	-33.1%	-13.2%	-3.1%	0.2%	-58.3%	-12.3%	0.0%	0.0%
25	Proposed Rate Revenue Increase (see: NW Natural/1600, Wyman)	$59,375,097	$41,058,032	$14,548,028	$186,520	$96,731	$651,355	$68,291	$207,955	$6,822	$920,065	$253,263	$64,933	$506,102	$189,431	$197,448	$33,328	$386,793	$0	$0
	25a *Proposed Increase as Percent of Present Margin Revenue*	9.4%	9.8%	9.5%	7.0%	12.3%	6.0%	6.0%	6.0%	7.0%	6.0%	6.0%	6.0%	7.0%	7.0%	7.0%	6.0%	7.0%	0.0%	0.0%
26	**Margin Revenue at Proposed Rates** *(incl misc rev)*	$689,500,049	$458,925,074	$167,008,085	$2,842,204	$884,308	$11,423,713	$1,197,722	$3,647,196	$103,951	$16,136,468	$4,441,835	$1,138,818	$7,711,993	$2,886,553	$3,008,719	$584,513	$5,893,965	$0	$1,664,933
	26a Revenue-to Cost Ratio at Proposed Rates	1.00	0.97	1.02	1.12	0.79	1.30	1.37	1.34	1.13	1.25	1.26	1.59	1.23	1.10	1.07	2.54	1.22	1.00	1.00
	26b Parity Ratio at Proposed Rates	1.00	0.97	1.02	1.12	0.79	1.30	1.37	1.34	1.13	1.25	1.26	1.59	1.23	1.10	1.07	2.54	1.22	1.00	1.00

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1602

December 30, 2024

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

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

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

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

Avg Parity Ratio for schedules above 1.29:	1.57

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1603

December 30, 2024

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Incremental Revenue Requirement Allocation by Rate Schedule:
Combined Revenue Requirement Effects
UG 520 NW Natural Proposed Rates Effective November 1, 2025

UG 520 Revenue Requirement Combined Impacts
Impacts of UG 520 Revenue Requirement items, including the application of the Plant EDIT Amortization Credit with Temporary Adjustments (Meter Modernization)

Line No.	Rate Schedule	Margin Revenue at Present Rates	Total Revenue at Present Rates	Revenue Requirement – Base Rate – Margin Increase ($) (1)	Plant EDIT Credit – Base Rate – Margin Decrease ($) (2)	Total: Rev. Req. Items – Margin Increase ($)	Meter Modernization – Temporary Rate – Revenue Increase ($)	Margin Revenue at New Rates	Total Revenue at New Rates	Combined Revenue Requirement Effects – Margin Revenue Increase (%)	Combined Revenue Requirement Effects – Total Revenue (In)(De)crease (%)	Combined Revenue Requirement Effects – Average Bill (In)(De)crease (%)
		A	B	C	D	F	H	I = A+F	J = B+F+G+H	K	L	M
1	02R	$ 417,867,041	$ 629,818,180	$ 44,186,195	$ (3,127,305)	$ 41,058,890	$ 1,794,765	$ 458,925,932	$ 672,671,835	9.8%	6.8%	6.8%
2	02R - *SF*	$ 373,307,026	$ 561,886,925	$ 39,315,593	$ (2,782,585)	$ 36,533,008	$ 1,596,930	$ 409,840,035	$ 600,016,863	9.8%	6.8%	6.8%
3	02R - *MF*	$ 44,560,015	$ 67,931,255	$ 4,870,602	$ (344,720)	$ 4,525,882	$ 197,835	$ 49,085,897	$ 72,654,972	10.2%	7.0%	7.0%
4	03C	$ 152,460,057	$ 254,696,468	$ 15,656,253	$ (1,108,616)	$ 14,547,637	$ 652,590	$ 167,007,694	$ 269,896,694	9.5%	6.0%	6.3%
5	03I	$ 2,655,683	$ 5,370,888	$ 200,722	$ (14,199)	$ 186,523	$ 11,119	$ 2,842,206	$ 5,568,530	7.0%	3.7%	3.6%
6	27R	$ 787,578	$ 1,268,018	$ 104,102	$ (7,371)	$ 96,731	$ 3,455	$ 884,309	$ 1,368,203	12.3%	7.9%	8.0%
7	31CSF	$ 10,772,358	$ 23,119,224	$ 700,993	$ (49,695)	$ 651,298	$ 44,689	$ 11,423,656	$ 23,815,211	6.0%	3.0%	3.5%
8	31CTF	$ 1,129,431	$ 1,129,431	$ 73,498	$ (5,201)	$ 68,296	$ 4,682	$ 1,197,727	$ 1,202,410	6.0%	6.5%	6.4%
9	31ISF	$ 3,439,241	$ 8,968,560	$ 223,790	$ (15,853)	$ 207,937	$ 14,224	$ 3,647,177	$ 9,190,721	6.0%	2.5%	2.7%
10	31ITF	$ 97,130	$ 97,130	$ 7,342	$ (519)	$ 6,822	$ 406	$ 103,952	$ 104,358	7.0%	7.4%	7.4%
11	32CSF	$ 15,216,403	$ 41,044,837	$ 990,107	$ (69,974)	$ 920,133	$ 62,910	$ 16,136,536	$ 42,027,879	6.0%	2.4%	2.8%
12	32ISF	$ 4,188,571	$ 16,009,003	$ 272,532	$ (19,278)	$ 253,255	$ 17,291	$ 4,441,826	$ 16,279,549	6.0%	1.7%	2.2%
13	32CTF	$ 1,073,885	$ 1,073,885	$ 69,893	$ (4,936)	$ 64,957	$ 4,442	$ 1,138,842	$ 1,143,284	6.0%	6.5%	7.2%
14	32ITF	$ 7,205,891	$ 7,205,891	$ 544,583	$ (38,560)	$ 506,023	$ 30,054	$ 7,711,915	$ 7,741,968	7.0%	7.4%	8.8%
15	32CSI	$ 2,697,122	$ 12,816,545	$ 203,911	$ (14,442)	$ 189,469	$ 11,284	$ 2,886,591	$ 13,017,299	7.0%	1.6%	2.2%
16	32ISI	$ 2,811,271	$ 15,222,405	$ 212,470	$ (15,009)	$ 197,462	$ 11,727	$ 3,008,732	$ 15,431,593	7.0%	1.4%	1.6%
17	32CTI	$ 551,185	$ 551,185	$ 35,852	$ (2,551)	$ 33,302	$ 2,293	$ 584,487	$ 586,780	6.0%	6.5%	6.4%
18	32ITI	$ 5,507,172	$ 5,507,172	$ 416,630	$ (29,706)	$ 386,924	$ 22,840	$ 5,894,096	$ 5,916,935	7.0%	7.4%	8.0%
19	33T	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0.0%	0.0%	0.0%
	Total (3)	**$ 628,460,019**	**$ 1,023,898,822** (4)	**$ 63,898,874** (5)	**$ (4,523,215)** (5)	**$ 59,375,658** (5)	**$ 2,688,772**	**$ 687,835,678**	**$ 1,085,963,252** (4)	**9.4%**	**5.8%**	(6)

NOTE **(1):** Revenue Requirement spread based on the Company's proposal described in Testimony NW Natural/1600, Wyman.
NOTE **(2):** Plant excess deferred income taxes (EDIT) amortization credit spread to all rate schedules based on the revenue requirement rate spread noted above.
NOTE **(3):** 02R indicates the entire Residential rate class. Below it are the two Residential sub-classes that make-up the class-wide total. They are as follow:
(1) 02R - SF: Residential Single-Family; and (2) 02R - MF : Residential Multi-Family.
NOTE **(4):** Total Revenues only includes margin (with miscellaneous revenues) and gas costs. It excludes temporaries associated with PGA filings. Therefore, for RS 31 and RS 32 rate classes, it is possible for margin revenues to exceed total revenues for new rates when rate case and PGA effects are combined.
NOTE **(5):** The margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement.
NOTE **(6)**: The average customer bill percentage impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 rate classes, and thus the bill rate impacts for these schedules are overstated. In addition to the revenue requirement items, average bill increase or decrease can be impacted by changes in expected use per customer between current and new rates.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 520

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST,
LONG-RUN INCREMENTAL COSTS,
AND RATE DESIGN/SPREAD
EXHIBIT 1604

December 30, 2024

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2026
Proposed UG 520 Base and Total Billing Rates by Rate Schedule and Block - Combined Effects
with Calculation of Effect on Customer Average Bill by Rate Schedule [1]
UG 520 NW Natural Proposed Rates Effective November 1, 2025

						Current Tariff	UG 520	Current Tariff Rate 11/1/2024	11/1/2024	11/1/2024	11/1/2024	11/1/2024	Current Tariff Rate 11/1/2024
Line No.	Schedule	Block	Block Volumes	Test Year Volumes	Test Year Customers	Current Monthly Base Charge	Proposed Monthly Base Charge	Current Rates: Base Rate	Current Rates: Base Rate Adjustment	Current Rates: Pipeline Capacity	Current Rates: Commodity	Current Rates: Temporary Adjustment	Current Billing Rates
	A	B	C	D	E	F	G	H	I	J	K	L	M
1	02R - *SF*		N/A	370,517,326	572,489	$ 10.00	$ 10.00	$0.80043	$0.00815	$0.10274	$0.43366	($0.01390)	$ 1.33108
2	02R - *MF*		N/A	45,901,440	71,175	$ 8.00	$ 8.00	$0.80043	$0.00815	$0.10274	$0.43366	($0.01390)	$ 1.33108
3	3C Firm Sales		N/A	196,563,124	59,713	$ 15.00	$ 15.00	$0.70009	$0.00815	$0.10274	$0.43366	($0.06288)	$ 1.18176
4	3I Firm Sales		N/A	5,220,344	335	$ 15.00	$ 15.00	$0.47523	$0.00815	$0.10274	$0.43366	$0.03439	$ 1.05417
5	27 Dry Out		N/A	923,707	1,735	$ 8.00	$ 8.00	$0.65119	$0.00815	$0.10274	$0.43366	($0.01906)	$ 1.17668
6	31C Firm Sales	Block 1	2,000	12,922,520	656	$ 325.00	$ 325.00	$0.33788	$0.00815	$0.00000	$0.43366	($0.03470)	$ 0.74499
7		Block 2	all additional	10,815,980				$0.30828	$0.00815	$0.00000	$0.43366	($0.03542)	$ 0.71467
8	31C Firm Transpt	Block 1	2,000	1,174,463	58	$ 575.00	$ 575.00	$0.30572	($0.00236)	$0.00000	$0.00000	$0.01154	$ 0.31490
9		Block 2	all additional	1,302,194				$0.27950	($0.00236)	$0.00000	$0.00000	$0.01067	$ 0.28781
10	31I Firm Sales	Block 1	2,000	3,404,637	173	$ 325.00	$ 325.00	$0.25629	$0.00815	$0.00000	$0.43366	$0.03140	$ 0.72950
11		Block 2	all additional	7,226,216				$0.23105	$0.00815	$0.00000	$0.43366	$0.03079	$ 0.70365
12	31I Firm Transpt	Block 1	2,000	89,044	6	$ 575.00	$ 575.00	$0.26118	($0.00236)	$0.00000	$0.00000	$0.00948	$ 0.26830
13		Block 2	all additional	135,301				$0.23606	($0.00236)	$0.00000	$0.00000	$0.00873	$ 0.24243
14	32C Firm Sales	Block 1	10,000	36,986,116	537	$ 675.00	$ 675.00	$0.18086	$0.00815	$0.00000	$0.43366	$0.03026	$ 0.65293
15		Block 2	20,000	10,403,619				$0.15268	$0.00815	$0.00000	$0.43366	$0.02947	$ 0.62396
16		Block 3	20,000	1,696,756				$0.10587	$0.00815	$0.00000	$0.43366	$0.02811	$ 0.57579
17		Block 4	100,000	572,115				$0.05889	$0.00815	$0.00000	$0.43366	$0.02675	$ 0.52745
18		Block 5	600,000	-				$0.02514	$0.00815	$0.00000	$0.43366	$0.02578	$ 0.49273
19		Block 6	all additional	-				$0.00914	$0.00815	$0.00000	$0.43366	$0.02531	$ 0.47626
20	32I Firm Sales	Block 1	10,000	8,740,856	87	$ 675.00	$ 675.00	$0.13366	$0.00815	$0.00000	$0.43366	$0.02798	$ 0.60345
21		Block 2	20,000	7,884,629				$0.11285	$0.00815	$0.00000	$0.43366	$0.02757	$ 0.58223
22		Block 3	20,000	2,734,034				$0.07806	$0.00815	$0.00000	$0.43366	$0.02688	$ 0.54675
23		Block 4	100,000	3,005,989				$0.04339	$0.00815	$0.00000	$0.43366	$0.02621	$ 0.51141
24		Block 5	600,000	360,845				$0.01918	$0.00815	$0.00000	$0.43366	$0.02573	$ 0.48672
25		Block 6	all additional	-				$0.00699	$0.00815	$0.00000	$0.43366	$0.02549	$ 0.47429
26	32C Firm Transpt	Block 1	10,000	2,582,927	28	$ 925.00	$ 925.00	$0.13867	($0.00236)	$0.00000	$0.00000	$0.00506	$ 0.14137
27		Block 2	20,000	1,913,154				$0.11783	($0.00236)	$0.00000	$0.00000	$0.00451	$ 0.11998
28		Block 3	20,000	658,765				$0.08320	($0.00236)	$0.00000	$0.00000	$0.00358	$ 0.08442
29		Block 4	100,000	801,516				$0.04854	($0.00236)	$0.00000	$0.00000	$0.00265	$ 0.04883
30		Block 5	600,000	-				$0.02771	($0.00236)	$0.00000	$0.00000	$0.00210	$ 0.02745
31		Block 6	all additional	-				$0.01390	($0.00236)	$0.00000	$0.00000	$0.00173	$ 0.01327
32	32I Firm Transpt	Block 1	10,000	9,097,654	102	$ 925.00	$ 925.00	$0.13081	($0.00236)	$0.00000	$0.00000	$0.00469	$ 0.13314
33		Block 2	20,000	13,826,375				$0.11118	($0.00236)	$0.00000	$0.00000	$0.00426	$ 0.11308
34		Block 3	20,000	9,323,568				$0.07849	($0.00236)	$0.00000	$0.00000	$0.00351	$ 0.07964
35		Block 4	100,000	20,536,589				$0.04581	($0.00236)	$0.00000	$0.00000	$0.00277	$ 0.04622
36		Block 5	600,000	25,117,468				$0.02614	($0.00236)	$0.00000	$0.00000	$0.00231	$ 0.02609
37		Block 6	all additional	12,349,190				$0.01313	($0.00236)	$0.00000	$0.00000	$0.00202	$ 0.01279
38	32C Interr Sales	Block 1	10,000	3,807,355	53	$ 675.00	$ 675.00	$0.14834	$0.00815	$0.00000	$0.43366	$0.02823	$ 0.61838
39		Block 2	20,000	4,921,696				$0.12525	$0.00815	$0.00000	$0.43366	$0.02766	$ 0.59472
40		Block 3	20,000	2,923,629				$0.08669	$0.00815	$0.00000	$0.43366	$0.02671	$ 0.55521
41		Block 4	100,000	6,581,522				$0.04812	$0.00815	$0.00000	$0.43366	$0.02575	$ 0.51568
42		Block 5	600,000	5,171,428				$0.02499	$0.00815	$0.00000	$0.43366	$0.02518	$ 0.49198
43		Block 6	all additional	-				$0.00807	$0.00815	$0.00000	$0.43366	$0.02477	$ 0.47465
44	32I Interr Sales	Block 1	10,000	4,626,759	39	$ 675.00	$ 675.00	$0.12919	$0.00815	$0.00000	$0.43366	$0.02796	$ 0.59896
45		Block 2	20,000	6,189,698				$0.10905	$0.00815	$0.00000	$0.43366	$0.02749	$ 0.57835
46		Block 3	20,000	3,482,963				$0.07549	$0.00815	$0.00000	$0.43366	$0.02670	$ 0.54400
47		Block 4	100,000	8,653,753				$0.04190	$0.00815	$0.00000	$0.43366	$0.02591	$ 0.50962
48		Block 5	600,000	5,753,036				$0.02174	$0.00815	$0.00000	$0.43366	$0.02544	$ 0.48899
49		Block 6	all additional	-				$0.00699	$0.00815	$0.00000	$0.43366	$0.02509	$ 0.47389
50	32C Interr Transpt	Block 1	10,000	1,057,554	3	$ 925.00	$ 925.00	$0.12687	($0.00236)	$0.00000	$0.00000	$0.00387	$ 0.12838
51		Block 2	20,000	1,508,006				$0.10784	($0.00236)	$0.00000	$0.00000	$0.00347	$ 0.10895
52		Block 3	20,000	883,383				$0.07614	($0.00236)	$0.00000	$0.00000	$0.00283	$ 0.07661
53		Block 4	100,000	3,092,303				$0.04440	($0.00236)	$0.00000	$0.00000	$0.00221	$ 0.04425
54		Block 5	600,000	531,701				$0.02539	($0.00236)	$0.00000	$0.00000	$0.00183	$ 0.02486
55		Block 6	all additional	-				$0.01273	($0.00236)	$0.00000	$0.00000	$0.00157	$ 0.01194
56	32I Interr Transpt	Block 1	10,000	4,966,401	73	$ 925.00	$ 925.00	$0.12471	($0.00236)	$0.00000	$0.00000	$0.00443	$ 0.12678
57		Block 2	20,000	8,229,093				$0.10600	($0.00236)	$0.00000	$0.00000	$0.00401	$ 0.10765
58		Block 3	20,000	6,135,971				$0.07485	($0.00236)	$0.00000	$0.00000	$0.00334	$ 0.07583
59		Block 4	100,000	17,243,649				$0.04365	($0.00236)	$0.00000	$0.00000	$0.00266	$ 0.04395
60		Block 5	600,000	30,016,183				$0.02497	($0.00236)	$0.00000	$0.00000	$0.00225	$ 0.02486
61		Block 6	all additional	96,923,006				$0.01252	($0.00236)	$0.00000	$0.00000	$0.00197	$ 0.01213
62	33		N/A	-	-	$ 38,250.00	$ 38,250.00	$0.00574	($0.00236)	$0.00000	$0.00000	$0.00127	$ 0.00465

	Includes Plant EDIT GRC BASE $59,375.1 Revenue Requirement		GRC TEMPS $2,687.1		UG 520 BILLING RATE	Proposed UG 520 and 2024-25 PGA Combined Effects						11/01/2024	UG 520+PGA 11/01/2025	UG 520+PGA 11/01/2025	UG 520+PGA 11/01/2025
Line No.	Proposed Increase: Base Rates	Proposed Base Rate	Proposed Increase: Temporary Rate Adjustment	Proposed Temporary Rate	Proposed Billing Rate	Base Rate	Base Rate Adjustment	Pipeline Capacity Rate (Demand)	Commodity Rate (WACOG)	Temporary Adjustment	Final Tariff Rate Effective: 11/01/25	Current Average Bill [2]	Proposed Average Bill [2]	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
	N	O=H+N	P	Q=P	R=I+J+K+L+O+Q	S	T	U	V	W	X	Y	Z	AA	AB
1	$0.09860	**$0.89903**	$0.00431	**$0.00431**	**$1.43399**	$0.89903	$0.00815	$0.10274	$0.43366	($0.00959)	$1.43399	$81.79	$87.34	$5.55	6.8%
2	$0.09860	**$0.89903**	$0.00431	**$0.00431**	**$1.43399**	$0.89903	$0.00815	$0.10274	$0.43366	($0.00959)	$1.43399	$79.79	$85.34	$5.55	7.0%
3	$0.07401	**$0.77410**	$0.00332	**$0.00332**	**$1.25909**	$0.77410	$0.00815	$0.10274	$0.43366	($0.05956)	$1.25909	$339.18	$360.39	$21.21	6.3%
4	$0.03573	**$0.51096**	$0.00213	**$0.00213**	**$1.09203**	$0.51096	$0.00815	$0.10274	$0.43366	$0.03652	$1.09203	$1,383.94	$1,433.10	$49.16	3.6%
5	$0.10472	**$0.75591**	$0.00374	**$0.00374**	**$1.28514**	$0.75591	$0.00815	$0.10274	$0.43366	($0.01532)	$1.28514	$60.20	$65.02	$4.82	8.0%
6	$0.02858	**$0.36646**	$0.00196	**$0.00196**	**$0.77553**	$0.36646	$0.00815	$0.00000	$0.43366	($0.03274)	$0.77553				
7	$0.02607	**$0.33435**	$0.00179	**$0.00179**	**$0.74253**	$0.33435	$0.00815	$0.00000	$0.43366	($0.03363)	$0.74253	$2,541.08	$2,630.47	$89.39	3.5%
8	$0.02888	**$0.33460**	$0.00198	**$0.00198**	**$0.34576**	$0.33460	($0.00236)	$0.00000	$0.00000	$0.01352	$0.34576				
9	$0.02640	**$0.30590**	$0.00181	**$0.00181**	**$0.31602**	$0.30590	($0.00236)	$0.00000	$0.00000	$0.01248	$0.31602	$1,653.21	$1,758.88	$105.67	6.4%
10	$0.02096	**$0.27725**	$0.00144	**$0.00144**	**$0.75190**	$0.27725	$0.00815	$0.00000	$0.43366	$0.03284	$0.75190				
11	$0.01890	**$0.24995**	$0.00129	**$0.00129**	**$0.72384**	$0.24995	$0.00815	$0.00000	$0.43366	$0.03208	$0.72384	$3,980.09	$4,087.90	$107.81	2.7%
12	$0.03228	**$0.29346**	$0.00192	**$0.00192**	**$0.30250**	$0.29346	($0.00236)	$0.00000	$0.00000	$0.01140	$0.30250				
13	$0.02918	**$0.26524**	$0.00174	**$0.00174**	**$0.27335**	$0.26524	($0.00236)	$0.00000	$0.00000	$0.01047	$0.27335	$1,382.15	$1,485.06	$102.91	7.4%
14	$0.01960	**$0.20046**	$0.00134	**$0.00134**	**$0.67387**	$0.20046	$0.00815	$0.00000	$0.43366	$0.03160	$0.67387				
15	$0.01654	**$0.16922**	$0.00113	**$0.00113**	**$0.64163**	$0.16922	$0.00815	$0.00000	$0.43366	$0.03060	$0.64163				
16	$0.01148	**$0.11735**	$0.00079	**$0.00079**	**$0.58806**	$0.11735	$0.00815	$0.00000	$0.43366	$0.02890	$0.58806				
17	$0.00638	**$0.06527**	$0.00044	**$0.00044**	**$0.53427**	$0.06527	$0.00815	$0.00000	$0.43366	$0.02719	$0.53427				
18	$0.00272	**$0.02786**	$0.00019	**$0.00019**	**$0.49564**	$0.02786	$0.00815	$0.00000	$0.43366	$0.02597	$0.49564				
19	$0.00099	**$0.01013**	$0.00007	**$0.00007**	**$0.47732**	$0.01013	$0.00815	$0.00000	$0.43366	$0.02538	$0.47732	$5,706.48	$5,867.84	$161.36	2.8%
20	$0.01405	**$0.14771**	$0.00096	**$0.00096**	**$0.61846**	$0.14771	$0.00815	$0.00000	$0.43366	$0.02894	$0.61846				
21	$0.01187	**$0.12472**	$0.00081	**$0.00081**	**$0.59491**	$0.12472	$0.00815	$0.00000	$0.43366	$0.02838	$0.59491				
22	$0.00820	**$0.08626**	$0.00056	**$0.00056**	**$0.55551**	$0.08626	$0.00815	$0.00000	$0.43366	$0.02744	$0.55551				
23	$0.00456	**$0.04795**	$0.00031	**$0.00031**	**$0.51628**	$0.04795	$0.00815	$0.00000	$0.43366	$0.02652	$0.51628				
24	$0.00202	**$0.02120**	$0.00014	**$0.00014**	**$0.48888**	$0.02120	$0.00815	$0.00000	$0.43366	$0.02587	$0.48888				
25	$0.00073	**$0.00772**	$0.00005	**$0.00005**	**$0.47507**	$0.00772	$0.00815	$0.00000	$0.43366	$0.02554	$0.47507	$13,561.76	$13,861.10	$299.34	2.2%
26	$0.01330	**$0.15197**	$0.00091	**$0.00091**	**$0.15558**	$0.15197	($0.00236)	$0.00000	$0.00000	$0.00597	$0.15558				
27	$0.01130	**$0.12913**	$0.00077	**$0.00077**	**$0.13205**	$0.12913	($0.00236)	$0.00000	$0.00000	$0.00528	$0.13205				
28	$0.00797	**$0.09117**	$0.00055	**$0.00055**	**$0.09294**	$0.09117	($0.00236)	$0.00000	$0.00000	$0.00413	$0.09294				
29	$0.00466	**$0.05320**	$0.00032	**$0.00032**	**$0.05381**	$0.05320	($0.00236)	$0.00000	$0.00000	$0.00297	$0.05381				
30	$0.00266	**$0.03037**	$0.00018	**$0.00018**	**$0.03029**	$0.03037	($0.00236)	$0.00000	$0.00000	$0.00228	$0.03029				
31	$0.00133	**$0.01523**	$0.00009	**$0.00009**	**$0.01469**	$0.01523	($0.00236)	$0.00000	$0.00000	$0.00182	$0.01469	$3,265.79	$3,501.15	$235.36	7.2%
32	$0.01268	**$0.14349**	$0.00076	**$0.00076**	**$0.14658**	$0.14349	($0.00236)	$0.00000	$0.00000	$0.00545	$0.14658				
33	$0.01078	**$0.12196**	$0.00064	**$0.00064**	**$0.12450**	$0.12196	($0.00236)	$0.00000	$0.00000	$0.00490	$0.12450				
34	$0.00761	**$0.08610**	$0.00045	**$0.00045**	**$0.08770**	$0.08610	($0.00236)	$0.00000	$0.00000	$0.00396	$0.08770				
35	$0.00444	**$0.05025**	$0.00026	**$0.00026**	**$0.05092**	$0.05025	($0.00236)	$0.00000	$0.00000	$0.00303	$0.05092				
36	$0.00254	**$0.02868**	$0.00015	**$0.00015**	**$0.02878**	$0.02868	($0.00236)	$0.00000	$0.00000	$0.00246	$0.02878				
37	$0.00127	**$0.01440**	$0.00008	**$0.00008**	**$0.01414**	$0.01440	($0.00236)	$0.00000	$0.00000	$0.00210	$0.01414	$7,207.79	$7,843.34	$635.55	8.8%
38	$0.01494	**$0.16328**	$0.00089	**$0.00089**	**$0.63421**	$0.16328	$0.00815	$0.00000	$0.43366	$0.02912	$0.63421				
39	$0.01262	**$0.13787**	$0.00075	**$0.00075**	**$0.60809**	$0.13787	$0.00815	$0.00000	$0.43366	$0.02841	$0.60809				
40	$0.00873	**$0.09542**	$0.00052	**$0.00052**	**$0.56446**	$0.09542	$0.00815	$0.00000	$0.43366	$0.02723	$0.56446				
41	$0.00485	**$0.05297**	$0.00029	**$0.00029**	**$0.52082**	$0.05297	$0.00815	$0.00000	$0.43366	$0.02604	$0.52082				
42	$0.00252	**$0.02751**	$0.00015	**$0.00015**	**$0.49465**	$0.02751	$0.00815	$0.00000	$0.43366	$0.02533	$0.49465				
43	$0.00081	**$0.00888**	$0.00005	**$0.00005**	**$0.47551**	$0.00888	$0.00815	$0.00000	$0.43366	$0.02482	$0.47551	$22,529.18	$23,017.79	$488.61	2.2%
44	$0.01261	**$0.14180**	$0.00075	**$0.00075**	**$0.61232**	$0.14180	$0.00815	$0.00000	$0.43366	$0.02871	$0.61232				
45	$0.01064	**$0.11969**	$0.00063	**$0.00063**	**$0.58962**	$0.11969	$0.00815	$0.00000	$0.43366	$0.02812	$0.58962				
46	$0.00737	**$0.08286**	$0.00044	**$0.00044**	**$0.55181**	$0.08286	$0.00815	$0.00000	$0.43366	$0.02714	$0.55181				
47	$0.00409	**$0.04599**	$0.00024	**$0.00024**	**$0.51395**	$0.04599	$0.00815	$0.00000	$0.43366	$0.02615	$0.51395				
48	$0.00212	**$0.02386**	$0.00013	**$0.00013**	**$0.49124**	$0.02386	$0.00815	$0.00000	$0.43366	$0.02557	$0.49124				
49	$0.00068	**$0.00767**	$0.00004	**$0.00004**	**$0.47461**	$0.00767	$0.00815	$0.00000	$0.43366	$0.02513	$0.47461	$34,889.67	$35,453.97	$564.30	1.6%
50	$0.00821	**$0.13508**	$0.00056	**$0.00056**	**$0.13715**	$0.13508	($0.00236)	$0.00000	$0.00000	$0.00443	$0.13715				
51	$0.00698	**$0.11482**	$0.00048	**$0.00048**	**$0.11641**	$0.11482	($0.00236)	$0.00000	$0.00000	$0.00395	$0.11641				
52	$0.00492	**$0.08106**	$0.00034	**$0.00034**	**$0.08187**	$0.08106	($0.00236)	$0.00000	$0.00000	$0.00317	$0.08187				
53	$0.00287	**$0.04727**	$0.00020	**$0.00020**	**$0.04732**	$0.04727	($0.00236)	$0.00000	$0.00000	$0.00241	$0.04732				
54	$0.00164	**$0.02703**	$0.00011	**$0.00011**	**$0.02661**	$0.02703	($0.00236)	$0.00000	$0.00000	$0.00194	$0.02661				
55	$0.00083	**$0.01356**	$0.00006	**$0.00006**	**$0.01283**	$0.01356	($0.00236)	$0.00000	$0.00000	$0.00163	$0.01283	$11,577.98	$12,313.88	$735.90	6.4%
56	$0.01033	**$0.13504**	$0.00062	**$0.00062**	**$0.13773**	$0.13504	($0.00236)	$0.00000	$0.00000	$0.00505	$0.13773				
57	$0.00879	**$0.11479**	$0.00052	**$0.00052**	**$0.11696**	$0.11479	($0.00236)	$0.00000	$0.00000	$0.00453	$0.11696				
58	$0.00621	**$0.08106**	$0.00037	**$0.00037**	**$0.08241**	$0.08106	($0.00236)	$0.00000	$0.00000	$0.00371	$0.08241				
59	$0.00361	**$0.04726**	$0.00022	**$0.00022**	**$0.04778**	$0.04726	($0.00236)	$0.00000	$0.00000	$0.00288	$0.04778				
60	$0.00207	**$0.02704**	$0.00012	**$0.00012**	**$0.02705**	$0.02704	($0.00236)	$0.00000	$0.00000	$0.00237	$0.02705				
61	$0.00104	**$0.01356**	$0.00006	**$0.00006**	**$0.01323**	$0.01356	($0.00236)	$0.00000	$0.00000	$0.00203	$0.01323	$11,470.59	$12,387.77	$917.18	8.0%
62	$0.00000	**$0.00574**	$0.00000	**$0.00000**	**$0.00465**	$0.00574	($0.00236)	$0.00000	$0.00000	$0.00127	$0.00465	$38,250.00	$38,250.00	$0.00	0.0%

NOTE: The two Residential sub-classes are as follow: (1) 02R - SF: Residential Single-Family; and (2) 02R - MF : Residential Multi-Family.
[1] Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those rate schedules.
[2] Average bill rate calculated using the UG 520 rate case volumes and customer count.